Unleashing Europe's offshore wind potential

A new resource assessment

June 2017

BVGassociates

Wind
EUROPE

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EXECUTIVE SUMMARY

The offshore wind industry is moving fast from a niche technology to a **mainstream** supplier of low-carbon electricity. There are 12.6 GW of offshore wind operating in Europe. Recent government auction results show that the industry has achieved unprecedented levels of **competitiveness** through rapid progress in technology, industrial growth and a reduction in the cost of capital.

According to WindEurope, **offshore wind is expected to produce 7% to 11% of the EU's electricity demand by 2030**. This is only a fraction of the resource potential available in the European sea basins.

This report prepared for WindEurope by BVG Associates and Geospatial Enterprises, highlights the economically attractive offshore wind resource that is potentially available to Europe in three sea basins (the Baltic, North Sea and Atlantic from France to the north of the UK) in 2030. It then identifies the location of the lowest cost resource.

The **economically attractive resource potential** and location for lowest cost resource are assessed considering two policy scenarios:

- A *baseline scenario* based on current policy frameworks and assumptions about future policy taking into account recent cost reductions;

- An *upside scenario* based on what the industry could deliver if governments respond positively to cost reductions, and if there are positive developments on grid access, market support mechanisms, site development and supply chain development.

KEY FINDINGS

Offshore wind could in theory generate between 2,600 TWh and 6,000 TWh per year at a competitive cost - €65/MWh or below, including grid connection and using the technologies that will have developed by 2030. This economically attractive resource potential would represent between 80% and 180% of the EU's total electricity demand in the baseline and upside scenarios respectively.

In addition, our analysis shows that up to **25% of the EU's electricity demand could, in theory, be met by offshore wind energy at an average of €54/MWh in the most favourable locations**. This assumes seabed-fixed foundations and includes grid connection. In the baseline scenario, this development would take place in the UK, Denmark, the Netherlands, Germany and France. In the upside scenario, capacity would be added in Ireland, Poland, Latvia and Lithuania, spanning all three sea basins and capitalising on the development of floating foundations.

To enable the exploitation of the most cost-effective areas and achieve at least WindEurope's expectation of 7% to 11% of the EU's electricity demand by 2030, we call governments to:

- Commit to **ambitious deployment for offshore wind to 2030 and beyond** as part of national energy, climate and economic development plans.

- Cooperate at inter-governmental level and with developers and suppliers to **provide a continuous, sufficient and visible pipeline of projects** that enables industry to deliver further investments in technology, skills development, job creation and cost reduction throughout the supply chain.

- **Coordinate the timeline of tenders** across all the sea basins to provide greater investment clarity.

- **Cooperate in spatial planning analyses and site development** to ensure that the areas of lowest levelised cost of energy (LCOE) are exploited whilst providing power to all the locations where it is needed.

- Facilitate the **development of international grid infrastructure** including offshore grid connection hubs to support the exploitation of the lowest LCOE resource.

- **Offer market support mechanisms in a format that drives competition** and supports successful project delivery, until the point that they are no longer needed.

Economically attractive resource potential at the end of 2030

% of total EU electricity demand in 2030

200%	
180%	
100%	
80%	
25%	

Baseline scenario
- At €65/MWh and below
- At average €54/MWh

Upside scenario
- At €65/MWh and below
- At average €51/MWh
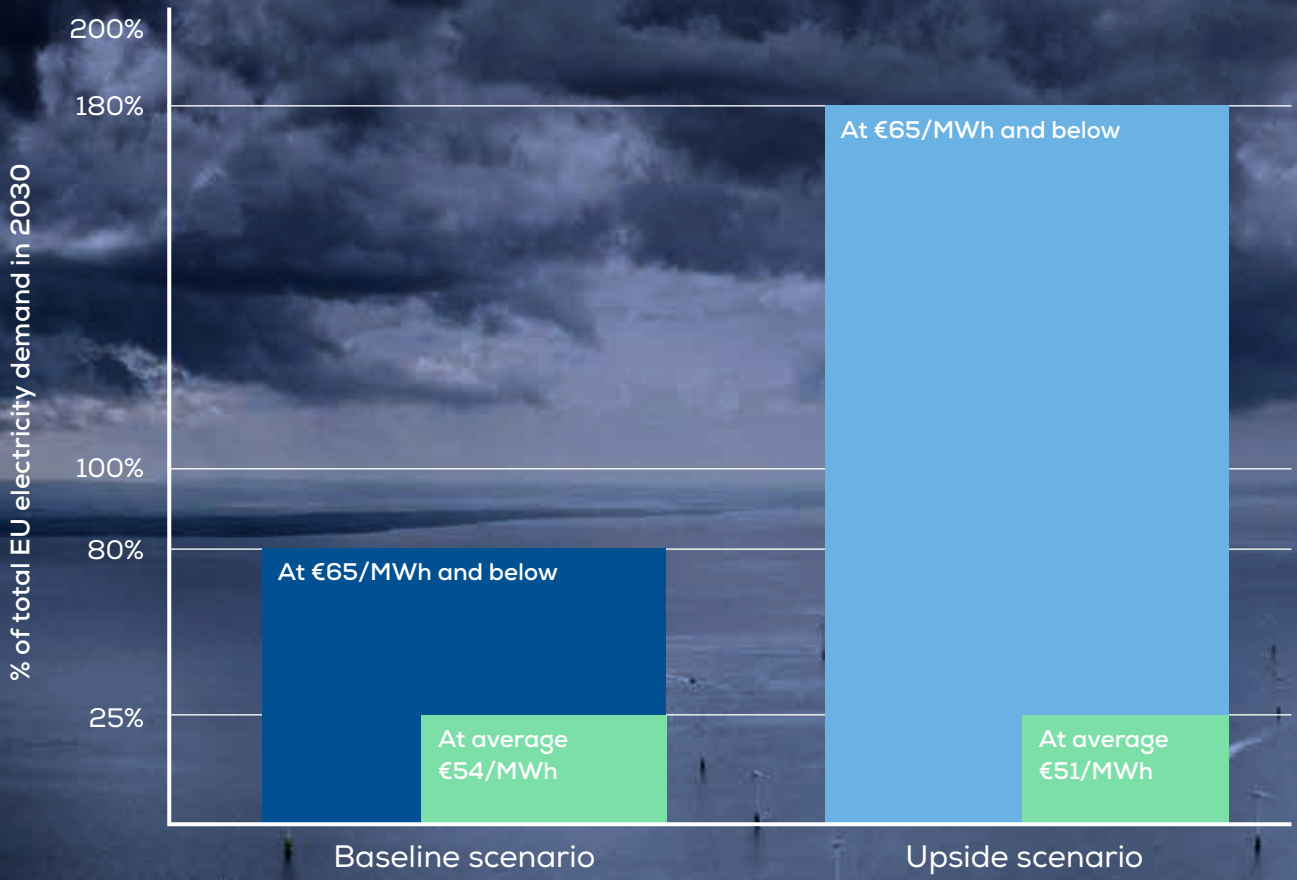
1.
INTRODUCTION

This report, prepared by BVG Associates (BVGA) and Geospatial Enterprises (GeoSE) for WindEurope:

- Derives the economically attractive offshore wind resource available to Europe in three defined sea basins (the Baltic, North Sea, and Atlantic from France to the north of the UK) at the end of 2030 in two policy scenarios:

  - A baseline scenario based on current policy frameworks and assumptions about future policy taking into account recent levels of costs achieved, and

  - An upside scenario based on what the industry could do with positive government responses to costs reduction and by overcoming barriers to deployment including grid access, funding support, site development and supply chain development.

- Identifies the location of the lowest cost resources, and

- Makes policy recommendations based on this analysis.

In using levelised cost of energy (LCOE) as a key determinant of economically attractive potential, we have included the cost of connecting to a suitable grid connection point, taking into account that some of these may be provided offshore. The LCOE calculation does not include social costs, such as those of dealing with the variability of wind power and transmission of power to locations of demand. Likewise, it does not consider the benefits, such as to the environment or in terms of local value creation or energy security.

This report has eight main sections and Appendices for supporting data.

In Section 2, we set out the approach to the study in terms of sea basins analysed, geospatial methodology and how we calculate gross, technical and economically attractive potential.

In Section 3, we set out the two scenarios, considering policy, technology and deployment from the start of 2017 to the end of 2030, and discuss the LCOE achievable in 2030 in the two scenarios. Section 3 is supported by Box 1, where we discuss the cost reduction achieved to date and the future trajectory for offshore wind cost, and Box 2 where we discuss the cost to consumers of the two scenarios.

In Section 4, we look geospatially across the sea basins considered, firstly establishing gross resource potential, and then the technical (or constrained) resource potential, excluding areas because of other uses such as shipping and conservation. Box 3 describes how we have defined competitive energy cost.

In Section 5, we derive the economically attractive resource potential. We present on maps and in charts how much resource is available at competitive cost and where it is located.

In Section 6, we explore the sensitivity of the economically attractive resource potential to future electricity price uncertainty.

In Section 7, by comparing the economically attractive potential at the end of 2030 with the expected capacity deployed, the policy scenarios, and the share of the energy mix that offshore wind could supply, we derive conclusions and present policy recommendations.

In Section 8, we provide background on the report's authors, BVGA and GeoSE.

In Appendix A, we define LCOE and our assumptions regarding costs and energy production.

In Appendix B, we compare LCOE in 2030 at a typical site.

In Appendix C, we list the geospatial data sources used and describe the geospatial methodology in more detail.

In Appendix D, we show the locations of ports and grid connection hubs used, and the distance from ports to each potential wind farm location.

In Appendix E, we provide a glossary of key terms used.

2.
APPROACH

2.1. SEA BASINS

In this study we focus on three key sea basins and the exclusive economic zones (EEZs) of EU member states shown in Figure 1. The study was restricted to these areas because these are the main areas in which WindEurope expects EU member states to deploy offshore wind. Despite giving notice to leave the EU, the UK is still included in this analysis as a current member state with significant offshore wind power interests. The sea basins we analysed are:

North Sea (excluding Norwegian EEZ)

The North Sea is the main area of offshore wind development and has good wind speeds across most of the area, shallow water in the southern part and at Dogger Bank, and deeper waters to the North. Distances to shore are up to 200km.

Baltic Sea (excluding Russian EEZ)

The Baltic has lower wind speeds than most parts of the North Sea, shallower water depths, less extreme sea states, and shorter distances to shore.

Atlantic Ocean (French, Irish and UK EEZs only)

The Atlantic has generally high wind speeds, deeper waters, more extreme sea states, and some long distances to established ports.

FIGURE 1
Sea basins and EEZs assessed

Atlantic
Baltic
North Sea

Source: GeoSE for WindEurope

2.2. GEOSPATIAL DATA SOURCES AND METHODOLOGY

To understand the spatial distribution of offshore wind energy resource potential across the sea basins considered, we compiled a database of spatial parameters for reference by a geographic information system (GIS). We used a wide variety of sources to populate the database and defined the geospatial methodology as shown in Appendix C.

2.3. GROSS POTENTIAL

The gross potential capacity of offshore wind is the number of GW of offshore wind that result from filling the entire analysis area with turbines, ignoring any restrictions, and ignoring existing wind farms. The gross resource potential is the gross energy production, in TWh per year that those turbines would theoretically produce, excluding losses.

We first calculated the gross potential offshore wind capacity in GW. We considered the area from the limits of the EEZs to 5nm from the shore, on the basis that few or no wind farms are likely to be built closer to the shore than this. We applied a wind farm density of 5.36 MW/km^2 to this area, which resulted in the same baseline and upside gross potential capacity in GW for both scenarios. We derived this density from our wind turbine specific rating assumption of 368 W/m^2 and the spacing assumption of six rotor diameters across the prevailing wind direction and nine rotor diameters in the prevailing direction as detailed in Appendix A.

For the turbine technology expected in the baseline scenario, we calculated the relationship between mean annual wind speed and gross annual energy production. Using the mean annual wind speed in each 5x5km cell, we calculated the gross resource potential in TWh. We used the same procedure for the upside scenario.

2.4. TECHNICAL POTENTIAL

The technical potential capacity of offshore wind is the number of GW of offshore wind that result from filling the analysis area with turbines, while avoiding excluded areas and areas not technically feasible for offshore wind, and after allowing for density reductions that enable wind speed recovery between wind farms and other uses. The technical resource potential is the energy production, in TWh per year that those turbines would deliver to the offshore substation of a wind farm after allowing for losses. We do not consider grid constraints on the technical potential, and we include the areas of sea currently used for offshore wind.

We first calculated the technical potential offshore wind capacity in GW. We started with the area derived in the calculation of gross resource potential then excluded 5x5km cells that overlapped with the following areas:

- Designated shipping lanes

- Environmental protection areas (marine protected areas and special protection areas)

- Areas of dumped munitions

- Areas with average wind speed below 8m/s at 100m above mean sea level (MSL) in the baseline scenario or below 7.5m/s in the upside scenario. We expect that offshore wind technology will not be viable below these wind speeds[1]

- Water more than 1,000m deep in the North Sea and Atlantic, and

- Water more than 70m deep in the whole of the Baltic (baseline) or in the gulfs of Bothnia and Finland (upside), because we do not expect floating foundations will be usable where there is significant sea ice.

Appendix C gives more detail of the sources for these areas of exclusion and Figure 2 shows the locations of the exclusions used.

---

1. Subsequent analysis has concluded that these wind speed exclusions did not impact the economic potential.

FIGURE 2

Exclusions used in the calculation of technical resource potential and capacity

Areas of low mean wind speed
and deep water are not shown for clarity

Shipping Lane
Baltic Sea Ice (Upside)
Baltic Sea Ice (Baseline)
Unexploded Ordnance
Marine Protected Area
Special Protection Area
Special Conservation Interest
Cables & Pipelines

Source: GeoSE for WindEurope
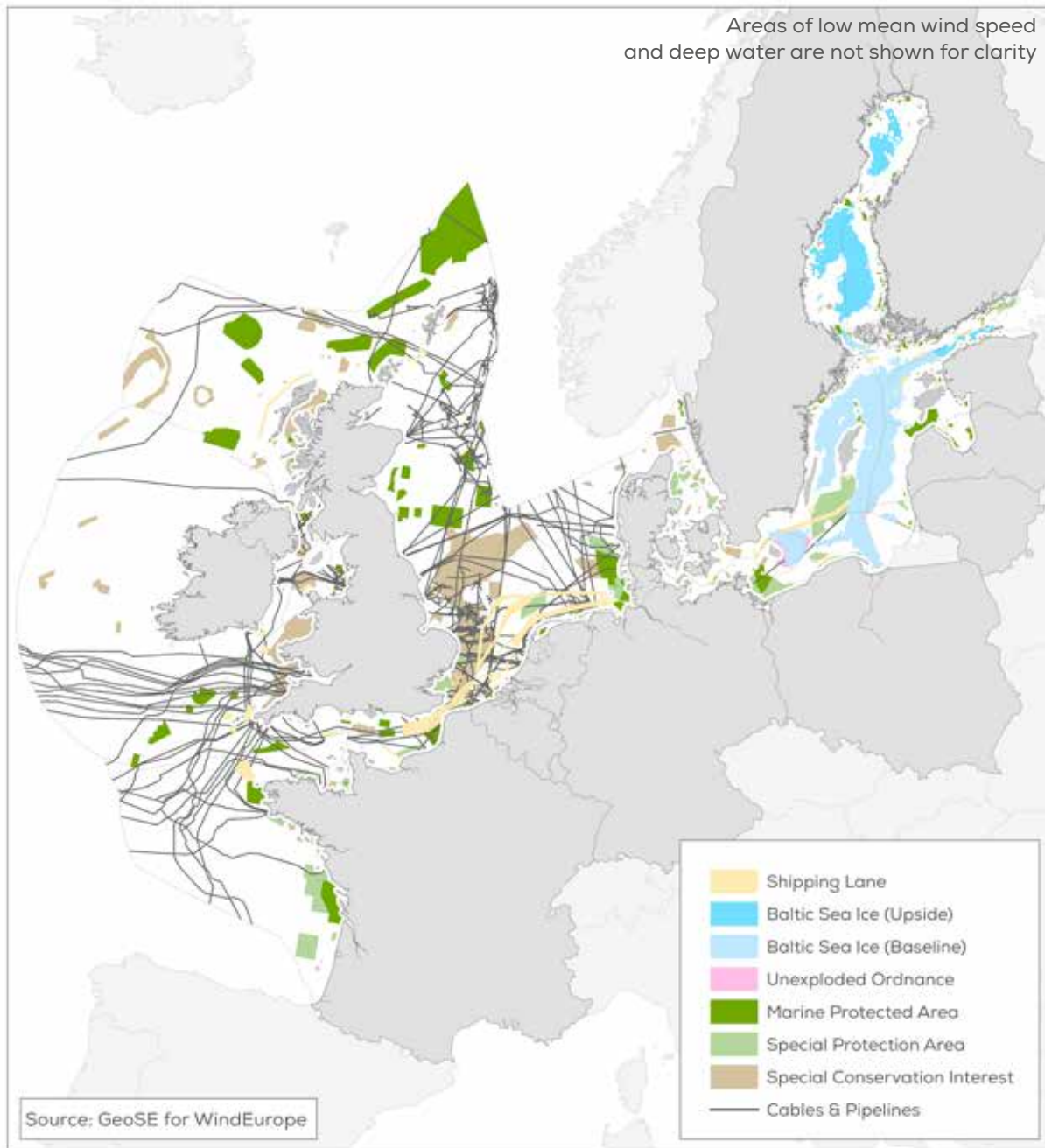
We used three wind farm densities to calculate technical potential capacity:

- A general density of 56% of that used for the gross resource potential, to allow one-third of each wind farm dimension as unused sea area for non-designated shipping lanes and wind speed recovery between wind farms, equal to 3.02 MW/km^2.

