Opti-OWECS Final Report Vol. 3:

Comparison of Cost of Offshore Wind Energy at European Sites

T.T. Cockerill [1], R. Harrison [1],
M. Kühn [2], G.J.W. van Bussel [2]

[1] Renewable Energy Centre, University of Sunderland,
[2] Institute for Wind Energy, Delft University of Technology

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Preface

Overview of the JOULE III project Opti-OWECS

The project described in this report, ‘Structural and Economic Optimisation of Bottom-Mounted Offshore Wind Energy Converters’ (Opti-OWECS), was supported by the European Commission under grant JOR3-CT95-0087 within the scope of the Non-Nuclear Energy Programme JOULE III (Research and Technical Development).

Objectives of the Opti-OWECS project

It was the mission of the Opti-OWECS project to extend the state-of-the-art in Offshore Wind Energy, by deriving methods and demonstrating practical solutions which will significantly reduce the electricity cost. Such work will facilitate the further exploitation of offshore wind energy within a medium term time scale of 5 to 10 years from now.

The specific objectives included:

- Calculation of a cost estimate for and comparison of offshore wind energy converters of different sizes and different design concepts.
- Estimation of the cost per kWh of offshore wind energy produced electricity at sites in different regions of the EU.
- Development of methods for the simultaneous structural and economic optimisation of offshore wind energy converters with due consideration of the site characteristics.
- Production of at least one design solution for a bottom-mounted offshore wind energy conversion system.

Partnership and responsibilities

The project was undertaken by an international co-operation of engineers and researchers from the wind energy field, offshore technology, power distribution and universities.

The participants included:

- Institute for Wind Energy (IvW), Delft University of Technology

  A Dutch research group active for more than 20 years in various fields of wind energy application, including major offshore wind energy research since 1992.
- Kvaerner Oil & Gas, Ltd. (KOGL)

  A major engineering and construction company, based in the United Kingdom, with an established track record for implementing innovative concepts for offshore oil and gas developments.

- Kvaerner Turbin AB (KT)

  A Swedish wind turbine manufacturer with expertise in the design of multi-megawatt machines (since the 1970s) and participant in another large study on offshore wind energy (1991).
- Renewable Energy Centre, University of Sunderland (US)

  A British research group involved in techno-economic studies of renewable energy sources since 1978 including two major projects on wind energy costs.
- Workgroup Offshore Technology (WOT), Delft University of Technology

  A Dutch research group with particular expertise in the fluid loading of offshore structures and probabilistic methods. WOT maintains good relations with Shell Research Rijswijk.
- Energie Noord West (ENW)

  A Dutch utility supplying 600,000 households in North-Holland and operating wind farms for more than 12 years amongst which is the first Dutch offshore plant (Lely, 1994).

Kvaerner Oil & Gas, Ltd. and Kvaerner Turbin AB both form part of the international Kvaerner group which is organised in seven core business streams - KOGL being part of the Oil & Gas stream and KT being part of the Energy business.
The role of the partners is summarised in Table 0-1.

Partner	Role	Major scientific tasks
IvW	Coordinator	- general expertise on (offshore) wind energy, - overall dynamics of OWEC, - wind turbine reliability, operation & maintenance, - design of grid connection and farm layout, - assistance in the cost analysis of OWECS, - aerodynamic rotor design,
KOGL	Contractor	- general expertise on offshore technology, - design of support structure and installation procedure, - assistance in the cost analysis of OWECS
KT	Contractor	- general expertise on wind turbine technology, - adaptation of wind turbine to offshore conditions
US	Contractor	- concept and economic analysis of OWECS - development of cost models for OWECS, - estimate of costs of offshore wind energy at European sites
WOT	Contractor	- general expertise on offshore technology, - structural reliability consideration, - assistance in the cost analysis of OWECS
ENW	Sub-contractor (of IvW)	- general expertise as utility and as operator of (offshore) wind farms, - design of grid connection

Table 0-1: Distribution of responsibilities among the partners**.**

Relation of this report to other work within Opti-OWECS

The project continued with earlier work from CEC Joule project JOUR 0072 and made use of recent developments in wind engineering and offshore technology. The study examined what are considered to be the most promising and feasible offshore wind farm concepts for the near future specifically horizontal axis wind turbines rated approximately between 1MW and 3MW, erected on bottom-mounted support structures in the Baltic or the North Sea.

The project comprised three consecutive major tasks:

- Task 1 Identification of main cost drivers

  The main cost drivers of offshore wind energy were identified and the base case concepts and the reference sites were selected.
- Task 2 Development

  The economic and structural optimisation and improved design methods were developed in three parallel tasks. A cost model for manufacturing, installation and operation and maintenance of offshore wind farms was compiled. Design concepts for all main sub-systems, the wind turbine, the support structure, the grid connection and operation and maintenance, were investigated and the best combination for certain sites were selected. Also, particular design methods for offshore wind energy applications including structural reliability considerations and overall dynamics of offshore wind energy converters were further developed.
- Task 3 Integration

  In the final phase the work of the preceding tasks was integrated and the relationships between them were fully considered. The progress achieved was demonstrated in a typical design solution for an offshore wind energy conversion system (OWECS). Moreover, energy costs at different European sites or regions were estimated.

The project was divided into three phases lasting from January 1996 to December 1997. Figure 0-1 presents an overview of the work packages (shaded boxes) and tasks (dashed boxes).

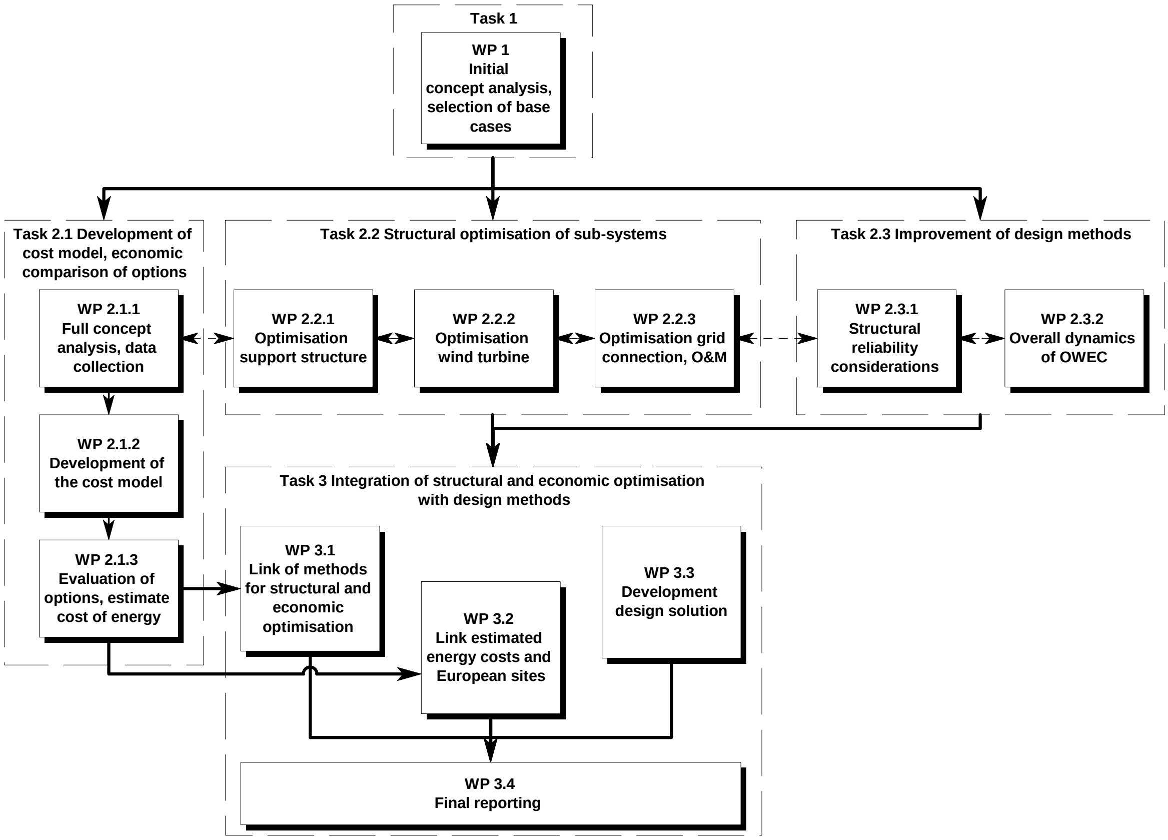

Figure 0-1: Opti-OWECS project organisation of tasks and work packages.

Results from the project have been written up into a final report consisting of six volumes:

- Vol. 0 Executive Summary [0-1]
- Vol. 1 Integrated Design Methodology for OWECS [0-2]
- Vol. 2 Methods Assisting the Design of OWECS [0-3]
- Vol. 3 Comparison of Cost of Offshore Wind Energy at European Sites
- Vol. 4 A Typical Design Solution for an OWECS [0-4]
- Vol. 5 User Guide OWECS Cost Model [0-5]

As illustrated by figure 0-2 the reports cover all of the work packages. It has been the intention of the authors that it should be possible to read each volume independently of the others and, as a result, some issues are tackled in more than one report. The individual documents, however, tackle such ‘common‘ issues from differing points of view. By way of an example, development of a cost model is described in volume 2, its use for economic evaluations is discussed in volumes 3 and 4, and a guide to its use may be found in volume 5.

This volume of the final report presents some general results produced by the detailed cost model described in volume 2 [0-3]. It also describes the development and use of a simplified version of the cost model within a Geographical Information System (GIS), which makes use of these results to compare the cost of OWECS produced energy at a number of real northern European sites.

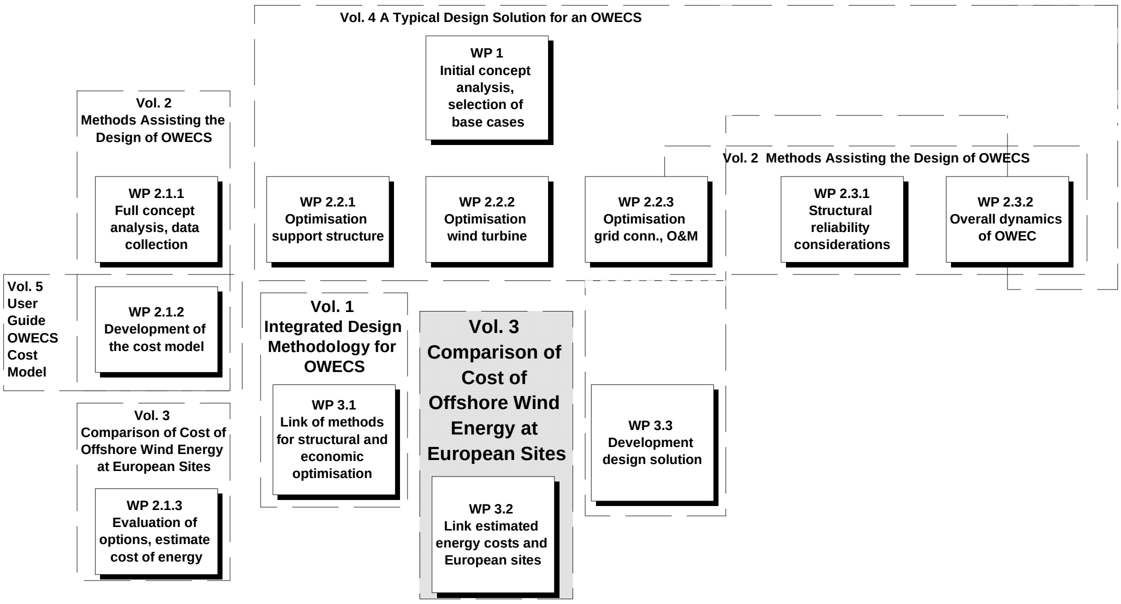

Figure 0-2: Interrelation between Opti-OWECS work packages and final report

Terminology used in this volume

Use is made of a terminology for OWECS which has been developed and successfully applied during the project (see appendix A of Vol.1 [0-2], [0-6]). In order to avoid misunderstandings there are two essential conventions that should be appreciated. Firstly, the acronym “OWECS” (standing for Offshore Wind Energy Conversion System) or its synonym “offshore wind farm” describes the entire system, that is the wind turbines, the support structures, the grid connection up to the public grid and any infrastructure for operation and maintenance. Secondly, “OWEC” (Offshore Wind Energy Converter) is used to refer to a single unit of an offshore wind farm comprising support structure (i.e. tower and foundation) and the wind turbine (i.e. aero-mechanical-electrical conversion unit on top of the tower).

Acknowledgements

Appendix A of this volume was written by David Milborrow, at the commission of the Opti-OWECS project participants but without their direct involvement. Appendix A contains only the independent opinion of Mr Milborrow, and is intended to provide the reader with an understanding of a wider range of issues than would otherwise be possible in a highly specialised report such as this.

The assistance of Garrad Hassan Ltd and of Germanischer Lloyd in making available their offshore wind energy environmental database compiled during the EU project JOUR 0072 is gratefully acknowledged.

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Appendices

1. Introduction

The location chosen for an OWECS is at least as important as its detailed engineering in determining the overall cost of the energy it will produce. Future technological developments may well render the role of careful site selection much less significant with regard to the economic viability of an OWECS, enabling a wide range of locations to be exploited. Current expertise, despite the contributions made by the project of which this work forms a part, will only allow the “best” sites to be exploited on a commercial basis. If near future OWECS developments are to succeed it is essential that a clear understanding of where the best OWECS sites are located is developed.

The work described in this report volume is an attempt to comparatively evaluate, in economic terms, all viable OWECS sites within a region of the Northern EU. This ambitious objective has been tackled by loosely coupling a detailed model of OWECS costs described in volume 2 [1-1] of this report with a Geographical Information System (GIS) and an electronic map of offshore conditions.

This work represents a substantial extension of the original objective of the project. The initial goal was to compare the cost of energy from just six sites within the EU, and is discussed in volume 4. After some consideration, it was decided to extend this work further and compare a much larger number of sites over most of the northern EU, rather than limit the analysis to a few, isolated locations. A side effect of this extension, and the magnitude of the work it involved is, to lower the absolute accuracy of the cost estimates.

1.1 Organisation of the report

We will begin, in traditional fashion for what is essentially an academic study, with a survey of existing estimates of OWECS energy costs at EU sites. The investigation is not comprehensive, but is intended to present a representative picture of the economic situation of northern European offshore wind energy converter systems.

Attention in chapter 3 is focused on the methodology employed for the new work presented in this report. Since considerable space has been devoted to the workings of the detailed cost model already in volume 2, the discussion is dominated by the Geographical Information Systems (GIS) based analysis, which is not touched on elsewhere.

Results produced by the detailed cost model and the GIS are presented in two chapters, 5 and 6. The first concentrates on an examination of medium scale OWECS, intended for realisation in the relatively near future, employing a 1.5MW capacity “Danish style” turbine. In the second results chapter, the outcome of work investigating the characteristics of more futuristic, large scale OWECS using an “advanced type” 4MW capacity turbine is described. In neither case does a real turbine form the basis of the studies, rather a ‘generic’ turbine design is employed, representative of real designs but based only loosely on any particular one (see appendix C for further details).

Analysis of both of the broad classes of OWECS has been carried out in the same way. Initially use was made of the detailed based cost model to investigate the economic performance of the OWECS. A series of parameter studies were performed ‘around’ a base case, varying the most important technical and environmental factors such as the hub height, overall farm size, wind speed and distance to shore. The cost sensitivity information so produced was then encapsulated within the GIS system, which in turn was employed together with a database of European sea conditions, to compare the cost of OWECS produced electricity at a wide range of sites.

Appendix A of this volume was written by David Milborrow, at the commission of the Opti-OWECS project participants but without their direct involvement. Appendix A contains only the independent opinion of Mr Milborrow, and is intended to provide the reader with an understanding of a wider range of issues than would otherwise be possible in a highly specialised report such as this.

1.2 Interpretation of the results

Although the calculations described in this report have produced seemingly definite and absolute cost of energy estimates for an OWECS at a large number of European sites, considerable care is needed in interpretation of the results. It must be kept in mind that many approximations and assumptions, which will be elaborated, have been necessary in order to make the calculations possible.

A particular issue is that within a constrained two year investigation there is only sufficient time to consider a limited range of OWECS design concepts in any detail. It is thus an implicit assumption of the work that these concepts are well suited to the full range of sites evaluated. The authors have, of course, endeavoured to ensure that the concepts are matched to the sites. Nevertheless, it would be highly surprising if, for all of the sites considered, it were impossible to conceive of alternative design concepts that would offer better economic performance than the authors more generalised concepts.

One further limitation concerns the grid connection costs. The calculations presented in this volume completely neglect the cost of any onshore grid connection equipment. This simplification was necessary because compilation of the data required to allow such costs to be incorpotated was, unfortunately, beyond the scope of the project. For particularly remote sites, these grid connection costs may well offset any economic advantages indicated by the results.

In consequence, the work described here should be regarded as a wide ranging comparison of possible European OWECS sites rather than as an attempt to calculate accurately the cost of energy at all of the sites considered. Conclusions about the economic performance of an OWECS concept located at a particular site should only be drawn in comparison to how that same OWECS concept would perform at the other considered sites. So, by way of an example, a site with a predicted energy cost of say 6-7 ECUc/kWh should only be regarded as (a) less economically attractive than a site associated with an energy cost of 5-6 ECUc/kWh (b) more economically attractive than a site at 7-8 ECUc/kWh and (c) much more attractive than a site with an estimate of 9-10 ECUc/kWh. While the cost estimates in this report do have some quantitative validity it would be a very serious mistake to regard them as absolute values.

2. Cost of energy estimated by other studies

2.1 Introduction

The last twenty years have seen the publication of more than 30 studies of the feasibility of offshore wind energy in northern European waters. Since 1991, those studies have been joined by a number of successful demonstration projects. More recently, offshore wind energy has adopted a more commercial hue with the unveiling of proposals to develop several large, economically viable OWECS by the first few years of the 21st century in Dutch, British and Danish waters.

We will begin by examining the overall economics of some of these project and proposals, and then move on to look, at detailed breakdowns of their costs. One striking feature of the development of offshore wind energy is the great reduction in costs that has been achieved during the 1990s. Some of the early studies produced predictions of very expensive energy, and in a modern context many of their estimates are no longer representative. We will therefore confine our attention mainly to recent studies and the more economically viable older work.

This chapter looks exclusively at offshore wind energy. No attempt is made to assess the viability of any of the schemes considered, the objective being only to compare and investigate their differences. It is important to fully appreciate the position of offshore wind energy within the broader scope of all wind energy, and indeed within the world energy market. To this end, reference should be made to appendix A.

2.2 Analysis of investment and energy costs

Table 2.2-1 summaries the main technical, environmental and economic features some existing (as at 1997) OWECS demonstration plants, whereas table 2.2-2 deals with some of the ‘older’ feasibility studies. Details of the (planned) features for some recently proposed commercial and semi-commercial OWECS developments are tabulated at 2.2-3. Within each table, the details are arranged broadly in order of increasing size.

For some cases difficulty has been experienced in obtaining complete information, and missing data is marked as not known (n/k). Details of the economic conditions used for estimation of the energy cost are particularly challenging to locate, but in the absence of other information it seems reasonable to assume an economic life of 20 years and an interest rate of 5%.

Project	**Lely [2.2-1]**	**Vindeby [2.2-2]**	**Tuno-Knob [2.2-3],[2.2-4]**
Date	1994	1991	1995
Site	IJsselmeer, NL	Baltic Sea, DK	Baltic Sea, DK
Capacity	4 x 500 kW	11 x 450kw	10 x 500 kW
Distance to Shore	1 km	1.5 km	6 km
Water depth	5-10 m	3-5 m	3.1-4.7 m
Specific investment cost	1700 ECU/kW	2150 ECU/kW	2200 ECU/kW
Energy cost, ***Interest rate*** ***Economic lifetime***	0.083 ECU/kWh 5% 20 years	0.085 ECU/kWh 5% 20 years	0.066 ECU/kWh 5% 20 years

Table 2.2-1: Details of three existing OWECS.
(**Exchange rates ECU 1 : £ 0.65 : HFL 2.23 : DKK 7.1**)

What is notable about all the tables is that arrangement of the contents in order of overall size approximately coincides with a chronological ordering. It appears that OWECS designers have become more ambitious over time. The chronological increase in size also coincides with a reduction in the cost of energy produced. Some of this reduction is undoubtedly due to technical innovation over the years, and some due simply to the economies of scale experienced with larger windfarms, whether off or onshore. Yet a part of the reduction would also appear to be due to an improved understanding of the cost drivers involved leading to better site selection. By way of example, it is notable that some of the sites selected in recent work differ considerably from those chosen earlier in the history of offshore wind energy.

Study	**RES Study [2.2-5]**	**Thyssen Study [2.2-6]**	**SK Power study [2.2-7]**
Date	1993	1995	1994
Site	Skegness, North Sea, UK	Baltic Sea, DE	Baltic Sea, DK
Capacity	41 x 400 kW	140 x 1.5 MW	180 x 1 MW
Distance to Shore	~ 5 km	4 km	17 km
Water depth	~ 12 m	5 – 10m	8 - 10m
Specific investment cost	4500 ECU/kW	1400 ECU/kW	1900 ECU/kW
Energy cost ***Real Interest rate*** ***Economic lifetime***	0.16 ECU/kWh 5% 20 years	0.066 ECU/kWh 5% 20 years	0.067 ECU/kWh 5% 20 years

Table 2.2-2: Details of three large OWECS design studies.
(**Exchange rates ECU 1 : £ 0.65 : HFL 2.23 : DKK 7.1**)

A further point worth noting is the increase in turbine size during the development of offshore wind energy. It is particularly striking that the turbine sizes in the proposals of table 2.2-3, at least some of which are very likely to be realised, are larger than the forward looking paper-only studies in table 2.2-2.

It must be born in mind that the projects detailed in table 2.2-3 are only at the proposal stage, and the quoted cost of energy is only an estimate. If the experience at Tuno-Knob is representative, it seems that a reasonable degree of reliance can be placed on these values. At Tuno-Knob, the estimated energy cost was 0.06-0.07 ECU/kWh, while the energy production cost achieved in practice is 0.075 ECU/kWh.

