Evaluation of offshore wind resources by scale of development

Möller, Bernd; Hong, Lixuan; Lonsing, Reinhard ; Hvelplund, Frede

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Bernd Möller*
Department of Planning and Development
Aalborg University, Denmark
e–mail: berndm@plan.aau.dk

Lixuan Hong
Department of Planning and Development
Aalborg University, Denmark
e–mail: lixuan@plan.aau.dk

Reinhard Lonsing
Independent researcher
Winsen, Germany
email: Reinhard@lonsing.de

Frede Hvelplund
Department of Planning and Development
Aalborg University, Denmark
e–mail: hvelplund@plan.aau.dk

ABSTRACT

Offshore wind energy has developed rapidly in terms of turbine and project size, and currently undergoes a significant up-scaling to turbines and parks at greater distance to shore and deeper waters. Expectations to the positive effect of economies of scale on power production costs, however, have not materialized as yet. On the contrary, anticipated electricity generation costs have been on the increase for each increment of technology scale. Moreover, the cost reductions anticipated for progressing along a technological learning curve have are not apparent, and it seems that not all the additional costs can be explained by deeper water, higher distance to shore, bottlenecks in supply or higher raw material costs.

The present paper addresses the scale of offshore wind parks for Denmark and invites to reconsider the technological and institutional choices made. Based on a continuous resource-economic model operating in a geographical information systems (GIS) environment, which describes resources, costs and area constraints in a spatially explicit way, the relation between project size, location, costs and ownership is analysed. Two scenarios are presented, which describe a state-of-the-art development as well as a sketch of smaller, locally owned parks that may have several economic advantages but require a greater planning and acceptance because of higher visual impact and area competition.

INTRODUCTION

Offshore wind energy was first developed in the early 1990s and has since expanded at a significant pace. Development has further accelerated since the year 2003, when larger turbines became available, experience was gained with greater water depths and distances to shore, and the confidence of developers grew [1]. There seems to be a law of scale, which directs development to ever larger turbines located at greater distances to shore, at greater water depths and in larger parks [2]. This law initially is driven by the facts that better wind resources exist further away from land; that one should have the largest possible power output per turbine foundation; and that collective infrastructure investments pay off better with larger installed park capacities. This scaling should eventually ensure that power production costs decrease and offshore wind energy becomes competitive with onshore wind energy and other forms of power production. Looking at the figures so far, this is not the case.

Currently there seems to be no limit to the increase of investment costs per MW of offshore wind energy. While early but influential studies from the year 2007 and before quote investment costs of 1.2 to 2.4 M€/MW [3], this figure increased to 3 M€/MW in 2007 [2]. The recently opened Thanet park in the UK cost 3.5 M€/MW [4] , while Bard 1 currently is estimated to cost 4 M€/MW [5] and near future installations are likely to cost 5 M€/MW. Albeit there has been a progression towards more efficient turbines located in better wind regimes, and one has to acknowledge the fact that offshore wind energy still is at the beginning of a long learning curve, it does not seem that the scaling law works properly.

Already in 2007 the German government [6] noticed an increase in costs driven primarily by the following factors: a) underestimation of risks and the necessary replacement of parts or entire early installations, b) developers' migration to countries with better feed-in tariffs, c) higher costs of turbines driven by a high demand and production bottlenecks, and d) the transition of offshore wind energy projects from medium scale businesses on a national level to pan-European projects run by multinational utilities, which necessarily have higher expectations to profit than the smaller companies, who have carried along the many projects while they were in their design phase. Furthermore it seems that investment costs generally have been underestimated for parks currently developed. The scaling that is witnessed is clearly expressed by the large utility E.ON [7], who speaks of a 20:20 threshold: moving beyond 20 m sea depth and 20 km distance to shore (this is where almost all current wind parks are located) requires even larger turbines, stronger foundations, and new logistics. This means a considerable increase in costs compared to the first Danish and British parks located within the 20:20 threshold.

Wind turbine manufacturers may be shy to admit that there are great potentials of cost reductions while demand exceeds supply. And while the cost shares of turbines are reduced from 70% to a mere 40% [8], this leaves the necessary cost reductions to foundations, cabling and installation. There is little reason to believe that these new technologies will see substantial cost reductions while still in exponential growth. And as long as the technological risk is substantial, and ever larger conglomerates of companies drive the development, there is not much hope for cheap offshore wind generation within the next 10 years, when the basic planning of off shore wind energy is going to be carried out and the best locations available are going to be exploited.

The objective of this paper is to evaluate the meaning of scale by carrying out resource-economic analyses for two development scenarios: one where the installation of offshore wind energy follows the trend; and another where the same amount of wind energy is produced in smaller parks near shore. Costs and a series of other parameters are then compared, and policy implications discussed. For this purpose two databases for the SCREAM-model (Spatially Continuous Resource Economic Analysis Model, [9, 10]) are being built, which include a spatial model of the Danish exclusive economic zone (EEZ) with most of the natural, technical and planning parameters that determine the availability of areas for offshore wind energy, the utilizable wind resource, and its marginal costs in a continuous manner.

Questions to be answered by this analysis are:

1. Is there space for sufficient amounts of smaller scale offshore wind energy in Danish waters?

2. Will a step back to smaller scale offshore wind energy lead to higher or lower generation costs?
3. Which scale of development is more robust to changes in technical, economic, environmental and social conditions?

Materials and methods

The SCREAM model is built using a raster-based geographical information system (GIS) [11], which divides the EEZ area into uniform square cells of 1 km^2 size, which form the smallest entities where choices are made on area availability, where the wind resource is calculated in MWh/a, and costs computed in €/MWh. Point of departure is the entire area of the Danish EEZ, see figure 1, and no areas are excluded to begin with other than, in this paper, the waters around the island of Bornholm, for which no usable wind resource map could be sourced. Wind energy potential is calculated using a WAsP/KAMM model prepared by Risø [12], measuring wind energy potential as power density in W/m^2. Power production is calculated using wind power density, specifications for a given choice of turbine, and a park configuration, which results in an installed power density map. Costs are computed using specific investments costs for turbines, foundations, grid connections and installation, which all or partly depend on spatial parameters such as water depth and distance to shore. Operation and maintenance costs are a function of distance to service harbour. Areas excluded for the development of offshore wind energy are derived from legislation (Natura 2000, Danish conservation), navigation charts (impure ground, anchorages, pipelines and offshore installations) [13] and by other planning data (gravel extraction, infrastructure, radar and communication). Areas sensitive to visual impact are modelled using an intervisibility model of coastal stretches, which takes into account the higher visibility from elevated coasts and their hinterland. Finally, areas used for shipping are excluded using data from AIS (Automatic Identification System) [14], which has been converted to a shipping density theme used to exclude areas and specify a safety buffer to navigation corridors. The remaining areas available for wind power development have been further scrutinised for coherent and sufficient geometry to exclude areas too small and too dispersed. All three model aspects: available areas, power production potentials, and the associated power production costs, are then used to model the cumulative available wind power resource and its marginal production costs, plotted in cost-supply curves for resource economic analysis. The SCREAM model has predecessors in [15] but works in a continuous manner, meaning that resources and costs are assessed continuously grid cell by grid cell for the entire available area, rather than specifying areas beforehand [16], merely locating spatially unspecific projects [3], or assuming a generic park size [17].