- A reduced density of 80% of the general density in areas designated as available for development, but within 1nm of oil and gas pipelines and other infrastructure and electrical and telecommunication cables. With turbines normally sited 1.3km to 2km apart, this amount of density reduction allows for micro-siting of turbines to avoid these features. The resulting reduced density is equal to 2.41 MW/km^2.

- A reduced density, of 50% of the general density in areas of special conservation interest equal to 1.51 MW/km^2, because these areas can be developed with suitable mitigation, which often includes leaving larger spacing between any wind farms and avoidance of specific local areas.

For the turbine technology expected in the baseline scenario, we calculated the relationship between wind speed and net annual energy production (AEP) delivered to the offshore substation (after all losses). Using the annual mean wind speed for each 5x5km cell in the analysis area, we determined the technical resource potential for two areas: from 5nm to 12nm from the coast and from 12nm from the coast to the limit of the EEZs. We used the same procedure for the upside scenario.

For comparison with other studies, we calculated the excluded areas (except for the technical restrictions of sea ice, water depth and mean wind speed) by distance from shore, as shown in Appendix C.

2.5. ECONOMICALLY ATTRACTIVE POTENTIAL

The economically attractive potential capacity of offshore wind is the portion of the technical potential capacity that can generate energy at or below a reference LCOE. The economically attractive resource potential is the energy produced by the economically attractive potential capacity. We do not consider grid constraints on this calculation.

We first calculated economically attractive potential offshore wind capacity in GW for the baseline scenario. For each 5x5km cell of the analysis area within the baseline technical resource potential, we calculated LCOE, based on the expected baseline technology available for installation in 2030, and the site characteristics with geospatial dependency. We used water depth to determine the technology choice between monopile, jacket (or gravity base) and floating foundations. We used distance to grid to determine the choice between high voltage alternating current (HVAC) and high voltage direct current (HVDC) transmission, and assumed that the grid connection point had no restrictions on the amount of capacity that could be connected. Appendix C shows the geospatial dependencies of components of LCOE. We kept all other elements of LCOE fixed. Appendix A details the assumptions regarding each element of LCOE.

As shown in Box 3 in page 34, we established the LCOE that represents the economic limit in 2030 for competitive offshore wind. We then calculated the baseline economically attractive potential capacity in GW from the area of all cells with LCOE at or below this economic limit.

After we calculated the economically attractive resource potential in TWh per year from this capacity using the same densities and energy production approach as for the technical resource potential.

We calculated the upside economically attractive potential capacity and economically attractive resource potential in the same way.

3.
SCENARIOS TO 2030

3.1. OFFSHORE WIND SCENARIOS TO 2030

We considered two scenarios for offshore wind to the end of 2030:

- A baseline scenario based on current policy frameworks and assumptions about future policy taking into account recent levels of costs achieved, and

- An upside scenario based on what the industry could do with positive government responses to costs reduction and by overcoming barriers to deployment including grid access, funding support, site development and supply chain development.

In the baseline scenario, a cumulative total capacity of 64 GW is installed across the whole of Europe by the end of 2030. In the upside scenario, the cumulative total is 86 GW. In comparison to the baseline scenario, this is an increase of around one-third. It reflects governments rapidly reacting positively to recent and expected ongoing LCOE reduction and developers overcoming barriers to deployment (funding support, site development, availability of grid connections and supply chain).

The main assumptions behind each scenario are shown in Table 1.

TABLE 1

Main assumptions for baseline and upside scenarios

	BASELINE	UPSIDE
Electricity market in 2030	A better-functioning international power market enables higher penetration of wind. The reference price for electricity from best-available and CO2-compliant despatchable technology is €75/MWh and the cost of variability attributed to offshore wind is €10/MWh (for more detail see Box 3).	Inefficient fossil fuel power plants become uneconomic and have been phased out. There is sustained development of renewable energies, including growth and industrialisation within the offshore wind market. The reference price for electricity from best-available and CO2-compliant despatchable technology and the cost of intermittency attributed to offshore wind is the same as for the baseline scenario.
Developers and supply chain in 2030	Two or three large developers (and/or consortia) are able to compete effectively, manage risk and secure long pipelines. Some areas of supply chain may be under-competitive (too few major players).	Three or four large developers secure large pipelines and are able to compete effectively. All major areas of supply chain are competitive.
Wind farm technology in 2030	Turbine rating of 13 MW, with rotor diameter of 212 m and hub height of 128 m. Installation vessels designed and built for the offshore wind industry. Service operation vessel (SOV) strategy in use for the vast majority of service and maintenance. Floating cost reductions will expand the market for offshore wind somewhat, but will not enable floating to compete with fixed foundations where these are feasible. Floating foundations not feasible where sea ice is possible. Projects are designed for 30-year operation.	Turbine rating of 15 MW with rotor diameter of 228 m and hub height of 136 m. Operations, maintenance and service (OMS) and construction infrastructure are shared across multiple projects. SOV strategy in use for service and maintenance. Floating comes further down in cost due to deployment in France during the 2020s. It is cost competitive in waters deeper than 70 m. Floating foundations can tolerate occasional sea ice found in the Baltic excluding gulfs of Bothnia and Finland. Projects are designed for 32-year operation.
Transmission and grid in 2030	Each offshore wind farm has a dedicated connection. As part of the EU 15% interconnection target, there are offshore hubs at Kreigers Flak and the Belgian offshore zone that enable connection into the onshore grid via shared infrastructure.	Each offshore wind farm has a dedicated connection. The EU 15% interconnection target is exceeded and there is an offshore hub at Dogger Bank. This is in addition to the offshore hubs at Kreigers Flak and the Belgian offshore zone.
Total installed capacity by the end of 2030	64 GW of offshore wind is installed by the end of 2030, at a rate of up to 4.5 GW per year, providing around 250 TWh per year which is just under 8% of the expected annual EU electricity demand of 3,225 TWh[2].	86 GW installed by the end of 2030 at a rate of up to 7.5 GW per year providing around 340 TWh per year which is just under 11% of the expected annual EU electricity demand of 3,225 TWh.
Capacity factor and LCOE for typical site in 2030[3]	46.7% €59.9/MWh	47.0% €55.9/MWh

2. EU Energy Roadmap 2050, the European Commission, December 2011, Scenario 1.
3. See Table 4 for details of the typical site.

	BASELINE	UPSIDE
Maximum depth for any offshore wind technology in 2030[3]	1,000m	1,000m
Minimum wind speed considered	8 m/s	7.5 m/s
Wind farm density	5.36 MW/km2	5.36 MW/km2

3.2. CAPACITY INSTALLED BY THE END OF 2030

Annual capacities are based on known, planned projects in the near term and our expectation of deployments by country beyond the near term, given the assumptions in the baseline and upside scenarios. Even in the baseline scenario these assumptions result in greater capacity than would be achieved by a simple extension to current policies. In the baseline scenario, a cumulative total capacity of 64 GW is installed by the end of 2030, with the installation rate rising to just over 4 GW per year by 2024, as shown in Figure 3.

FIGURE 3

Installed capacity in the baseline scenario to the end of 2030 for the EU member states in all sea basins
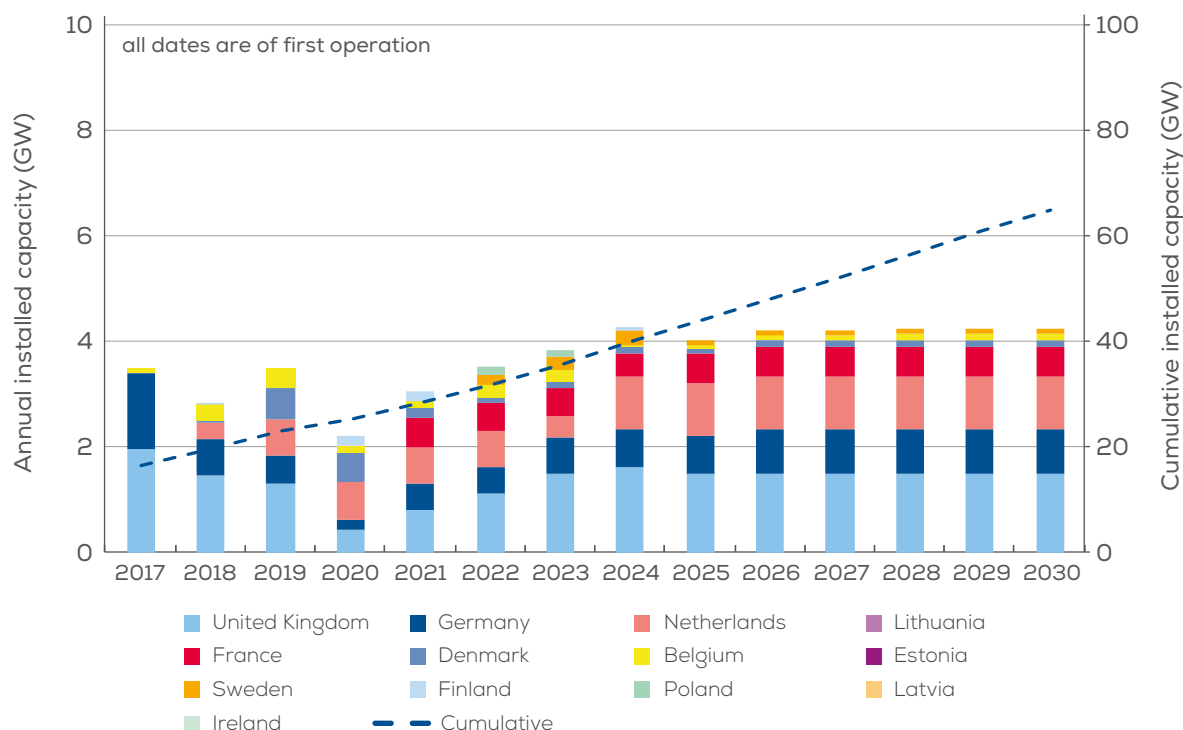
Source: BVG Associates for WindEurope

In the upside scenario, 86 GW capacity is installed by the end of 2030, with the installation rate rising to 7.5 GW per year by 2027, as shown in Figure 4.

FIGURE 4

Installed capacity in the upside scenario to the end of 2030 for the EU member states in all sea basins
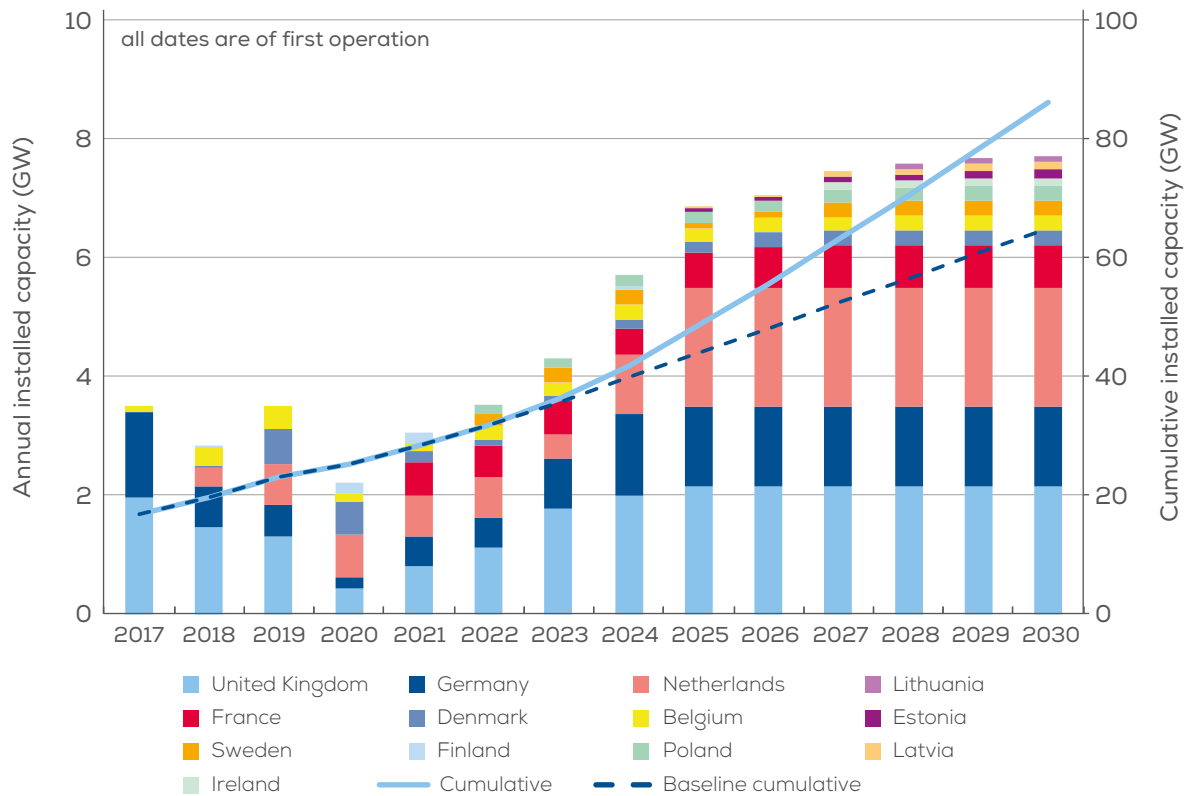
Source: BVG Associates for WindEurope

Figure 5 shows the cumulative capacity installed at the end of 2030 by country for both the baseline and upside scenarios. In the baseline scenario, North Sea countries contribute most of the capacity, with the UK, Germany and the Netherlands dominating. In the upside scenario, we expect more capacity in the Baltic including in other countries, in particular Poland, Sweden, Estonia and Latvia.

FIGURE 5

Cumulative installed capacity by country by the end of 2030
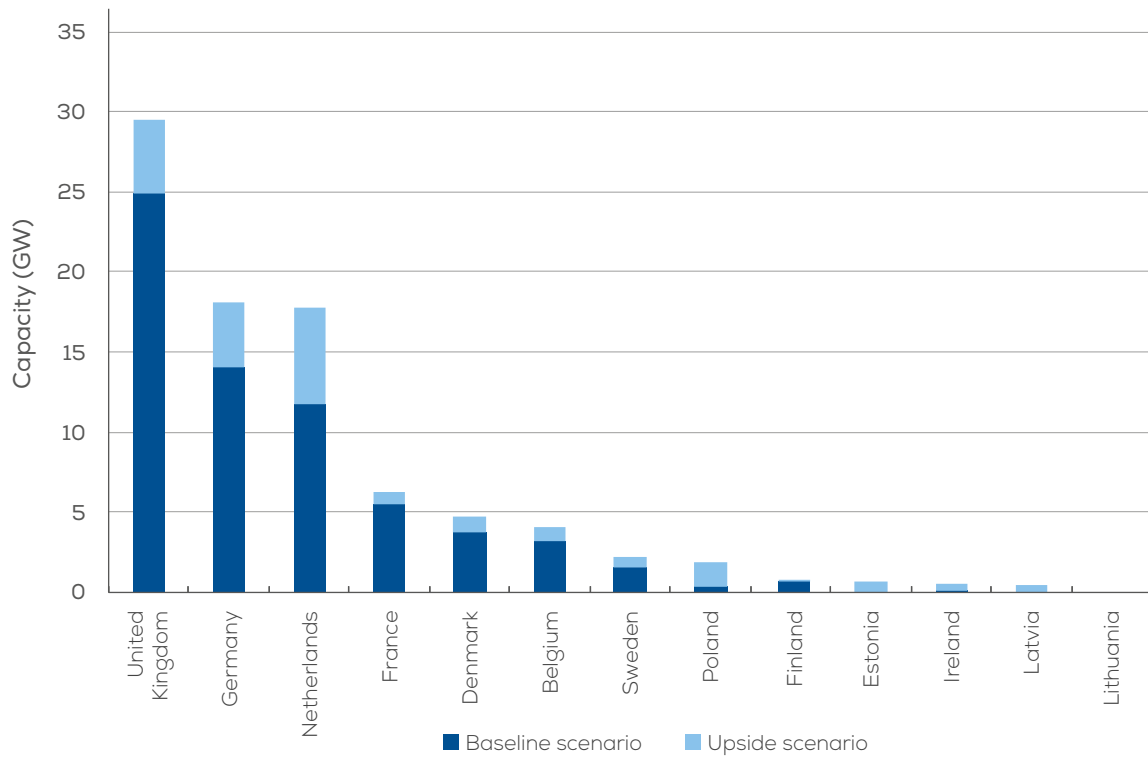
Source: BVG Associates for WindEurope

Even in the baseline scenario, as noted above, our assumptions about installed capacity go beyond the current stated policy ambitions of the EU member states as shown in Figure 6. This seems reasonable, given that current policy ambitions are less clear after the early 2020s and they do not yet generally include all of the effects of the recent low offshore wind auction prices.