Study	**Scroby Sands [2.2-8]**	**Nearshore [2.2-9]**	**Omo [2.2-10]**	**Horns Rev [2.2-10]**	**Gedser 1 [2.2-10]**
Study date	1997	1997	1997	1997	1997
Date proposed	~2000	~2000	~2002	~2003	~2006
Site	Norfolk coast, UK	IJmuiden, NL	Omo, DK	Horns Rev, DK	Gedser DK
Capacity	25 x 1.5 MW	100 MW	144 MW	120 MW	144 MW
Distance to Shore	3 km	9-16 km	n/k	~ 15 km	~17 km
Water depth	Up to 6m	17 m	n/k	5 – 11 m	8 - 10m
Specific investment cost	1150 ECU/kW	1900 ECU/kW	1550 ECU/kW	1650 ECU/kW	1750 ECU/kW
Energy cost	~0.045 ECU/kWh	0.064 ECU/kWh	0.051 ECU/kWh	0.046 ECU/kWh	0.052 ECU/kWh
Interest rate	5%	5%	5%	5%	5%
Economic lifetime	20 years	20 years	20 years	20 years	20 years

Table 2.2-3: Details of some proposed OWECS.
(**Exchange rates ECU 1 : £ 0.65 : HFL 2.23 : DKK 7.1**)

2.3 Analysis of cost breakdowns

It is informative to examine more detailed breakdowns of the costs associated with OWECS projects. Unfortunately, the increasingly commercial nature of offshore wind energy makes such information quite difficult to obtain for many of the more recent projects and proposals. By necessity, much of the discussion will be confined to older projects, for which information is more readily available.

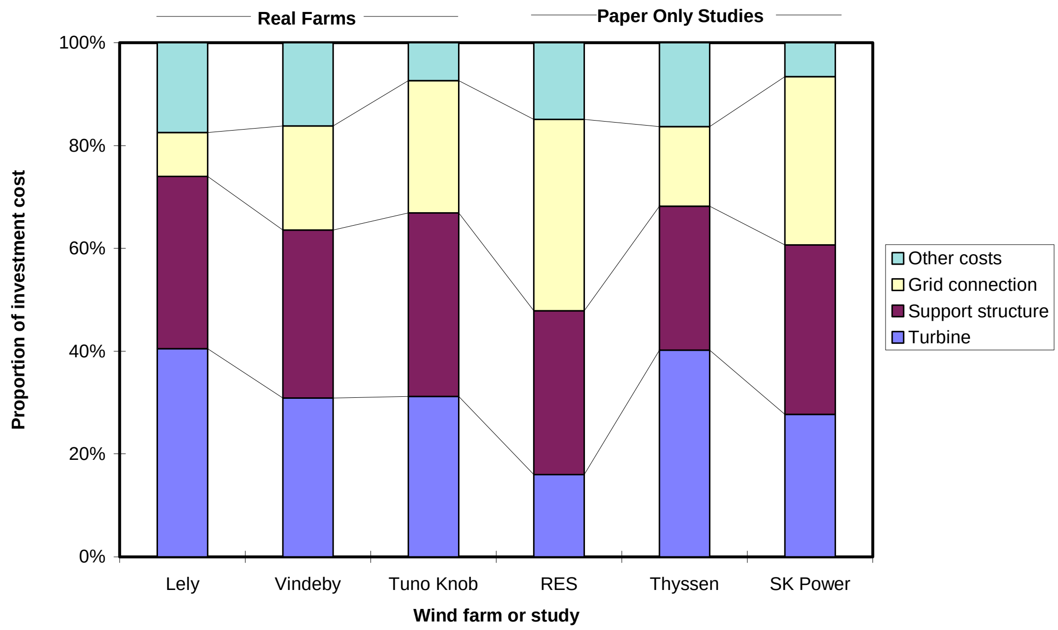


Figure 2.3-1: Comparison of the cost breakdown for several OWECS.

Figure 2.3-1 shows the contribution of the major components to the overall cost of several OWECS, using figures taken from Cockerill [2.3-1] and from the references in the tables. The importance of the components varies greatly from case to case. In addition, all the cost distributions show substantial

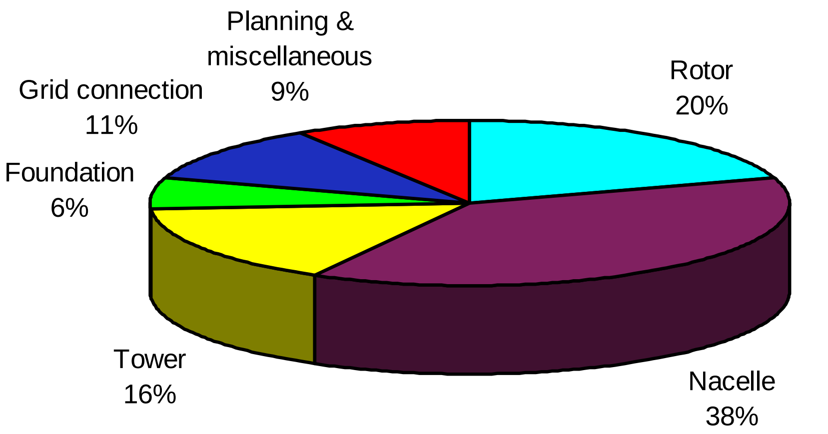


Figure 2.3-2: Breakdown of costs for a large onshore WECS.

differences from those characteristic of onshore wind farms. For comparison, figure 2.3-2 summarises the cost break down for a large onshore wind energy converter, using data taken from the Post-WEGA study [2.3-2] For the onshore situation, the nacelle and rotor (the 'turbine') together represent 58% of the overall costs. None of the offshore cases however exhibit a turbine cost exceeding 40% overall.

Some trends can be seen in the data of figure 2.3-1. The first three columns of the figure show real OWECS with broadly comparable turbine specifications (~500kW), and the fourth column shows a paper based design study, again employing a turbine of approximately 500kW capacity. It seems reasonable to suppose that the turbines in each of these four cases cost comparable amounts. The site and farm conditions are not comparable however, with the loading, distance from shore, and farm size broadly increasing from Lely, through Vindeby to the RES study. The effect of these toughening conditions is to decrease the relative contribution made by the turbine to the overall costs, while boosting that of the grid connection and support structure.

The last two columns of the figure both deal with proposals for farms with turbines in the megawatt class. In this case the offshore nature of the farms becomes stronger from the relatively close to shore Thyssen study to the 17 km offshore SK Power study. Again the same general trend as for the smaller turbines, that of decreasing relative turbine cost with increasingly offshore features, can be observed. As a rule of thumb, it seems reasonable to suggest that a true offshore wind farm, as opposed to one that is merely, in or near shore, is characterised by the wind turbine, grid connection and support structure each making roughly equal contributions to the overall capital cost of around thirty percent. These characteristics become apparent in OWECS located more than, say, 10km from the shore in water depths of 10m or larger.

We have so far considered only bottom mounted OWECS proposals. While the bottom mounted schemes are undoubtedly the most highly developed OWECS solution, floating OWECS have been devised. Figure 2.3-3 gives the cost breakdown for a floating wind farm with turbines mounted on spar buoys [2.3-3]. Despite the optimisation efforts made by the designers, the supporting buoy has the same economic impact as the turbine, much as for the support structure in a bottom mounted OWECS. In addition, the surprisingly large cost of mooring does nothing to improve the economics of the scheme. There would not seem to be any economic advantage in replacing a bottom mounted support with a floating support therefore.

Extensive direct comparison of bottom mounted and floating OWECS schemes is not useful, as the two concepts have been developed to fulfil different design requirements. Bottom mounted designs are well suited to locations where the seabed is relatively accessible, say with a water depth of 40 m or less. At very deep water sites a bottom mounted structure is clearly impractical and it is in such instances that floating structures come into their own. Unlike a bottom mounted design, the cost of constructing a floating structure has only a weak dependence on the depth of water in which it is to be deployed. In general terms though, fixed OWECS have demonstrated better economics to date than their floating counterparts and the former would seem to offer the greatest opportunities for short to medium term developments. Looking to the longer term, if offshore wind energy becomes substantially exploited, floating concepts will undoubtedly have a role to play. This will be particularly true in deep water regions, such as the Mediterranean seas for instance.

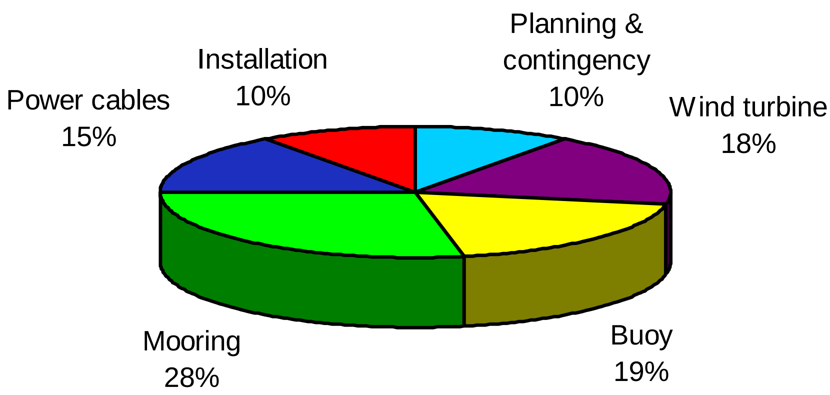


Figure 2.3-3: Breakdown of costs for a proposed floating OWECS.

2.4 Conclusions

We have reviewed energy cost estimates for real and proposed OWECS sited in northern European waters. A number of conclusions can be drawn which should be kept in mind as a benchmark for the results of the Opt-OWECS project.

- Increasing technical understanding allows reductions in the cost of OWECS produced electricity. Cost reductions can be achieved both through improved design and more effective site selection.
- The major components of a 'truly offshore' bottom mounted OWECS have broadly equal economic impacts. For a floating OWECS, the mooring is the most expensive component.
- Recently proposed large OWECS schemes predict an energy cost of around 0.05 ECU/kWh (5% interest rate, 20 year economic lifetime).
- Bottom mounted OWECS concepts offer the greatest potential for offshore wind energy developments in the short and medium terms. Floating concepts will have a role to play in the long term.

3. Methodology

3.1 Overview

All the results within the remainder of this report have been obtained by cost modelling. Cost modelling is a predictive technique that attempts to simulate the major technical and economic features of a complex system in order that conclusions can be drawn regarding the most economic configuration of that system. Using a combination of fundamental principles and empirical relations, a cost model ’sizes’ the options available for an engineering system, and estimates their costs.

Cost models are useful for investigating the sensitivity of overall cost to changes in one or more design parameters. They have been employed extensively for optimising process industries and other renewable energies, but until recently their application to wind energy had been limited to the NASA MOD projects [3.1-1],[3.1-2].

Two cost models have been employed here. One, used for detailed parameter studies of design options, is a sophisticated simulation of the engineering aspects of OWECS. It has been developed in close co-operation with the project partners and runs under the standard spreadsheet software, Microsoft Excel 5.0.

The second model is far simpler, and has been developed using the output of main model. It runs within a GIS environment and is intended for outline calculations of the cost of energy that an OWECS might produce at any site.

3.2 Detailed cost model

The detailed cost model has been used to perform a series of parameter studies, attempting to relate quantitatively the effect of design changes on the economic performance of OWECS. A series of sensitivity curves have been produced of which a very limited number are presented briefly in this report volume. More comprehensive parameters studies are described in volume 4 [3.2-1].

To perform an economic evaluation with the detailed model, a base case design must first be defined. The detailed cost model can then be used to investigate the effects of parameter variations around that base case. Each of the individual base cases employed here are detailed close to the relevant results but there are essentially two situations: one employing a 1.5 MW turbine and one a 4 MW turbine. The first base case is intended to be representative of medium scale, very near future OWECS, while the second has a more forward looking perspective focused on large scale OWECS.

The model itself was developed within the context of certain 3MW design concepts investigated during other parts of the project (see volume 4). Extension of its use to 1.5MW and 4MW concepts has been undertaken in the light of experience gained in the rest of the project, but nevertheless represents something of an extrapolation. As will hopefully become apparent, the considerable degree of uncertainty implicit in this procedure is acceptable for the calculations discussed here.

Although the detailed cost model has been used to provide results reported here, no further explanation of its operation will be provided in this volume. A full description of the model is provided in volume 2 [3.2-2]. The remainder of this chapter will be devoted to the methodology of the GIS calculations.

3.3 Geographical information system

3.3.1 Introduction to GIS

A GIS or 'Geographical Information System' is essentially a computer based mapping and manipulation tool. Spatially varying data, such as surface elevations, is stored along with information fixing the data geographically, for example, the latitude and longitude of a particular feature.

The data can be stored and manipulated in either a vector or a raster format. With the former, data is dealt with in the form of lines, points or contours with a distinct geographical location. Each vector feature must be associated with a precise co-ordinate pair. In a raster format, the area under consideration is divided into a regular array of cell and each cell is allocated a value. The entire area encompassed by the cell is assumed to be represented by its particular value.

In comparison to conventional mapping techniques, one great advantage of a GIS is its ability to perform mathematical manipulation of the stored data figure 3.3-1). This ability is most easily realised with raster format data,

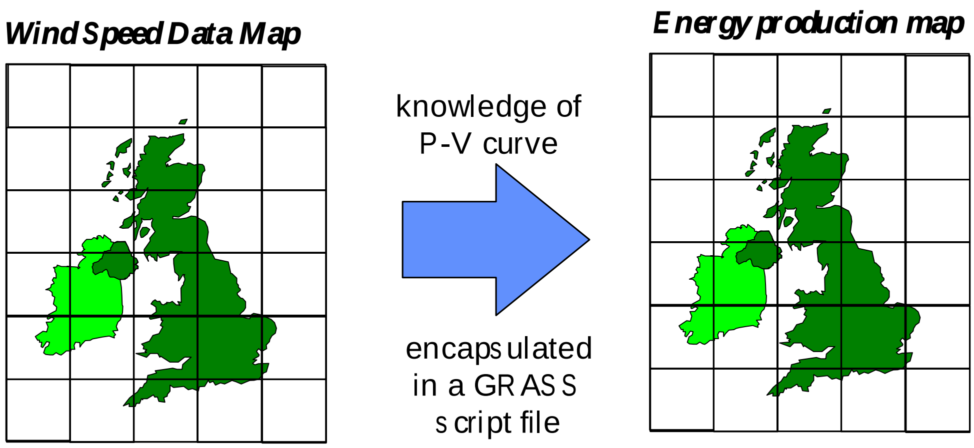


Figure 3.3-1: Use of a GIS for mathematical manipulation of raster data.

making it a simple task to undertake identical operations with every cell in a data set. All the GIS computations here will involve only raster data.

A GIS map can be divided into a number of layers, with corresponding cells of each layer being associated with a single geographical location. Thus the GIS can store information about the behaviour of a number of spatial variables over a single area in separate layers. Spatial mathematical operations involving data from more than one layer are possible.

3.3.2 The GIS offshore wind energy database from JOUR0072

As part of an earlier European Commission funded investigation of offshore wind energy (Joule 1 project JOUR0072: ‘Study of Offshore Wind Energy in the EC’ [3.3-1]), Garrad-Hassan and Germanischer-Lloyd have developed a GIS base database of conditions in European waters. The information included is specifically oriented towards offshore wind energy and includes information on the important environmental parameter of wind speed, water depth and distance to shore. Details of areas unsuitable or unavailable for wind energy developments are also incorporated within the database. Such areas include military areas, the paths of undersea pipelines and cables, 10km buffers around oil platforms, any nature reserves, shipping ‘corridors’ and regions with sea bed slopes in excess of 5 degrees.

Superficial examination suggests the database to be deceptively simple. The effort involved in collecting the information contained within the database and converting it to a consistent digital form however is considerable. It would be quite beyond the scope of the current project to repeat the exercise of creating the database. For this reason the JOUR0072 database has been used, with the kind permission of Garrad Hassan and Germanischer Lloyd, as a basis for the calculations presented here.

The accuracy of the calculations reported here cannot of course exceed the accuracy of the input data taken from the JOUR0072 database. Discussion in this volume is limited only to the accuracy and validity of the calculation procedures, taking no account of any possible errors or inaccuracies in the data base. This additional factor must be kept in mind when interpreting the results. For information on the accuracy of the database, reference should be made to [3.3-1].

3.3.3 Choice of GIS

The GIS adopted for this study is the GRASS system [3.3-2], [3.3-3] initially developed by the US Army for munitions and range calculations. Until a few years ago, when active development of the package ceased, GRASS represented the state of the art in GIS. It still remains a very powerful package able to deal equally with raster and vector data and its engineering, rather than purely geographical, heritage makes it arguably the best suited system for our purposes here. GRASS runs under the Unix operating system, with X-windows, and has the distinct advantage of being free of charge to the user.

3.3.4 Preparation of data

The offshore data provided by Garrad-Hassan/Germanischer-Lloyd had originally been compiled using the IDRISI system [3.3-4], and had first to be converted to a format compatible with GRASS. This was achieved by loading the data into IDRISI for DOS, and saving it in a file format compatible with GRASS.

The offshore data is distributed over a grid with 30 cell divisions per degree of longitude and 50 rows per degree of latitude. Distances between lines of longitude vary with latitude and thus the spatial East-West direction resolution of the data decreases in a southerly direction from 1.88 km at the north of Scotland to 2.71 km at the French Adriatic. Since meridians of latitude have an invariant separation the spatial North-South resolution of the data remains constant at approximately 2.2 km.

At even the relatively modest resolutions employed here, a large number of grid cells are required to cover coastal European waters. To prevent processing from becoming unwieldy, the data is subsetted on a country by country basis. For Britain and Ireland this still results in too much data, and thus here that data is further subdivided into separate North and South sets.

3.4 Development of simplified cost model within the GIS

3.4.1 Overview

The spatial calculation facilities of the GIS have been exploited to develop a simplified version of the Opti-OWECS detailed cost model. This enables easy economic evaluation of a range of sites and outline concepts.

By necessity, the GIS implementation of the cost model is highly simplified in comparison to its detailed predecessor. The computational facilities of GIS, have, until relatively recently been rather inferior to more generalised packages. As such, the GIS cost model does not contain the intelligence of the detailed code. Instead, it is based essentially on a series of look up tables relating design and environmental factors to overall costs, which have been established using the main model. The look up tables themselves are embedded within a series of GRASS commands, which in turn, are bound together by several Unix shell scripts. It has not proved possible to automate the calculation to the same degree as with the main cost model, and thus a certain degree of manual control is necessary in performing the calculations.

In common with most GIS, GRASS can only store integer quantities within its geographical maps, although it is quite capable of performing floating point arithmetic. Any attempt to store floating point variables within maps results in truncation of the value to an integer. This feature makes calculation of floating point quantities, with significant digits on the right hand side of a decimal point, somewhat challenging. Fortunately, most of the quantities dealt with here are sufficiently large that the inaccuracies involved in treating them as integers are insignificant. For a few variables, and in particular the wind speed and energy costs, the fractional values are important. In these cases, the difficulty may be surmounted by multiplying such quantities by a sufficient powers of ten that all significant digits are moved into whole number positions. Care must be taken to account for this transformation in any subsequent calculations.

What might be termed a "cell by cell" approach to the calculation is adopted. The routines assume that all the OWECS investigated would fit within a single cell of the map layers. No account is taken of the possibility that wind farms straddling cells might have more favourable qualities than those located wholly within a single cell. The averaging calculations that would be required to allow such possibilities are too difficult to be worthwhile. In addition, no account is taken of the effect of any changes across a map cell, nor indeed is it possible to do so with any GIS. For many GIS applications, the fact the spatial resolution of the data is limited is not problematic. Here however, this is not the case, especially with regard to the water depth. Any sudden changes in depth within a map cell, which are not discernible from the average values, could have a significant influence on the energy cost which will not be reflected in these calculations.

The simplified cost model processes the input environmental and design data to produce estimates of six major quantities required to evaluate the economics of OWECS, specifically:

- Annual energy production
- Cost of the support structure
- Cost of the grid connection
- Cost of the turbine
- Availability of the wind farm
- Annual operation and maintenance costs

These values are combined, using a standard discounting approach [3.4-1] to produce an estimate of the energy cost.

3.4.2 Annual energy production calculation

The annual energy production calculation procedure estimates the annual energy production of the proposed wind farm. The first part of the calculation employs the power law to estimate the windspeed, v_{hub}, at the hub height h_{hub} from the reference windspeed v_{ref} and the reference height h_{ref}.

$$v_{hub} = v_{ref} \times \left(\frac{h_{hub}}{h_{ref}}\right)^{0.14} \qquad (3.4\text{-}1)$$

Only small corrections are necessary because a reference height of 60m above sea level is used by the database. The result is used in a look up table to establish the annual energy production of a single wind turbine in kWh, and then multiplied by an array efficiency, an availability and the total number of turbines, to estimate the total energy production. A different look up table is available for each of the two turbines capacities considered. Figure 3.4-1 shows a graphical representation of the tables used for the 1.5 MW and 4 MW turbines respectively.

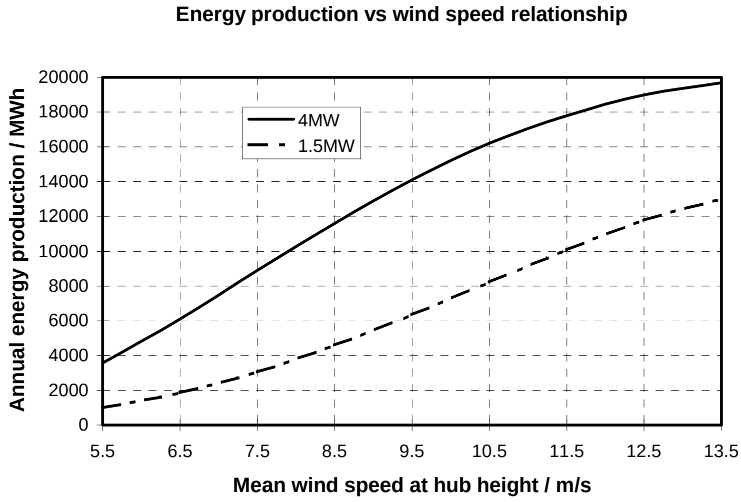


Figure 3.4-1: Energy production of an isolated turbine as a function of windspeed for both turbine concepts examined.