Data was collected using a review of available technology and cost data [3, 9, 10, 17, 18, 19]. The model derives spatially explicit cost functions from empirical offshore project data, by extracting the correlation of costs and spatial parameters such as water depth and distance to shore and harbours. Apart from spatial parameters, a few other assumptions independent of location were included in the cost calculations, see table 1.

Table 1. Assumptions related to non-spatial parameters.

ASSUMED NON-SPATIAL PARAMETER	VALUE
Fixed turbine investment costs [€/MW]	1,300,000
Average power coefficient [1]	0.4
Average turbine availability [1]	0.8
Average park efficiency [1]	0.9
Socio-economic discount rate, Danish government	6%
Socio-economic lifetime [years]	20

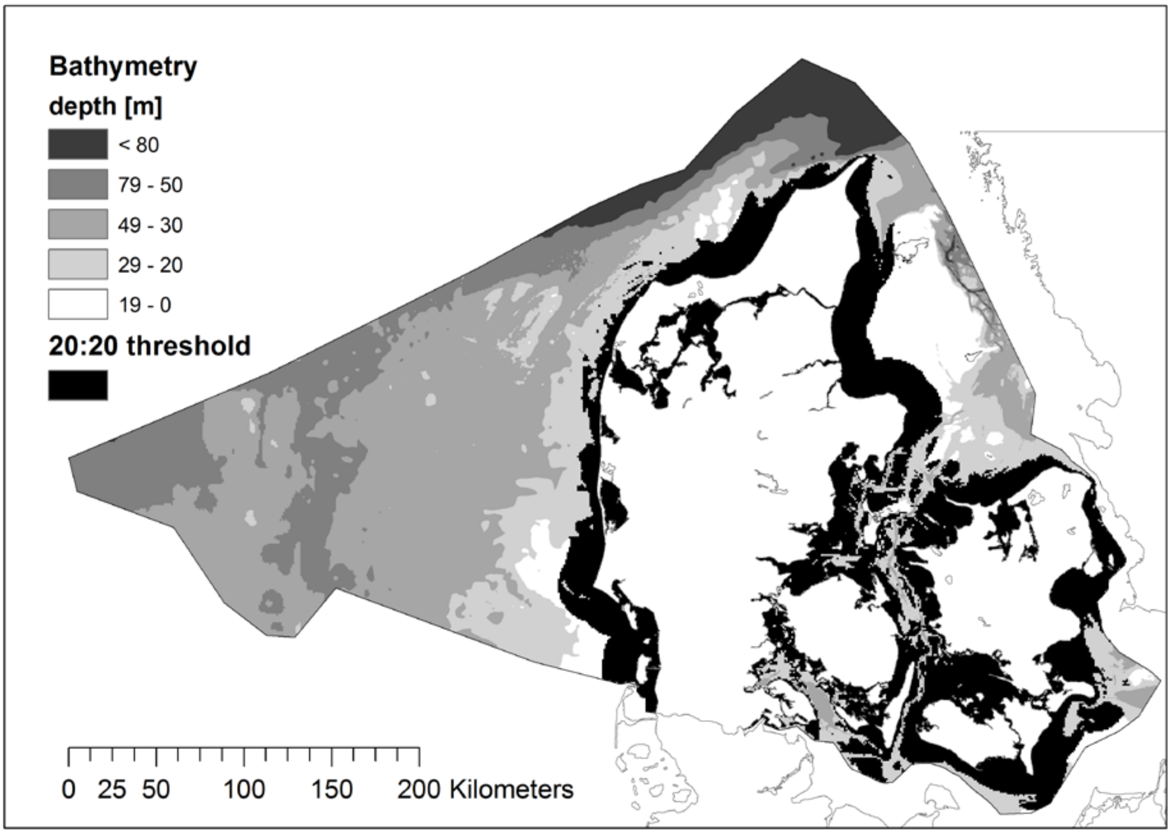

Figure 1. The study area of 93,800 km^{2}comprises the Danish EEZ excluding the island of Bornholm. The map visualises the so-called 20:20 threshold, areas nearer than 20 km to any mainland or large island coast, and with water depths of less than 20 m.

Hypotheses on the meaning of scale and specification of scenarios

The main thought driving this analysis is that it may be advantageous for the economy of renewable energy to reverse the trend towards ever larges scales of development. Besides lower costs to society, such a paradigm change may possibly avoid some other disadvantages of large scale offshore wind energy: high financial and operational risk, system integration challenges, low public acceptance and little economic benefit for those regions where renewable energy plants are going to be placed. At the same time the analysis must relate to the significant amount of uncertainty, which characterises the offshore wind energy industry, in order to make results robust. The analysis therefore uses scenarios and conditions to produce a matrix of results, which distinguishes between technological choice among several available technical solutions on one hand, and exogenous influence by natural conditions, commodity prices, or legislation on the other. Furthermore, a sensitivity analysis of each development scenario assesses the potential influence of changing planning parameters such as area competition or conservation. Common for the scenario analyses in this paper is the final goal to produce 17 TWh annually from offshore wind turbines in the year 2020 in Denmark, equivalent to 50% of the prognosticated electricity demand.

A few assumptions regarding the economy of these choices are generic. System costs for maintaining backup reserves, transmission capacity to onshore grid access points, and other are excluded as they are assumed to be the same for the two scenarios. Interest rates are specified on three levels: a socio-economic interest of 6% for general purposes, a low rate of 4% for cooperative and public ownership, and an 8% rate for large corporations, where higher expectations to profit are reflected in higher interest rates.

Two sets of scenarios were specified. One uses a progression of park size, turbine capacity, and required distance from shore for corporately owned large scale projects. This basically follows a trend already now visible for the next generations of offshore parks to be built, which results in parks up to 600 MW with 120 turbines of 5 MW each. These parks will require at least 20km distance to shore and involve massive investments in grid connections and offshore transformer platforms, manned service stations etc. Larger parks may lead to better utilisation of common infrastructure, and will produce more electricity from installed capacity. They do require large buffer zones to reduce wake and onshore grid access points need to be on the 400kV level, if not require a completely new offshore supergrid infrastructure.

The second scenario uses smaller parks with 75 MW in size with turbines of 3 MW capacity, which can be located nearer to shore, particularly if they are locally owned. They will be located within the 20:20 threshold. Requirements to infrastructure are fewer, and less space is required for the single projects, but more in total for meeting the power production targets. Investment costs are generally lower, but specific power production is less than for the large scale scenario. Onshore grid access points can be 60 kV for smaller parks, and 132/150 kV for the larger parks in this scenario. Offshore transformers are only required for multiple parks at greater distances, while single parks less than 10km from the shore can spare this expense and be connected using 33 kV AC lines.

Spatial aspects determining costs and availability

Costs of grid connection, foundations, installation, operation and maintenance, and finally of power production all depend on spatial aspects such as distance to shore or harbour, water depth and wind energy potential. Hence these cost components have been modelled using geographical distributions of input.

Choice of grid connection technology is given by park size and distance to shore [17, 20], see table 1. While the smallest parks near shore can do with simple AC systems with onshore feed-in transformers, larger parks at greater distances soon need higher voltage AC connection cables and thus offshore transformer stations. Even larger distances require DC systems, which are cheaper by the kilometre but require costly off- and onshore converter stations. On the other hand, these systems then can accommodate massive parks of several GW.