FIGURE 6

WindEurope analysis of current policy ambitions of EU member states compared to installed capacity in the baseline scenario to the end of 2030
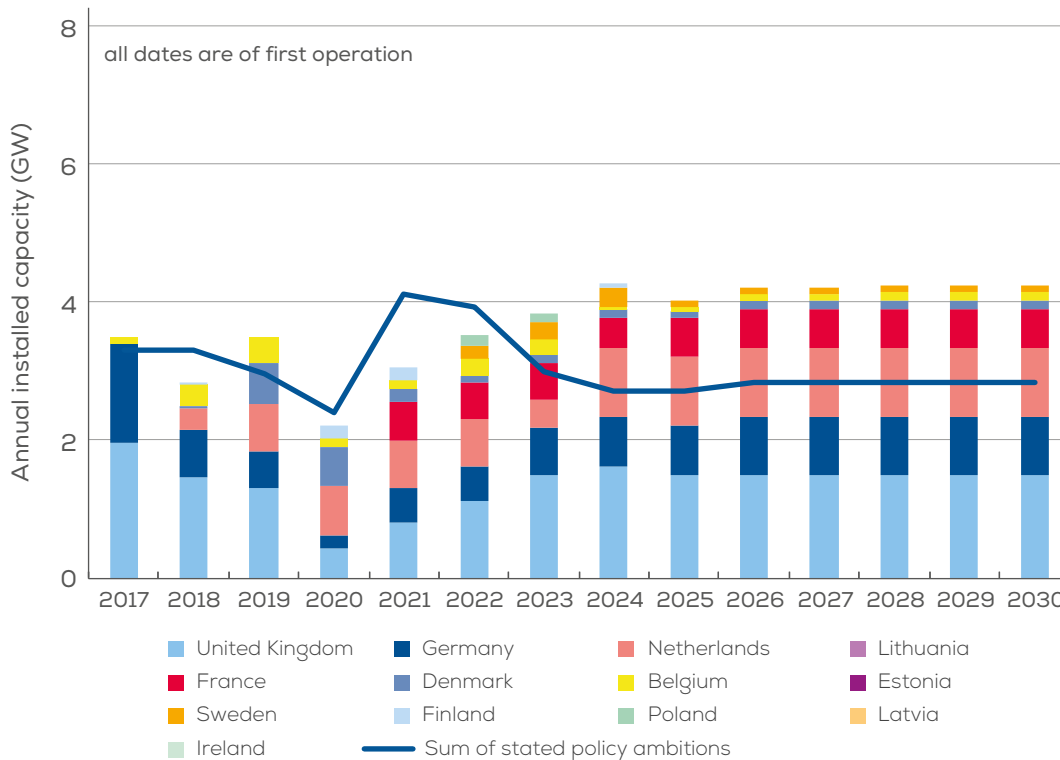
Source: BVG Associates for WindEurope

3.3. OFFSHORE WIND COSTS IN 2030

We modelled LCOE for projects starting operation in 2030, based on the expected status of technology, finance and supply chain in the two scenarios and the assumptions in Appendix A. A lower LCOE is achieved in the upside scenario because of our assumption that larger turbines will be available. We also assumed that other technology and supply chain improvements will be achieved through the higher installed volumes in this scenario. Weighted average cost of capital (WACC) is the same in both scenarios.

The LCOE calculations for a typical reference site in the baseline and upside scenarios are shown in Appendix B.

We constructed our LCOE model for 2030 with geospatial dependencies as detailed in Appendix C. This enabled us to model the LCOE in 2030 for both scenarios for each 5x5km cell on a geospatial map.

A general discussion of LCOE reduction achieved to date and anticipated in 2030 is given in Box 1 and the cost to consumers of the two scenarios is given in Box 2.

BOX 1

OFFSHORE WIND COST REDUCTION

LCOE is the standard way in which industries and governments compare the cost of different energy sources. In this study, we have calculated offshore wind LCOE including the cost of electrical connection to a suitable grid connect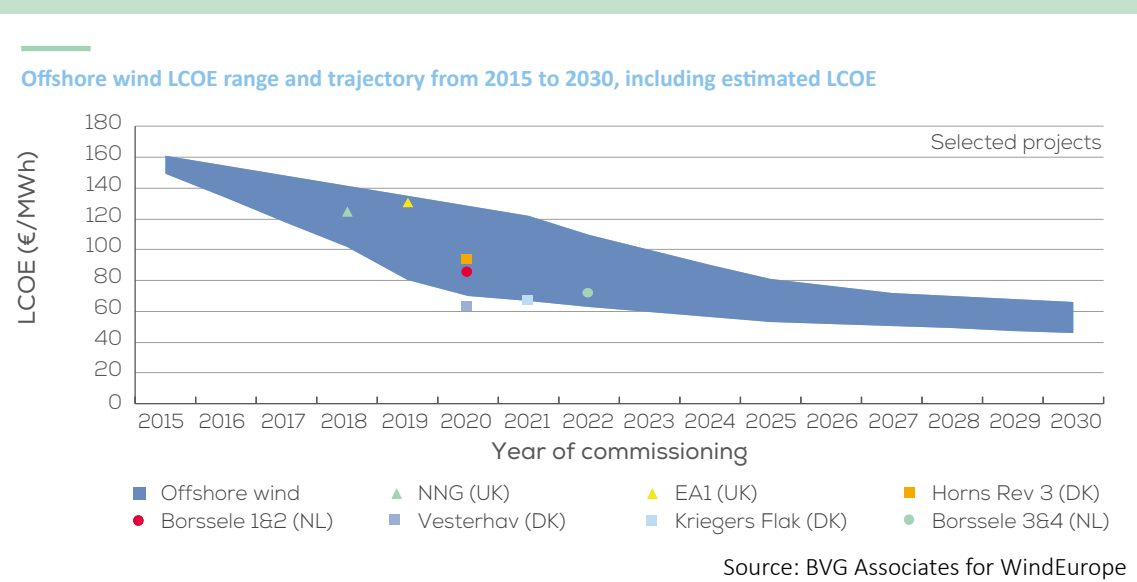ion point. It does not include the costs of dealing with the variability of renewable energy, or other benefits, including to the environment or of energy security.

The LCOE of offshore wind projects has come down significantly over the last ten years. The reduction has been steep and non-linear, due to some rapid changes in project finance costs, turbine technologies, supply chain capability and competitive auctions that have had an impact alongside the learning effect of greater volumes. This rapid and uneven trend of LCOE reduction is expected to continue for the foreseeable future as shown in the figure below. In addition to the band of LCOE for offshore wind, this chart shows the estimated LCOE from a selection of projects that have recently won competitive auctions. These illustrate the rapid recent drop in LCOE.

The largest reductions in LCOE for projects installed up to the end of 2015 came from technology innovations in turbines and installation, and reductions in financing costs. The offshore wind industry has already shown it can deliver new projects quickly at much reduced cost, and which are considered commercially safe enough to attract significant finance at low cost.

Offshore wind LCOE range and trajectory from 2015 to 2030, including estimated LCOE

Source: BVG Associates for WindEurope

In the period 2015 through to 2030, we expect LCOE to fall further as the industry continues to grow. The largest single reduction will come from lower financing costs due to a reduction in perceived risk. The second greatest reduction is due to turbine technology innovations that will enable greater power output and higher reliability without increasing the cost per MW of capacity. Also of great importance is the impact of increasing competition and anticipated greater long-term market visibility. We expect a range of LCOEs in this period as different countries pursue the best opportunities in their own exclusive economic zones, which is not the same as pursuing the best opportunities across the EU member states as a whole.

The net capacity factor of projects has steadily increased over time, due to increased turbine rating and rotor sizes, improved technology reliability and more sophisticated servicing and maintenance strategies. This trend will continue in the future, with net capacity factors exceeding 50% for projects commissioned in 2030 in the best sites.

The LCOE achievable on any particular site in 2030 will depend in part, on the market and policy conditions between now and then, and we illustrate these effects in the two scenarios chosen for modelling in this study.
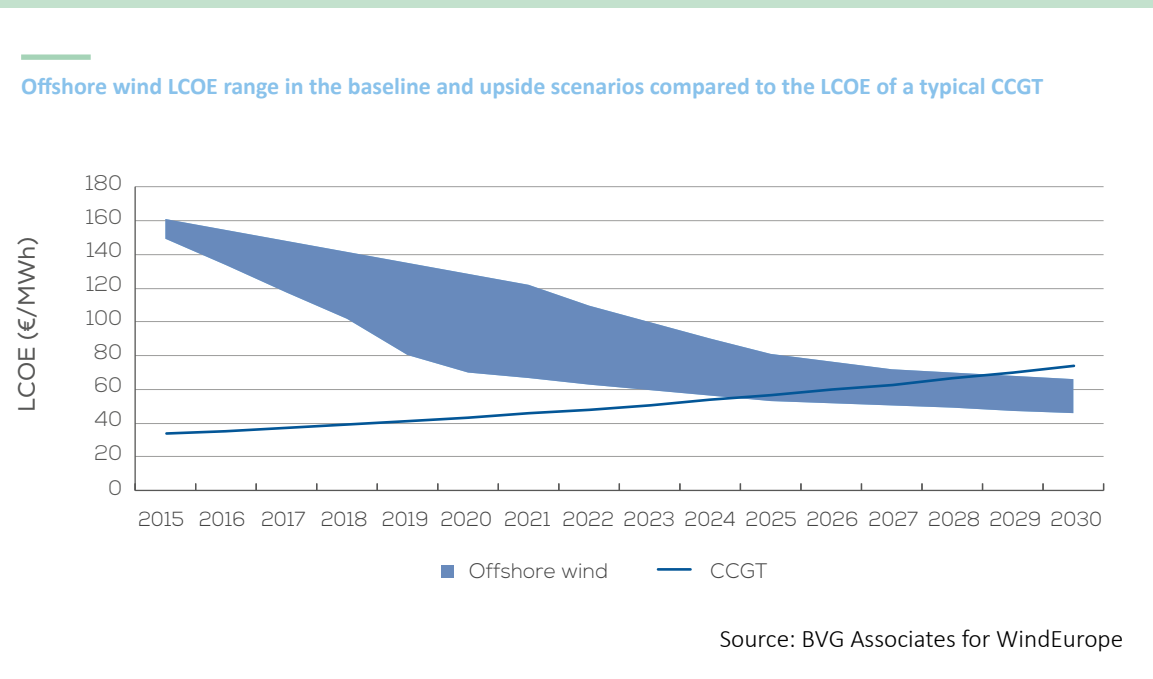
BOX 2

COST TO CONSUMERS

The difference in the cost to consumers between the baseline and upside scenarios is likely to be small. Of the 22 GW additional capacity installed in the upside scenario by the end of 2030, only 10% is added before the end of 2025 when subsidy requirements will be significant.

From 2025 onwards, as we have seen in the 'zero-subsidy' bids in the auctions of April 2017 in Germany, there are some markets where we expect offshore wind will be able to compete at market level without additional subsidy, other than having access to a grid connection point very close by that is ready to receive the power.

Our analysis shows that even including the costs of connecting to more remote grid connection points the middle of the range of LCOE for new-build offshore wind projects will drop to the electricity price (including carbon price) from combined cycle gas turbine (CCGT) plant in Europe by 2027, as shown below.

Offshore wind LCOE range in the baseline and upside scenarios compared to the LCOE of a typical CCGT

Source: BVG Associates for WindEurope

Using this CCGT new build LCOE as a reference price (in place of the wholesale market price) and using the off-shore wind LCOE, volumes and timings from the baseline and upside scenarios shown in Figure 3 and Figure 4, we calculate that the total annual support required for the installed capacity between 2017 and 2030 is €4.4billion in the baseline scenario and €4.7billion in the upside scenario. Thus, a 7% increase in support can deliver 34% more capacity by the end of 2030. In addition, the extra volume will enable better turbines and other technologies to be developed and brought to market in 2030 and beyond that provide electricity at 7% lower cost, which will directly reduce the cost to the consumer.

4.
GROSS AND TECHNICAL POTENTIAL

4.1. GROSS POTENTIAL

The gross potential capacity in both the baseline and upside scenarios is 10,020 GW for the area from 5nm from the shore to the limit of the EEZs considered. This delivers a gross resource potential of 50,205 TWh per year in the baseline scenario, distributed as shown in Figure 7. White areas are outside the EEZs of the member states consid-

ered. The gross resource potential in the upside scenario is just under 1% higher at 50,516 TWh per year due to the higher energy production delivered by a larger turbine in this scenario. As would be expected, the largest gross resource potential is in the Atlantic basin. This comes from the UK and Ireland, as shown in Figure 8 and Figure 9.

FIGURE 7

Gross resource potential at the end of 2030 per 100km² in the baseline scenario

Source: GeoSE for WindEurope

TWh/yr/100km²

High: 3

Low: <2
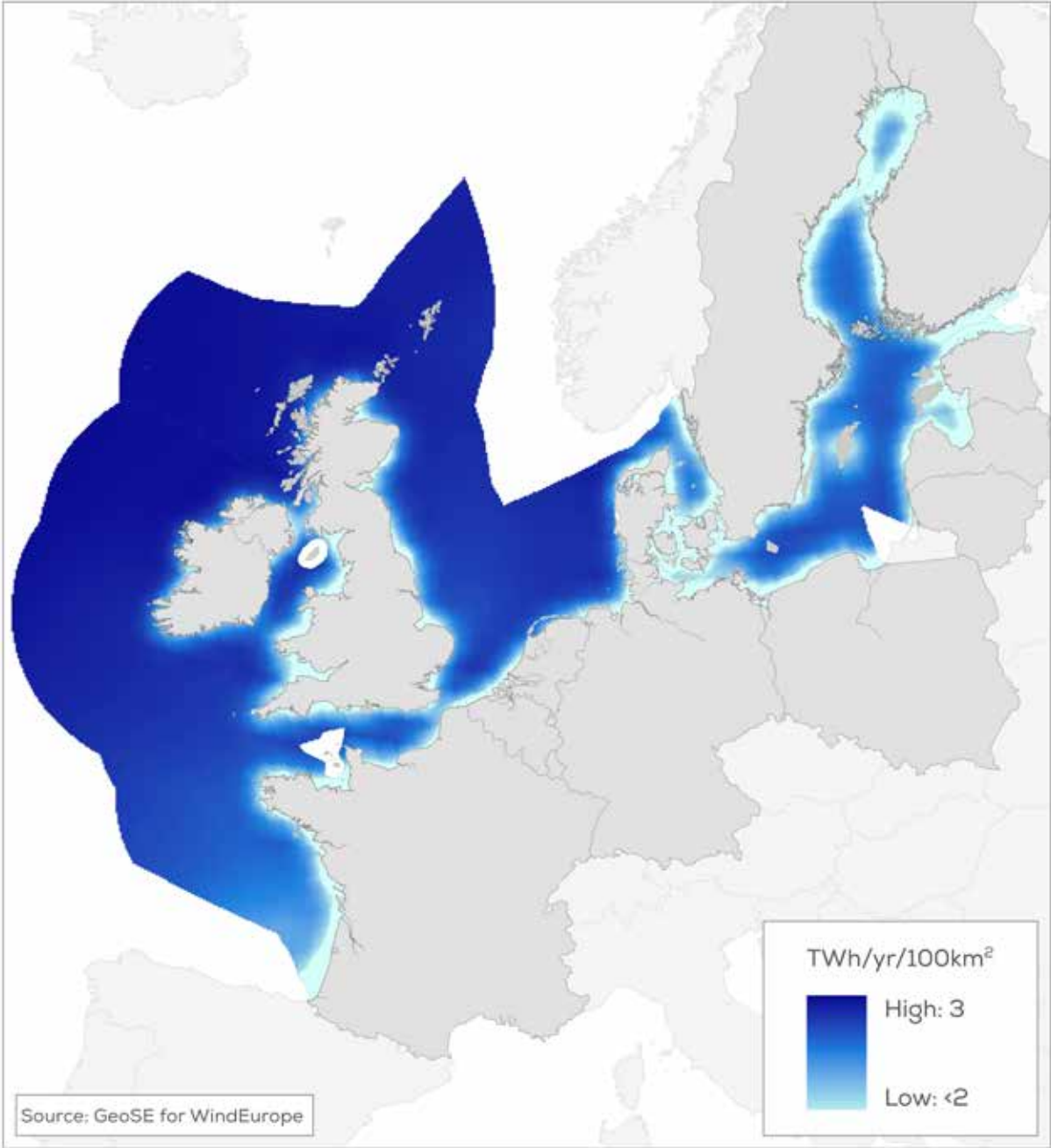
FIGURE 8

Gross resource potential at the end of 2030 by sea basin
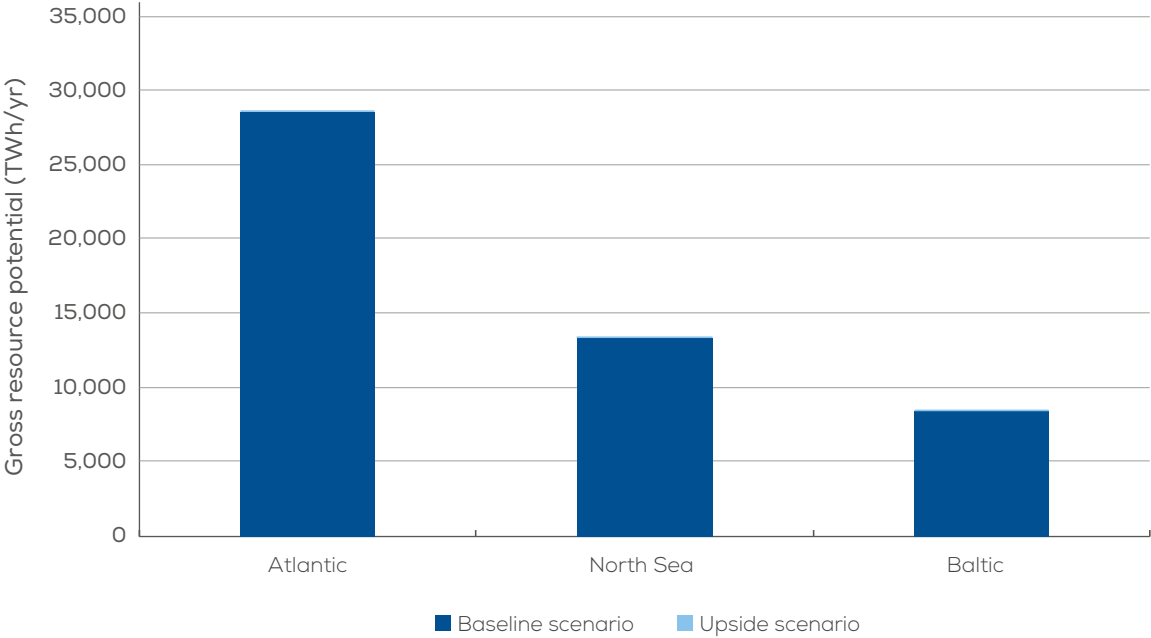
Source: BVG Associates for WindEurope