All of the inputs to the routine are in the form of spatial variables, and the output is a spatial map of the energy production.

3.4.3 OWECS investment cost calculation

Cost of support structure.

Three types of support structure have been considered in detail during the Opti-OWECS project, specifically a monopile, a gravity based monotower and a gravity based lattice tower. The simplified cost model can deal equally well with both monopile and gravity based monotower concepts, although only results for monopile based calculations will be presented here. While both of the monotower concepts can be dealt with in very similar ways, the costs associated with each type of support structure differ. To make matters more complex, support structure costs depend strongly on the type of turbine employed, and thus separate sets of look up tables are needed for each possible turbine/support structure combination.

The cost of the support structure is divided into two parts, one for the material costs and one for the physical construction and installation.

Aside from the influence of the design concept and turbine type already noted, the support structure material costs are a strong function of the hub height and the water depth. The latter is available from the offshore data base, whereas the former has to be input manually as a 'geographic' quantity. Dependence of the material costs on these two variables is incorporated within look up tables derived using the main cost model. A typical result for a monopile support structure with a 1.5MW turbine and an overall height (seabed to nacelle) of 90m is shown in figure 3.4-2

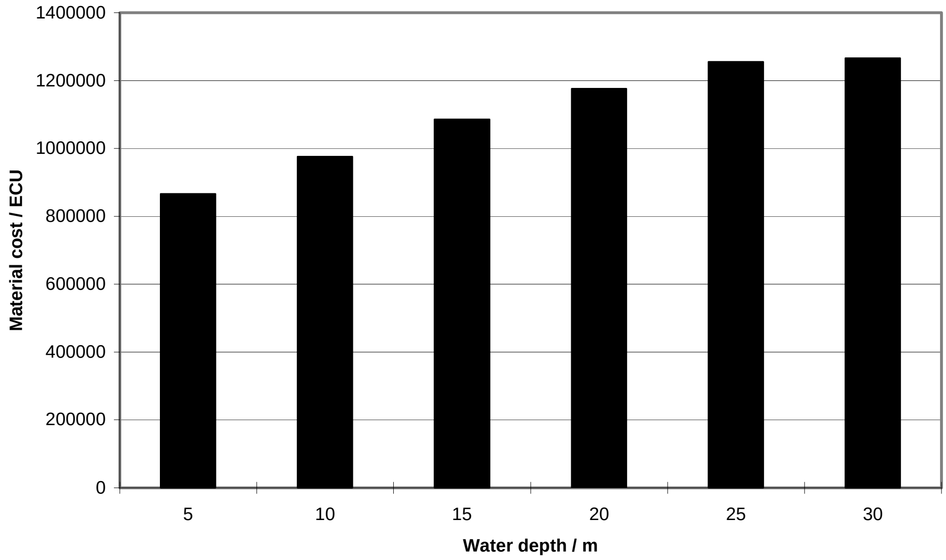


Figure 3.4-2 : Typical result for variation of support structure material costs with depth (for a 1.5MW turbine and 90m overall height)

The wave height at any site will also have an important effect on the cost of the support structure. It had originally been intended to take some account of this within the GIS based calculations, and some information on wave heights in the geographical areas of interest had been compiled. Unfortunately the detailed cost model was found to be insufficiently sensitive to wave height effects to make inclusion of this factor sensible.

For the range of concepts considered during the Opti-OWECS project, the installation costs are largely a function of the number of machines installed, rather than their size or distance from the shore. Of course these two latter factors have an influence on the cost of the installation, but as the detailed cost model is not able to detect it, there seems little purpose in including it here. The installation cost for a single support structure is determined from a look up table, purely on the basis of the total number of turbines to be installed (see figure 3.4-3). By combining this value with the previously evaluated material cost, and then multiplying by the number of turbines, the cost of the support structure is determined.

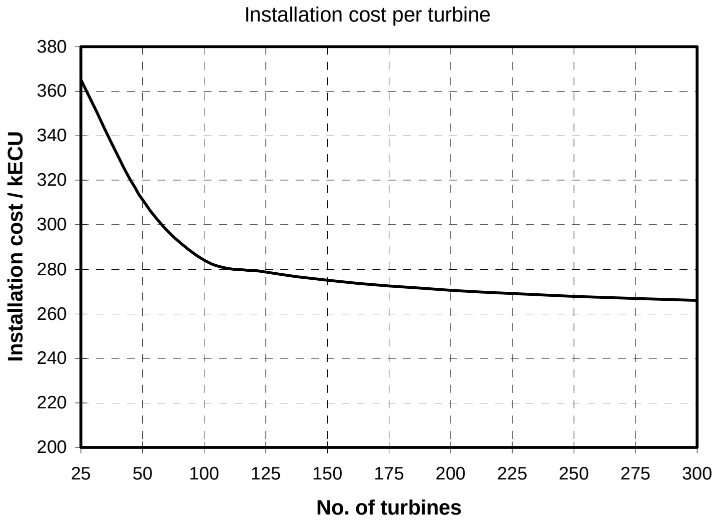


Figure 3.4-3 : Variation of structure installation costs assumed for all concepts.

The characteristics of the sea bed and their influence on the dynamic behaviour of the foundation and support structure do have some effect on the design, and therefore cost. Their main contribution is through the dynamics of the support structure. A design which is quite satisfactory at one location, may be unsatisfactory at another by virtue of differences in soil stiffness causing the natural frequency to move into a band where resonance might occur. While it would be desirable to account for this within the model, the lack of information on the dynamic characteristics of the sea bed makes it impractical in all of the cases investigated here. Where specific information is available, the main cost model can be used to compile an additional look up table that takes account of the soil characteristics.

At the end of the calculations, a spatial map of the support structure costs, in ECU, for the specified input parameters is produced.

Grid connection costs

Grid connection costs are most strongly a function of the number of turbines in the OWECS, their individual power capacity, and the distance of the OWECS from the shore. Separate look up tables have been developed for each of the turbine capacities, relating the grid connection costs to the number of turbines and the distance from shore. The calculations detailed here only consider AC power transmission, which for distances to shore in excess of 50-70km is likely to be less economic than DC technology. Typical results are shown in figure 3.4-4. Estimates resulting from the look-up table are placed within a map layer for later use. Variation of the spacing of turbines within a farm has only a small influence on the grid connection costs and its effect is not included here.

A serious limitation of the procedure is that grid connection costs are calculated assuming that a cable is built from the OWECS directly to the nearest shore. For most locations this will produce a sensible estimate of the cost of delivering electricity to the land, neglecting of course the cost of any land based electrical equipment. At certain locations however, it may well turn out that the nearest shore is located on a small island away from the mainland. There is no guarantee that any such isolated landmass would be a useful place to which to deliver electricity: for example it may be uninhabited, or have too small a population to make full use of the electricity. This is particularly a problem with the results for northern Scotland and for the Wadden Sea, and some caution is needed in reading the results.

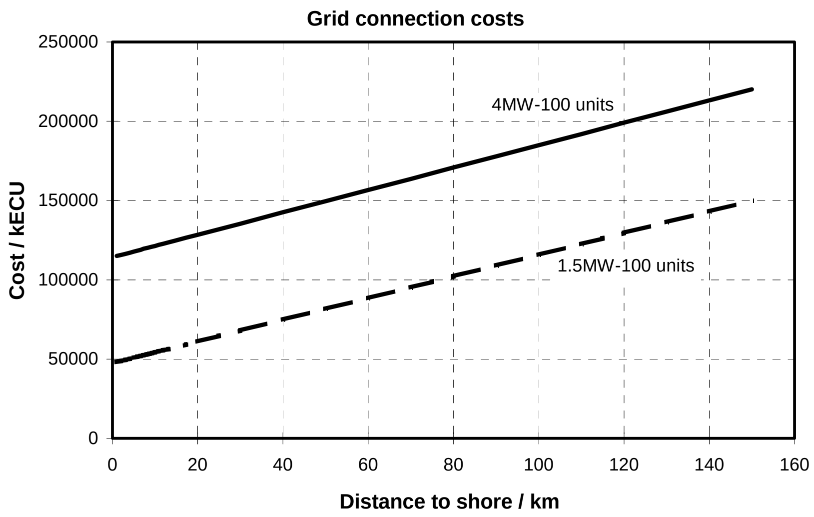


Figure 3.4-4: Assumed variation of grid connection costs.

An additional important limitation is that no account is taken of the costs of any land based grid connection equipment. Compilation of the data required to allow such costs to be incorporated was, unfortunately, beyond the scope of the project. Thus, the costs quoted are for delivery of electricity to the nearest beach.

Turbine costs

Calculation of the turbine costs is a very simple matter. The cost of each type of turbine is contained within a look up table. Once the user has specified the turbine type, the routine calculates the total cost of the turbines, multiplying the individual cost by the total number of turbines, and places the result in each cell of a map layer. Details of the assumed costs are shown in table 3.4-1.

Turbine	Unit cost
4MW - 90m rotor diameter	2,550,000 ECU
1.5MW	1,000,000 ECU

Table 3.4-1: Assumed unit costs for turbines

The cost assumed for the 4MW turbine are derived from extraplotaion of the trend in commercial machine rated 500 kW to 1.65 MW (see appendix C). The cost for the 1.5MW concept is based on advice from several turbine manufacturers.

Operation & maintenance costs

The operation and maintenance (O&M) costs make a substantial contribution to OWECS economics and thus it is important to include them even in an 'order of magnitude' calculation such as this. Unfortunately, O&M costs are very difficult to predict, and the relevant quantities closely interlinked.

In essence, the major features affecting O&M costs are the distance of the OWECS from shore, the exposure of the site (as indicated by the annual mean wind speed), the size of the OWECS, the reliability of the turbines, the maintenance strategy under which they are operated and the availability that is required. The OWECS operation and maintenance model of the Institute for Wind Energy has been used to investigate the relationships between the main quantities in some detail. For use within the GIS calculations, a series of functions have been fitted to the results that estimate wind farm availability and operation and maintenance costs on the basis of the other important variables.

There is not space here to detail the relationships used, not would it be particularly instructive to do so as they are essentially empirical. In effect though, the O&M costs and availabilities predicted by the calculation are those that would be predicted under similar circumstances by the Institute for Wind Energy detailed O&M model.

3.4.4 Calculation of levelised production cost

The preceding parts of the calculation have calculated the following as spatial variables

- Annual energy production (taking account of OWECS availability)
- Cost of turbines
- Support structure costs
- Grid connection costs
- Operation and maintenance costs

Decommissioning costs, which only make a small contribution to the overall energy cost, were neglected.

Each of the results is stored within a spatial map, with a specific value associated with each cell. All that remains is to combine the values to produce an estimate of the overall energy cost for each cell.

The values are combined using the standard discounting expression for estimating levelised energy production costs:

$$\text{L.P.C.} = \frac{I}{aE} + \frac{\text{T.O.M}}{E} \qquad (3.4\text{-}2)$$

where

L.P.C	=	Levelised production costs
I	=	Total investment costs
a	=	Annuity factor
E	=	Annual energy production
T.O.M	=	Total annualised O&M cost

and

$$a = \frac{1 - \left(\frac{1}{1-d}\right)^{l}}{d} \qquad (3.4\text{-}3)$$

$$\text{T.O.M} = \frac{1}{a}\sum_{t=1}^{l}\left(OM \times (1+d)^{-t}\right) \qquad (3.4\text{-}4)$$

with

d	=	real interest rate
l	=	economic lifetime
OM	=	Annual operation and maintenance costs

A GRASS routine processes the values in each cell, finally producing a map layer containing values of the energy cost. This calculation falls foul of the integer value limitation noted earlier, and thus cost values are expressed in units of 1/1000 ECUs.

3.5 Use of system to identify sites and estimate the cost of energy.

The JOUR0072 offshore database contains information regarding environmental conditions and the location of man made objects within the seas. Before proceeding with the economic calculations, all areas in which it would be impossible to build an OWECS, due for example to the presence of man made objects such as oil platforms or undersea pipes, should be eliminated. This can be achieved by performing spatial calculations to develop a "mask" map layer which causes unsuitable areas to be "masked out" of any further calculations.

The procedure adopted here to establish which areas are without question, unsuitable for OWECS development follows closely that elaborated by Matthies et al. [3.5-1]. With regard to man made constraints the rules adopted were

- *Traffic Zones*: All cells in which there is a record of a shipping traffic zone were excluded.

- *Undersea pipelines and cables:* All cells in which there is evidence of undersea pipeline or cables were added to the ’mask’.
- *Oil platforms*: A 10 km radius around any oil platforms was excluded.
- *Conservation areas:* Only one conservation area, the Wadden Sea National Park, is noted in the database and this was excluded from consideration.
- *Military areas:* Any areas noted as reserved for military use were excluded.

Construction of OWECS can also be precluded by the natural environment, and such areas must be eliminated before the economic evaluation can take place. Two types of natural constraint are exercised here. Firstly, areas with a water depth greater than 30 m, where the economic calculation is not reliable are excluded. Secondly, cells where a simple calculation of the sea bed slope, by comparing the water depth with that of adjacent cells, results in an angle in excess of 5 degrees are labelled as unsuitable.

Once the clearly unsuitable areas have been eliminated the next stage is to prepare the map layers for the economic calculation. The calculation requires the following input information in addition to that incorporated in the JOUR0072 wind database:

- Number of turbines
- Type of turbine (specified by capacity in kW, i.e. either 1500 or 4000)
- Type of support structure
- Hub height
- Availability of an isolated turbine for instantaneous service
- Real interest rate for the economic calculation
- Economic lifetime of the plant.

This information must be set in appropriate map layers over the area of interest, and is easily achieved using GRASS commands. In general it is not envisaged that there would be any need for these values to vary spatially for any single calculation, although there is no reason in principle why this should not be done.

With the preparations complete, the economic calculation script can be launched, to produce a further map layer with a cost of energy estimate in every cell. This map layer can be used to identify the most promising locations.

4. Regions considered

The scope of the Opti-OWECS project is limited to Northern European waters. It is impractical at this stage to build OWECS at locations very far from the shore, and thus consideration must be confined to waters with some proximity to the shore, taking, say 100 km as an upper limit. Within these broad boundaries, attention has been focused on those areas with which the project partners have some prior experience, specifically from the British North Sea, through Dutch waters and into the Baltic. This is of course an entirely pragmatic decision, but can be justified on the basis that it is the only region for which we can obtain environmental data with any certainty. Our experience is that a significant difficulty in selecting a site for an OWECS is obtaining sufficiently detailed environmental information about the candidate sites to allow a design study of sufficient detail to sensibly distinguish between them.

A further issue concerns how close to the shore it would be possible to build an offshore wind farm. There are relatively few technical obstacles to building an OWECS in shallow, near shore water, but whether any such proposals would be acceptable to the public is more difficult to discern. For this reason some of the results from the geographical investigation of energy cost in the following sections are divided into two groups. One group combines results from locations which are considered to be too close to the shore for public acceptance. For OWECS composed of 1.5MW turbines this includes all locations less than 5 km from the shore, and for 4MW turbines, all locations less than 10km from the shore. The other group combines all locations further from the shore than these distances. This division is rather arbitrary, and is only intended to provide a broadly representative division between sites that might and might not be exploitable for non-technical reasons.

For pragmatic reasons the region of northern Europe considered is divided into four areas. The geographical subsets of data employed in this report are listed in table 4-1 along with a short form of reference that will occasionally be used.

Geographical region	**Short reference**
Denmark and Germany	de_dk
Belgium and the Netherlands	be_nl
Northern UK	gb_n
Southern UK & French Channel coasts.	gb_s

Table 4-1: Geographical division of data.

5. Economic investigation of medium scale offshore wind farms

5.1 Overview

The characteristics of medium scale OWECS, proposed for development in the relatively near future have been investigated. Medium scale OWECS in this context are defined as 1.5 MW machines mounted on monopiles, with overall sizes in the region of 150MW. It is envisaged that such farms would be more suited to sites with more mild environmental conditions.

Section 5.2 provides details of the base case farm used as the focal point for the studies undertaken with the detailed cost model on which the results in this chapter are based. Section 5.3 contains the output of the GIS based model intended to associate the results from the detailed model with some real locations. As noted previously the information in section 5.3 must be interpreted with considerable caution with respect to the underlying assumptions and simplifications.

5.2 Base case wind farm and scope of calculations

The major parameters assumed for the base case medium scale OWECS are listed in table 5.2-1. The third column in the table shows whether the effects of changes in the particular parameter were investigated using the detailed cost model, and thus whether account is taken of changes in that parameter in the GIS calculations presented here.

Some of the parameters listed, the support structure height, the number of turbines within the OWECS and the support structure concept being the main examples, have in fact been investigated using the detailed cost model. The GIS based calculations incorporates the results of these studies and therefore can accommodate variations in these values. Time and space constraints however prevent any details of these variations being presented here and thus they are listed as not being varied. Similarly, the GIS calculations can also accommodate real interest rates and economic lifetimes other than those listed, but no other values will be employed in this report.

Component	Description	Varied in GIS?
OWECS design feature		
Turbine	• Capacity: 1.5MW • Rotor diameter: 64m • 3 blades • Based on Micon 1.5MW design • Energy production as a function of windspeed given in figure 3.4-1 • Unit cost :1,000,000 ECU	• No • No • No • No • Yes • No
Support structure	• Concept: Monopile • Overall height (seabed to nacelle): 70m • Pile height : waterdepth + 10m • Cost: as predicted by detailed cost model (see section 3.4.3)	• No • No • Yes • Yes
Grid connection type	• Type: AC undersea • Cost: as predicted by detailed cost model • Connection assumed to be to the nearest beach • No account taken of cost of any over land cables	• No • Yes
Farm layout	• Turbine spacing: 10 x rotor diameter • Array efficiency: 0.96 • No of turbines: 100	• No • No • No
Environmental parameters		
Wave height	9.1m	No
Mean sea level	15m	Yes (0-30m)
Distance to shore	10km	Yes
Mean annual wind speed	8m/s	Yes
Other parameters & costs		
Operation & management costs	As predicted by IvW O&M model (see volume 2 for details)	Yes
Overall windfarm availability	As predicted by IvW O&M model (see volume 2 for details)	Yes
Project management cost	2% of initial capital cost	No
Economic parameters		
Rate of interest	5% p.a.	No
Economic lifetime	20 years	No

Table 5.2-1: Base case for medium scale investigation

5.3 Cost of energy at European Sites

The difference between the strength of the parameter studies outlined previously in section 3.4 and in volume 4, and the results that follow in this section cannot be emphasised too strongly. For the preceding parameter studies, the detailed cost model was employed, whereas here, the much cruder GIS based model is used. While the GIS model is based on the results of the parameter studies, it is a much less reliable tool than the detailed cost model. At best, the results here should be regarded as a demonstration of the analytic technique, rather than as absolute statements of the suitability of the sites for OWECS. Of course, considerable efforts have been made to ensure the results are as reliable as practicable, but it would be a mistake to regard them as the ‘last word’ on the matter.

The GIS model was used to investigate the offshore waters of certain Northern European states. Maps comparing the costs of siting OWECS at a number of locations have been produced and will be presented region by region.

Some crude attempts to analyse the ranges of costs predicted by the calculations have also been made. These results are presented graphically as plots of showing the OWECS capacity that could be installed to produce electricity at various cost levels. The estimation of installed capacity here is very approximate, being reached by first estimating the total area available for OWECS at each cost level, and then multiplying by a constant value for the installed capacity per unit area. For the medium scale OWECS considered in this section, this value is assumed to be 3.66 MW/km^2.

Northern Britain (gb_n)

The result of the GIS based calculations for medium scale OWECS near northern Britain is shown in figure 5.3-2, with a breakdown of the capacity it would be able to install at each cost level in figure 5.3-1. Sites for which the estimated energy cost was in excess of 13 ECUc/kWh have been excluded from the results on the basis that, even accounting for the large uncertainty in the results, they are likely to be too expensive to warrant consideration. Within this constraint, the total offshore capacity that could be installed in the region shown is approximately 86 GW.

Figure 5.3-1 divides the estimated capacities in each cost and into two categories. Sites considered too close to the shore to be useful or labelled “1.5MW < 5km”, whereas those further than 5km from the shore carry the label “1.5MW > 5km”. It is clear that most of the capacity, 65% of the total, in the North Britain region is too close to the shore for exploitation. The map also shows that most of the OWECS sites ‘cling’ closely to the shore. This result must be regarded with some caution however, as the map shows many small islands which may not all be inhabited. Some distortion of the distribution of energy prices may also be caused by the presence of so many small islands, as noted in section 3.4.3, such that the energy prices at sites near to small island may be under-estimated.

An interesting feature may be seen in the region between the coast of Cumbria, to the lower west of the British mainland shown in the map, and the Isle of Man. There is some evidence that here, moving comparatively far offshore would cause a reduction in the energy cost. This appears to be due to increased windspeeds being found in the more open waters.

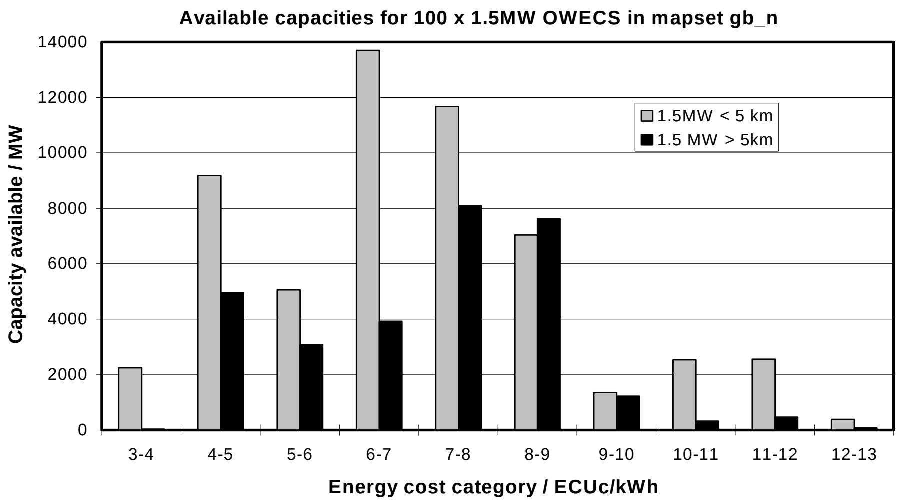


Figure 5.3-1: Distribution of medium scale capacity that could be installed in region gb_n as a function of energy cost.