Grid costs are calculated by the cost weighted distance from the nearest grid access point to the offshore location. All power lines and cables on the medium (132/150 kV) and high voltage (400 kV) levels are included for the near shore scenario, while the far shore development only can be connected to the 400 kV level. A cost weighted distance function then uses specific cabling costs, which are a function of system choice (33 kV AC, 150 kV

AC or HVDC), which again is a function of distance (10, 50, 100 km or longer) and installed park power. Neglected here is the fact that while current small scale developments each have their own individual grid connections, future large scale developments may see the installation of HVDC super infrastructures with offshore grid access points, probably on an international scale. Instead, the economy of scale is left to the choice of technology, which is a matter of scenario specification: near shore installations use AC systems of 33 kV or 150 kV with or without offshore transformers, while far shore installations use 150 kV AC systems with offshore transformers if within 100 km from the nearest grid access point, otherwise they use modular HVDC connectors. This is very much in line with the recent grid development plan by the Danish TSO [21]. Cost data are derived from ABB [20] and the EU Windspeed project [17]. Table 2 describes the cost model for grid connection

Table 2. Cost components of offshore grid connection by scale and distance.

SYSTEM CHOICE	DISTANCE TO GRID [KM]	CABLING COSTS [€/MW/M]	SYSTEM COSTS [€/MW]
Near shore direct, small parks, 33 kV AC	0 - 10	6.00	10,000
Near shore with offshore transformer	10 – 50	3.00	100,000
Far shore with offshore transformer	50 - 100	3.00	100,000
Far shore HVDC	100 - 500	1.00	300,000

Foundation technology is primarily determined by water depth, but also turbine size. While gravity foundations are used for the first offshore parks in shallow waters up to 15 m and with smaller turbines, the currently most used design is the monopole design for sea depths up to 30 m. Greater depths require tripod, jacket or triple pile foundations. Floating designs are currently being developed for high water depths, but are not relevant for Danish waters. A cost function has been derived from various sources [3, 17, 22] which expresses costs per MW of installed capacity as a linear function of water depth:

$$C_f = -14557 * d + 270667 \qquad (1)$$

Where C_f are the foundation costs in €/MW and d is the water depth in negative values. Depths of 60 m or more are excluded.

The accessibility to installation and service harbours of sufficient tonnage capacity and short distance to offshore installations is important, mainly during construction but also for operation and maintenance. While near-shore installations may be serviced from existing harbours, large parks at great distances from the coasts will be equipped with manned platforms carrying converters or transformers as well as accommodation. The cost function used is based on [17] and expresses operation and maintenance costs as a function of distance. It is assumed here that far shore installations beyond 50 km from the coast have manned operation platforms, which reduce the distance related costs at a higher fixed cost.

$$C_{om} = \begin{Bmatrix} 0.00026 * d + 17 if\_d < 50000 \\ 0.0001 * d + 25 if\_d \geq 50000 \end{Bmatrix} \qquad (2)$$

Where C_{om} are the operation costs in €/MWh net electricity production and *d* is the distance to coast [m].

Costs for turbine installations are modelled using available experiences from existing projects, including the daily rent for an installation vessel, as well as terminal time and a distance component for the installation of one turbine:

$$C_{inst} = 0.114 * d + 25000 \quad (3)$$

Where c_{inst} is the installation cost [€] per turbine and d is the distance [m] from a major supply harbour.

The costs of power production are here calculated as the levelised production costs (LPC), which express the average cost of generating one unit of electricity during the useful lifetime, including annualised investment costs:

$$LPC = \frac{I}{aE} + \frac{om}{E} \quad (4)$$

Where *I* is the total investment (turbine, grid, foundation and installation costs) in €, *om* the operation and maintenance costs [€/MWh], *E* the annual power production [MWh] and a the annuity factor:

$$a = \frac{1-(1+r)^{-n}}{r} \quad (5)$$

with *n* being the useful lifetime in years (20 years are assumed) and *r* the interest rate.

The actual wind regime at a given offshore location is the single most important aspect of the wind energy economy, defining the income of the park. Wind resources are generally better at greater distances from the shores, but this is asymmetric and depends on the prevailing wind direction, which generally favours locations in the North Sea. Locations in the Baltic Sea are often leeward, with significantly reduced wind potentials.

Shipping may constitute competition on areas available for wind energy. Three ship movement patterns can be identified: 1) random shipping and fisheries, 2) dense traffic patterns in waters busy with undirected ship movements, and 3) naval routes as marked in charts with clear traffic patterns. Wind turbines may be installed following two rules: either outside routes or areas with intense traffic, where ship movement density is the only criterion, or at a distance of clearly marked routes. Using shipping data recorded by land based AIS by the Danish Naval Safety Authority for 14 periods of 48 h duration evenly distributed from January to December 2008 it was possible to extrapolate annual shipping density within each grid cell [14]. If a cell was passed through less than 10 times per year, it was found well outside the busy areas and even at a safety distance of at least one nautical mile from the centrelines of the international routes in the Baltic. To create coherent areas where shipping disallows for the erection of offshore wind parks, the areas with sufficient shipping density were further refined by minimal focal sums of densities around each cell.

Visibility of an offshore wind energy project is subject to turbine size and distance. In a worst case situation, taking into account the curvature of the Earth, a 100 m high object is visible at a distance of 40 km for an eye height of 2 m, or a flat beach. A coast elevated to 30 m extends visibility to theoretically 60 km. While a large number of factors influence the visibility of and, in particular, the visual impact caused by wind turbines [23], the essence is that it is in the eye of the beholder at which distance an offshore wind park needs to be built to be less of a problem. The approach used here applies intervisibility calculations between all land locations represented by a digital elevation model, to all offshore locations using hub heights of 80 and 100 m for possible offshore plants. This way, it can be modelled which parts of the surrounding seas are particularly sensitive to installing offshore parks. In contrast to applying fixed distances, which do not take into account the increased visibility by coastal elevation, this method allows for ranging the visibility buffer by hypothetical visibility thresholds, which express how visible any given offshore area containing wind turbines of a selected height is from the surrounding land areas. By weighing visibility count higher for natural and conservation areas than for harbour and industrial areas, the visibility criterion can be further refined.

Turbine installation patterns have a significant influence on area use, output, visual impact and costs. Studies [24] have shown that wake issues, because of less turbulent flow over open seas, are generally more critical than at land locations. Two sizes of offshore parks have been selected for near shore and far shore developments. While far shore parks are based on a generic size of 600 MW and made up of 120 turbines, these will be placed in a 8x15 rectangular pattern. The smaller near shore parks consist of 25 turbines to reach 75 MW installed capacity each, placed in a 5x5 pattern. The precise geometry of the park is however not addressed here; rather, an average area use is assumed and a generic park density is applied to the areas found suitable, which assumes an 8x8 times rotor diameter spacing between turbines and which includes distances to be kept to neighbour developments because of wake effects. A combination of park size, turbine capacity, turbine spacing and wake buffer results in park densities of 0.6 MW/km2 for far shore parks and 0.4 MW/km2 for near shore parks.