FIGURE 9

Gross resource potential at the end of 2030 by country
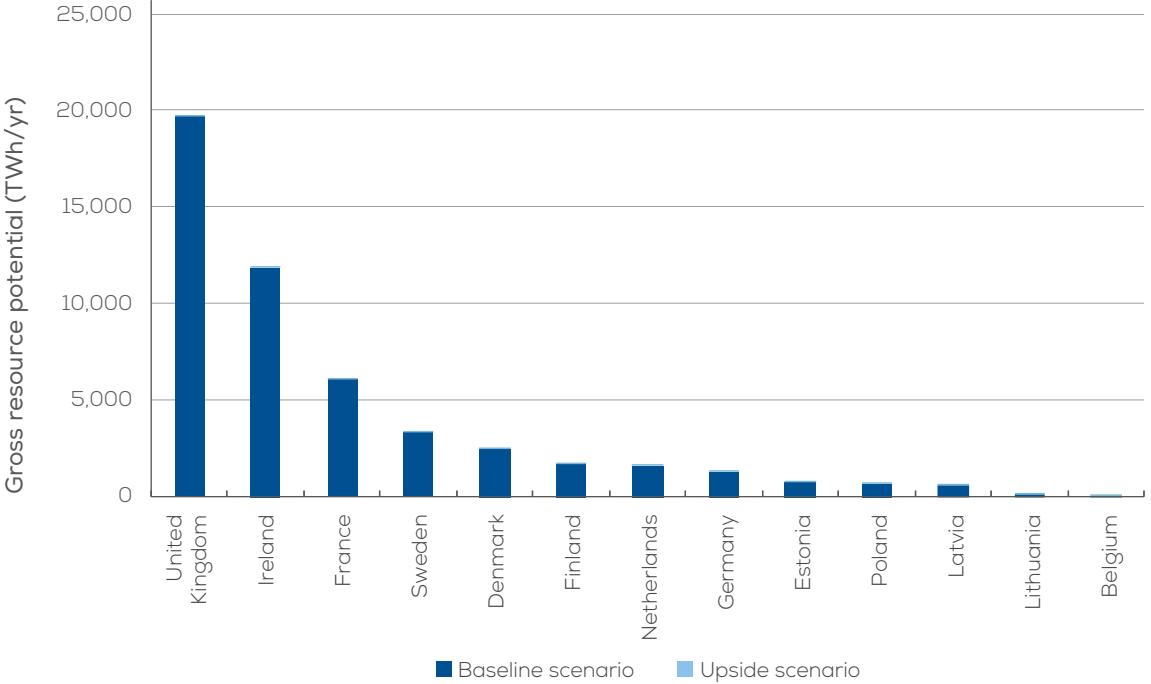
Source: BVG Associates for WindEurope

4.2. TECHNICAL POTENTIAL

The technical potential capacity from 5nm to the limit of the EEZs considered in the baseline scenario is 2,695 GW (27% of gross potential capacity) and in the upside scenario is 2,919 GW (29% of gross potential capacity). The baseline scenario technical resource potential beyond 12nm is 10,520 TWh per year as shown in Figure 10. This grows to 11,968 TWh per year if the area from 5nm to 12nm from

shore is also included. The upside scenario resource potential from 5nm from shore is 8% higher at 12,896 TWh per year. (It is not shown as the images are very similar.) White areas on the map indicate areas that are fully excluded. Areas where a density reduction has been applied can be seen as lighter blue shades.

FIGURE 10

Technical resource potential at the end of 2030 per 100km² in the baseline scenario
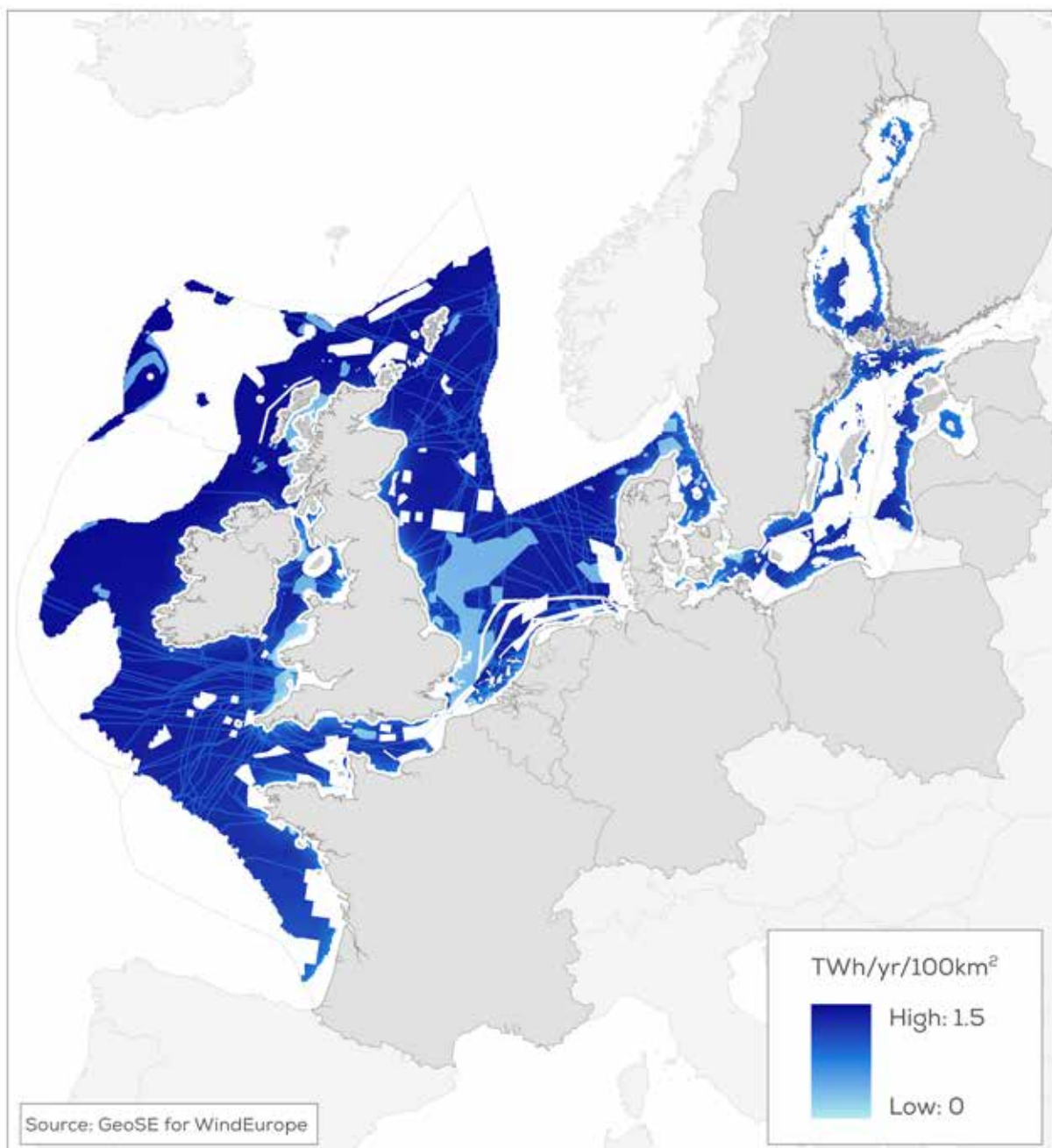
Figure 11 shows the breakdown of technical resource potential by sea basin. There is significant technical resource potential in the area from 5nm to 12nm from shore. The largest technical resource potential is in the Atlantic. In the upside scenario, the only significant increase in technical resource potential is in the Baltic. This is based on our assumption about the improved capability of floating foundations in conditions of occasional sea ice in the upside scenario. The largest technical resource potential is in the UK and Ireland, but France, Sweden, Denmark, the Netherlands, Finland and Germany also have technical resource potentials over 300 TWh per year in the upside scenario, as shown in Figure 12.

The benefit of use of sea area between 5nm and 12nm from shore varies between countries. For the remainder of this analysis we consider the area from 5nm, noting that the resulting potentials may be slightly overstated for some countries.

FIGURE 11

Technical resource potential at the end of 2030 by sea basin
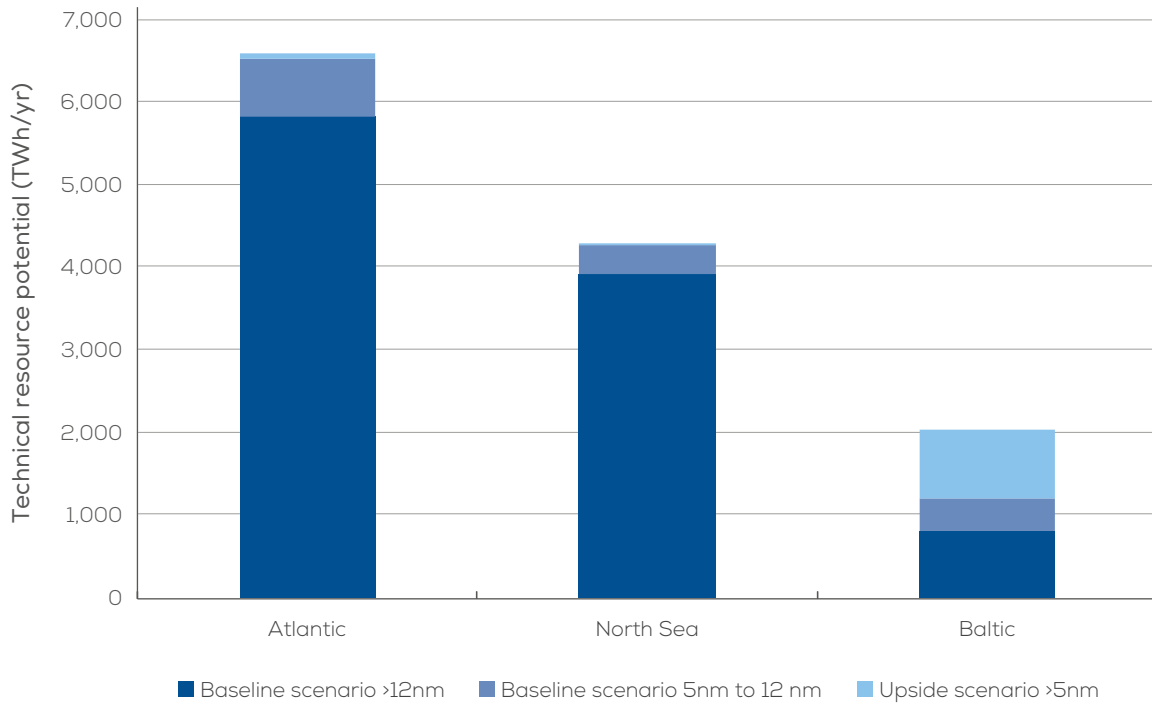
Source: BVG Associates for WindEurope

FIGURE 12

Technical potential at the end of 2030 by country
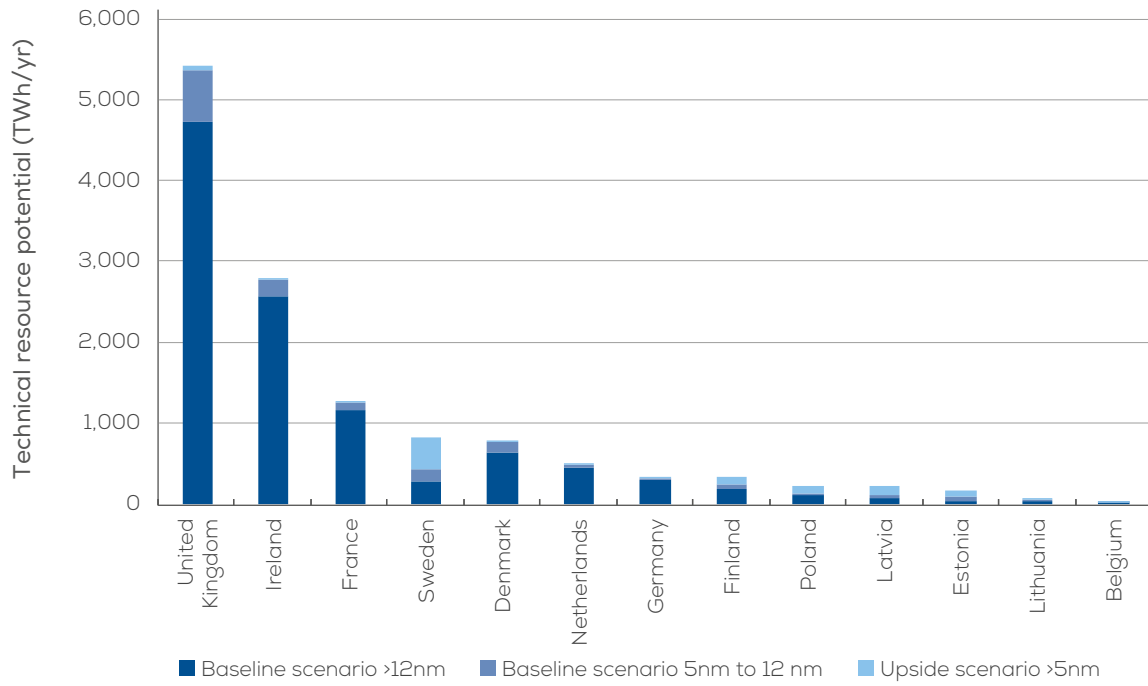
Source: BVG Associates for WindEurope

BOX 3

DEFINING ECONOMICALLY ATTRACTIVE OFFSHORE WIND

The reference LCOE in 2030 represents limit at which offshore wind is considered economically attractive. We based the reference LCOE on the expected cost of electricity from a typical large CCGT power plant. This is chosen as the best available conventional new build technology in 2030, and represents the technology that is most likely to be put in place were power not being generated by offshore wind.

The cost of this electricity is dominated by the cost of gas fuel and the expected environmental charges for emitting CO_2. For the other costs and factors, we used the data for H class CCGT from the UK Government Department of Business, energy and industrial strategy (BEIS)[4]. At a WACC of 6% and assuming a capacity factor of 90%, this gave contributions to LCOE of €6.7/MWh for capital expenditure (CAPEX) and €6.3/MWh for non-fuel and non-carbon operational expenditure (OPEX) in end 2016 prices.

Fuel price varies widely across Europe, as do forecasts of its cost in 2030 and beyond. Where forecasts beyond 2030 are available, they tend to show level or increasing prices. For this study, as a cautious method for establishing a reference, we used an average of two sources for forecast gas prices in 2030:

- The Danish Energienet 2030 gas price forecast of DKr66.1/GJ[5], and

- The Netherlands Nationale Energieverkenning 2016 forecast of gas prices in 2030 of €0.028/m[3][6].

Assuming a power plant efficiency of 54%, the average equates to a fuel cost of €54.7/MWh (of electricity produced).

We assumed an EU cost for emitting CO_2 of €20 per tonne and emissions of 360 kg/MWh (of electricity produced), giving a carbon cost of €7.2/MWh. The total cost of CCGT generation in 2030 is therefore calculated as €75/MWh.

We also assumed the additional cost of integrating variable renewables will be €10/MWh, (agreed with WindEurope based their analysis of multiple data sources), meaning that the reference cost for offshore wind to be economically attractive is an LCOE of €65/MWh including the costs of connecting from the wind farm to the onshore grid or any offshore connection hubs. We used this value for both the baseline and the upside scenarios.