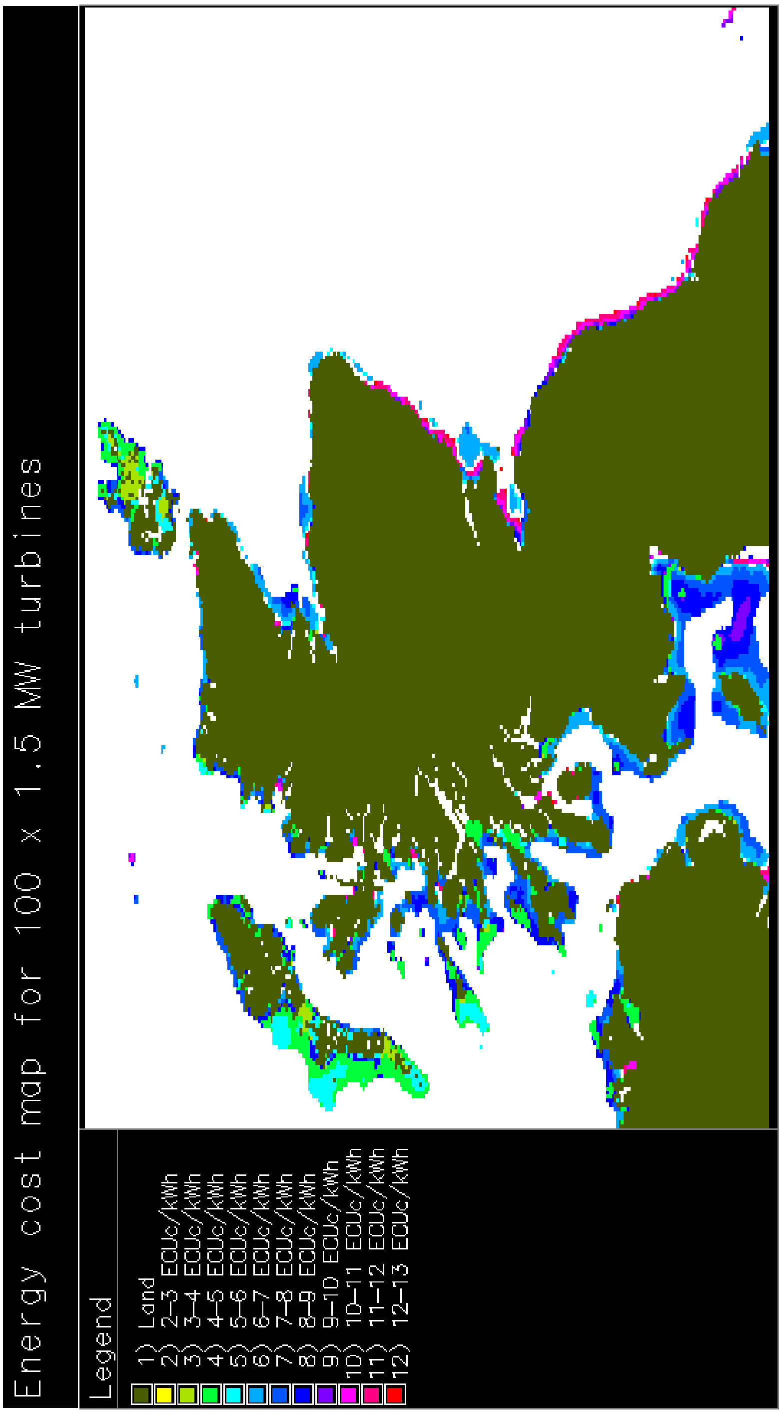


Figure 5.3-2: Energy cost map for medium scale OWECS in region gb_n.

Southern Britain and French channel cost (gb_s)

The region of Southern Britain and the French channel coast shows much greater potential for offshore wind farms than in “gb_n”, as can be seen from the map in figure 5.3-4 and the distribution of available capacities in figure 5.3-3. Again only locations for which the predicted energy cost was less than 13 ECUc/kWh are included, giving a total available capacity for OWECS installations of 210 GW. Approximately 25% of this capacity would be too close to the shore to be exploited.

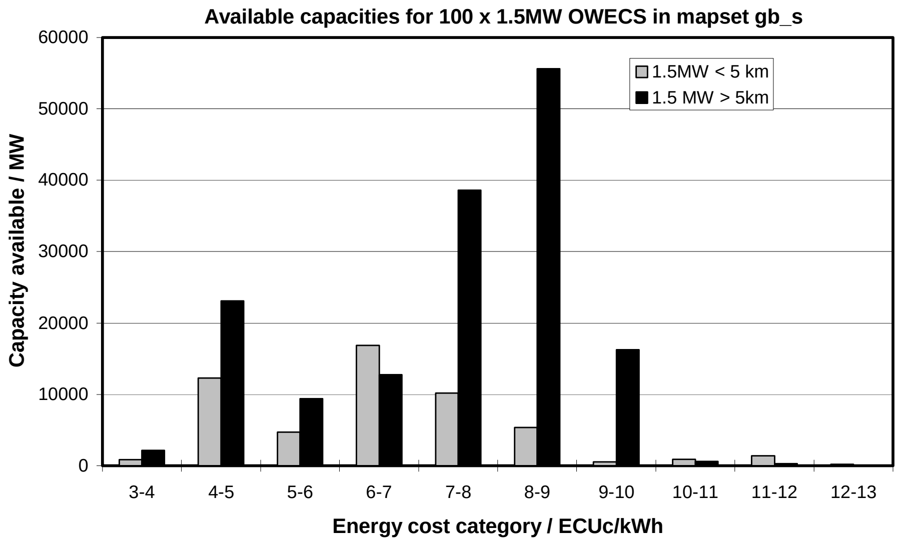


Figure 5.3-3: Distribution of medium scale capacity that could be installed in region gb_s as a function of cost.

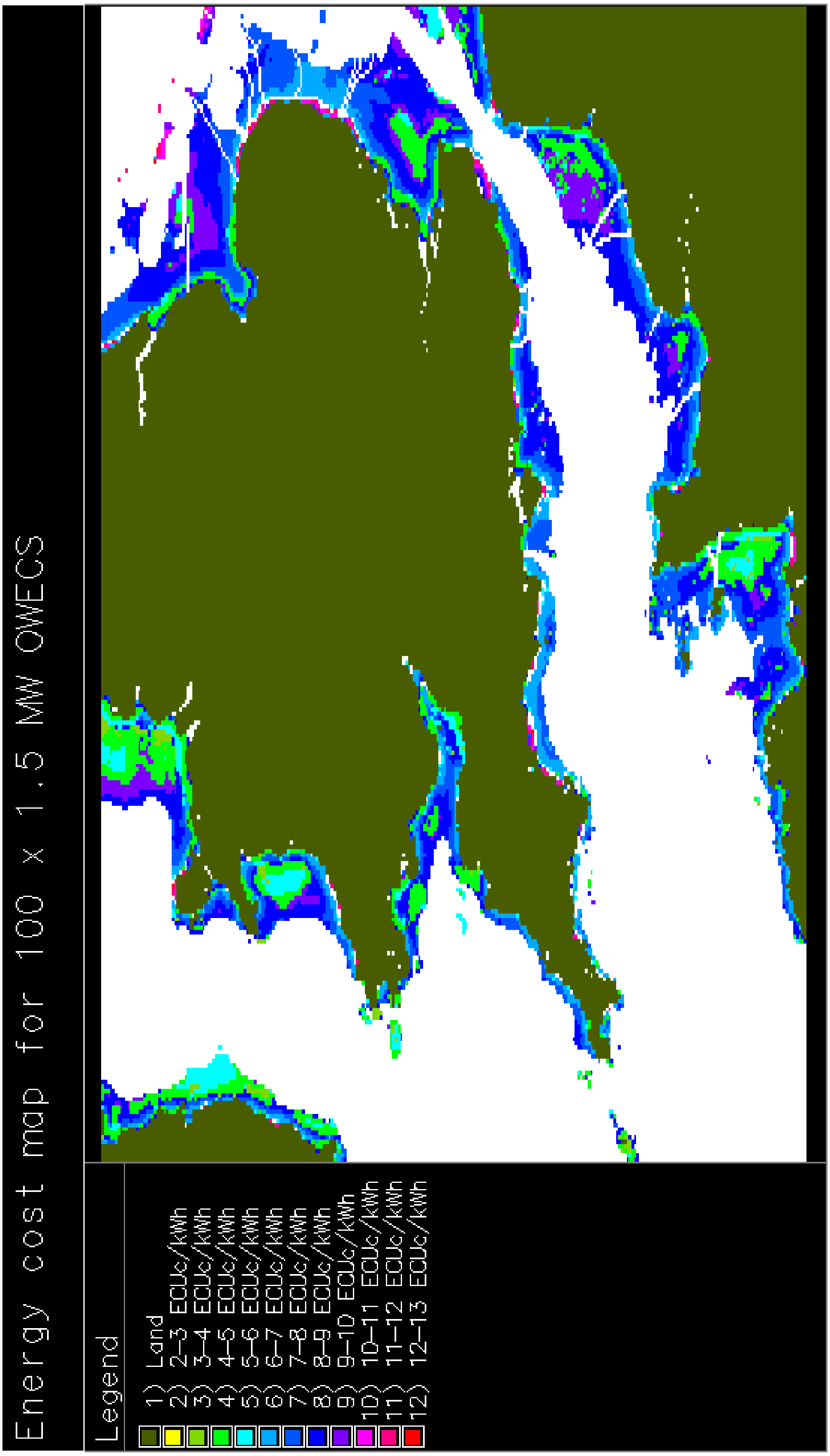


Figure 5.3-4: Energy cost map for medium scale OWECS in region gb_s.

Belgium and Netherlands (be_nl)

Results of the GIS calculation for Belgium and The Netherlands are shown in figure 5.3-6, for all sites with a predicted energy cost of below 13 ECUc/kWh. The distribution of capacities that could be installed at each cost band is given in the graph of figure 5.3-5. The total estimated capacity that could be installed in the region is 73 GW, of which approximately 23% is considered too close to the shore for utilisation.

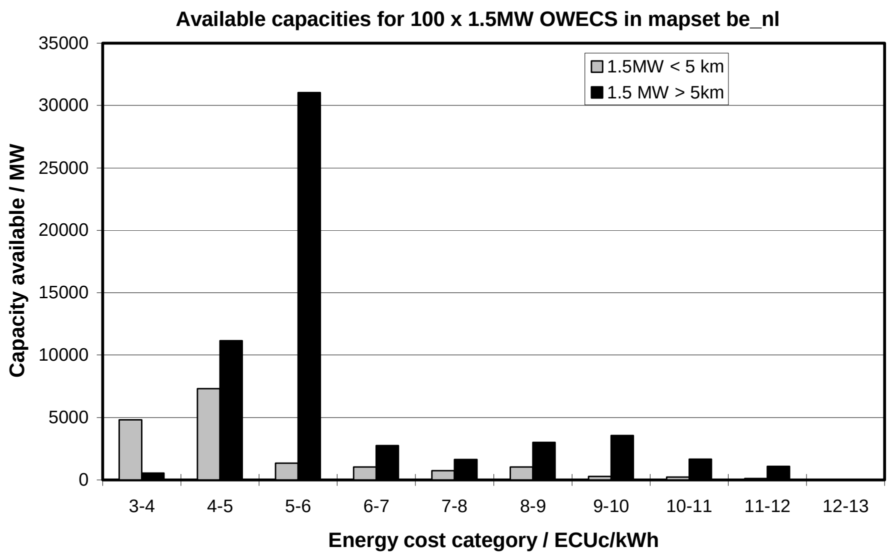


Figure 5.3-5: Distribution of medium scale capacity that could be installed in region be_nl as a function of cost.

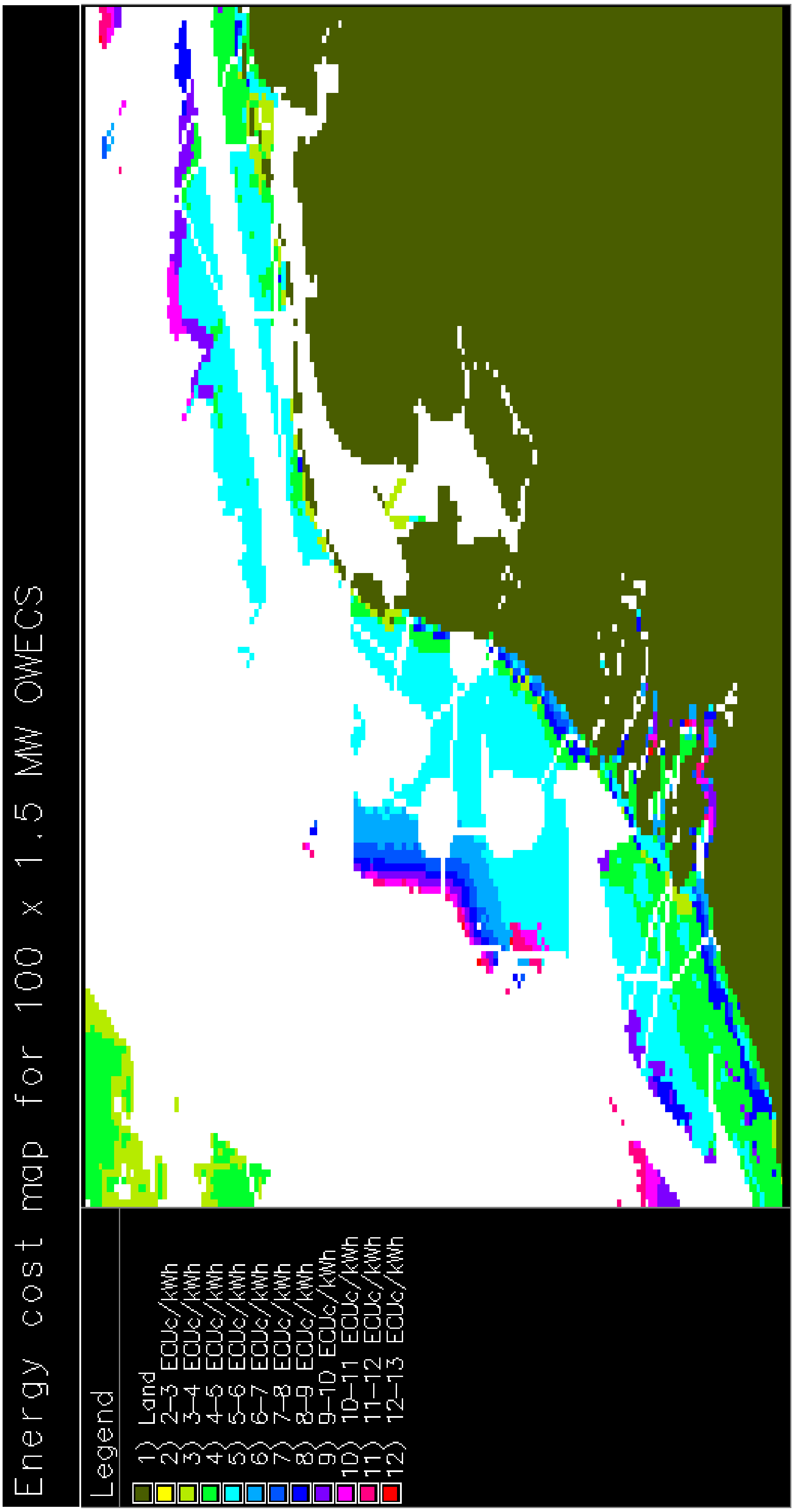


Figure 5.3-6: Energy cost map for medium scale OWECS in region be_nl.

Denmark and Germany (de_dk)

There are many sites available for OWECS exploitation in German and Danish waters. Even though a smaller range of results are presented here, with only those sites having a predicted energy cost of less than 11 ECUc/kWh being included, the region has an estimated available capacity of 343 GW. Most of this capacity, 81%, is far enough away from the shore that it is unlikely there would be objections to its use. Figure 5.3-8 shows a map of the results, while figure 5.3-7 shows a breakdown of the capacities with cost category.

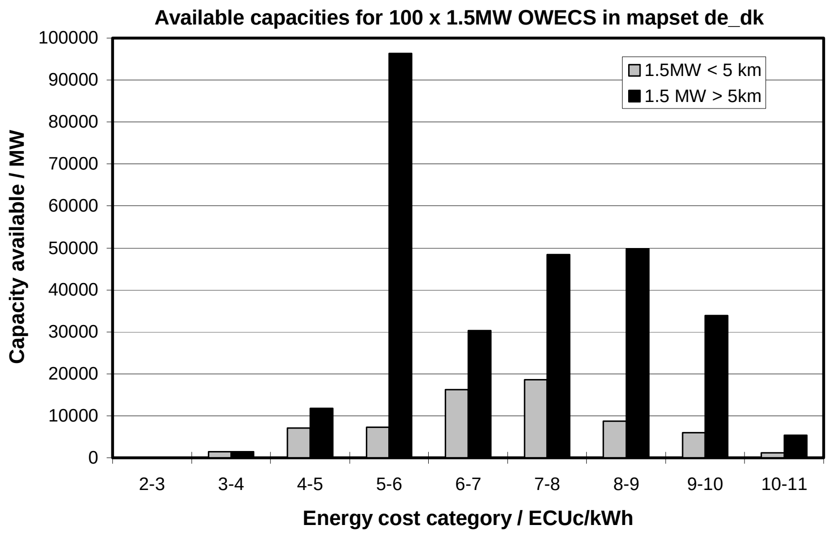


Figure 5.3-7: Distribution of medium scale capacity that could be installed in region de_dk as a function of cost.

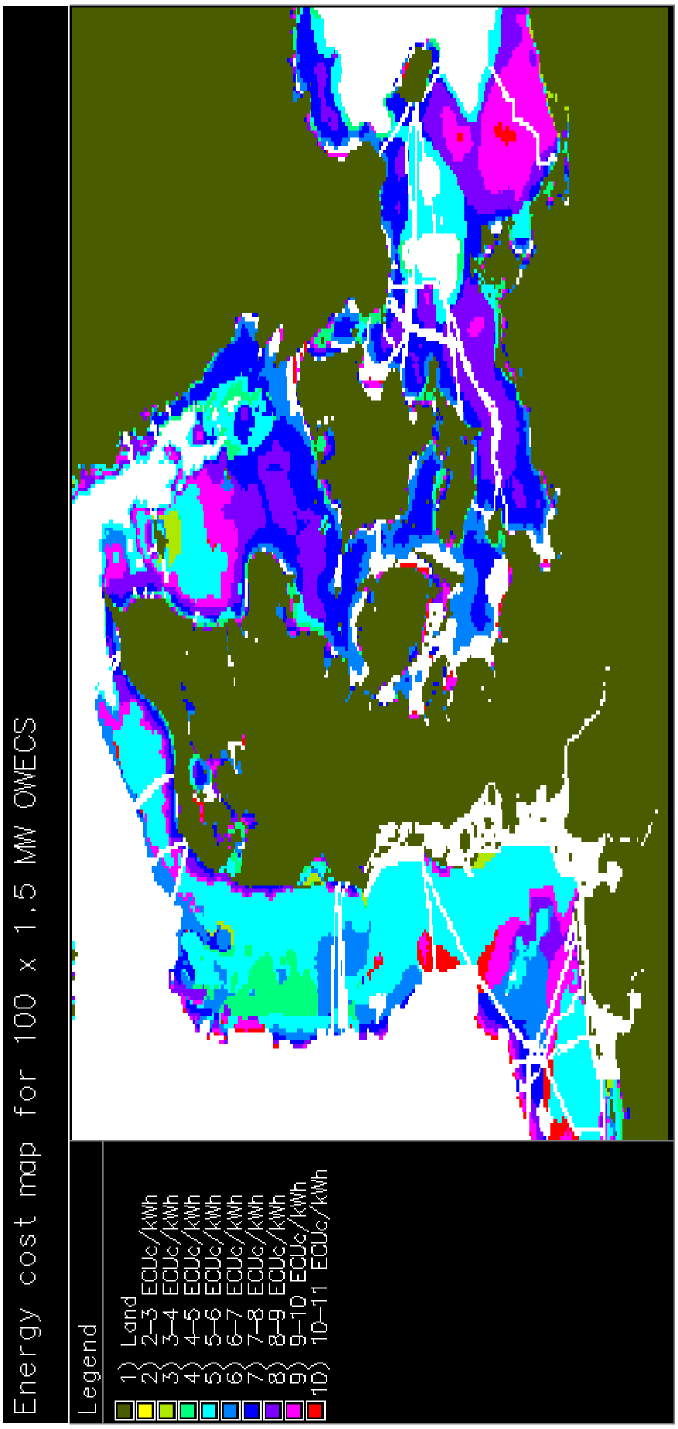


Figure 5.3-8: Energy cost map for medium scale OWECS in region de_dk.

6. Economic investigation of large scale offshore wind farms

6.1 Overview

In this chapter, results pertaining to more forward looking large scale OWECS will be examined. A large scale OWECS is defined here as being constructed with a 4 MW turbine, again mounted on a monotower with a piled foundation. The overall size of the farm is envisaged to be in the region of 400MW, probably with a more demanding location than that for the medium scale OWECS.

Section 6.2 provides details of the base case farm used as the focal point for the studies undertaken with the detailed cost model on which the results in this chapter are based. Section 6.3 contains the output of the GIS based model intended to associate the results from the detailed model with some real locations. As noted previously the information in section 6.3 must be interpreted with considerable caution.

6.2 Base case wind farm and scope of calculations

The major parameters assumed for the base case large scale OWECS are listed in table 6.2-1. The third column in the table shows whether the effects of changes in the particular parameter were investigated using the detailed cost model, and thus whether account is taken of changes in that parameter in the GIS calculations presented here.