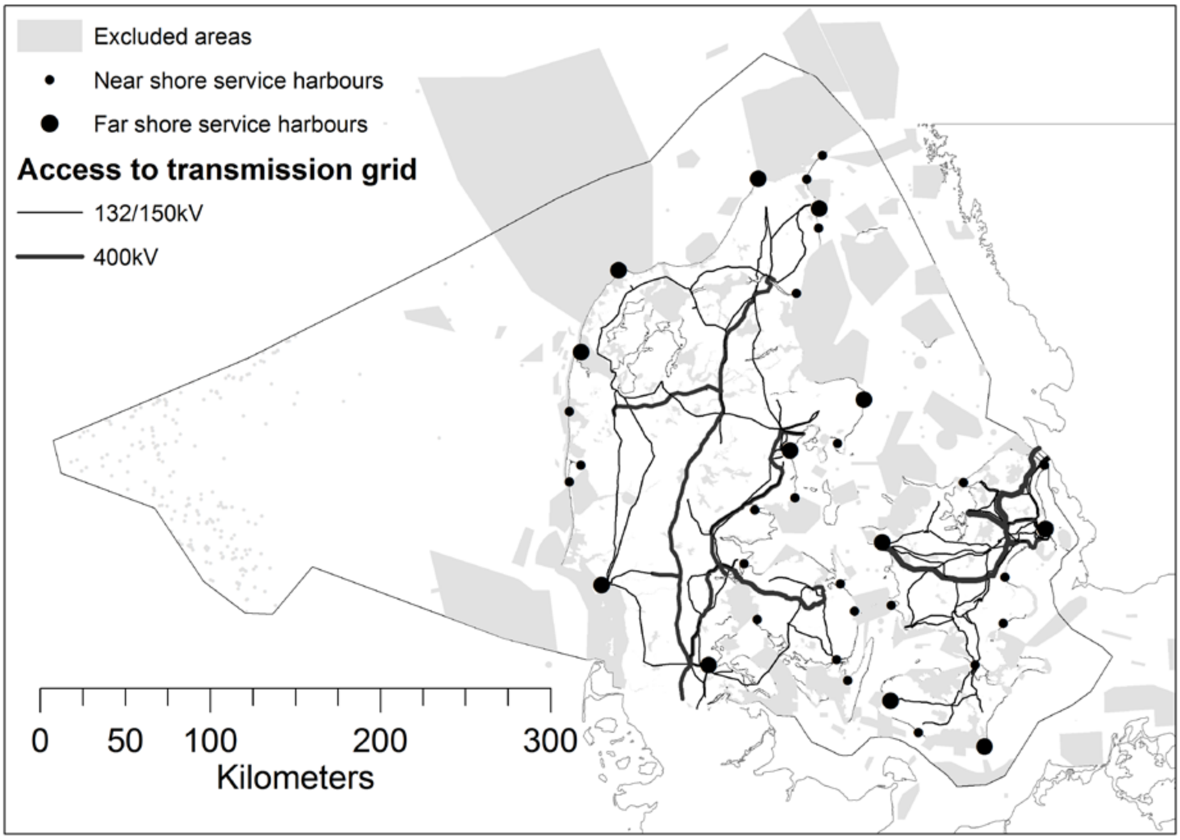

Figure 2. Areas excluded in the scenarios, service harbours for both scenarios, as well as the main AC grid infrastructure, to which parks are to be connected.

Specification of scenarios

The two scenarios represent the basic choice between either near shore development at a small scale, or large scale development at larger distances to coast. The choice of scenarios is not so much motivated as a choice of exclusive alternatives, as the most likely development will be a combination of both. Rather, it is to find an answer to the research question, primarily if the benefits of large scale, far shore development outweigh the costs.

To avoid overlap and double accounting of the limited wind resource, the 20:20 threshold forms the divide between the two scenarios. A number of assumptions are made for each scenario, based on an assessment of technology, planning and other options, see table 3.

Table 3. Assumptions of technological and planning parameters for the near- and far shore development scenarios.

PARAMETER	NEAR SHORE SCENARIO	FAR SHORE SCENARIO
Distance and water depth	< 20 km, < 20 m	≥ 20 km, ≥ 20 m
Turbine size	3 MW, 100 m rotor, 80 m hub	5 MW, 126 m rotor, 100 m hub
Park specification	25 turbines, 5 by 5	120 turbines, 8 by 15
Distance to NATURA 2000	1000 m	2000 m
Distance to Danish conservation	500 m	1000 m
Distance to impure ground, anchorages, fishing areas	1000 m	2000 m
Harbours for service	36 smaller harbours	12 larger harbours
Shipping criterion	< 1000 ship movements /year	< 1000 ship movements / year
Visibility criterion	30% of total visibility	10% of total visibility

The underlying thought of the scenario setup is the hypothesis that technology development can be rolled back to the first generation of commercial offshore power generation, thereby harnessing several benefits of smaller scale development such as local ownership, better local acceptance, lower power production costs, and lower risk. Larger distances are reserved for far shore developments, as it is assumed that these projects will be more critical in terms of spatial planning.

In terms of model development, a generic model SCREAM OW 2.0 was developed in ArcGIS Desktop/ArcInfo 10, Model Builder including the Spatial Analyst extension. The model was thoroughly tested and validated against existing offshore parks in [9]. The near and far shore scenarios were then derived from this model, resulting in two models distinguished by the scenario parameters presented above. The model takes about 5 minutes to run on a workstation with an Intel® i5 2.8 GHz quadruple processor CPU with 8 GByte RAM running 64 bit Windows 7®. As a deterministic model it yields consistent and replicable results, and all model conditions and parameters are transparent to the user-operator through the ArcGIS Model Builder graphical programming interface.

RESULTS

Estimation of area consumption and available electricity generation

Table 4 shows the resulting gross area consumption including wake buffers for the near shore and far shore scenarios. It can be seen that the far shore option gives a much higher resource base than the near shore scenario, which is restricted by the 20:20 threshold. However, results suggest that near shore could cover about 20% of the electricity demand in the year 2020, at costs lower than far shore, see next chapter.

Figure 3 compares the available areas in the near shore and the far shore scenarios. Note they do not overlap, because the 20:20 threshold is the divide between the two alternatives. It can be seen how the near shore scenario finds areas, which require substantial planning in order to be approvable. Some areas, however, seem compatible with the current planning regime [3].

Table 4. Basic comparison of the near- and far shore scenarios. Far shore installation yields energy at a much larger scale. Completely exploited, it may cover 3 times the Danish electricity demand.

SCENARIO	NEAR SHORE	FAR SHORE
Annual power production [TWh]	7.02	119
Gross area consumption [km^2]	4,175	34,250
Installed capacity [MW]	1,600	20,860