4. Electricity generation costs, BEIS, November 2016, available online at: https://www.gov.uk/government/publications/beis-electricity-generation-costs-november-2016, last accessed 8 May 2017

5. Energinet.dk's analyseforudsætninger 2015-2035 available online at https://www.energinet.dk/SiteCollectionDocuments/Danske%20dokumenter/El/Energinet.dk's%20analyseforuds%C3%A6tninger%202015-2035%20-%20ekstern%20version.docx%202516716_2_1.pdf, last accessed 4 May 2017

6. Nationale Energieverkenning 2016, available online at https://www.rijksoverheid.nl/documenten/rapporten/2016/10/14/nationale-energieverkenning-2016, last accessed 4 May 2017

5.
ECONOMICALLY ATTRACTIVE POTENTIAL

5.1. LCOE OF OFFSHORE WIND FOR PROJECTS STARTING OPERATION IN 2030

We calculated the LCOE for each 5x5km cell in the technical potential and ranked them in a merit-order from low to high LCOE for both scenarios as shown in Figure 13 in terms of resource potential. There is some economically attractive resource potential available below €50/MWh in the baseline scenario (around 40 TWh per year or 9 GW installed capacity) and more in the upside scenario (around 260 TWh/year or 60 GW).

We used a reference LCOE of €65/MWh in 2030 as defined in Box 3 in page 34, and consider all locations with an LCOE at or below this value to be economically attractive. The resource potential for offshore wind at this level is 2,632 TWh per year under the baseline scenario, produced by 607 GW of capacity. Under the upside scenario the available economically attractive resource potential rises to 5,981 TWh per year, produced by 1,350 GW of capacity as shown in Figure 13. For reference, the forecast electricity demand of the EU member states in 2030 is 3,225 TWh per year.

FIGURE 13

Economically attractive resource potential at the end of 2030 shown as a merit order
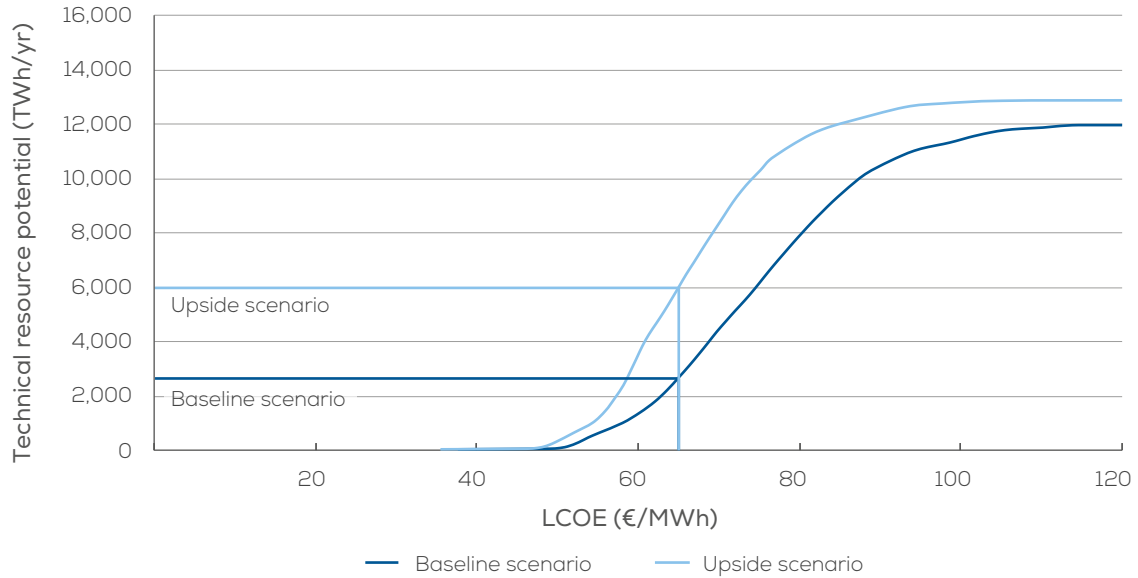
Source: BVG Associates for WindEurope

Figure 14 and Figure 15 show the LCOE spatial plots across the three sea basins analysed for the baseline and upside scenarios. The scale is the same for both figures and the dark green areas show where LCOE in 2030 is below €50/MWh. The areas of lowest LCOE in the baseline scenario are almost all in the southern North Sea and within about 60km of the coast. In the upside scenario, the areas of lowest LCOE expand, thanks to the better turbine and other wind farm technology and processes available, and now include areas in the north part of the North Sea, the Baltic and the Atlantic.

FIGURE 14

Map of economically attractive resource potential at end of 2030 (baseline scenario)

Dark green shows all resource available below €50/MWh.

€/MWh

High: 65

Low: <50

Source: GeoSE for WindEurope
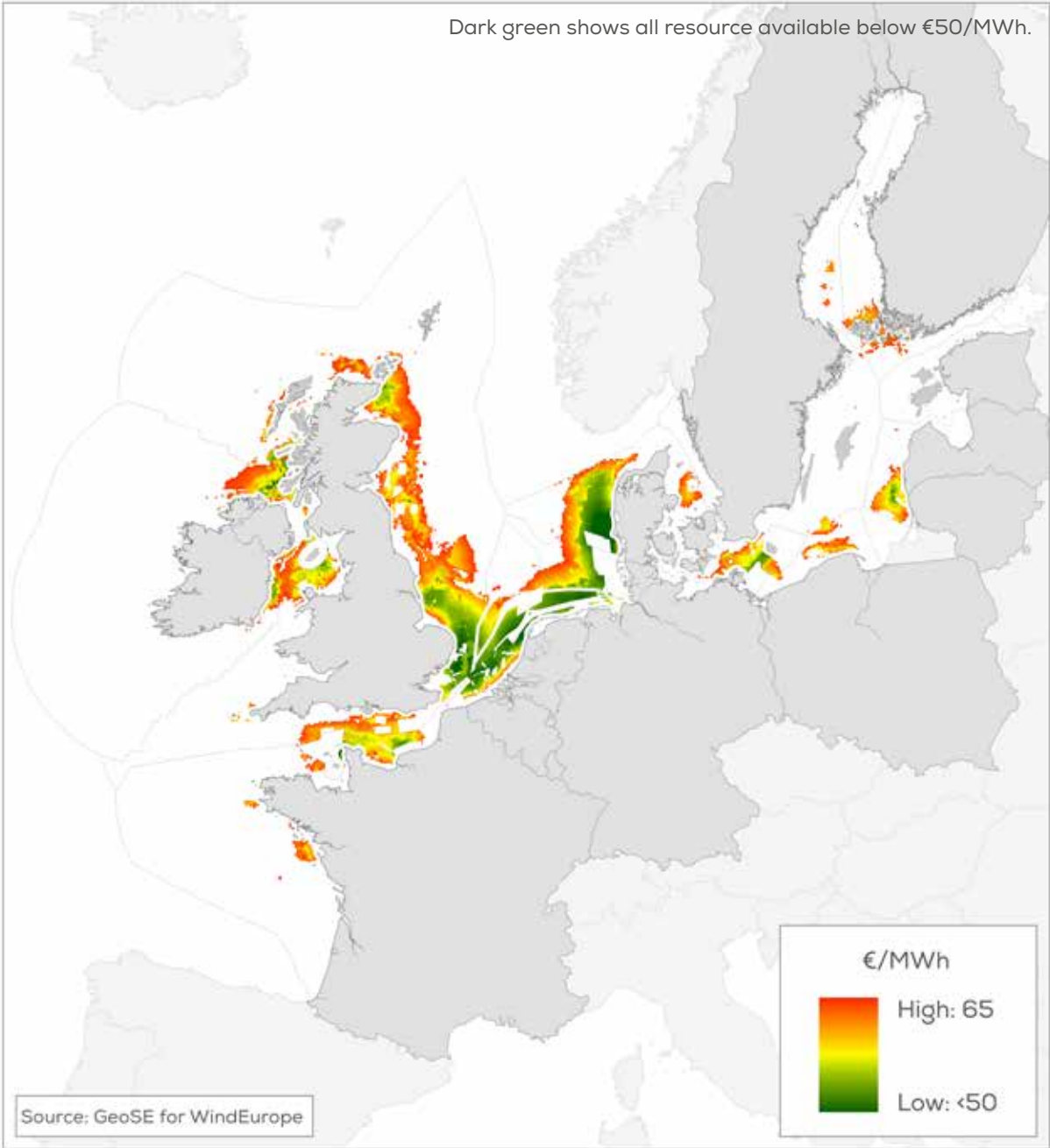
FIGURE 15

Map of economically attractive resource potential at end of 2030 (upside scenario)

Dark green shows all resource available below €50/MWh.

€/MWh

High: 65

Low: <50

Source: GeoSE for WindEurope
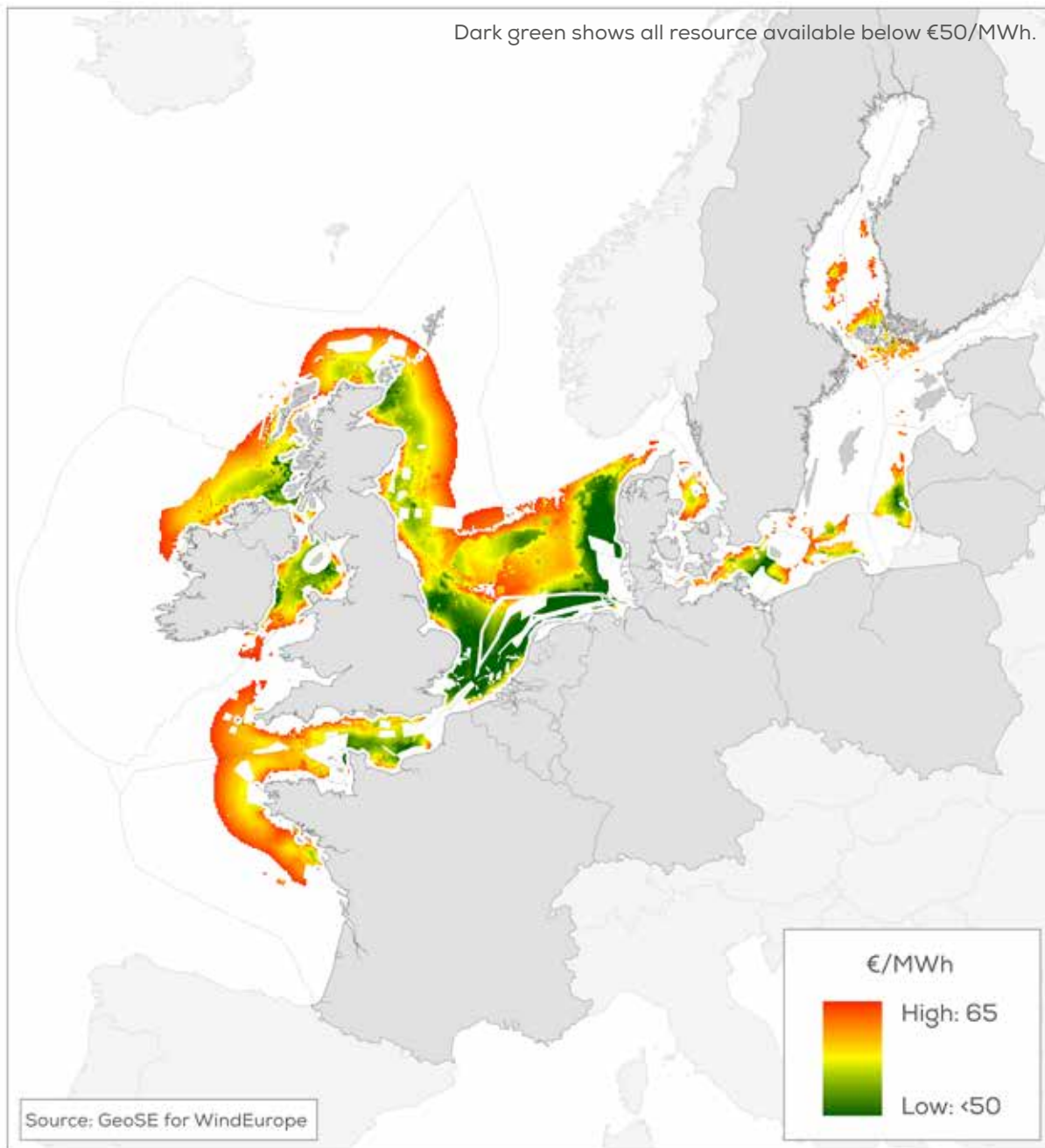
5.2. ECONOMICALLY ATTRACTIVE POTENTIAL BY SEA BASIN, COUNTRY AND FOUNDATION TYPE

The sea basins and country EEZs that contribute capacity to the baseline and upside economically attractive potential are shown in Figure 16.

FIGURE 16

Wind farm areas delivering the economically attractive potential at or below an LCOE of €65/MWh under the baseline and upside scenarios at the end of 2030

Source: GeoSE for WindEurope

Baseline scenario

Upside scenario
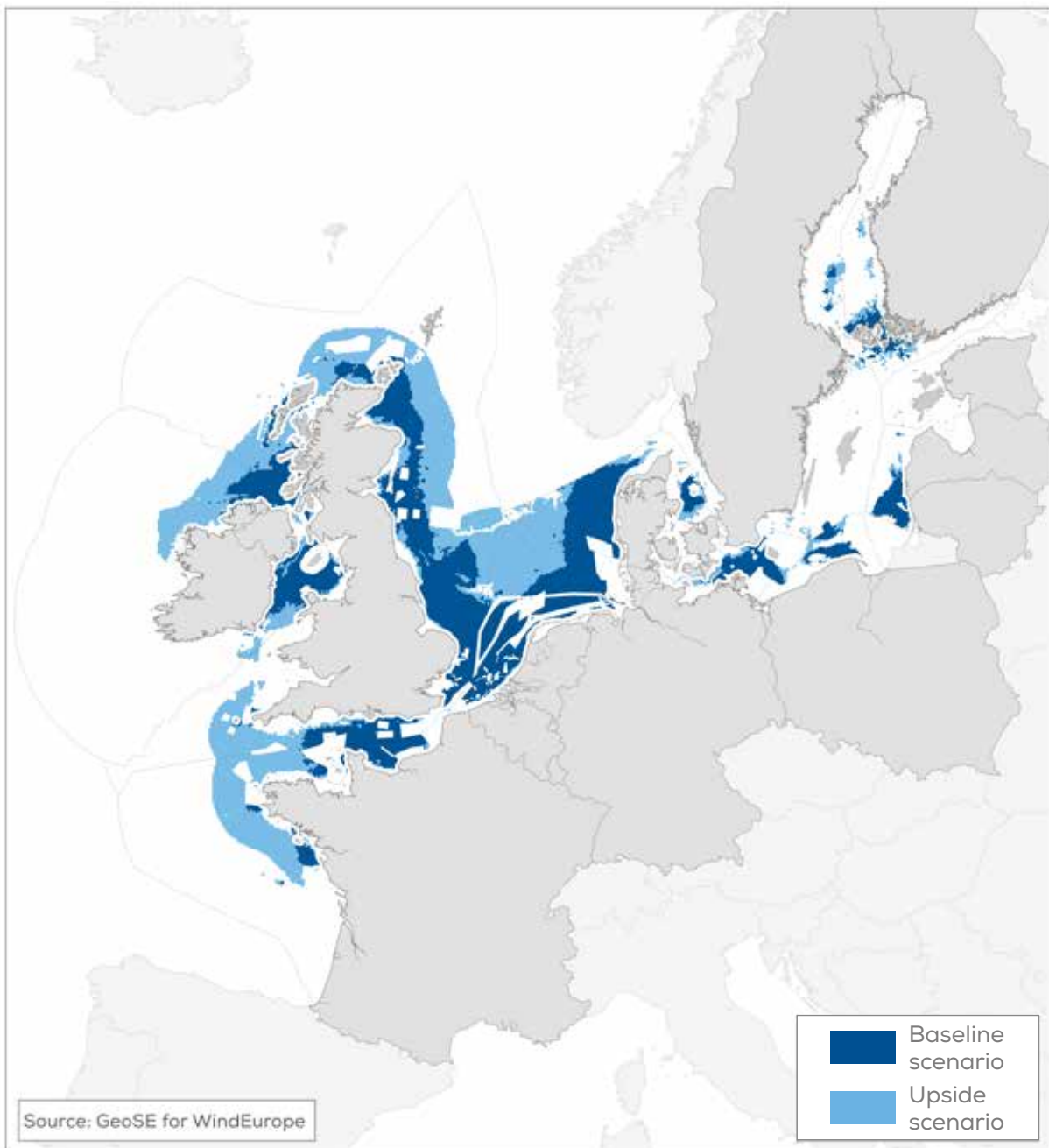
The split of economically attractive resource potential by sea basin is shown in Figure 17. In the baseline scenario, the North Sea has the greatest economically attractive potential at 1,572 TWh per year, produced by 355 GW of capacity. The Atlantic has about half this potential and the Baltic around a quarter. In the upside scenario, the economically attractive resource potential in the Baltic doubles to over 750 TWh per year (186 GW). The North Sea economically attractive resource potential also approximately doubles to 2,880 TWh per year (635 GW), while the potential in the Atlantic more than triples to 2,343 TWh per year (527 GW).

The split by country is shown in Figure 18. The most significant upsides are for the UK, Ireland, France, the Netherlands and Denmark. With the total upside potential capacity of 1,350 GW, many of these economically attractive potentials are far beyond what an individual country would need to target and would be far beyond the capabilities of the supply chain to deliver. Only in Belgium does national aspiration approach the economically attractive resource potential.