As with the medium scale investigations the support structure height, the number of turbines within the OWECS and the support structure concept being the main examples, have in fact been investigated using the detailed cost model. The GIS based calculations incorporates the results of these studies and therefore can accommodate variations in these values. For the final calculation presented in this chapter, the facility to vary the structure height has been used to estimate energy costs for OWECS with structure heights of 70m, 80m and 90m in the de_dk geographic region only. A composite map displaying the lowest energy cost offered by the three concepts at each location has then been produced. The first four calculations presented assume a fixed structure height however.

It should also be noted that the 4 MW turbine has been treated as having the same instantaneous availability as the 1.5 MW concept. In other words, it has been assumed that the **large scale OWECS technology has the same level of maturity as the medium scale technology**.

Component	Description	Varied in GIS?
OWECS design feature		
Turbine	• Capacity: 4MW • Rotor diameter: 90m • 3 blades • Identical to the upscaled 4MW 90m version of WTS-80L described in volume 4 [6.2-1] • Energy production as a function of windspeed given in figure 3.4-1 • Unit cost :2,550,000 ECU	• No • No • No • No • Yes • No
Support structure	• Concept: Monopile • Overall height (seabed to nacelle): 80m Pile height : waterdepth + 10m • Cost: as predicted by detailed cost model (see section 3.4.3)	• No • No (see text) • Yes • Yes
Grid connection type	• Type: AC undersea • Cost: as predicted by detailed cost model • Connection assumed to be to the nearest beach • No account taken of cost of any over land cables	• No • Yes
Farm layout	• Turbine spacing: 10 x rotor diameter • Array efficiency: 0.96 • No of turbines: 100	• No • No • No
Environmental parameters		
Wave height	9.1m	No
Mean sea level	15m	Yes (0-30m)
Distance to shore	10km	Yes
Mean annual wind speed	8m/s	Yes
Other parameters & costs		
Operation & maintenance costs	As predicted by IvW O&M model (see volume 2 for details)	Yes
Overall windfarm availability	As predicted by IvW O&M model (see volume 2 for details)	Yes
Project management cost	2% of initial capital cost	No
Economic parameters		
Rate of interest	5% p.a.	No
Economic lifetime	20 years	No

Table 6.2-1 : Base case wind farm for the large scale investigation.

6.3 Cost of energy at European Sites

As with the medium scale OWECS study, efforts have been made to associate cost model results with some real potential locations in northern

European waters. Again, the GIS model has been used, and the comments made in section 5.3 regarding the relative reliability of various aspects of the work are equally valid here.

“Cost maps” for each of the regions considered will be presented along with a breakdown of the distribution of energy costs at individual sites. Breakdowns of the OWECS capacity that could be installed at energy particular cost level are again provided. Just as with the medium scale results, what these graphs really show is the area available at each coat level, multiplied by an assumed constant value for the capacity installed per unit area. In this case the value used is 4.94 MW/km$^{2.}$

The distribution of capacity available at each cost level for the large scale results produced here, and for the medium scale results from the previous section, is compared. Examination of the cumulative capacity available at or below any particular cost level has been found helpful in this respect, clearly showing the differences between both offshore wind farm concepts.

Northern Britain (gb_n)

Using large scale OWECS in the gb_n region increases to 126 GW the total capacity that could be installed to produce electricity for 13 ECUc/kWh or less. Most of this capacity, 85%, however is within 10 km of the shore - too close to be exploited. The distortive influence that a large number of small islands might have on the results must be kept in mind though.

Figure 6.3-3 shows a map of the results, with the distribution of capacity with cost given in figure 6.3-1. As with the medium scale results, the west coast of the British mainland appears to offer better economics than the east coast, but the difference is not as pronounced. Again the region between the Cumbrian coast and the Isle of Man is interesting because it contains an area where costs appear to fall with distance from the shore.

Further comparison of the medium and large scale windfarm results is made in figure 6.3-2. Using a larger scale wind farm does not appear to have much influence on the minimum cost for which electricity could be produced by an OWECS. In other words, larger scale OWECS seem to offer little advantage over their smaller counterparts at the most economically attractive sites. Instead, the benefit offered by large scale OWECS is visible at the more mediocre sites. The figure clearly shows that a greater proportion of sites are available at any particular cost level if a large scale wind farm is used in preference to a medium scale plant.

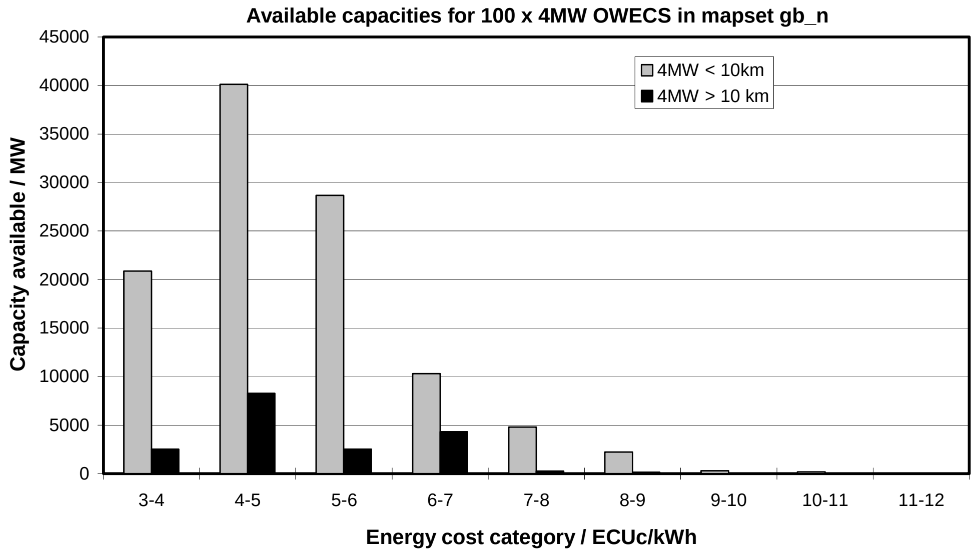


Figure 6.3-1: Distribution of large scale capacity that could be installed in region gb_n as a function of cost.

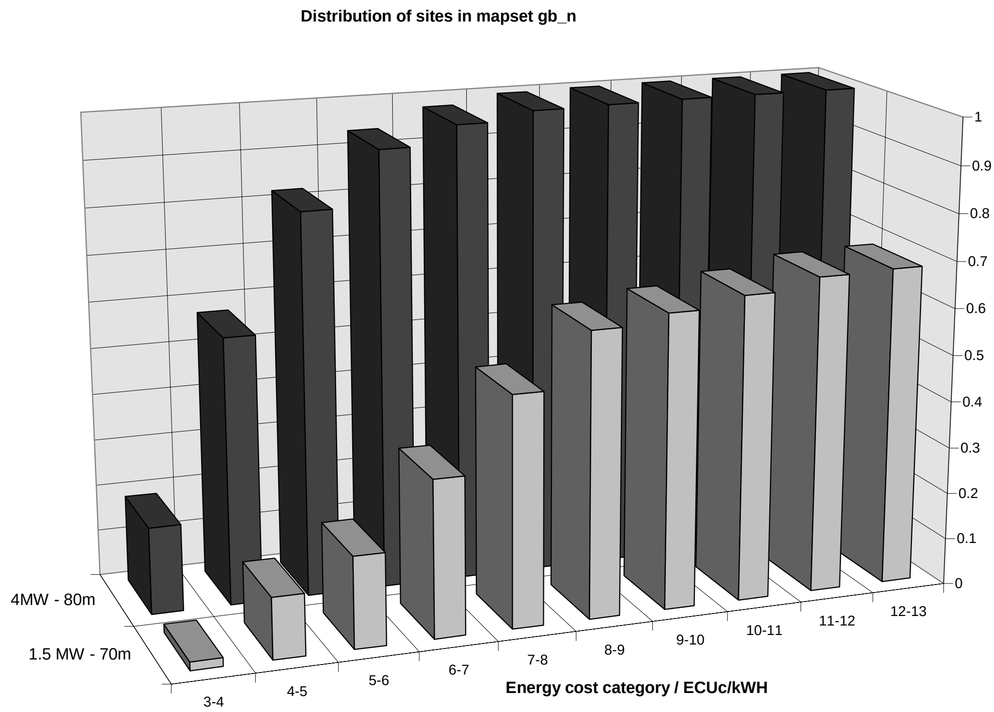


Figure 6.3-2: Comparison of results for medium scale (1.5 MW - 70m overall height) and large scale (4MW - 80m overall height) OWECS in region gb_n.

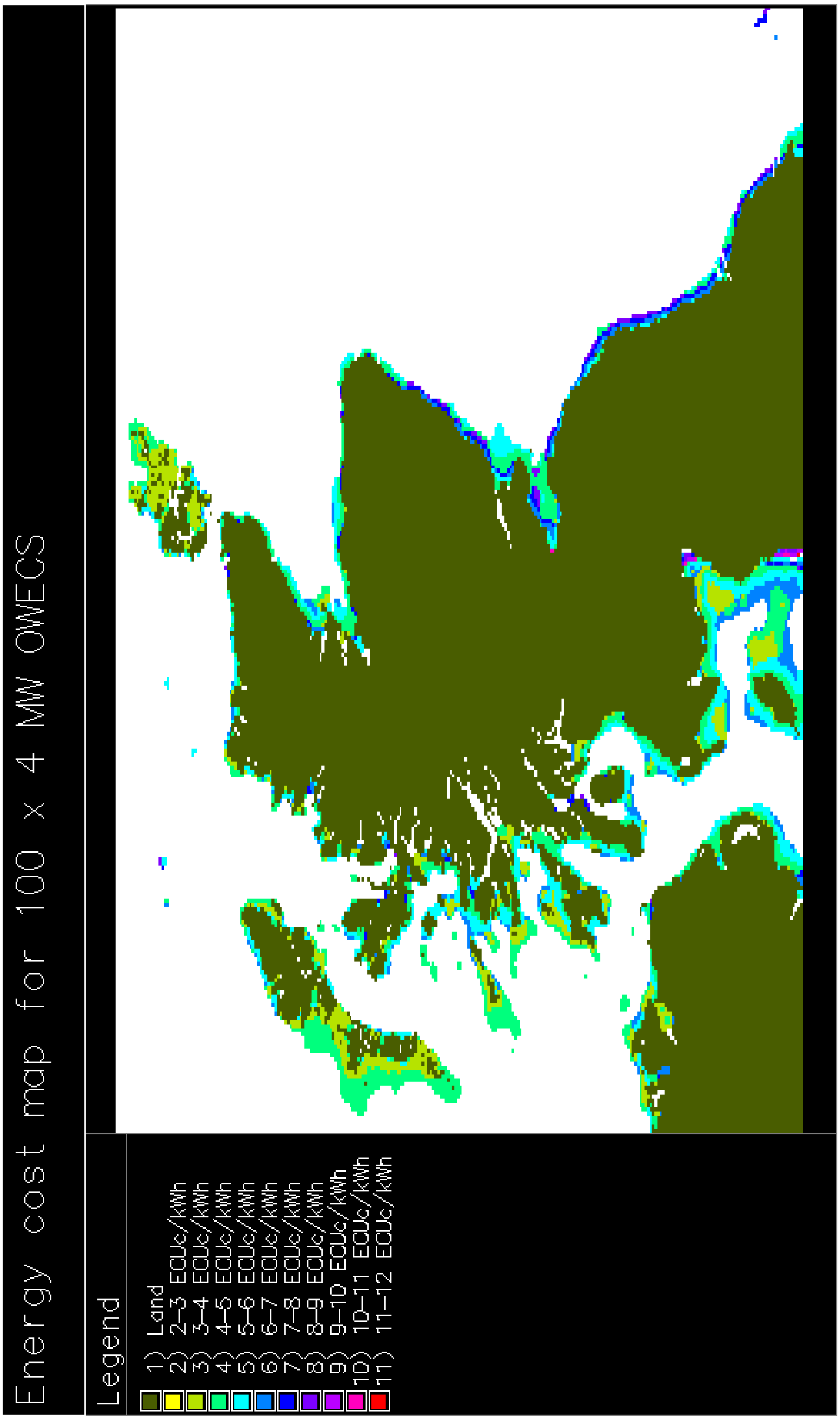


Figure 6.3-3: Energy cost map for large scale OWECS in region gb_n.

Southern Britain and French Channel coast (gb_s)

A total capacity of approximately 295 GW could be installed with an energy cost of below 13 ECUc/kWh in the gb_s region if large scale OWECS were to be employed. Around 51% of this capacity would be sited too close to the shore to be usable. Figures 6.3-4 and 6.3-6 show details of the results.

Comparison of the large scale results with the medium scale in figure 6.3-5 exhibits the same general trends as for the gb_n region.

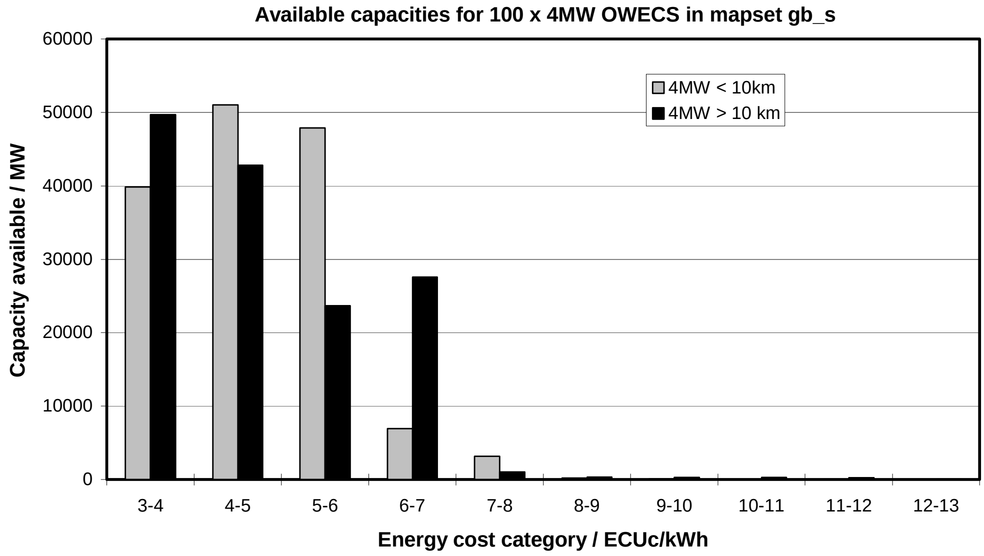


Figure 6.3-4: Distribution of large scale capacity that could be installed in region gb_s as a function of cost.

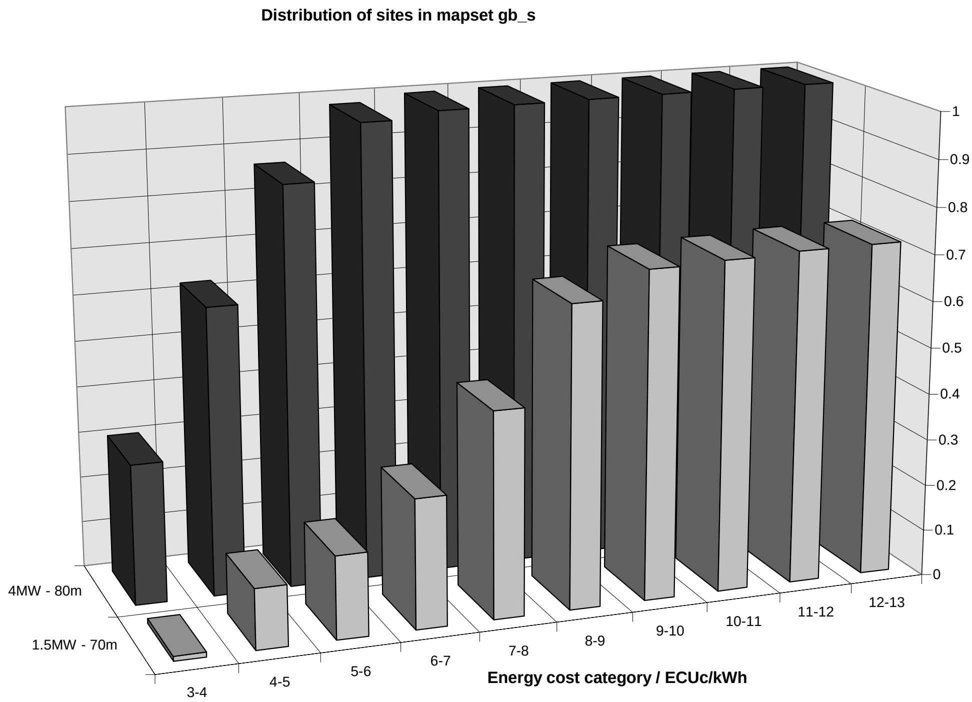


Figure 6.3-5: Comparison of results for medium scale (1.5MW - 70m overall height) and large scale (4MW - 80m 70m overall height) OWECS in region gb_s.

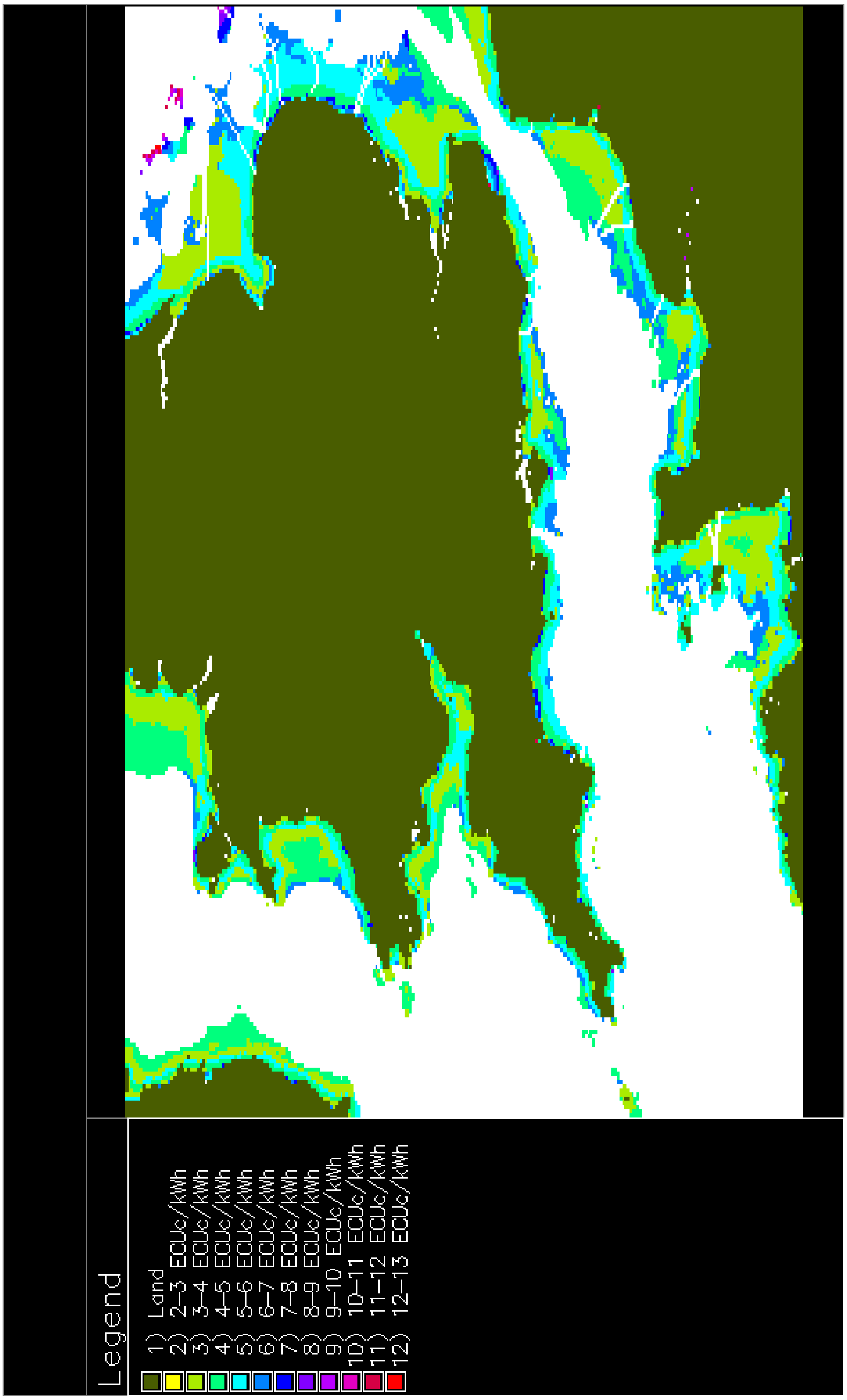


Figure 6.3-6: Energy cost map for large scale OWECS in region gb_s.

Belgium and Netherlands (be_nl)

In the Belgium and Netherlands region, the calculations suggest that a total capacity of 105 GW large scale OWECS could be installed to generate electricity at a cost of below 13 ECUc/kWh. Of this, around 32% is probably too near to the shore to be useful. A map of the geographical variation of energy cost and a breakdown of the distribution of capacities is shown in figures 6.3-9 and 6.3-7 respectively. Once again the main benefit of using large scale OWECS seems to be in “shifting” the distribution of costs towards the lower cost categories as can be seen in figure 6.3-8.