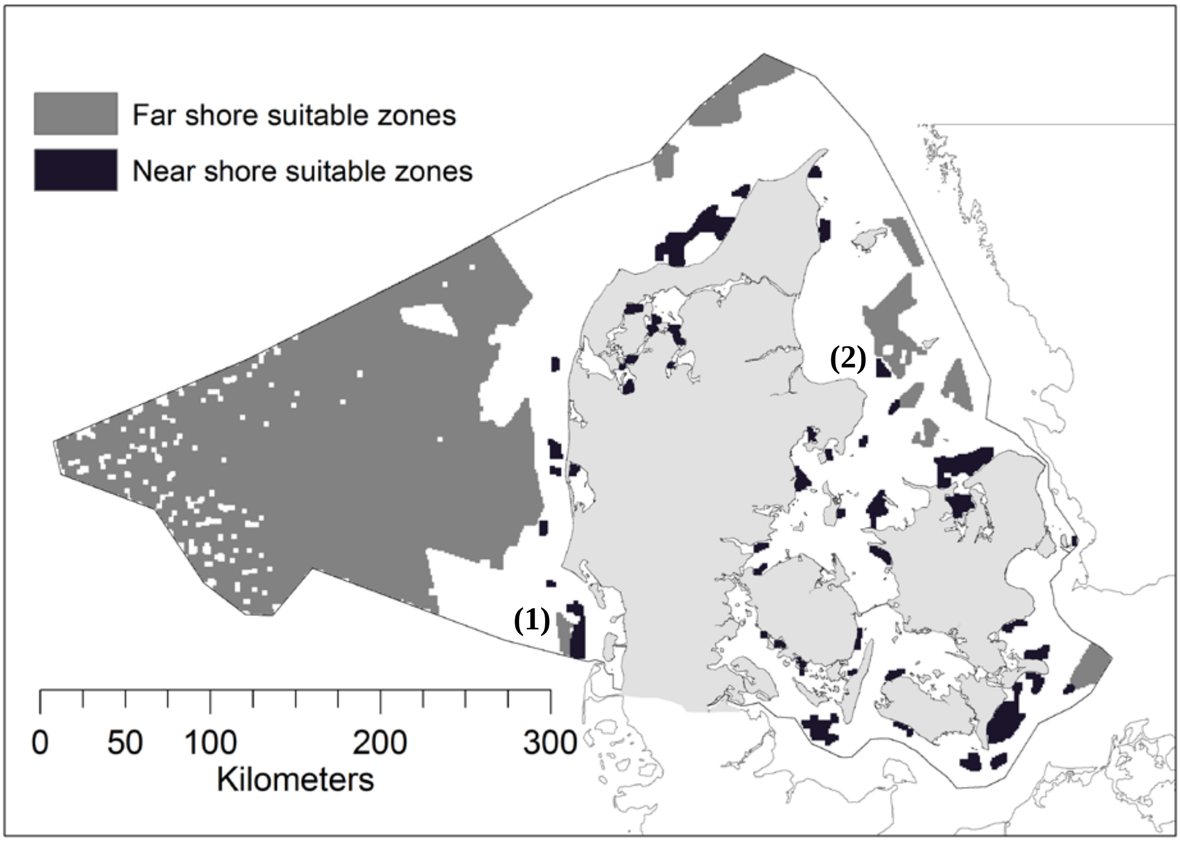

Figure 3. Areas modelled to be suitable for the far shore and near shore scenarios. The non-overlapping scenarios yield very different areas, in terms of size, costs, and wind regime. Some of the areas may be called intermediate, typically where areas from two scenarios are

adjacent such as the area in the Wadden Sea (1) or close to the island of Anholt (2) in the Kattegatt area.

Costs of supply

Costs of offshore wind power generation increase with installation costs and decreasing wind energy potential. Figure 4 shows two maps displaying LPC in either scenario. It appears that there is a general tendency of production costs increasing with distance, but the pattern is more complex. An evaluation of the annual energy production has to be included, and the resulting maps need to be filtered by the area available.

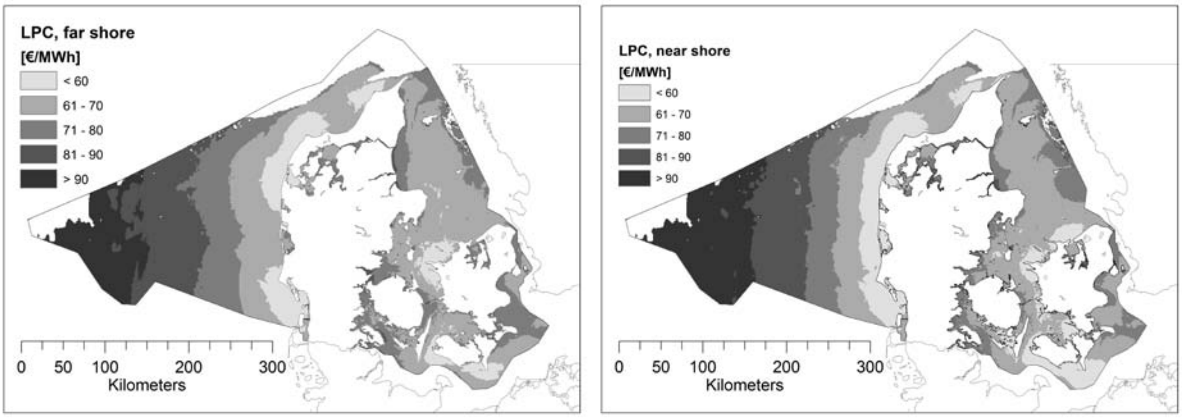

Figure 4. Levelised production cost surfaces for far shore (left) and near shore (right) scenarios. Particularly grid connection to fewer high voltage access points and operation and maintenance from few, centralised harbours have an influence on production costs.

As both aspects are given by geographical variations, representations of how costs increase with the utilized potential can be drawn, here called cost-supply curves. Figure 5 shows a basic curve of the marginal costs of cumulative supply, which compares the near and far shore alternatives. It can be seen that near shore wind energy has lower marginal costs of generation than far shore until a break-even at 5 TWh/year. The steeper curve however suggests that near shore is more sensitive to cost variations, while the far shore potential is less influenced by variations in the assumptions for costs and incomes. Sensitivity analyses therefore need to be carried out.

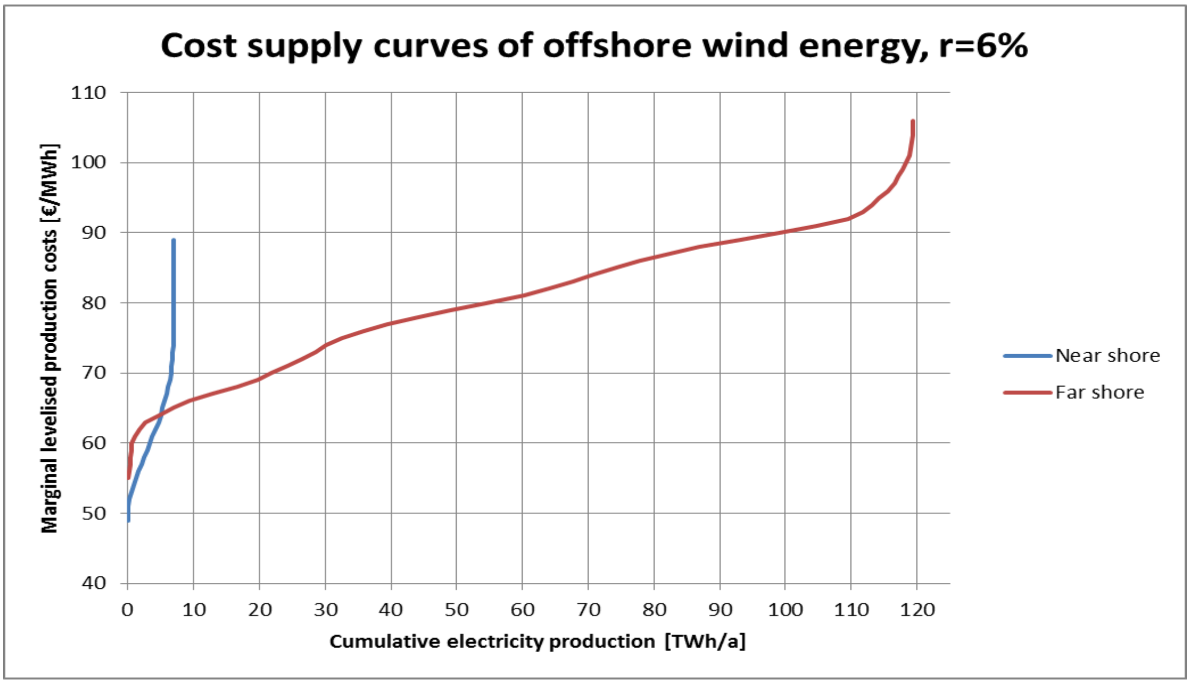

Figure 5. Cost supply curves of near- and far shore scenarios, basic assumptions. The curve plots the marginal costs of producing increasing amounts of electricity for the near shore as well as the far shore scenario.