FIGURE 17

Economically attractive resource potential at the end of 2030 by sea basin
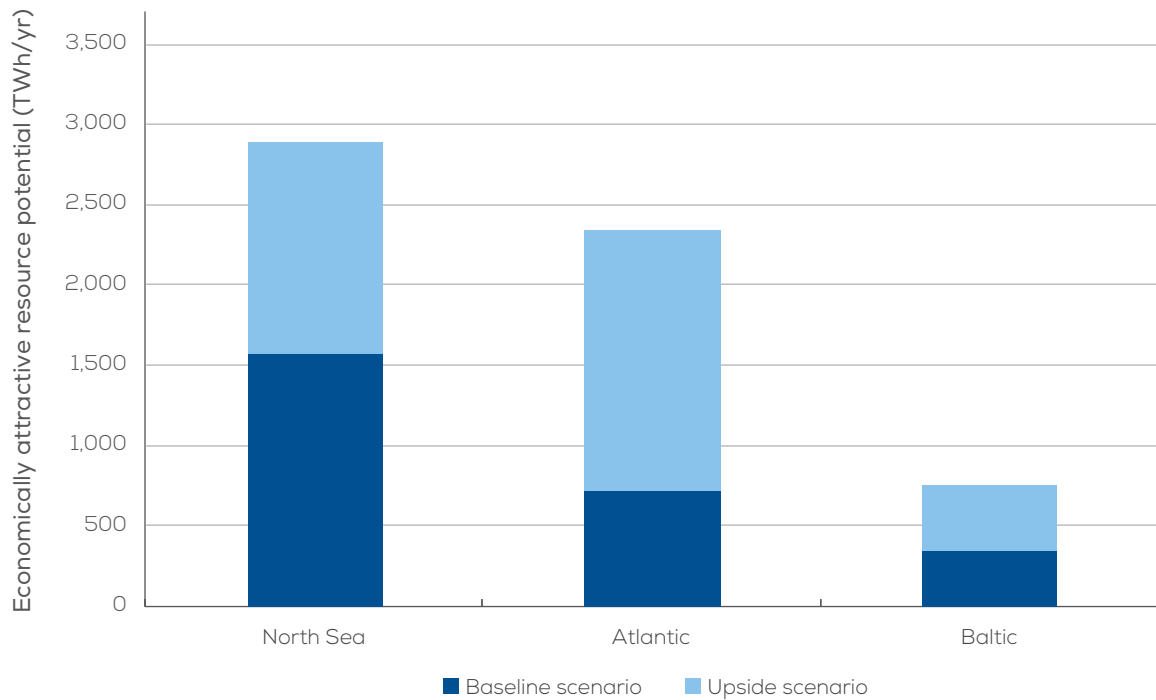
Source: BVG Associates for WindEurope

FIGURE 18

Economically attractive resource potential at the end of 2030 by country

Source: BVG Associates for WindEurope

We also analysed the economically attractive resource potential by foundation type as shown in Figure 19. In the baseline scenario, turbines mounted on floating foundations are producing 14% of the economically attractive resource potential across the basins analysed and 1% of the economically attractive resource potential below €60/MWh.

Turbines mounted on floating foundations produce over 70% of the additional economically attractive potential in the upside scenario, however, of which nearly half is resource potential below €60/MWh indicating their value in enabling additional capacity in areas with deep water. The availability of floating foundations at competitive cost is also key to enabling other markets in Europe, such as in the Mediterranean Sea, and beyond.
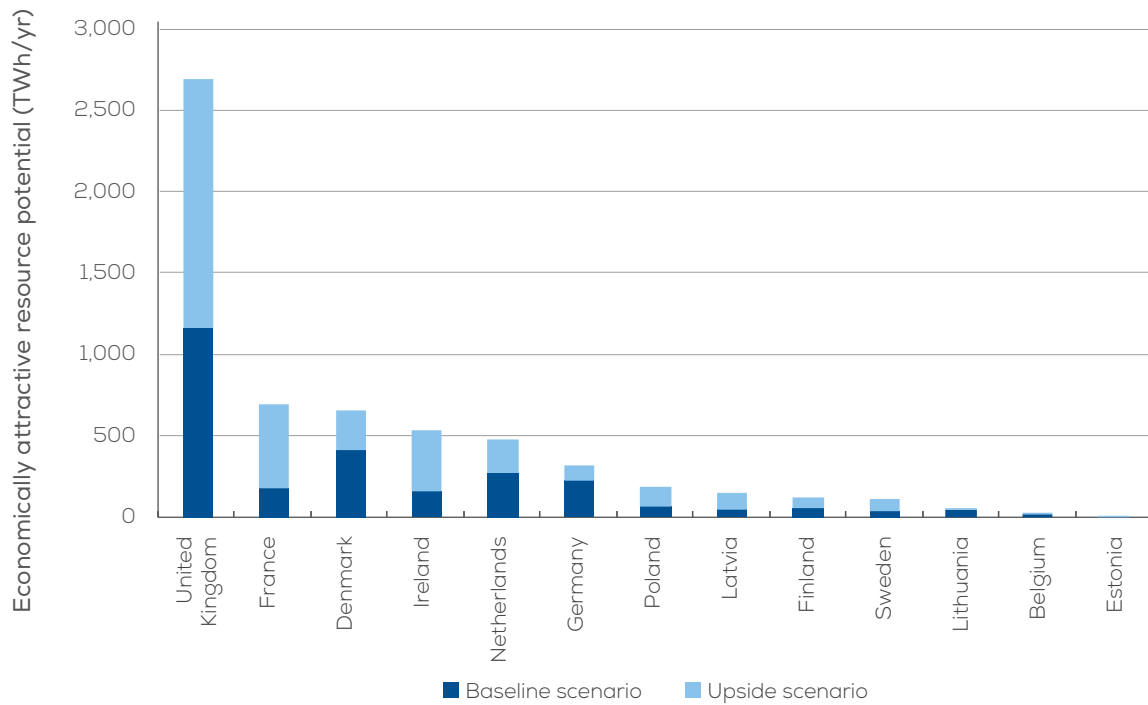
FIGURE 19

Economically attractive resource potential at the end of 2030 by foundation type
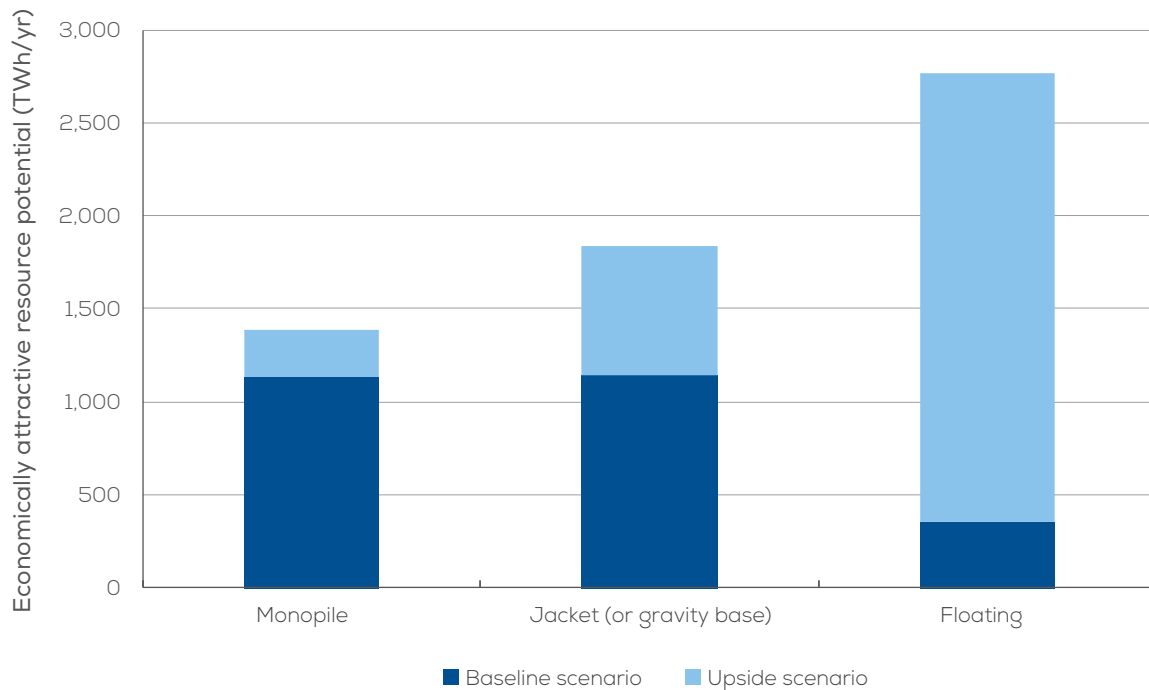
Source: BVG Associates for WindEurope

5.3. ECONOMICALLY ATTRACTIVE RESOURCE POTENTIAL AND ELECTRICITY DEMAND

The total economically attractive resource potential up to an LCOE of €65/MWh is over 80% of EU member states' electricity needs in 2030 in the baseline scenario and over 180% in the upside scenario. With such a large economically attractive potential, it is rational to target significant offshore wind capacity in the European energy mix, taking into account what the grid can accommodate and the characteristics and capacities of the other sources of power on the grid.

It is not the purpose of this study to analyse how much capacity the EU members states and other nations of Europe should seek to install. Instead, Figure 20 presents the resource potential available against the average LCOE at which that resource can be delivered, assuming the use of 2030 wind farm and turbine technology in all areas.

We calculated this using a weighted average of the lowest LCOE areas that together can supply a particular level of resource, independent of location.

We can see that 25% of EU electricity demand in 2030 (806 TWh/year) could be supplied at an average of €54/MWh in the baseline scenario and at €51/MWh in the upside scenario. If more offshore wind power can be accommodated by the grid, then, for example, 50% of EU electricity needs (1,613 TWh/year) could be supplied at an average of €57/MWh in the baseline scenario and at under €53/MWh in the upside scenario. Although not technically viable, 100% of electricity needs (3,225 TWh per year) could be supplied at an average of €61/MWh in the baseline scenario and under €56/MWh in the upside scenario.

FIGURE 20

Cumulative resource potential at end of 2030 and the average LCOE of that resource potential
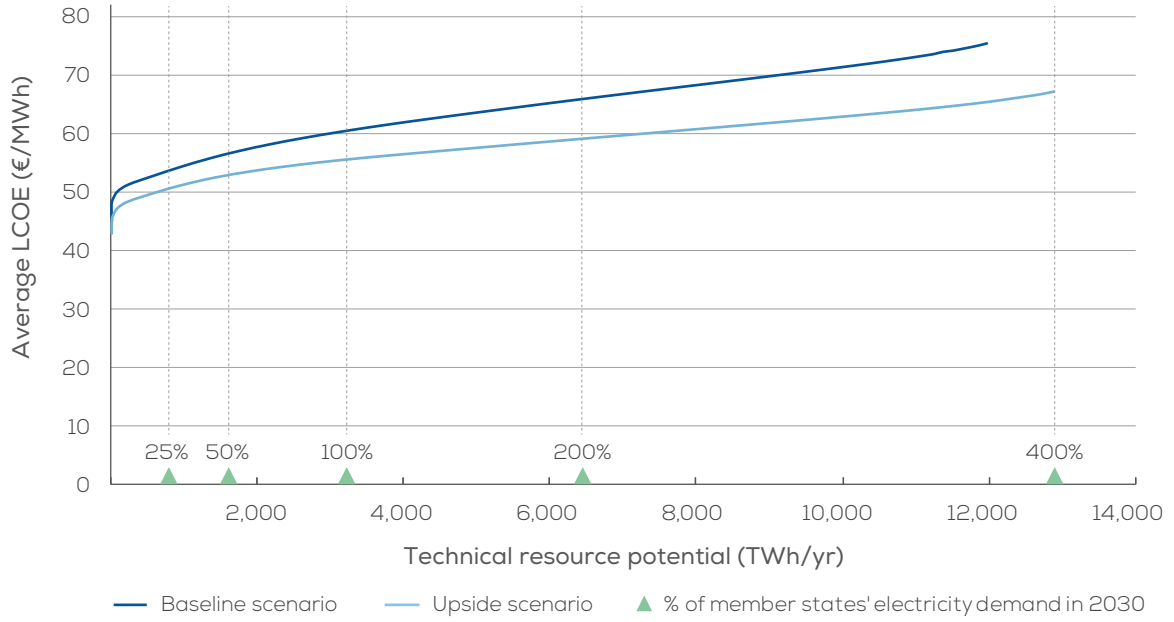
Source: BVG Associates for WindEurope

6.
SENSITIVITY ANALYSIS

To explore the sensitivity to electricity price, instead of using €65/MWh as the reference LCOE we used €60/MWh (a 7.7% reduction, representing a 10% lower forecast of gas price). With this LCOE, the economically attractive potential for offshore wind is 1,306 TWh per year under the baseline scenario, delivered by 300 GW of capacity. Under the upside scenario, the economically attractive potential rises to 3,475 TWh per year (780 GW), as shown in Figure 21.

Economically attractive resource potential at €60/MWh in 2030 shown as a merit order
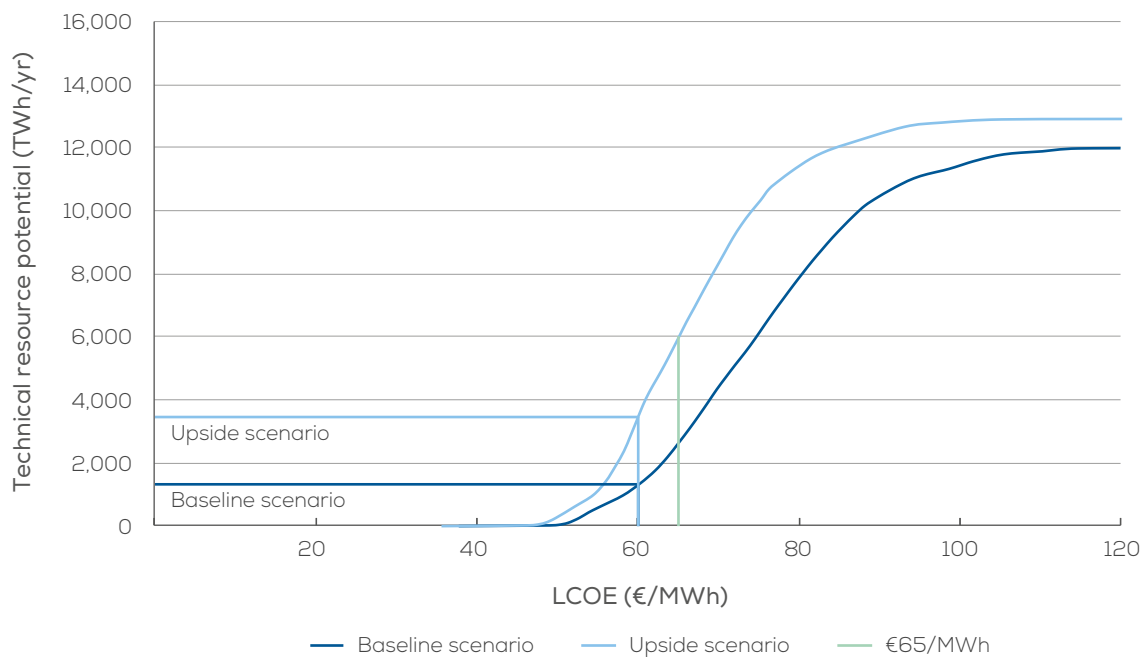
Source: BVG Associates for WindEurope

The split of economically attractive resource potential at €60/MWh by sea basin is shown in Figure 22. The split by country is shown in Figure 23. The baseline economically attractive resource potential is reduced from the case with a reference LCOE of €65/MWh, but at just over 1,300 TWh per year is still more than one-third of the EU member states' electricity demand in 2030. The baseline potential is dominated by the North Sea. The upside scenario significantly increases the potential in the Atlantic

and the Baltic. At a total of nearly 3,500 TWh per year the upside is still more than the whole electricity demand of the EU member states in 2030.