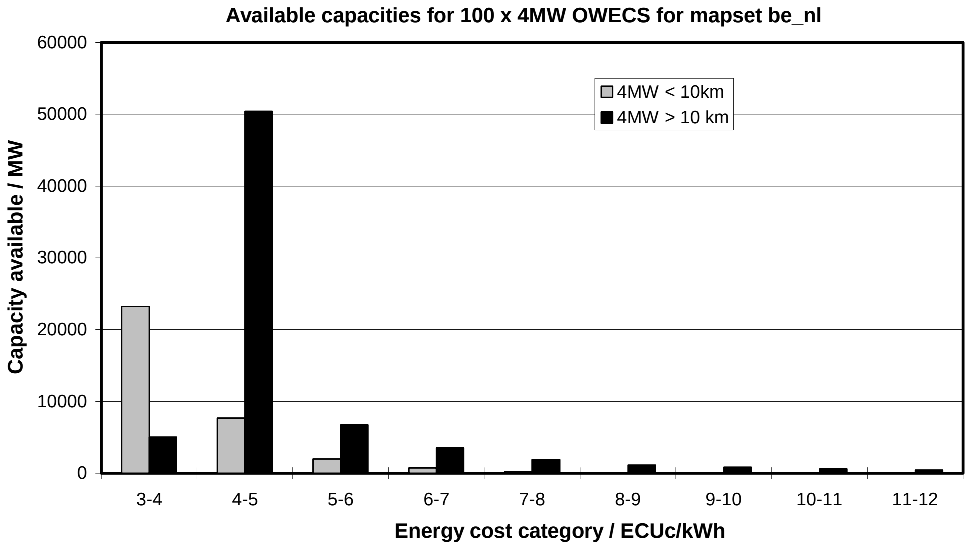


Figure 6.3-7: Distribution of large scale capacity that could be installed in region be_nl as a function of cost.

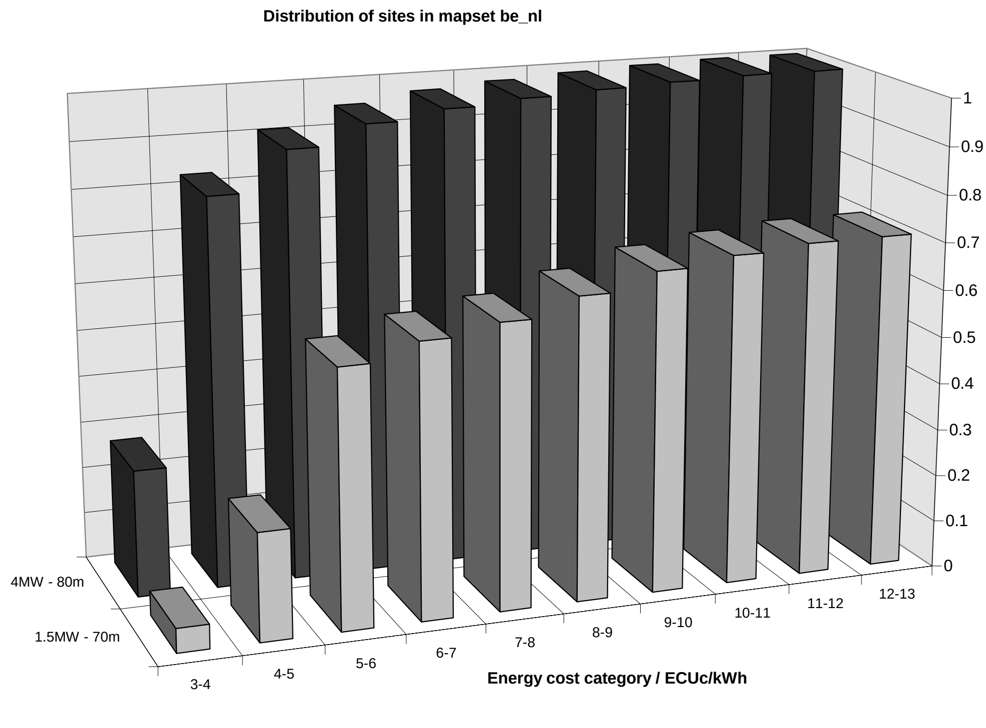
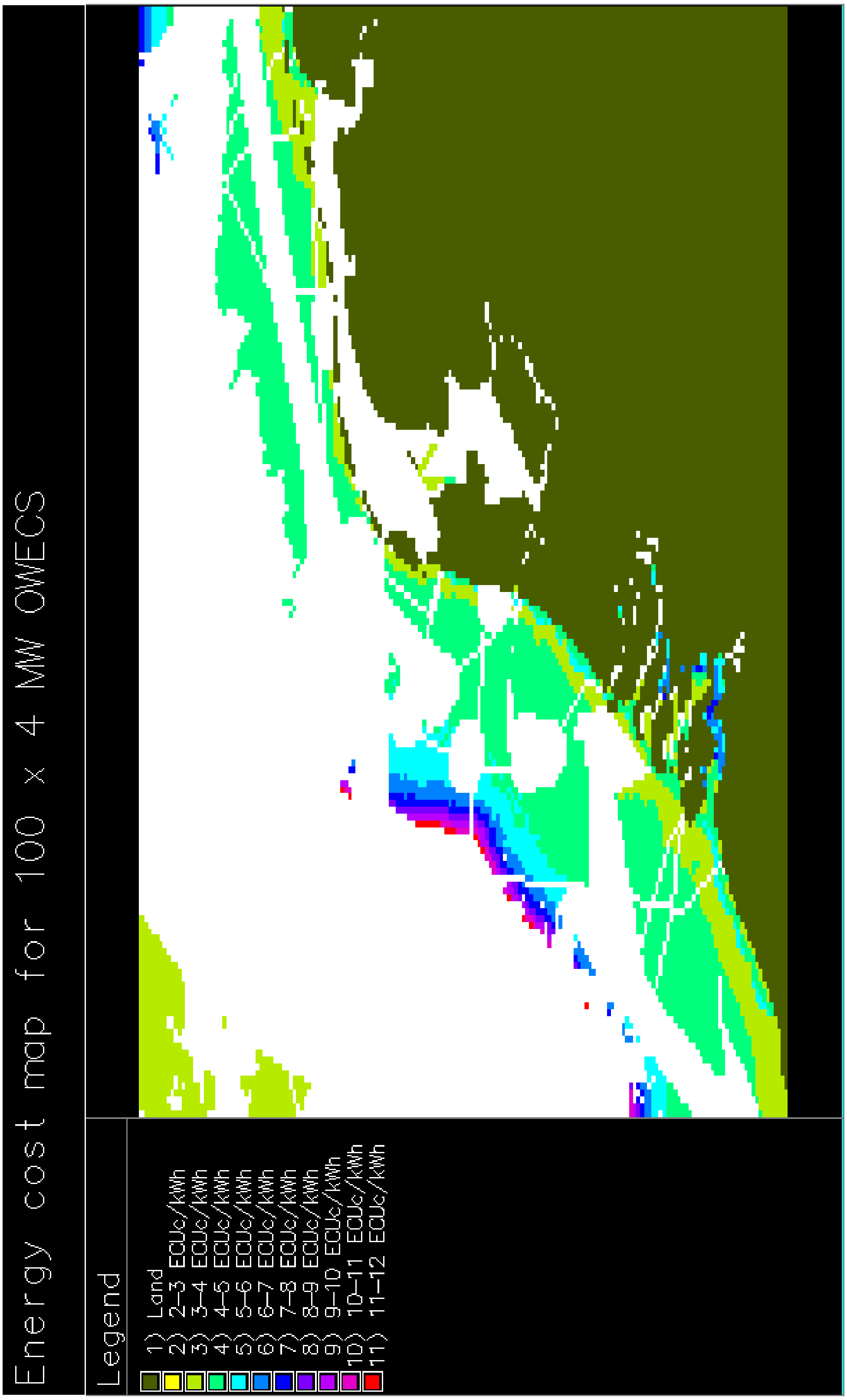


Figure 6.3-8: Comparison of results for medium scale (1.5MW - 70m 70m overall height) and large scale (4MW-80m 70m overall height) OWECS in region be_nl.


Energy cost map for 100 x 4 MW OWECS
Legend
1) Land
2) 2–3 ECUc/kWh
3) 3–4 ECUc/kWh
4) 4–5 ECUc/kWh
5) 5–6 ECUc/kWh
6) 6–7 ECUc/kWh
7) 7–8 ECUc/kWh
8) 8–9 ECUc/kWh
9) 9–10 ECUc/kWh
10) 10–11 ECUc/kWh
11) 11–12 ECUc/kWh

Denmark and Germany (de_dk)

Approximately 506 GW of capacity could be installed with an energy cost of less than 11 ECUc/kWh in the de_dk region. A good proportion of this, 64% is more than 10 km from the shore. Figures 6.3-10 and 6.3-12 present the results, and comparison with medium scale OWECS is made in figure 6.3-11.

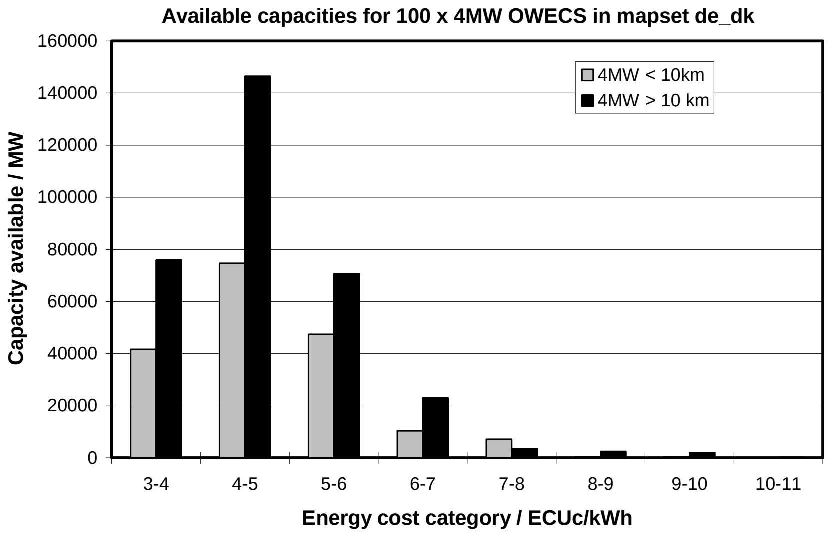


Figure 6.3-10: Distribution of large scale capacity that could be installed in region de_dk as a function of cost.

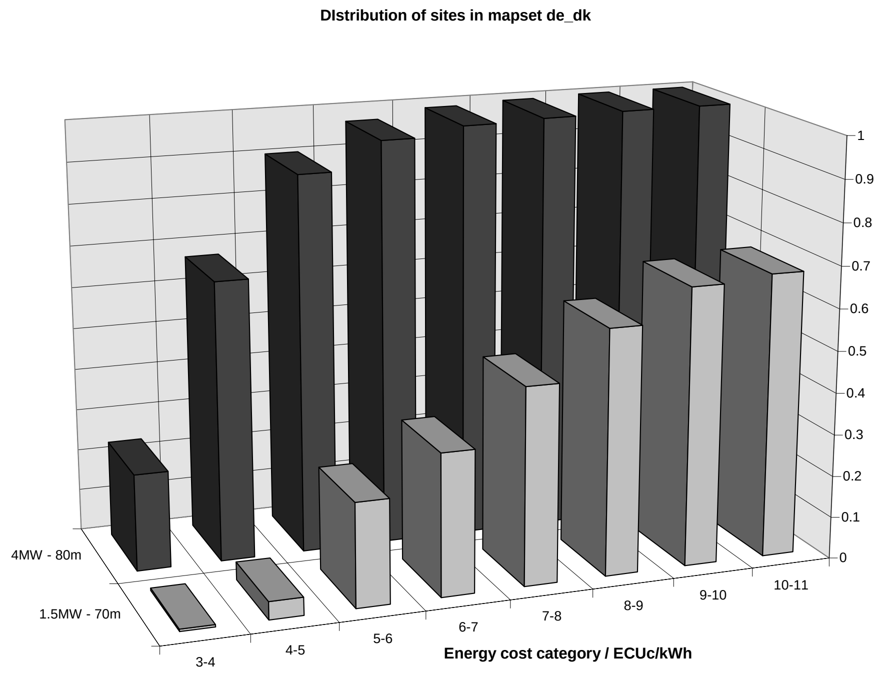


Figure 6.3-11: Comparison of results for medium scale (1.5MW-70m overall height) and large scale (4MW-80m 70m overall height) OWECS in region de_dk.

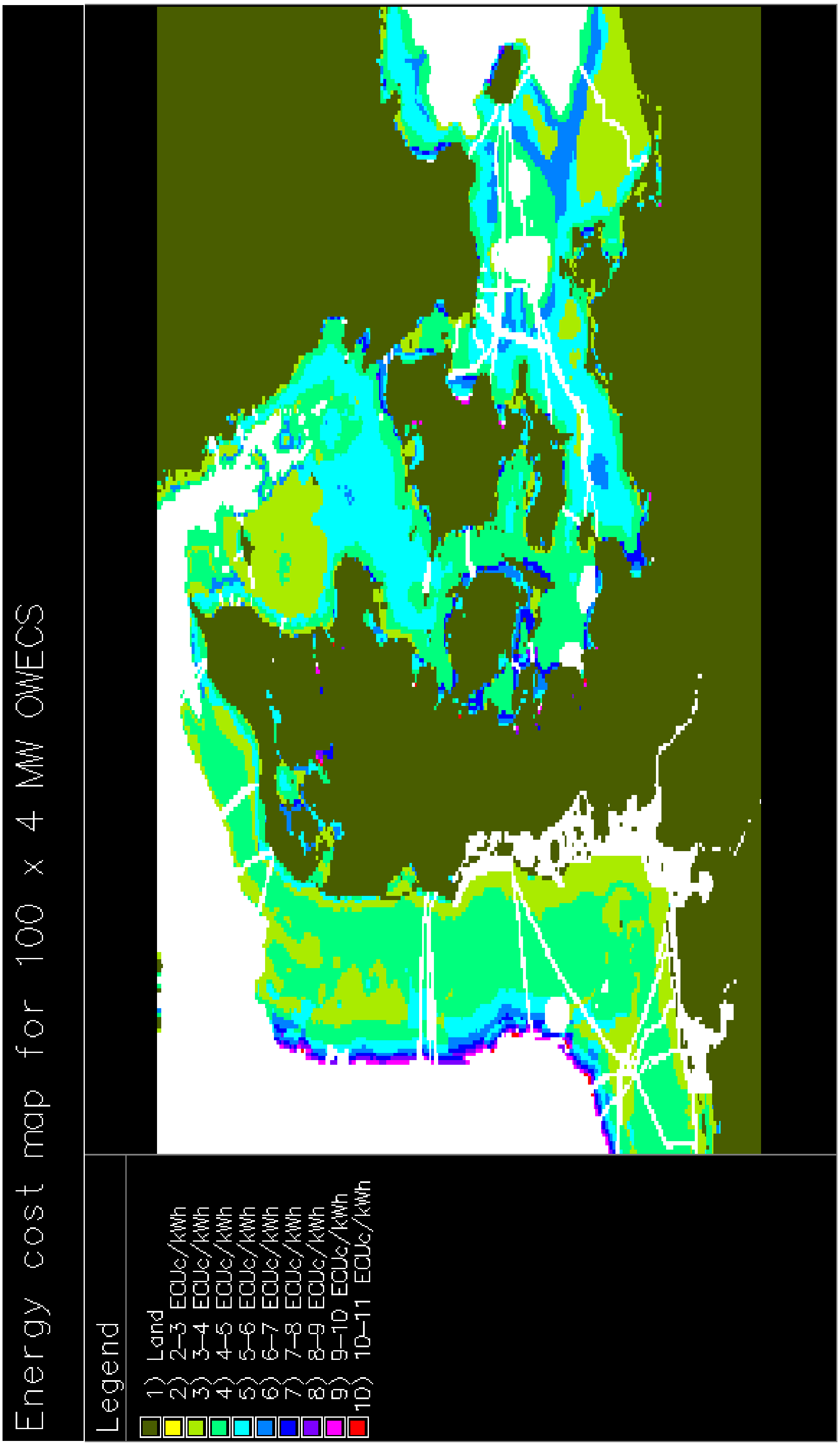


Figure 6.3-12: Energy cost map for large scale OWECS in region de_dk (overall height of support structure 80 m).

Denmark and Germany optimised for structure height

All the previous calculations have examined the economic effects of using a single support structure, with a fixed height from seabed to nacelle, at all of the sites considered. It is likely that this single support structure is not well suited to all of the sites, and that at many of them, the cost of energy could be reduced by tailoring the support structure to the site conditions.

An attempt has been made to investigate the effect that 'tailoring' the support structure would have on the distribution of energy costs in the Denmark and Germany (de_dk) region. Separate maps of energy cost have been calculated for large scale OWECS based on three sizes of support structure, with heights from seabed to nacelle of 70m, 80m, and 90m. A further map, showing the minimum of the energy costs predicted for each of these three concepts at every location was then compiled. The 70m support structure is too short to be used in the deeper areas considered, and thus has been limited to regions with mean sea levels of 15m or less. Similarly, the 80m structure is also a little too short to be deployed in some of the very deepest areas, but this fact has been ignored. This represents something of an inconsistency. It does, however, mean that there is a choice of at least two structures at every location and that any economic advantage that might be gained by optimising the designs should be emphasised.

The final 'minimum energy cost map' produced by the procedure is shown in figure 6.3-15, with the distribution of available capacity against costs in figure 6.3-13. Note that the "10-11 ECUc/kWh" category is omitted from figure 6.3-14 as no sites were found in this category.

The results do suggest that tailoring the support structure to specific sites might offer some economic advantage. Comparing figure 6.3-14 with 6.3-11 clearly shows that optimising the design shifts the distribution of available capacities towards the lower cost categories. It must be remembered in interpreting these results that the optimised calculation takes no account of any additional manufacturing costs or installation costs that might be incurred in using support structure of variable height. Further work is necessary to determine whether these costs might offset the advantage perceived here.

Figure 6.3-14 compares the cumulative capacity distributions predicted by the optimised calculation for sites too close to the shore to be exploited (within 10km) and those further offshore. The values are normalised by the total capacity that could be installed for an energy cost of 11 ECUc/kWh or below.

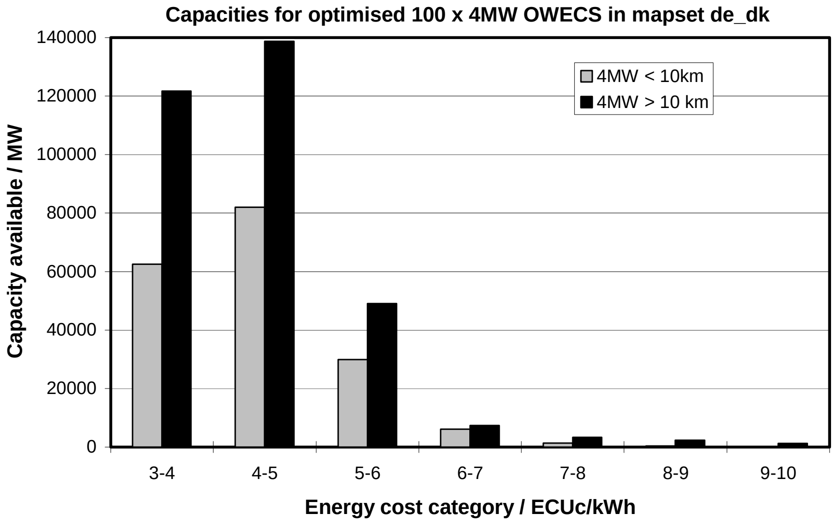


Figure 6.3-13: Distribution of optimised large scale capacity that could be installed in region de_dk as a function of cost.

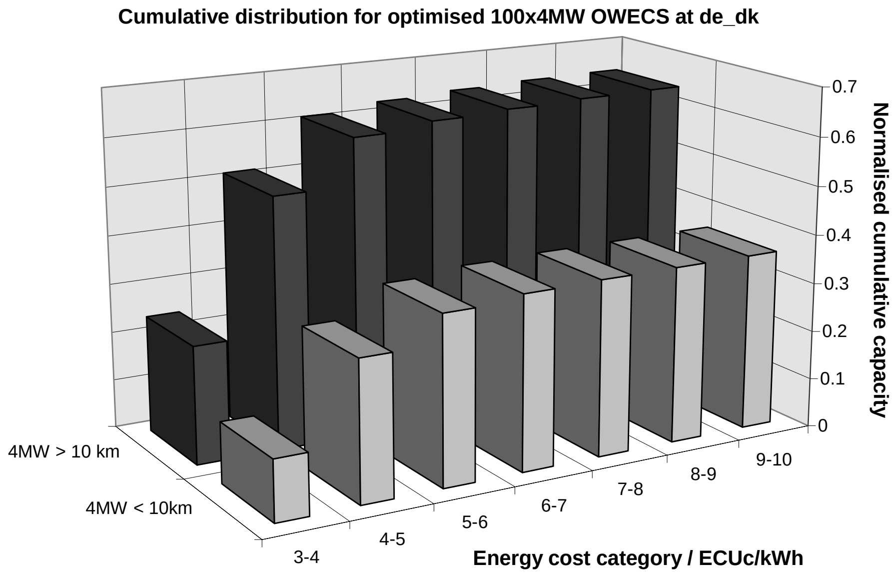


Figure 6.3-14: Comparison of results for optimised large scale OWECS in region de_dk within 10km of shore (4MW<10km) and beyond 10km of shore (4MW>10km).