Sensitivity analyses

Wind turbines off shore have a high sensitivity to investment costs, which may be rooted in higher commodity prices, demand, bottlenecks, or expectations to profit. Higher total investment costs disfavour locations with longer cables and deeper foundations, as well as lower energy production. For the two scenarios sensitivity analyses have been carried out with a variation of all investment costs by -25% and +25%, see figure 6.

It can be seen that far shore installations are more sensitive to variations in investment costs, simply because investment costs play a higher role. For both scenarios the locations with the least costs are less prone to investment cost sensitivity, which can be explained by wind resource having a higher influence on the economy of these plants than investment costs.

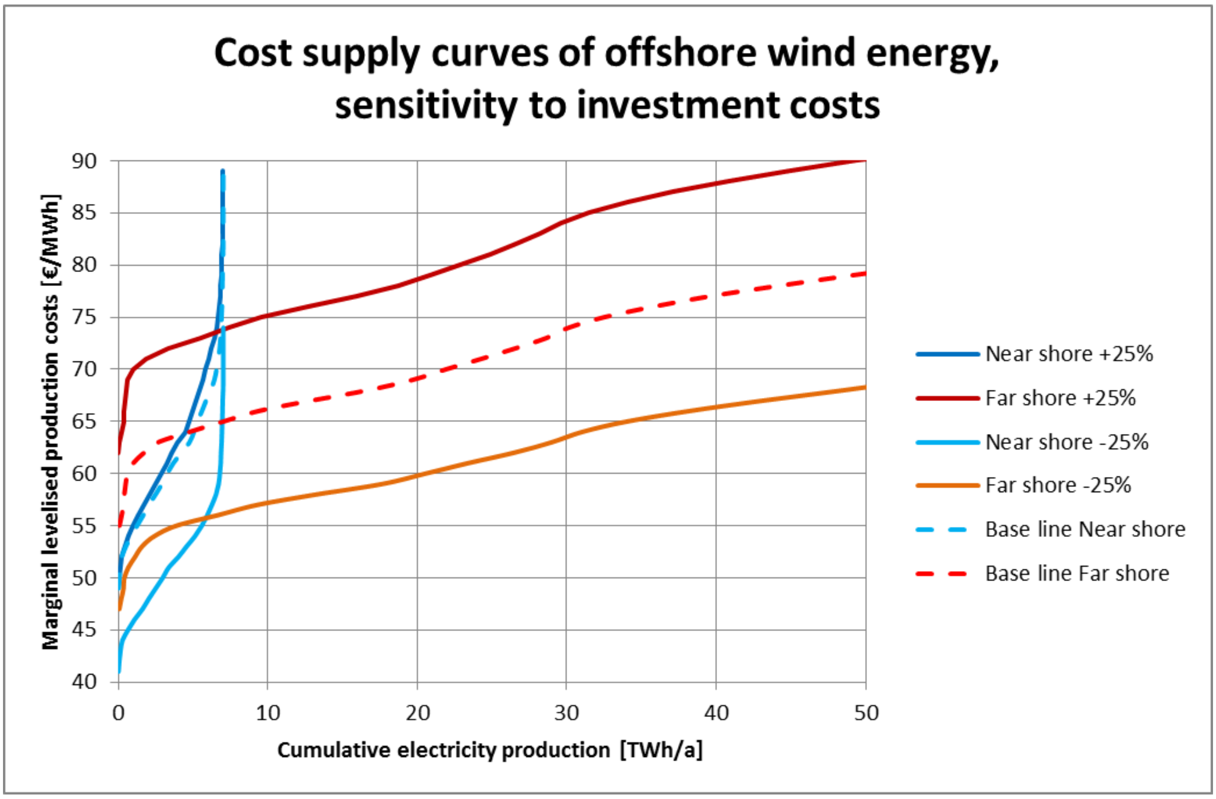

Fig. 6. Sensitivity of offshore wind power LPC to variations in investment costs. It appears that sensitivity is greater for far shore installations, which are generally costlier than near shore installations. It is also visible that the least cost resources in both scenarios are less sensitive to cost fluctuations, which indicates that the least cost locations are those, where wind regime generally is better.

A basic assumption in the setup of scenarios is that smaller, near coast parks with local ownership lead to higher acceptance levels of visibility than large scale developments, which are located at greater distances from the shore and operated by large corporations. One further sensitivity analysis therefore aims at looking at the sensitivity of the chosen visibility thresholds by using the same threshold for the two scenarios. A threshold of 20% visibility yields the following cost-supply curve, see figure 7. It follows from applying the same visibility thresholds to both scenarios, that the costs become very similar for the first 3 TWh/yr. This is effectively because vast areas deemed suitable for offshore development of near shore parks become no longer available if those developments are to compete with the far shore criteria.