The baseline scenario for a €60/MWh reference LCOE is delivered mostly from five countries with more than 10 GW of economically attractive capacity: the UK, Germany, the Netherlands, France and Denmark

FIGURE 22

Economically attractive resource potential by sea basin at end 2030 at €60/MWh
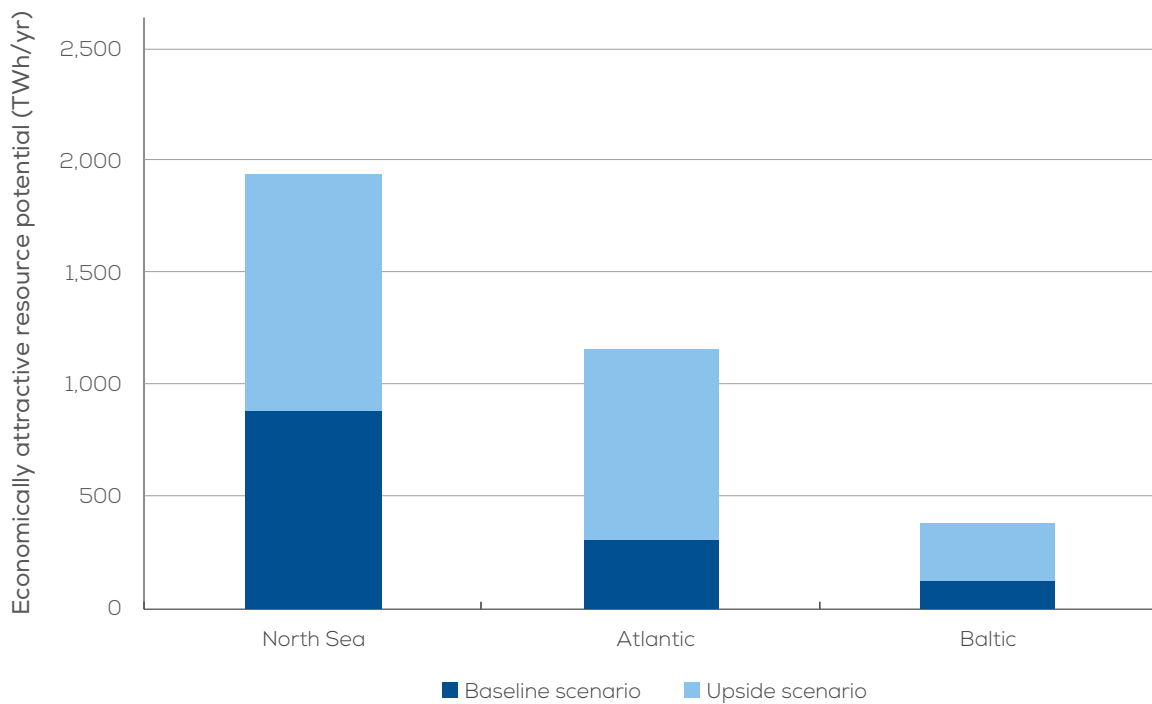
Source: BVG Associates for WindEurope

FIGURE 23

Economically attractive resource potential by country at end 2030 at €60/MWh
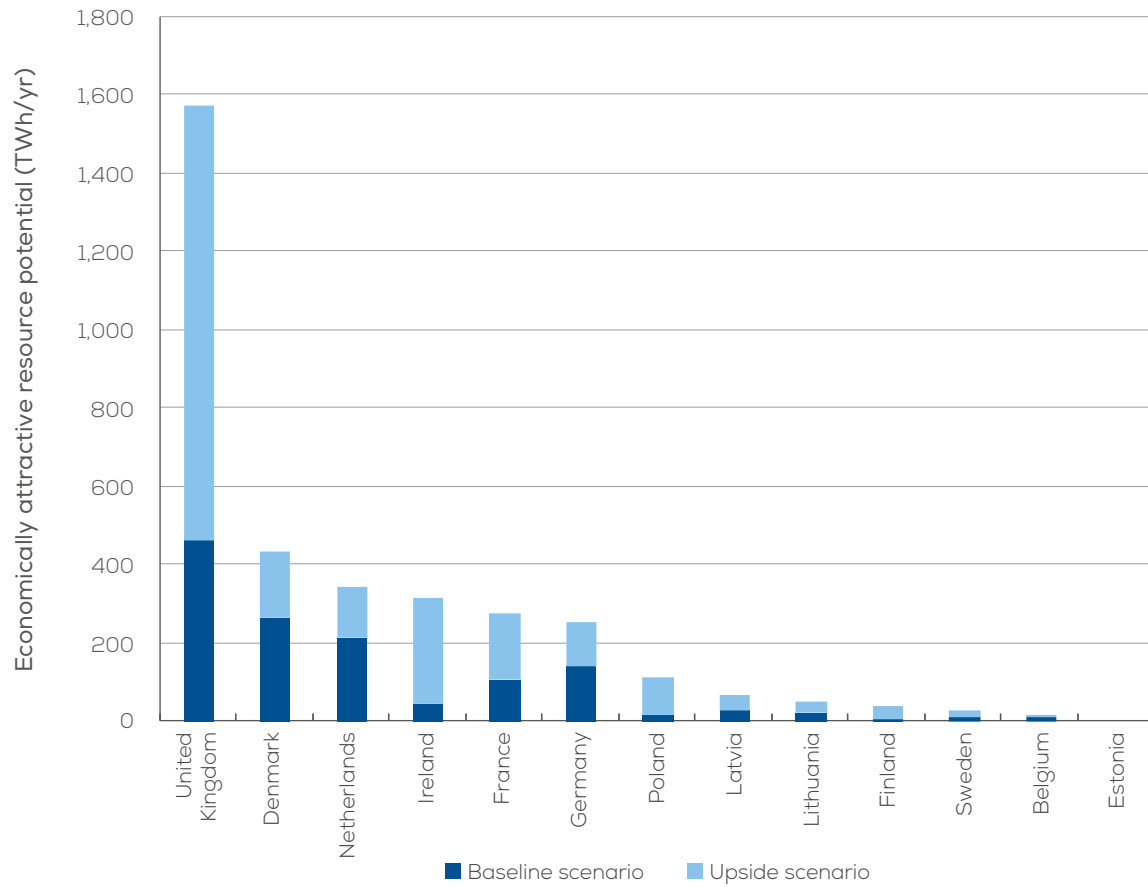
Source: BVG Associates for WindEurope

7.
CONCLUSIONS AND POLICY RECOMMENDATIONS

7.1. CONCLUSIONS

The offshore wind industry is moving fast from a niche technology to a **mainstream** supplier of low-carbon electricity. There are 12.6 GW of offshore wind operating in Europe. Recent government auction results show that the industry has achieved unprecedented levels of **competitiveness** through rapid progress in technology, industrial growth and a reduction in the cost of capital.

According to WindEurope, **offshore wind is expected to produce 7% to 11% of the EU's electricity demand by 2030**. This is only a fraction of the resource potential available in the European sea basins.

Our analysis shows that **offshore wind could in theory generate between 2,600 TWh and 6,000 TWh per year at a competitive cost - €65/MWh or below**, including grid connection and using the technologies that will have developed by 2030. This economically attractive resource potential would represent between 80% and 180% of the EU's total electricity demand in the baseline and upside scenarios respectively.

In addition, our analysis shows that up to **25% of the EU's electricity demand could, in theory, be met by offshore wind energy at an average of €54/MWh in the most favourable locations**. This assumes seabed-fixed foundations and includes grid connection. In the baseline scenario, this development would take place in the UK, Denmark, the Netherlands, Germany and France. In the upside scenario, capacity would be added in Ireland, Poland, Latvia and Lithuania, spanning all three sea basins and capitalising on the development of floating foundations.

The economically attractive resource potential from the baseline and upside scenarios is shown in Figure 24.

Economically attractive resource potential at the end of 2030

Economically attractive resource potential at the end of 2030
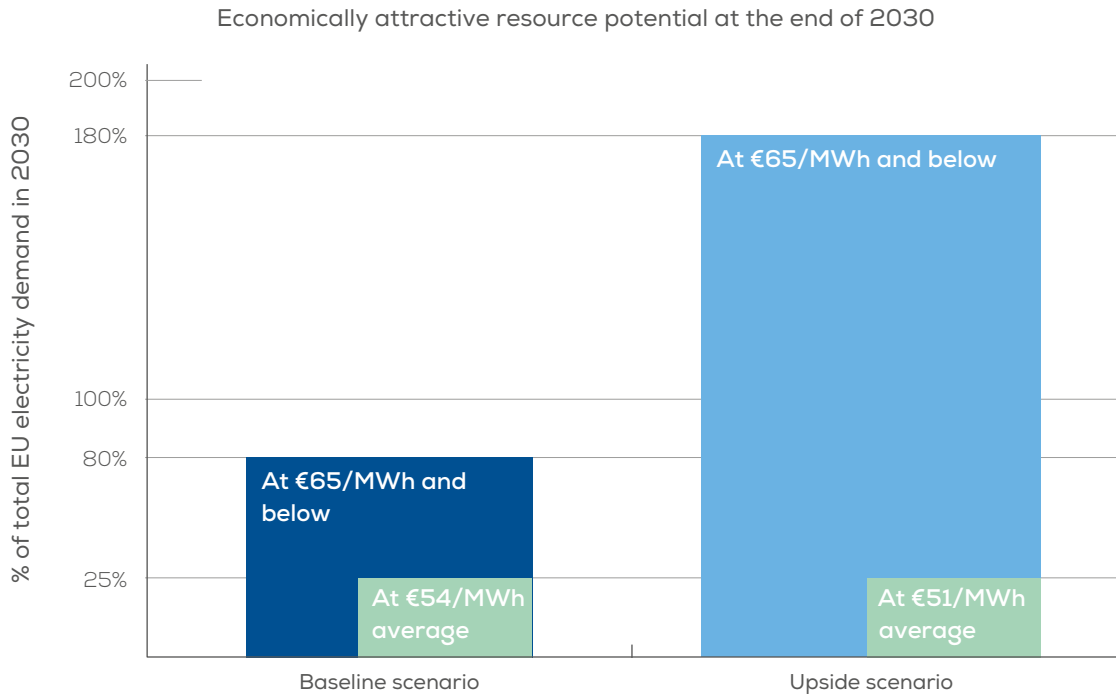
Source: BVG Associates for WindEurope

Delivering the upside scenario, will incur 7% higher funding support costs than the baseline scenario, but delivers 34% more capacity by the end of 2030. It also delivers benefits in terms of cost of energy reduction (an acceleration of two years compared to the baseline scenario) and spread of offshore wind within Europe. The upside scenario will also equip the supply chain in Europe with more of the experience and capability needed to export, especially to those markets with deeper water.

7.2. POLICY RECOMMENDATIONS

To enable the exploitation of the most cost-effective areas and achieve at least WindEurope's expectation of 7% to 11% of the EU's electricity demand by 2030, we call governments to:

- Commit to **ambitious deployment for offshore wind to 2030 and beyond** as part of national energy, climate and economic development plans.

- Cooperate at inter-governmental level and with developers and suppliers to **provide a continuous, sufficient and visible pipeline of projects** that enables industry to deliver further investments in technology, skills development, job creation and cost reduction throughout the supply chain.

- **Coordinate the timeline of tenders** across all the sea basins to provide greater investment clarity.

- **Cooperate in spatial planning analyses and site development** to ensure that the areas of lowest levelised cost of energy (LCOE) are exploited whilst providing power to all the locations where it is needed.

- Facilitate the **development of international grid infrastructure** including offshore grid connection hubs to support the exploitation of the lowest LCOE resource.

- **Offer market support mechanisms in a format that drives competition** and supports successful project delivery, until the point that they are no longer needed.

8.

ABOUT THE AUTHORS

8.1. BVG ASSOCIATES

BVGA is a technical, business and economics consultancy with expertise in wind and marine energy technologies. We are dedicated to helping our clients establish renewable energy generation as a major, responsible and cost-effective part of a sustainable global energy mix. BVGA has an average of over 10 years' experience in renewable energy, many of these being "hands on" with manufacturers, leading RD&D, purchasing and production departments. BVGA has consistently delivered to clients in many areas of the wind energy sector, including:

Market leaders and new entrants in wind turbine supply and UK and EU wind farm development

Market leaders and new entrants in wind farm component design and supply

New and established players of all sizes within the renewable energy industry across the globe, and

Government and regional agencies in the UK, France, Germany, USA, China and the Middle East including ADEME, NYSERDA, RenewableUK, The Crown Estate, the Energy Technologies Institute, Scottish Enterprise and other similar enabling bodies.

BVGA led this project for WindEurope with GeoSE as a significant subcontractor.

www.bvgassociates.com

8.2. GEOSPATIAL ENTERPRISES

GeoSE is a geospatial technology consultancy specialising in creating simple, yet elegant solutions to complex spatial problems, with a primary focus on supporting the renewable energy sector. With over 15 years consulting experience in the US, UK and Norway, we pride ourselves in delivering all of our projects on-time and within budget.

www.geose.co.uk.

APPENDIX

APPENDIX A:
LCOE DEFINITION, COST AND ENERGY ASSUMPTIONS

COST OF ENERGY

Levelised cost of energy (or LCOE) is defined as the revenue required (from whatever source) to earn a rate of return on investment equal to the discount rate (also referred to as WACC) over the life of the wind farm. Tax and inflation are not modelled. The technical definition is:

$$LCOE = \frac{\sum_{t=1}^{n} \dfrac{I_t + M_t}{(1+r)^t}}{\sum_{t=1}^{n} \dfrac{E_t}{(1+r)^t}}$$

Where:

I_t investment expenditure in year t

M_t operations and maintenance expenditure in year t

E_t energy generation in year t

r discount rate; and

n lifetime of the project in years.

A value for LCOE for a specific year (annual LCOE) can be calculated by setting the value of t to the year in question.

DEFINITIONS

Definitions of the scope of each element that makes up LCOE are summarised in Table 2, below.

TABLE 2

Definitions of the scope of each element

TYPE	PARAMETER	DEFINITION	UNIT
CAPEX	Development	Development and consenting work paid for by the developer up to the point of works commencement date (WCD). **Includes:** • Internal and external activities such as environmental and wildlife surveys, met mast (including installation) and front end engineering design (pre-FEED) and planning studies up to FID • Further site investigations and surveys after FID • Engineering (FEED) studies • Environmental monitoring during construction • Project management (work undertaken or contracted by the developer up to WCD) • Other administrative and professional services such as accountancy and legal advice, and • Any reservation payments to suppliers **Excludes:** • Construction phase insurance, and • Suppliers own project management.	€/MW
	Turbine	Payment to wind turbine manufacturer for the supply of the nacelle and its sub-systems, the blades and hub, and the turbine electrical systems to the point of connection to the array cables. **Includes**: • Delivery to nearest port to supplier • Five-year warranty, and • Commissioning costs. **Excludes**: • Tower • OMS costs, and • RD&D costs.	€/MW
	Tower	Tower, **including** internal fittings, ladders and lifts. **Excludes** turbine electrical systems even if located in the tower.	€/MW
	Support structure	**Includes:** • Payment to suppliers for the supply of the support structure comprising the foundation (including any piles, transition piece and secondary steelwork such as J-tubes and personnel access ladders and platforms) • Delivery to nearest port to supplier, and • Warranty. **Excludes:** • OMS costs, and • RD&D costs.	€/MW
	Array electrical	**Includes:** • Delivery to nearest port to supplier, and • Warranty. **Excludes:** • OMS costs, and • RD&D costs.	€/MW

TYPE	PARAMETER	DEFINITION	UNIT
CAPEX	Installation	**Includes:** • Transportation of all from each supplier's nearest port • Pre-assembly work completed at a construction port before the components are taken offshore • All installation work for support structures, turbines and array cables • Commissioning work for all but turbine (including snagging post-WCD) • Scour protection (for support structure and cable array), and • Subsea cable protection mats etc., as required. **Excludes** installation of offshore substation / transmission assets.	€/MW
	Transmission	**Includes:** • Offshore substation • Export cables • Onshore substation electrical works to facilitate connection • Installation of substation and export cables including trenching and burial **Excludes** costs of dedicated offshore wind connection hubs.	
OPEX	Operation and planned maintenance	Starts once first turbine is commissioned. **Includes**: • Operational costs relating to the day-to-day control of the wind farm including the costs of port facilities, buildings and personnel on long-term hire. • Condition monitoring, and • Planned preventative maintenance, health and safety inspections	€/MW/yr
	Unplanned service	Starts once the first turbine is commissioned. **Includes** reactive service in response to unplanned systems failure in the turbine or electrical systems.	€/MW/yr
	Other	Other OPEX covers fixed cost elements that are unaffected by technology innovations, **including**: • Seabed leasing costs • Contributions to community funds, and Monitoring of the local environmental impact of the wind farm.	€/MW/yr
	Transmission	All operation, maintenance and service costs associated with the wind farm electrical transmission system.	€/MW/yr
AEP	Gross AEP	The gross AEP averaged over the wind farm life at the output of the turbines. **Excludes** aerodynamic array losses, electrical array losses and other losses. **Includes** any site air density adjustments from the standard turbine power curve.	MWh/yr/MW
	Losses	**Includes:** • Lifetime energy loss from cut-in / cut-out hysteresis, power curve degradation, and power performance loss. • Wake losses. • Electrical array losses to the offshore metering point, and • Losses due to lack of availability of wind farm elements. **Excludes** transmission losses.	%
	Net AEP	The net AEP averaged over the wind farm life at the offshore metering point at entry to offshore substation.	MWh/yr/MW
	Net capacity factor	The net AEP divided by the total theoretical maximum AEP of 8766 MWh/MW/year	%

WIND FARM ASSUMPTIONS

Baseline costs and the impact of spatial effects are based on the following assumptions for offshore wind.

Global assumptions

- Real (end 2016) prices
- Commodity prices fixed at the average for 2016, and
- Market expectation "mid view" for the baseline scenario and constant macro-economic factors.

Wind farm assumptions

General
The general assumptions are:
- A 1,000MW wind farm in an established Northern European market, using European supply chain
- Turbines are spaced at nine rotor diameters (in prevailing wind direction) and six rotor diameters (across prevailing wind direction) in a rectangle
- A wind farm design is used that is certificated for an operational life 30 years (baseline) and 32 years (upside) in 2030
- The lowest point of the rotor sweep is at least 22m above MHWS
- The development and construction costs are funded entirely by the project developer
- A multi-contract approach is used to contracting for construction, and
- WACC is 5.5% for the wind farm and 4.5% for the transmission system.