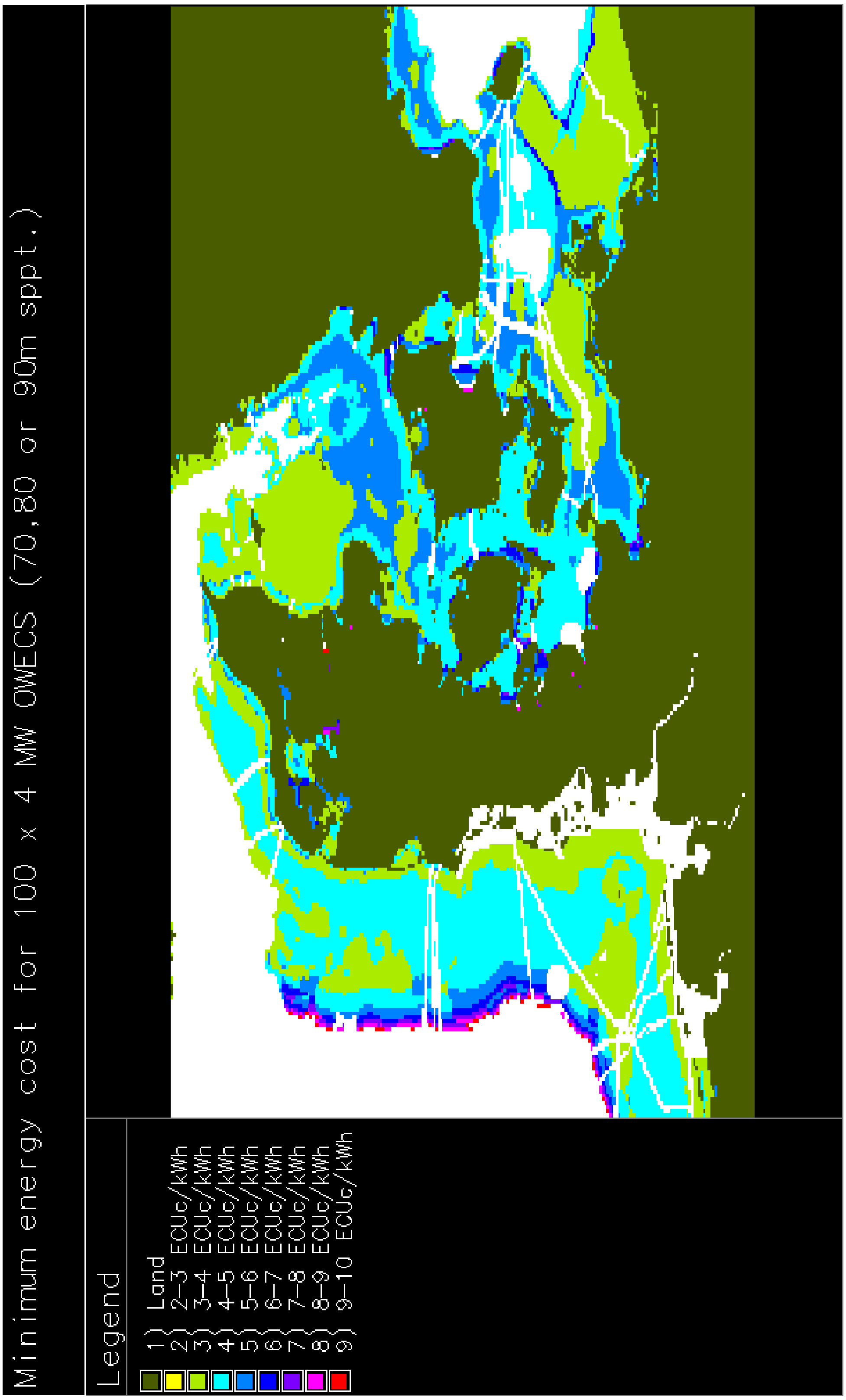


Figure 6.3-15: Energy cost map for large scale OWECS in region de_dk with optimised overall height.

7. Conclusions

The major conclusions of this volume are as follows:

1. There is evidence of a reduction in the predicted and achieved energy costs for bottom mounted OWECS over recent years. This appears to be due to improvements in technical understanding bringing better engineering design and selection of sites.

2. While the absolute values of the cost figures contained within this report volume are at best tentative in nature, it seems likely that further improvements in technical understanding can reduce the cost of energy from bottom mounted OWECS to still lower levels.

3. A Geographical Information System based cost model for the estimation of the cost of energy produced by bottom mounted OWECS has been developed. This model allows rapid estimation of the economic viability of certain OWECS concepts over a large geographic area. It also allows identification of sites best suited in economic terms, as locations for OWECS.

4. As part of the development of the GIS based cost model, a methodology for the use of a GIS system in OWECS site selection has been outlined. This methodology would form a good basis for further development of the technique.

5. Results confirm previous work reporting that there are huge offshore wind energy resources within the EU. A significant proportion of these resources will be exploitable on a commercial or near-commercial basis within the near future (assuming that technical innovation within the wind energy industry continues its current rapid progress).

6. Comparisons have been made of OWECS concepts based on turbines with rated capacities of both 1.5MW and 4MW at many real locations around Northern Europe. Results suggest that the use of large scale OWECS based on large turbines would not necessarily reduce the *lowest* achievable energy cost below that obtainable with a medium scale OWECS employing smaller turbines. In other words a large scale OWECS positioned at one of the most economically attractive locations would offer negligible economic advantage over a medium scale OWECS built in the same place.

7. The effect of using larger scale technologies is not so much as to lower the cost of OWECS produced electricity as to increase the proportion of possible locations at which offshore wind energy could be exploited on a commercial basis. Figure 7-1 illustrates the point using data for Belgian and Dutch waters. The data set labelled “4MW > 10km” shows the capacity that could be exploited at or below each particular cost level using large scale OWECS. The values have been normalised by the total

capacity that would be available using medium scale OWECS located at least 5 km from the shore in the same region Similar information for medium scale offshore wind farms is provided in the data set labelled "1.5MW > 5km". At each cost level a greater proportion of sites could be exploited with a large scale OWECS than with a medium scale OWECS. Further data but for sites considered too close to the shore to be reasonably exploitable[1] is also shown for both medium ("1.5MW < 5 km") and large ("4MW < 10km") scale wind farms. The same general trend is visible. In evaluating this result it must be kept in mind that large scale OWECS make much more efficient use of the wind resource than do smaller scale wind farms. Thus use of a large scale installations mean that dramatically more energy is available at any particular cost level. As an example, considering only those sites sufficiently far from the shore to be usable, the total capacity in Belgian and Dutch waters that could be exploited using large scale OWECS for a cost level of 7-8 ECUc/kWh or cheaper is estimated as 67 GW (96% of capacity more than 10 km from shore). When using medium scale wind farms the total such capacity is 47 GW (83% of capacity more than 5km from shore).

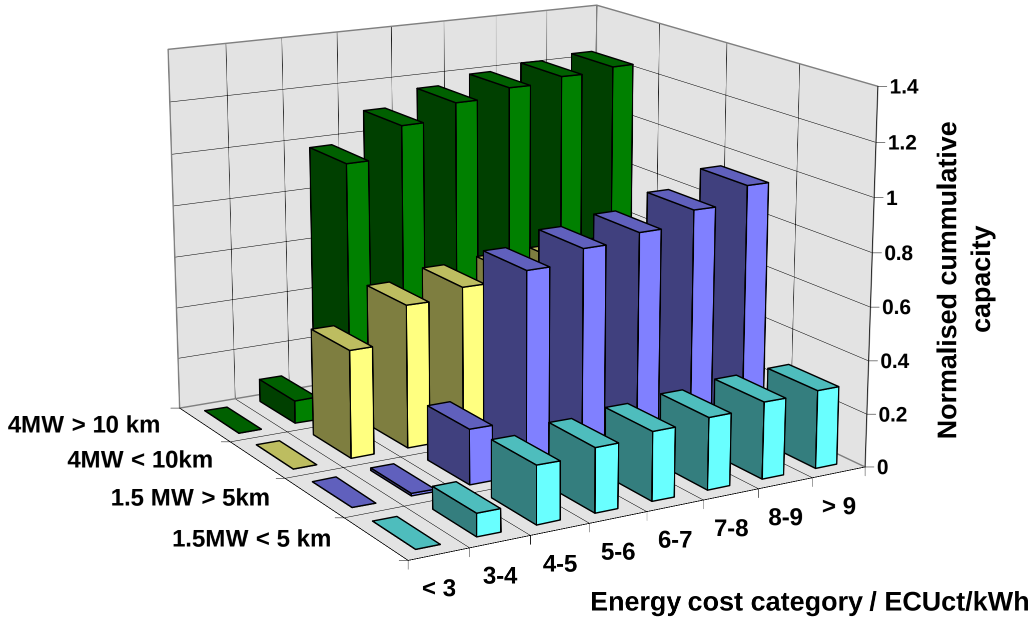


Figure 7-1 : Distribution of proportion of OWECS installed capacity available at or below particular cost levels for medium (1.5 MW turbines) and large scale (4 MW turbines) OWECS consisting of 100 units in Belgian and Dutch waters.

[1] Within 5km of the shore for medium scale OWECS and within 10km for large scale OWECS.

8. Further Work

The calculations presented in this report volume are not definitive in nature. While every effort has been made to ensure that the results are reliable, it must be understood that the work has been undertaken as much to develop and demonstrate a calculation methodology as to provide accurate quantitative results. The experience gained has proved extremely valuable and the authors opinion is that the quantitative validity of the results could be dramatically improved by recalculating them so as to avoid a number of inconstancies that only became apparent at the end of the project. Much of the suggested further work is directed at this recalculation. There are, in addition, several limitations in the modelling work that could now be addressed with relative ease. Most of the remainder of the suggested work would result in the extension of the modelling processes to account with greater accuracy for a wider range of factors.

Revision of the calculations

1. The assessment calculations should be re-done in such a way so as to allow information to be presented on a country by country basis, rather than according to the arbitrary regions currently used.

2. Calculations should be carried out for the full range of concepts incorporated within the models.

3. Maps showing the minimum cost of energy achieved across a range of concepts should be prepared for regions other than de_dk. For the de_dk assessment a wider range of concepts should be considered. A corresponding set of maps showing which concepts are economically best suited to each location should be produced.

Extensions of the modelling process

1. The treatment of the influence of wave height on support structure costs within the detailed cost model should be improved. This would allow the GIS calculations to be developed to include the effect of this parameter on costs.

2. Differences in the installation costs for the 1.5MW based concept and the 4MW based concept should be included.

3. The cost estimates provided take no account of the expense of constructing overland power cables to a suitable electricity grid feeder point. One of the reasons for this omission was the difficulty in finding the locations of suitable feeder points. A source of this information has been discovered and it would be a relatively simple task to include these additional costs within the modelling.

4. The support structure modelling within the GRASS GIS should be extended to accommodate the influence of differences in the foundation

properties of the seabed. From a computational viewpoint, this is a straightforward task. Difficulties arise from the fact that detailed, geographically extensive information on sea bed properties is not easy to obtain. Indeed, it seems likely that for many locations in EU waters such information simply does not exist. Compilation of a GIS database of undersea soil stiffnesses would represent a major, and probably very costly, undertaking.

5. With additional development, and an improved user interface, the GRASS GIS model could form a valuable OWECS site selection tool for use in the feasibility stage of the design process.

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Appendix A: Background to wind energy prices

by David Milborrow

A.1 Introduction

The European Union's Energy White paper proposes that 12% of energy within the EU should be provided by renewables by 2010, with possibly 40 GW from wind. It is unlikely that all this can be accommodated onshore, but a previous study, supported by the Joule programme, had shown Europe has large offshore wind resources.

Winds are generally higher offshore than onshore, which partially offsets the higher construction costs, and the purpose of this paper is to compare onshore and offshore plant costs and electricity prices, on the basis of available data. Fewer data are available for offshore installations, but some general conclusions can be drawn. This paper draws on material prepared for the European Wind Energy Association's Strategy Document [A.1-1], but it has been updated where appropriate and uses test discount rates which are consistent with those used in the Opti-OWECS study.

A.2 Wind energy plant costs and energy prices

A.2.1 Terminology and conventions

There are many ways of reporting wind plant costs and wind energy prices, and it is important to distinguish between the cost of plant (such as wind turbines and wind farms) and the price of the electrical energy which they produce.

Installed (capital) costs are usually quoted in terms of price per installed kilowatt, or ECU/kW, and, broadly speaking, are primarily a function of the size of the installation (due to economies of scale). Energy prices, however, are strongly dependent on wind speeds, and on institutional factors, such as test discount rates and repayment periods, and have two principal components:-

- Capital repayments, including interest charges
- Operating costs

The capital repayments depend on institutional factors, principally the project interest rate, or "test discount rate" and repayment period. The capital element of total generation price depends, in addition, on the energy output of the wind plant. This is primarily dependent on the wind regime, i.e. on its geographical location.

Some components of operating cost are fixed, while others depend on the output of the plant. Operating costs may quoted, therefore, in terms of the annual cost per kilowatt, or of the cost per unit of energy output, i.e. ECU/kWh.

As energy prices depend on interest rates and repayment periods, standardised values are often used to derive reference prices. This facilitates comparisons between different types and sizes of wind installation. Wind energy prices are then primarily a function of wind speed. It must be emphasised that reference prices may not correspond to the actual prices which apply in particular EU states,

A.2.2 Energy price calculation methods

The calculation of wind energy generation prices follows procedures which are reasonably standardised across the power industry. The International Energy Agency has published guidelines in the form of a "Recommend Practice" [A.2-1]. The document advocates the use of "real", i.e. net of inflation, interest rates - more accurately, test discount rates - to calculate levelised costs and this widely used technique is adopted in this paper.

The following items are included in energy price calculations:-

- planning costs)
- capital cost of plant) Capital
- construction costs)
- interest during construction)
- land costs (either as part of the capital or as annual leasing payments)
- fuel costs - zero for renewable energy plant
- operating costs (O & M) including labour, materials, rents, taxes and insurance
- decommissioning

When levelised costs are calculated, three parameters must be specified:-

- the base year used for the calculations, as the effects of inflation are excluded.
- the period over which the capital investment is assumed to be recovered - this is not necessarily equal to the life time of the plant
- the test discount rate

The IEA document recommends that capital costs are amortised over the technical life of the plant and that standard test discount rates are used. While this may produce useful data for comparative purposes, actual interest rates and amortisation periods are controlled by regulatory or institutional frameworks.

A.2.3 Interest rates

In the case of projects built by public sector companies, test discount rates are often set by Government. These vary across the EU, generally between 5% and 8%. Private companies, however, set their own rates, which may vary between projects. These vary widely. In practice, however, most private sector projects are financed using a mixture of loan and equity funding. A typical ratio is 80/20 and if the loan interest rate is, say 6%, and the equity return - both real - is 25%, then the equivalent test discount rate is 10%. Energy prices in this study use sample discount rates of 5 and 10% - in line with the conventions adopted for thermal plant [A.2-2].

A.2.4 Amortisation periods

Amortisation periods, like discount rates, vary widely, and are not necessarily as long as the expected life of the plant. The latter represents an upper limit, and is rarely used outside public sector utilities. The IEA Recommended Practice notes that “20 years is commonly used for proven grid connected wind turbines” and is used in this paper as a default value.

A.2.5 Typical interest rates and repayment periods

Table A.2-1 shows sample data used in Europe and elsewhere and Figure A.2-1 illustrates how repayment periods and test discount rates influence wind energy prices. The plant cost is assumed to be 1000 ECU/kW, the capacity factor 26%, and operation and maintenance costs 0.01 ECU/kW.

	Interest rate, % real	**Repayment period**
Denmark	7	20
Germany	Varies, 5 upwards	10
The Netherlands	5	10
Portugal	10	
United Kingdom	Developer’s choice	15
United States	7	

Table A.2-2: Interest rates and repayment periods used for wind plant

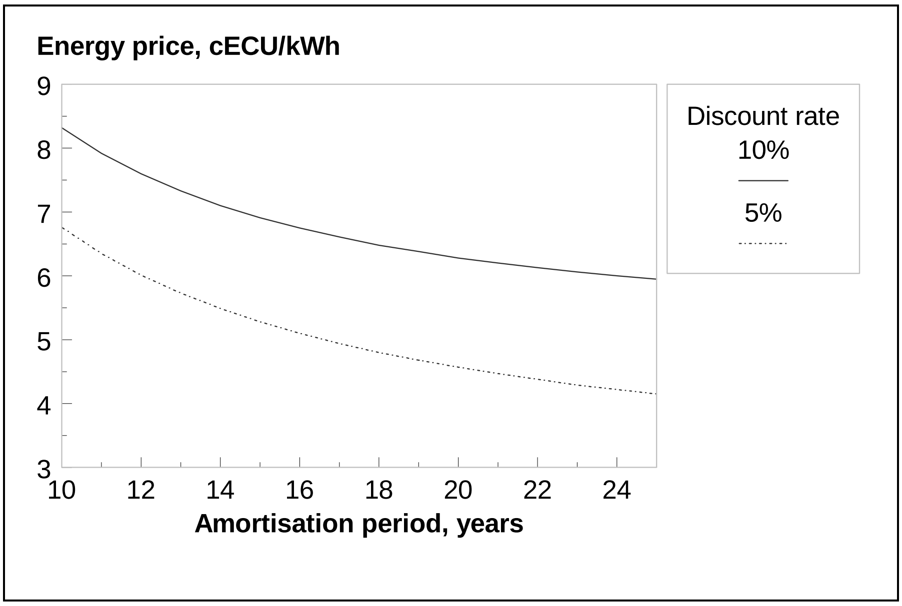


Figure A.2-1: Wind energy prices - influence of interest rates and repayment periods.

A.3 Historical summary

The cost of wind energy wind plants has fallen substantially during the last fifteen years, and analyses of recent data indicates that this trend is continuing. This reduction in energy prices is due to:-

- Lower wind turbine prices
- The turbines have become larger, with taller towers (thus the wind speeds intercepted by the rotors have increased). Most of the machines installed in the 1980s were around 50 kW whereas most modern wind farm designs are in the range 600 kW to 750 kW with a number of installations planning to use machines around the one megawatt mark.
- Better understanding of the technology and improved production methods
- Efficiency and availability have improved,
- Operation and maintenance costs have fallen.

The overall trend in Danish wind energy prices over the last 10 years, assuming a 6.3 m/s site, 5% interest rate and 20 year life, is illustrated in Figure A.3-1, which shows an 8% per annum fall in prices.

The minimum bid prices for wind energy in the UK NFFO are also shown in Figure A.3-1, and show a similar rate of fall. The appropriate wind speeds and interest rates are not known; minimum bid prices are shown, rather than averages, as the latter are influenced by the size of the NFFO orders.

This summary of historical trends is intended to give a broad picture of price movements; the energy prices quoted are comparable as far as possible but the all-important question of wind speeds test discount rates and depreciation periods need to be taken into account when making more detailed comparisons between energy prices, particularly across national boundaries.

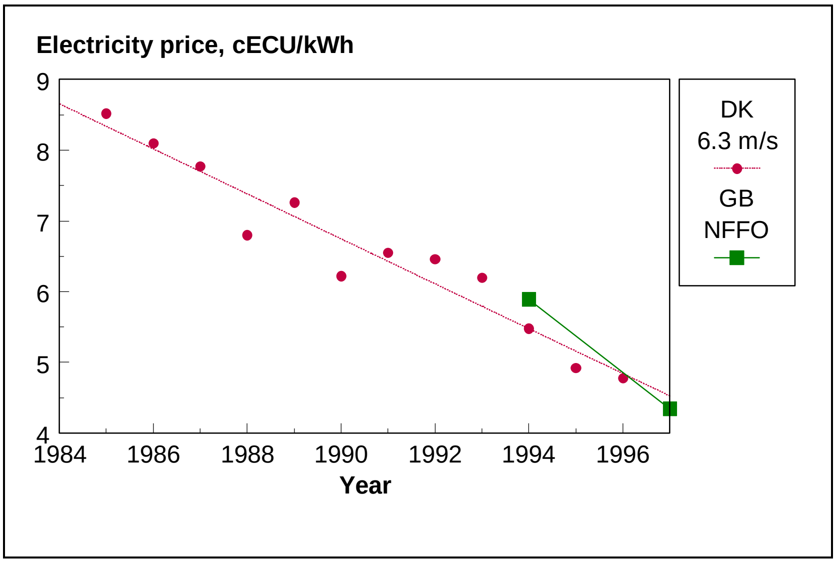


Figure A.3-1 : Wind energy price trends.

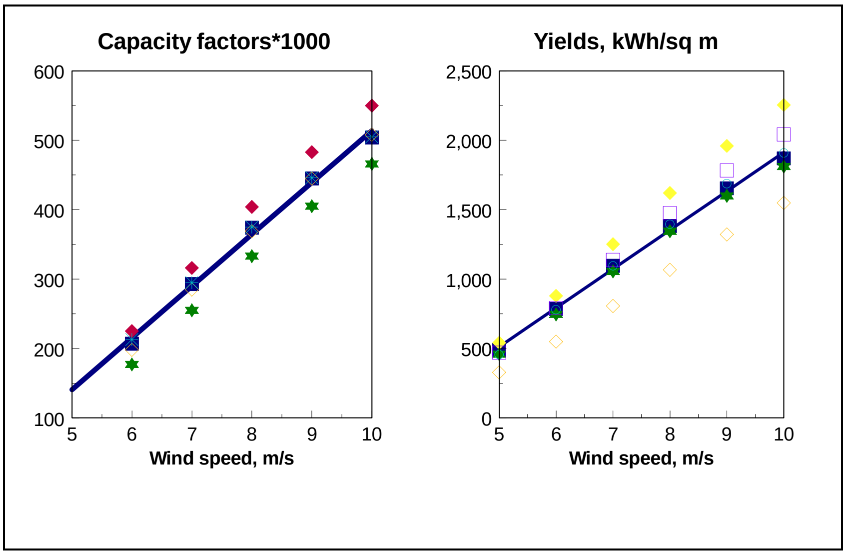
A.4 Current plant costs and energy prices

This analysis of current energy prices uses data for machines around 500-600 kW rating, as these are currently being deployed in large numbers around the EU and generally give the lowest energy prices.

A.4.1 Key factors

Wind speeds: Wind energy prices are critically dependent on site wind speeds, so links between wind speed and machine productivity (in kWh/sq m and kWh/kW) need to be established for the purposes of generalised analyses. Energy yield data for a number of modern machines were collated and these show that capacity factors are typically around 0.2 at 6 m/s, rising to 0.45 at 9 m/s. Yields are typically around 750 kWh/sq m at 6 m/s, rising to 1600 kWh/sq m at 9 m/s. These data are shown in Figures A.4-1 and A.4-2.

Wind speeds vary widely across the European Union. The best resources are in upland regions, particularly in Ireland, Britain and Greece, parts of Spain and the Canary Islands, where average wind speeds (at hub height) may be around 8-10 m/s. In Western Denmark, and the coastal regions of north Germany, wind speeds range up to about 7.5 m/s, and elsewhere winds are lower, with speeds decreasing further inland. Further information on wind speeds is given in the European Wind Atlas [A.4-1].



Figures A.4-1 (left) and A.4-2 (right) : Capacity factors and yields for modern machines (500-750 kW)

Wind turbine prices: Danish wind turbine prices are broadly representative of levels across the EU, and price lists are published, which facilitates empirical analysis. Data from these are shown in Figure A.4-3. There is no clear link between price per unit swept area and size, and the price of modern turbines around the 45 m diameter mark is around 300 ECU/sq m.