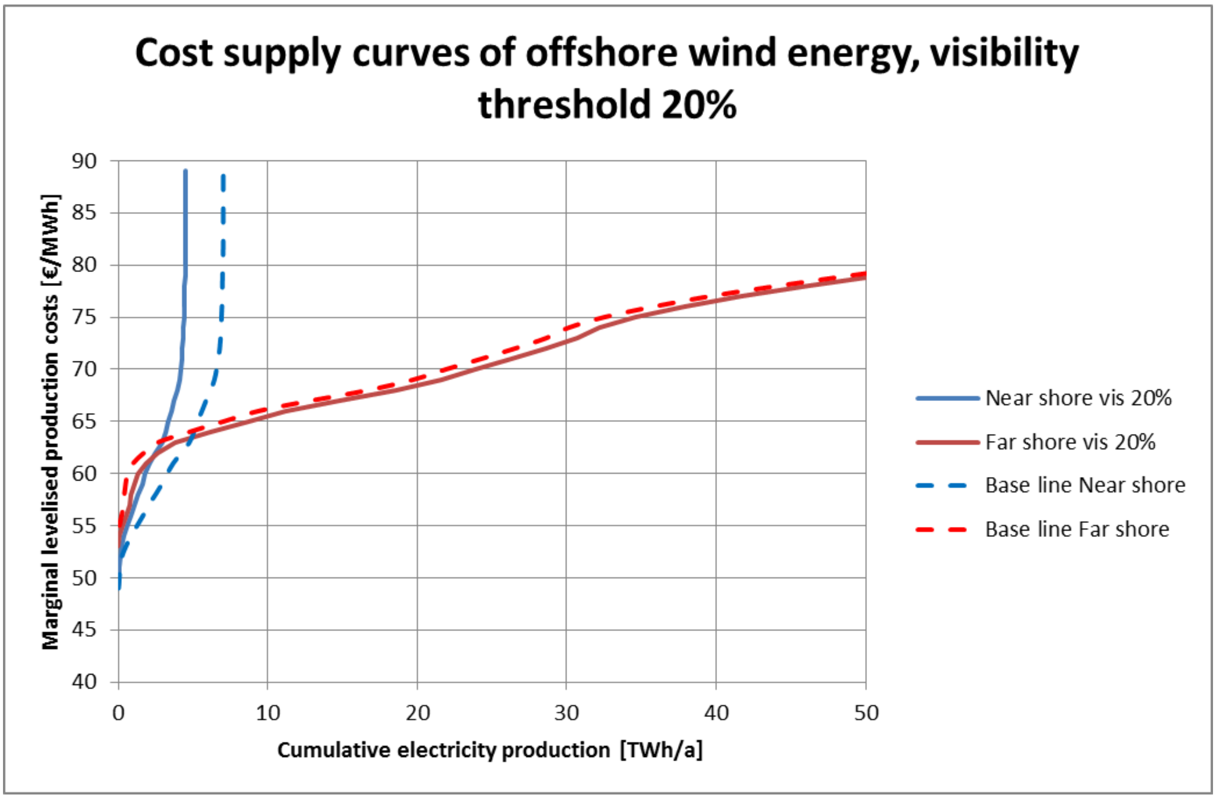

Fig. 7. If the visibility threshold is set to 20% of maximal visibility, allowing greater levels for near shore and lower levels for far shore installations, then both technology scenarios appear competetive for the first 3 TWh. Soon after that the near shore potentials become exploited, and the far shore potentials reach a plateau of only gradual increasing production costs. Further, near shore potentials are far more sensitive to the visibility criterion.

From the previous analysis it appears that near shore installations in particular have a higher sensitivity to locations, and this may especially be true for areas with particular values to society. For the majority of coastal locations wind energy is subordinate to e.g. tourism and recreation, and for a substantial amount of theoretically available areas further conflicts may smoulder. Apart from views, physical national and international conservation areas may compete with wind energy development. To assess this sensitivity, buffers to conservation and other no-go areas have been doubled, reducing the area for offshore development and increasing the costs of generation. Again a cost supply curve is drawn, which shows the additional costs of generation because of less available area. The difference between the curves reflects the opportunity costs of increased distances to conservation areas.
It can be seen that the far shore scenario gets its potential reduced by almost 20%, while marginal costs increase by 1-2 €/MWh for most of the areas. The near shore areas lose about 30% of their potential despite shorter buffer distances, and costs increase by 3-6 €/MWh. This shows that near shore areas are more sensitive to planning issues, which is caused by the higher area competition and the higher share of protected areas near the coasts. As can be seen from figure 3, many near shore areas are located in poor wind conditions. This is a main reason for the steep supply curve.

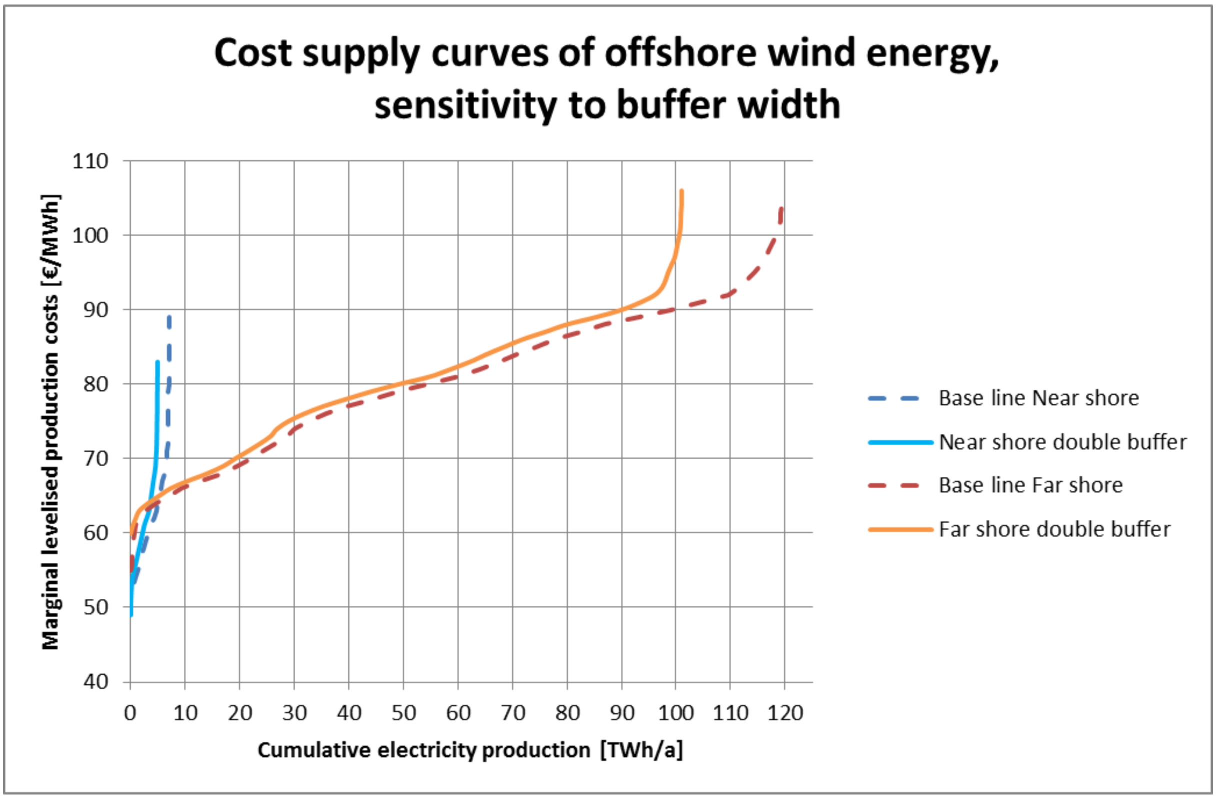

Figure 8. Near shore areas are more sensitive to increasing the buffers around conservation and other prohibited areas than far shore areas because the near costal waters to a higher degree are subject to conservation and alternative use. This is reflected in the costs of supply.

So far we have found that coastal areas may be less expensive to produce smaller amounts of electricity than far shore areas, where resources seem unlimited, but this comes at the cost of higher cost sensitivity to planning issues including conservation and alternative area use, which can be confirmed by Wolsink [25]. They are also less sensitive to variations of investment costs. So can the critical planning be addressed by letting the public own a higher proportion of what the public needs to tolerate?

Options for ownership and the distribution of income generated are quite different for the two development scenarios. While the far shore development to an increasing rate is subject to international corporative involvement, many of the current near shore developments are owned by smaller utilities, cooperatives, public bodies or groups of individuals. This can be explained partly through better access to capital for larger corporations, partly through local involvement and to a lesser extent through regulation [26].

In order to analyse how local ownership as a means of compensation to visually impacted and an opportunity to create local wealth may have a further benefit through lower expectations to profit, a further analysis applies different discount rates to investments. Figure 9 shows how supply costs in the two scenarios react on discount rates of 4 and 8%. A 4% level may represent a publicly owned long term investment with low expectations to return, while an 8% rate may reflect the higher interest in generating profit, which could be the lowest rate accepted by a large corporation. If further assuming that there is a division between small scale public or cooperative ownership and large scale corporate ownership which follows the 20:20 threshold, than it may be possible to expand the near shore potential from 5 TWh to 7 TWh before break-even with far shore developments.