Spend profile

TABLE 3
CAPEX spend profile

YEAR	-5	-4	-3	-2	-1	0
CAPEX SPEND			6%	10%	34%	50%

Year 1 is defined as year of first full generation.
AEP and OPEX are assumed as 100% for each year within the operational lifetime.

Meteorological regime
The meteorological regime assumptions are:
- A wind shear exponent of 0.12
- Rayleigh wind speed distribution
- A mean annual average temperature of 10°C
- The tidal range of 4m and the Hs of 1.8m is exceeded on 20% of the days over a year on average, and
- No storm surge is considered.

Turbine
The turbine assumptions are:
- The turbine is certified to Class IA to international offshore wind turbine design standard IEC 61400-3
- The 13MW baseline turbine has a three-bladed upwind, low-ratio gearbox mid speed, mid-voltage AC generator, a full-span power converter. It has a rotor of 212m diameter, and a specific rating of around 368W/m². The upside 15MW turbine has a rotor diameter of 228m and hence the same specific rating.

Support structure
The support structure assumptions are:
- A monopile with separate transition piece and tower, which is used for all waters shallower than 35m
- A four-legged piled jacket with a separate tower, which is used for waters 35m to 70m deep. We assumed that in some locations, gravity base foundations would be used in place of jackets, but that the overall cost impact is neutral, so these were not separately modelled.
- A floating tension-leg platform foundation, which is used in water deeper than 70m
- Ground conditions are "typical", namely 10m dense sand on 15m stiff clay, only occasionally with locations with lower bearing pressure, or the presence of boulders or significant gradients.

Array electrical
The array electrical assumption is that a three-core 66kV AC cable in fully flexible strings is used, that is, with provision to isolate an individual turbine.

Construction

The construction assumptions are:

- Construction with fixed foundations is carried out sequentially by the foundation, array cable, then the pre-assembled tower and turbine together. For the floating foundation, construction takes place at the quayside, and the complete system is towed out using a stabilising barge, and connected to pre-installed tendons and array electrical cables.
- A jack-up vessel collects components from the construction port for turbine installation
- A single jack-up is used to install the monopile and transition pieces
- Two jack-ups are used for jacket installation and pre-piling, collecting components from the construction port
- Two tugs or anchor handling vessels are sued to install floating foundations and their moorings, and
- Array cables are installed via J-tubes, with separate cable lay and survey and burial.
- Decommissioning reverses the assembly process to result in construction taking one year. Piles and cables are cut off at a depth below the sea bed, which is unlikely to lead to uncovering. Environmental monitoring is conducted at the end. The residual value and cost of scrapping are ignored.

Transmission

The transmission system uses 220kV AC for distances to grid up to 135km. For 135km and beyond, the transmission uses 300kV DC.

OMS

Access is by SOVs or accommodation platforms, while jack-ups are used for major component replacement for fixed foundations, while towing back to port is used for floating foundations.

APPENDIX B:
LCOE COMPARISON IN 2030

To enable a like-for-like comparison of the LCOE that can be achieved in 2030 under the two scenarios, we used a typical site, as detailed in Table 4. This is representative of sites expected to start operating in 2030.

Based on the expected status of technology, finance and supply chain in for project to be installed in 2030 in the two scenarios and the assumptions in Appendix A, we anticipate that at this typical offshore site, the LCOE in the baseline scenario will be €59.9/MWh and the upside scenario will be €55.9/MWh. The expected breakdown of costs and their contributions to LCOE is shown in Figure 25.

The lower LCOE achieved in the upside scenario results from our assumption that larger turbines will be available. We also assumed that other technology and supply chain improvements will be achieved through the higher installed volumes in the upside scenario. WACC is the same in both scenarios.

TABLE 4

Typical site used for LCOE comparison between scenarios

VARIABLE	VALUE
Annual mean wind speed at 100m above mean sea level (MSL) (m/s)	10
Water depth below MSL (m)	35
Distance to construction port (km)	100
Distance to operations and maintenance port (km)	100
Offshore export cable route length (km)	70
Onshore export cable route length (km)	15

FIGURE 25

LCOE breakdowns and capacity factors for a project installed on a typical site in 2030 under baseline and upside scenarios
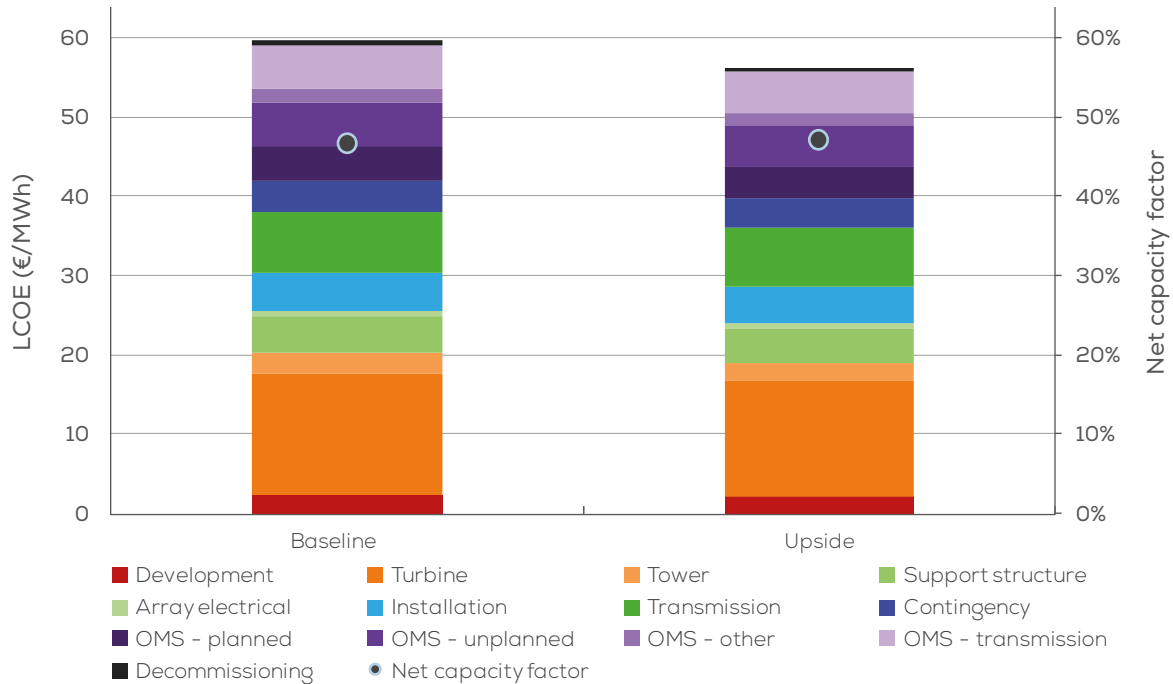
Source: BVG Associates for WindEurope

APPENDIX C:
GEOSPATIAL DATA SOURCES AND DETAILED METHODOLOGY

Data sources

We compiled a database of spatial parameters for reference by a geographic information system (GIS). We used the wide variety of sources to populate the database detailed below.

We quality assured the data, resampled it to a consistent 5x5km resolution and aligned it to ensure consistency in the calculations across international boundaries. The spatial parameters and features we included were:

- **Annual mean wind speed:** The wind speed at 100m above MSL, determined as the average of all hourly values from the 30-year coverage of the National Centers for Environmental Prediction (NCEP) Climate Forecast System Reanalysis and Reforecast wind hindcast dataset.

- **Water depth:** Water depth from MSL, as derived from the General Bathymetric Chart of the Oceans (GEBCO) global 30 arc-second interval grid, reprocessed to a 5x5km resolution using standard GIS resampling methods.

- **Distance to construction port:** Port locations as identified by BVGA and WindEurope from which the GIS generated steaming distances around land features. These are shown in Appendix D, along with a chart showing the distances.

- **Distance to shore:** Straight-line distance to mainland-shore (excluding islands) as determined by the GIS[7].

- **Distance to grid:** Straight-line distance to either the nearest shore landing point, or an offshore hub, as determined by the GIS. Where the connection is to the shore, we increased the distance by 15km to allow for the export cabling from the shore landing point to the grid network connection point.

- **Exclusions:** We compiled a database of spatial features representing other uses of the seabed. This database covers areas that are not available for offshore wind energy development, or are only available at a reduced density. It includes:

- International Maritime Organization (IMO) shipping routes. The IMO is the authoritative provider of information on travel separation schemes, traffic lanes, deep-water routes, anchorage areas, and other vessel transit information.

- Exclusive environmental designations
  › The Common Database on Designated Areas (CDDA) is the official source of marine protected areas (MPAs) for European countries. It includes nationally designated areas such as: marine conservations zones (MCZs), marine nature parks, nature reserves, national parks, and other protected sites.

  › Natura2000 is an ecological network of protected areas setup to ensure the survival of Europe's most valuable species and habitats and is based upon the 1979 Birds Directive and 1992 Habitats Directive. The database consists of special protection areas (SPAs) and special conservation interests (SCIs).

- Oil and gas pipelines and telecommunication cables, including a buffer distance of one nautical mile (nm) either side of the line feature.

- Dumped munitions: – European Marine Observation and Data Network locations for munitions dumping grounds and sites of unexploded ordnance.

- Water over 1,000m deep, which we anticipated will not be viable for floating foundations in 2030.

- Inshore waters comprising sea area within 5nm of the coast and between 5nm and 12nm from the coast, so that we could explore the contribution of near-shore sea to the technical potential.

- Sea ice in the Baltic Sea coincident with water depths over 70m.

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7.   The primary landmasses of Ireland and England, Scotland and Wales are considered "mainland" for the purposes of this analysis.

We reviewed the possible additional exclusions for fisheries, civil and military aviation and archaeology but did not add these. Given the wind farm densities we used and assuming that appropriate mitigation techniques would be adopted, we considered the averaged impact of this to be small.

Geospatial analysis methodology

The geospatial analysis had three steps:

1. Geospatial extraction. After data collation and pre-processing, the Spatial Cost Engine (SCE) extracted the information for each 5x5km cell of the analysis area.

2. Energy and cost algorithm processing. We developed cost parameters and algorithms for capital expenditure (CAPEX), operational expenditure (OPEX), annual energy production (AEP) to calculate LCOE as discussed in Appendix A.

We processed the extracted geospatial information for each data point and passed the LCOE results back to the SCE. With the addition of EEZ and exclusion information for each data point, the energy and cost algorithms derived the summary statistics for the gross, technical and economically attractiveal resource potential analyses

3. Spatial output analysis. After energy and cost algorithm processing, we spatialised the resulting values and produced spatial plots of the analysis area and the supporting data by sea basin and country.

Depending on the density used, between 13 and 26 5x5km cells are required to make-up a 1,000 MW wind farm. In this study we assumed that any isolated cells could be included with nearby areas without additional cost and thus we did not exclude them from the analysis.

TABLE 5

Analysis of area excluded in the analysis of technical potential

DISTANCE FROM SHORE	TOTAL AREA USED IN DERIVING GROSS POTENTIAL (KM²)	PERCENTAGE OF TOTAL AREA EXCLUDED FOR THE ANALYSIS OF BASELINE AND UPSIDE TECHNICAL POTENTIAL (exclusions for sea ice, water depth and mean wind speed are not considered; and density reductions are not factored-in)
	Total area used in deriving gross potential (km2)	100.0%
>5nm to 12nm	220,787	18.6%
>12nm to 50nm	650,231	13.2%
>50nm to boundary of EEZ	784,977	7.1%

TABLE 6

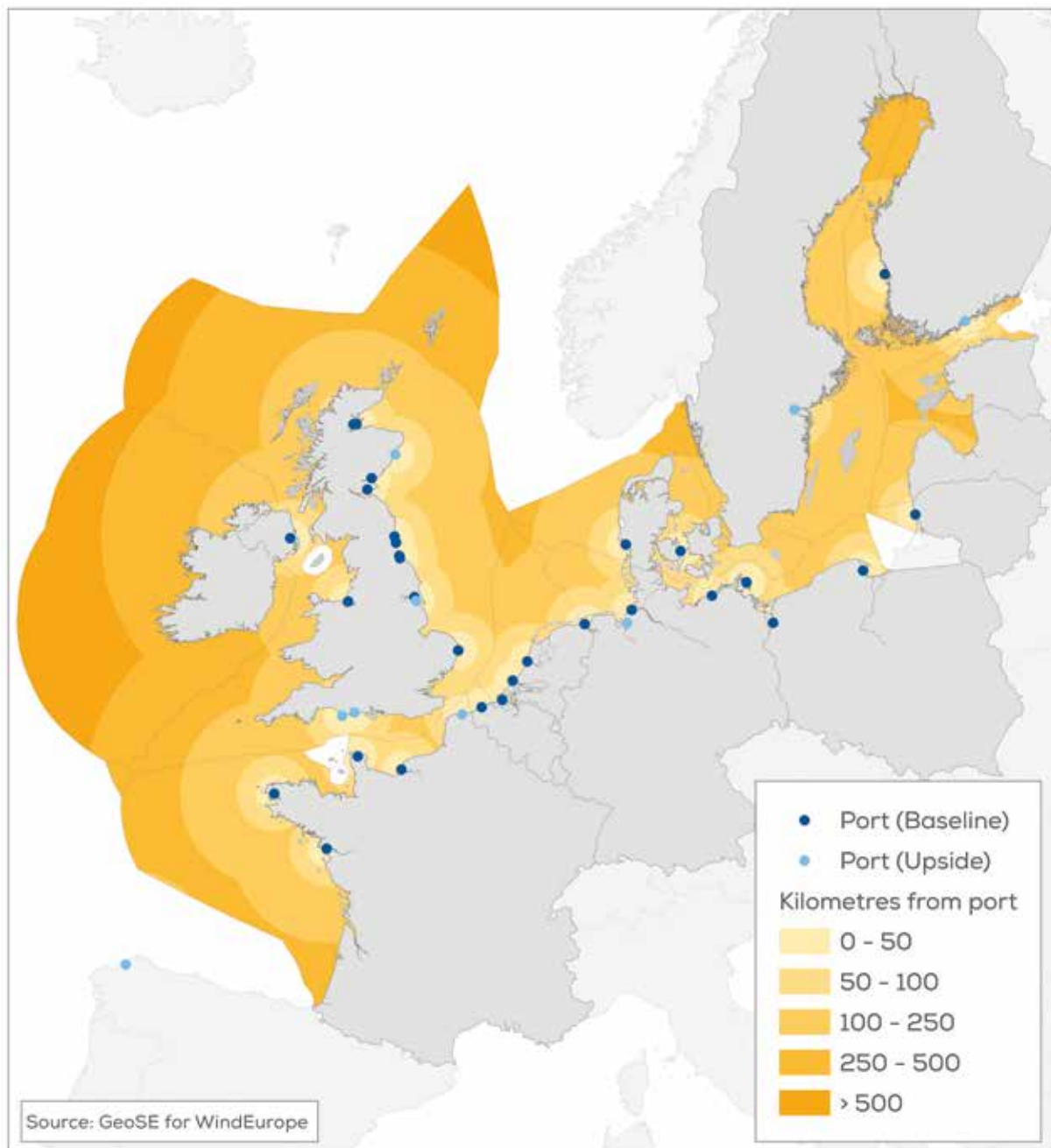Geospatial dependencies of components of LCOE

COMPONENT OF LCOE	DEPENDENCY OF LCOE COMPONENT ON GEOSPATIAL CRITERIA
Support structure (foundation) choice: Monopile, jacket (or gravity base), floating foundation	Water depth
Transmission choice: HVAC, HVDC	Distance to grid connection or offshore hub
Development CAPEX	Distance to shore (assumes a development port can be used close to the nearest point on the shore)
Foundation CAPEX	Foundation choice Water depth
Transmission CAPEX	Transmission choice Water depth Distance to grid connection or offshore hub
Installation CAPEX	Foundation choice Water depth Distance to construction and operations port (additional ports apply in upside scenario)
Operation, planned maintenance, unplanned service and transmission OPEX	Distance to construction and operations port (additional ports apply in upside scenario)
Gross AEP	Mean wind speed at hub height
Losses	Mean wind speed at hub height

APPENDIX D:
PORT LOCATIONS USED

The locations of the ports used for construction and for operations, and the distance from those ports to all parts of our analysis area are shown in Figure 26.

FIGURE 26

Ports used in the upside scenario for construction and operations and distances to all areas analysed

Source: GeoSE for WindEurope

APPENDIX E:
GLOSSARY

AEP	Annual energy production.
CAPEX	Capital expenditure.
DECEX	Decommissioning expenditure.
FID	Final investment decision, defined here as that point of a project life cycle at which all consents, agreements and contracts that are required in order to commence a project construction have been signed (or are at or near execution form) and there is a firm commitment by equity holders and, in the case of debt finance, debt funders, to provide or mobilise funding to cover the majority of construction costs.
Gross AEP	Predicted annual energy production based on turbine power curve, excluding losses.
GW	Gigawatt
GWh	Gigawatt hour
Hs	Significant wave height.
LCOE	Levelised cost of energy, considered here as pre-tax and real in end 2016 terms. For details of methodology, see Appendix A.
MSL	Mean sea level.
MW	Megawatt.
MWh	Megawatt hour.
Net AEP	Metered annual energy production at the offshore substation, including wind farm losses.
OMS	Operation, planned maintenance and unplanned service.
OPEX	Operational expenditure.
TWh	Terrawatt hour
WACC	Weighted average cost of capital, considered here as real and pre-tax.

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