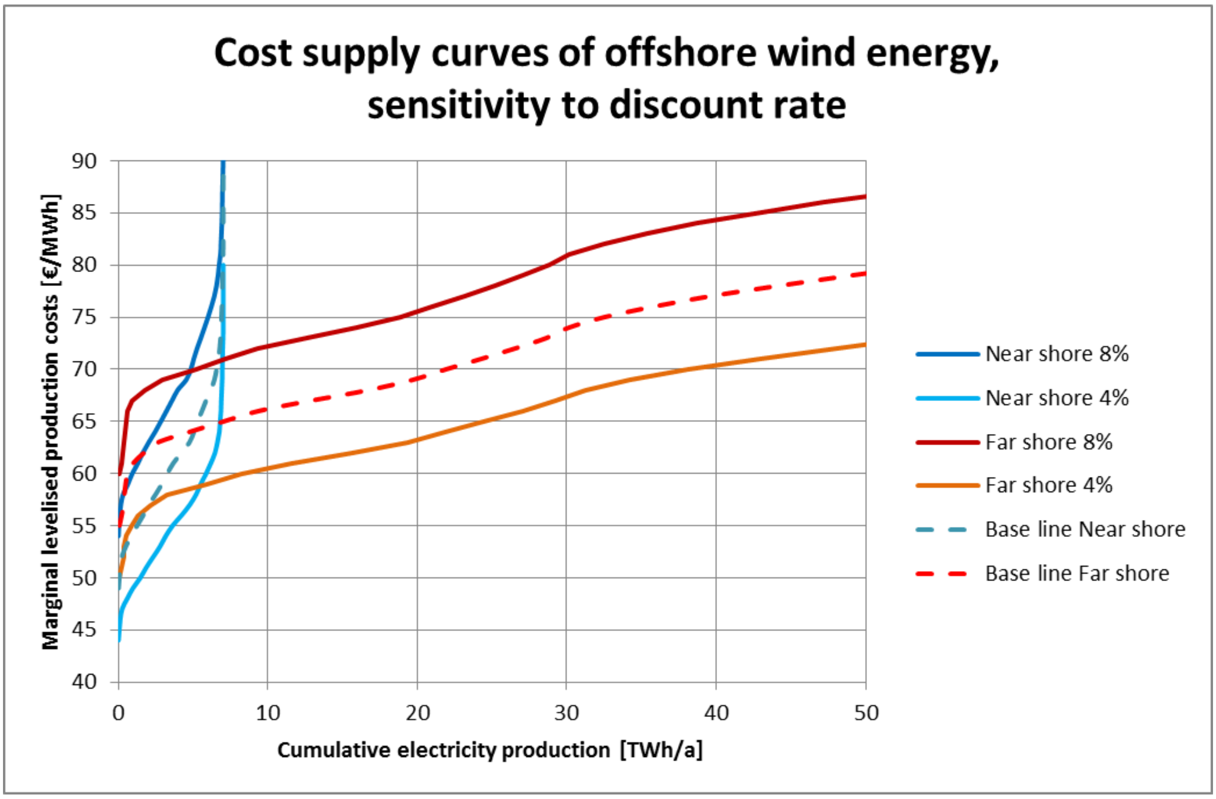

Fig. 9: The feasibility of investment-intensive enterprises like offshore wind energy highly depends on the expectations to generate profit. This sensitivity analysis calculates costs as a function of the discount rate applied. Applying lower interest rates for publicly or cooperatively-owned smaller, near shore installations could substantially increase their economic potential.

CONCLUSIONS

The present paper addresses the question whether future offshore development could be subject to consider rescaling, with benefit to society. The recent development of offshore wind energy in Europe has shown ever-increasing costs of installation, and an inverse economy of scale. This may have to do with the increasing size of offshore wind development, where high costs dictate large parks, which only can be built at large distances from shores, *at high costs*. To break this seemingly vicious circle, the present study reopens for development of offshore at a minor scale, with smaller turbines installed in smaller parks near shore, where turbines may produce less, but at lower generation costs. The higher visibility of these installations may be offset by local ownership, social responsibility and higher public involvement.

A GIS-based model has been built, which in a spatially continuous manner allows for the assessment of resources, their potentials and costs. Using available data for wind resources, technology parameters as well as costs, the model calculates the potential power production, the costs of power production (LPC) and the availability of a given area for wind energy development in a cell-by-cell manner. Of particular interest are those cost and planning parameters, which depend on geography.

Two sets of scenarios have been specified, which divide possible wind energy development by a 20:20 threshold. Near shore developments are smaller in scale, at closer distance to shore and in shallow waters, and they may be less sensitive to visibility. Outside the threshold, large scale offshore parks are planned, which follow the current technological pattern.

Results indicate that near shore wind energy can be produced at lower costs even if reducing turbine capacity and park size, and utilising the often poorer wind resources near the coast. The potential is limited to 5-7 TWh/yr, which may cover 15-20% of the Danish electricity demand in the year 2020. This near shore potential is very sensitive to planning restrictions such as visibility and distance to competing land use. It is however less sensitive to variations in investment costs induced e.g. by commodity prices, bottlenecks in the supply chain, high demand for offshore capacity or technological or financial risk.

Far shore wind energy yields the highest potential, probably exceeding 3 times the Danish electricity demand in 2020. Costs are higher than for near shore plants, but less sensitive to planning issues and wind regimes. Higher input of hardware such as foundations and cables causes a higher sensitivity to variations in investment costs.

Several areas have been found, which straddle the 20:20 threshold, and several more areas may be suitable for intermediate park sizes of 200-400 MW, for which less strict planning rules and beneficial scales may exist.

If allowing for different interest rates, as it could be argued for when looking at different forms of ownership, a lower interest rate generally increases the potential of economically feasible near shore wind energy. If striving for public or cooperative ownership in order to raise acceptance levels in areas affected by wind energy development (which is a mechanism already in place in Danish legislation and which may counteract generic not-in-my-back-thinking), then there may be several benefits, which need to be further scrutinised: a) local income generation in rural areas, particularly harbours and condemned industrial sites, but also as a “warm shower” of income generation in rural populations; b) lower costs of expanding the national grid as fewer 400 kV cables may be needed in a system with more grid access points on 132/150 kV levels; and c) a more secure electricity supply from a diversified and distributed generation capacity. Likely drawbacks are: 1) losing the leadership in large scale offshore development; 2) visually impacted coastal areas, many of them with unique scenic beauty; and 3) the requirement of a highly complex planning regime.

Further improvement of the SCREAM-model may aim at better representations of park geometries, where only crude area requirements per turbine capacity and generic park size are possible to adjust today. Further, one big unknown is the subsea geology, which in some parts of the Danish waters means a significant increase in foundation costs, or that offshore wind energy simply cannot be utilised. Thirdly, environmental impact on migrating birds, sea mammals and other species need to be described in a format compatible with the SCREAM model in order to be included in this form of studies. Fourthly, the wind resource model needs to be further improved [27], probably by measured wind speed and more observations. And finally, the authors trust that the next round of offshore wind energy development will deliver more trustworthy empirical data, made available in the public domain.

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