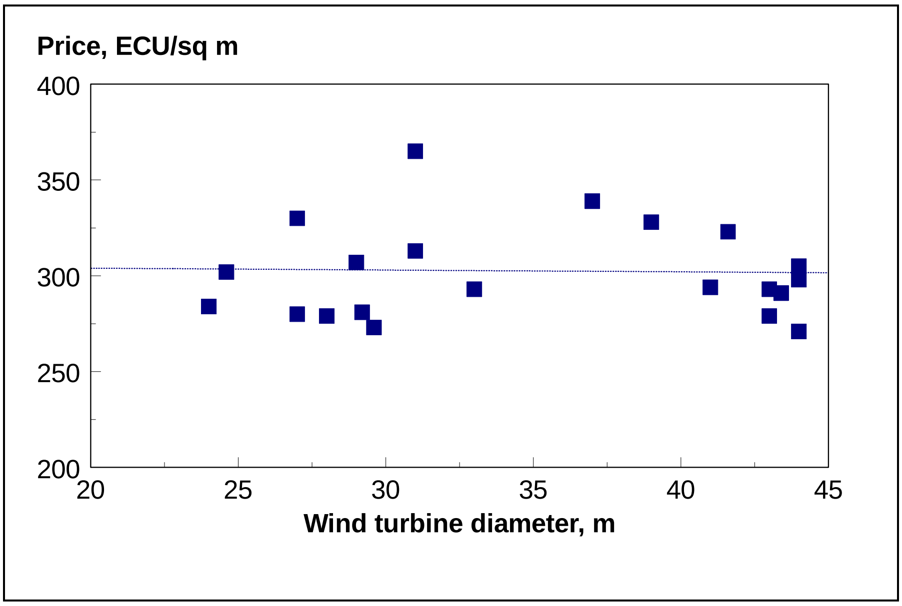


Figure A.4-3: Turbine prices - Denmark

Balance of plant costs: Wind turbine prices, discussed above, vary little with size, but there are sound reasons for pursuing the development of large machines. The use of large machines means fewer are required for a given capacity, and a number of items in the "balance of plant" cost category decrease with machine size, or machine numbers, especially:-

- Foundation costs
- Electrical interconnection costs
- Access tracks

Overall, balance of plant costs add between 15 and 40% to wind turbine costs, depending on the number and size of machines in the wind farm, and the location. The windiest sites - on hilltop sites, often remote from a grid connection, or coastal locations where deep piling into silt is needed, tend to incur costs above average.

Table A.4-1 summarises the components of “balance of plant costs”, and shows typical values [A.4-2].[A.4-3],[A.4-4].

Item	**Costs, % turbine price**
	Range
Foundations	5-11
Electrical connections	5-11
Planning costs	1.5-3
Approvals	3-8
Infrastructure	2-4
Management	3-6
Miscellaneous	2-4
Grid connection	7.5-15
TOTAL	13-40

Table A.4-1 : Wind farm balance of plant costs.

Operational Costs: Table A.4-2 shows the main components of operational cost. and the usual basis of charging (underlined). Operational costs vary between countries and between wind farm sites. As some elements are fixed annual sums, wind farms on high wind speed sites will tend to have lower operational costs per unit of electricity, and this is reflected in the table.

Item	ECU/kW/year, or other cost basis	cECU/kWh (approx)
Service contract	4-8, or based on output	0.15-0.6
Administration	Cost basis varies	0.1-0.3
Insurance	4-7	0.15-0.5
Land rent	2-4, or 1-2% of revenue	0.08-0.4
Local taxes	3-5	0.1-0.2
Electricity imports	Standard tariffs	0.05-0.2
Reactive power	Up to 0.4 kVArh	0-0.1
TOTAL	Up to 24 ECU/kW/year	0.6-1.5

Table A.4-2 : Operational costs - 500 kW turbines.

4.2 Reference energy prices

Although wind energy prices, as noted earlier, depend on national institutional frameworks, reference values may be calculated, using the IEA "Recommended Practice". The key assumptions which have been used are set out in Table A.4-3. It is assumed that installed costs increase linearly with wind speed above 7 m/s by 8% per m/s, as noted earlier, and that array, availability and other losses account for 10% of the energy. The energy prices corresponding to the mid-range costs are 9.6 cECU/kWh at 5 m/s, declining to 3.4 cECU/kWh at 10 m/s. The energy prices are shown in Figure A.4-4.

Price parameter	Minimum	Average	Maximum
Installed cost, ECU/kW, at 7 m/s	700	850	1,000
Real interest rate, %	5	7.5	10
Construction period, years	0.5	0.5	0.5
Amortisation, years	20	20	20
Running costs, fixed, ECU/kW/yr	12	18	24
Running costs, variable, cECU/kWh	0.2	0.3	0.4

Table A.4-3 : European reference wind energy prices - summary

A.5 Offshore wind energy

Offshore wind has the potential to deliver substantial quantities of energy - at a price which is cheaper than most of the other renewable energies, but more expensive than onshore wind. Offshore wind energy has the added attraction that it has minimal environmental effects and, broadly speaking, the best European resources are reasonably well located relative to the centres of electricity demand.

Wind speeds are generally higher offshore than on land, although the upland regions of the British Isles, Italy and Greece, do yield higher speeds. In the UK, for example, onshore winds at hilltop sites range up to 9 m/s at hub height - higher in some instances - whereas offshore winds at, say, 5 km from the East Coast are around 8.5 m/s. Offshore wind power will initially, therefore, be most attractive in locations such as Denmark and the Netherlands where pressure on land is acute and where windy hill top sites are simply not available. In these areas offshore winds - which increase with distance from land - may be 0.5 to 1 m/s higher than onshore, depending on the distance offshore.

5.1 Operational experience and economics

A number of factors combine to increase the cost of offshore wind farms above onshore costs:-

- the cost of the cable connection from the wind farm to the shore.
- the need for more expensive foundations, where a number of options have been examined:-
  - gravity-based structures, simple, but heavy
  - piled structures
  - tethered, floating structures, which support individual turbines or groups

- operation and maintenance costs are increased with the risk of lower availability due to difficulties in obtaining access to the wind turbines during bad weather.
- the need to "marinise" the wind turbines, to protect them from the corrosive influence of salt spray

Several offshore wind farms have now been built, so it is possible to assess the economics in the light of operational experience. To do so, data from the two experimental Danish installations, Vindeby and Tuno Knob [A.5-1], may be compared, and set alongside other recent cost assessments, including the pilot Dutch farm in the Ijselmeer [A.5-2]. The quoted costs of Tuno exclude the extra cost of special environmental studies. Table A.5-1 summarises the principal operational data for these early wind farms together with a proposed installation by the English PowerGen off the East coast of England [A.5-3], and recent proposals for large farms off the coast of the Netherlands and Denmark [A.5-4],[A.5-5].

Although the cost of the Vindeby wind farm was 85% higher than the cost of an onshore installation the anticipated energy yield was 20% higher, partly because availability was higher than expected. Concerns about low availability offshore - due to problems of access - have not been realised.
PowerGen’s proposals for Scroby Sands were for a much larger wind farm, comprising 25 63m 1.5 MW wind turbines. The site is 3 km off the Norfolk coast near Yarmouth and the initial estimate of the project was around 44 MECU, bringing costs per annual megawatt hour to about half that of Vindeby

- due partly to continuing maturity of the industry and partly to the use of larger machines.

The two major utilities, Elkraft and Elsam, have recently announced their intention to build 750 MW of offshore wind, and there are also plans for a 30/40 MW scheme near Copenhagen. Two major utilities in the North of Holland, ENW and NUON have proposed a windfarm in the shallow waters along the 35 kilometre long "Afsluitdijk" between the Provinces of Friesland and Noordholland. The line of about 60 MW-sized turbines will be sited at 500 meters from the dike and 500 meters apart from each other. The project is budgeted at around 114 MECU and could be built within three years**.**

Location	Date	Turbines	Capacity	Wind	Output	Cost		
		No.xkW	MW	m/s	GWh	MECU	ECU/MWh	ECU/kW
Vindeby, DK	1991	11x450	4.95	7.9*	11.2	9.6	857	1939
(Comparable onshore farm)				7.2*	10	5.3	530	1071
IJsselmeer, NL	1994	4x500	2	7.7	3.8	5.2	1370	2600
Tuno, DK	1995	10x500	5	7.4*	12.5	10.2	817	2040
Gotland, SE	1997	5x500	2.5	8.0	8.0	4.1	512	1640
Scroby, UK	Planned	25x1500	37.5	8.2*	102*	44	429*	1173
IJmuiden, NL	Planned	100x1000	100	8.8	300	205	683	2050
Laeso, DK	Planned	78x1500	117	9.1	396	934	485	1650
*Author’s estimate								

Table A.5-1 : Offshore wind farm performance and costs.

5.2 Offshore and onshore energy prices

There are insufficient data on offshore costs to enable firm conclusions to be drawn, but the average “offshore premium” currently appears to be about 40-60%, but there is a wide spread of data. The lowest installed cost in Table A.5-1 is 1173 ECU/kW, about 20% higher than the average onshore level of around 850-1000 ECU/kW, but the most recent Dutch estimate of 2050 ECU/kW is 100% higher. To provide an indication of how onshore and offshore energy prices compare, Figure 6 shows data for

- onshore mid-range plant costs of 850 ECU/kW,
- offshore, a low cost estimate of 1300 ECU/kW - similar to “maximum” onshore price levels
- offshore, a high cost estimate of 1600 ECU/kW

The test discount rate is 5%, and the depreciation period 20 years. In each case it is assumed that costs increase linearly at 8% per 1 m/s increase in wind speed above 7 m/s, which is in line with an analysis of onshore sites. This accounts for the increased costs of exploiting the higher wind speed sites, which, offshore, are further from land. Indicative wind speed ranges for offshore plant are also shown in Figure A.4-4. It may be noted that Danish offshore installations benefit from higher winds than onshore, which reduces the energy price premium, but winds in UK offshore waters are not necessarily higher than those onshore.

An analysis of energy prices has recently been carried out for the Danish utilities [A.5-6]. This showed that the use of larger wind turbines - up to 1500 kW rated output - would realise substantial savings. Assuming a wind farm is sited around 6 km from the coast, in a water depth of 5-6 m, the electricity price may be expected to fall from around 6 cECU/kWh (at Tuno) to around 3.8 cECU/kWh.

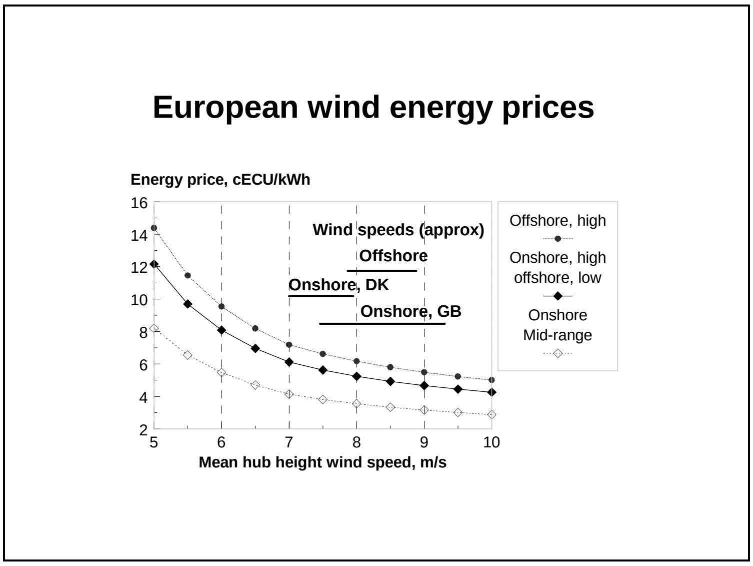


Figure A.4-4 : Indicative comparison between offshore and onshore wind energy prices.

A.6 Generation costs of competing fuels

The electricity generation costs from coal, gas, hydro, oil and lignite - the fuels most commonly used across the EU - vary widely. There is no single price that can be assigned to any source of generation, for reasons similar to those discussed earlier (section A.2). The institutional arrangements which influence discount rates and amortisation periods are, again, frequently the dominant factor in setting energy prices from thermal and hydro plant, but variations in plant and fuel costs also play a part. Government support for the nuclear and coal industries also means that the real generation costs are higher than is apparent. For example, the pithead price of coal in Germany is more than three times the world market price, so the ***true*** generation price from coal there is over 9 cECU/kWh (The utilities do not actually pay the higher price, as an annual subsidy of 7400 million DM is paid by the taxpayer to the coal industry. This is a classic example of a "hidden", or "external" cost.)

Capital costs for large combined-cycle gas turbine (CCGT) plant are falling as the "dash for gas", in Britain and elsewhere, leads to intense competition. Gas prices, however are moving upwards.

All future coal plant is likely to be fitted with flue gas desulphurisation plant and increasingly stringent controls on emissions may raise plant costs. "Clean coal" technology is being explored, but dramatic changes in generation prices in the short term are unlikely.

The costs of nuclear power are the subject of much debate. One key issue is the difference between "mature" costs for a series of Pressurised Water Reactors (the most popular option) and "first of a kind" costs, which are inevitably higher. With the exception of France, "production runs" of nuclear plant are rare. Further uncertainty arises from the treatment and precise level of decommissioning costs. Nuclear generation price estimates therefore span a wide range and a UK government review of 1995 quoted 5.2-8.5 1995cECU/kWh (rebasing the prices from the 1990 levels used).

The status and costs of thermal plant are summarised in Table A.6-1. The energy prices have been derived using a 5% discount rate - to correspond with one set of wind price estimates. This yields lower prices for nuclear than those which stem from systems which have been privatised. These prices are compared with wind energy prices in Figure A.6-1.

Plant	Capital cost, ECU/kW	Fuel cost, cECU/kWh	O&M cost, cECU/kWh	Total cost, cECU/kWh
Gas	450-700	1.7-2	0.4-0.6	3.1-4
Coal	1000-1300	1.8-2.3	0.7-1	3.7-5.5
Nuclear	1200-2000	0.7-0.9	0.8-1	3.3-8

Table A.6-1 : Thermal plant data - current levels.

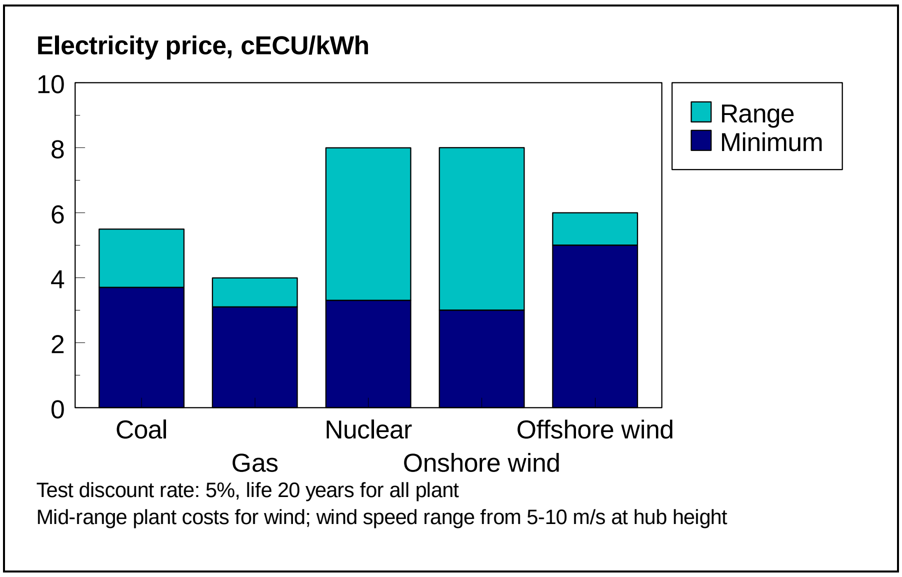


Figure A.6-1 : Current electricity prices.

A.7 Future price trends

There are a number of factors which are causing a steady fall in the cost of wind energy systems:-

- The trend towards larger wind turbines
- Falling infrastructure costs
- Possible reductions in the cost of raw materials

Manufactured items which are produced in quantity benefit from increased production, as the manufacturer improves his manufacturing and assembly techniques. The way in which costs fall as a function of increased production varies depending on the product, and is a function of the relative inputs of material and labour. For wind turbines it has been estimated that the price is likely to fall by 8% for each doubling of production. Given that other factors, such as better understanding of wind loads and materials properties, also contribute to cost reduction this figure may be improved. As wind turbines are relatively small in output - in power generation terms - the need for significant numbers of machines enhances their prospects for cost reduction, relative to other electricity generating technologies such as gas turbine plant.

The energy price trends shown in Figure A.3-1 do not give any indication that the trend in price reductions is slackening. The recently-completed European Renewable Energy Study (TERES II) reaches a similar conclusion. It also expects that further R&D will enable further technological advances to be made. By 2020 capital costs are expected to be 50-75% of present levels, allowing financially viable, unsubsidised wind on high and medium wind regime sites.

A.8 Conclusions

Currently, an average EU-wide installed onshore costs of 850-1000 ECU/kW may be taken as a typical. Offshore costs are around 50% higher. A direct comparison between wind energy prices and those of thermal plant is misleading, as wind has lower external costs and often has a higher value. Nevertheless, onshore wind becomes competitive with gas at the 5% discount rate, if both use amortisation periods of 20 years; at the 10% discount rate, gas is cheaper. Given that wind prices are falling, its competitive position is expected to improve.

The key conclusions may therefore be summarised:-

- Wind plant costs have been falling steadily and there are strong indications that this trend is continuing
- Wind energy prices are falling faster, as machines become more reliable and efficient
- No single figure can be assigned to price of wind energy, as wind speeds, interest rates, amortisation periods and plant costs vary across the EU, but -
- On best sites, current wind prices are within ranges quoted for thermal plant

- External costs of thermal plant need to be taken into account when making comparisons with wind energy prices. Some external costs, like the cost of coal support in Germany, are irrefutable. Others more difficult to quantify, but nonetheless real.
- Wind energy must also be credited with additional value, as it is usually injected into low voltage distribution networks, enabling utilities to save on transmission and other costs
- Offshore wind energy prices are now moving down rapidly and will probably continue to do so, as new installations are commissioned
- There is considerable scope for future price reductions, supported by several studies

Appendix B: Exchange rates used in document body

Unless stated explicitly the exchange rates employed were those given by the Financial Times On-line service [B-1] at 1530 GMT on Tuesday 10 March 1998:

Currency Unit	ECU Equivalent
1 British Pound	1.51 ECU
1 Danish Krona	0.13 ECU
1 German Deutschmark	0.5 ECU
1 Netherlands Guilder	0.44 ECU
1 US Dollar	0.92 ECU

Appendix C: Wind turbine data for economic comparison of European Sites

C.1. Introduction

This appendix presents the main data of the two wind turbine concepts that have been chosen for the reference offshore wind farms used in the economic comparison of European sites.

C.2. Design data

Estimates of leading manufacturers have been used for the concept of the 1.5 MW wind turbine [C.2-1], [C.2-2]. A P-v curve is calculated from an upscaling of the NEG-MICON M2300 - 1000 kW turbine.
The 4 MW turbine is based on the WTS 80 M design of Kvaerner Turbin [C.2-3]. Here the 4 MW - 90 m design from a study of FFA is considered [C.2-4]. Load data were derived by a rule of thumb from figures valid for the WTS 80 M.
The main design data and the P-v curves are arranged in table C.2-1 and figure C.2-1, respectively.

Concept	1.5 MW turbine	4 MW turbine
base case concept used for upscaling	typical Danish design e.g. NEG-MICON 1 MW	Kvaerner Turbin WTS 80 M
rotor concept	3 bladed, stall regulated, upwind orientated	2 bladed, pitch regulated, upwind orientated
rated generator power	1.5 MW	4 MW
rotor diameter	64 m	90 m
rotor speed	12 rpm / 18 rpm	20 rpm
rated efficiency of gear box, generator	94.5 % (assumed)	90 % in total
tower top mass	75 tonnes	141 tonnes

Table C.2-1: Assumed design data of the reference wind turbines

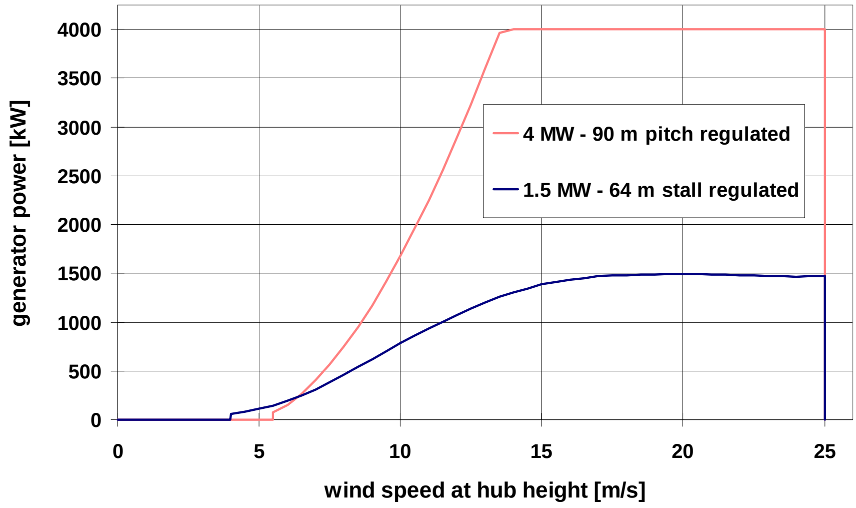


Figure C.2-1: P-v curve of the two reference wind turbines

C.3. Capital costs

For the 1.5 MW turbine the cost figure of the Danish study i.e. 1.3 M ECU for wind turbine and tower is used [C.3-1]. The investment cost of the wind turbine itself i.e. without tower is estimated to 1 MECU.

A cost estimate for the 4 MW designs is difficult since no similar commercial designs exist on the market. Therefore here the extrapolation of current commercial designs ranging between 500 and 1650 kW [C.3-2] is applied. Figure C.3-1 shows the specific wind turbines cost (excl. tower)[2] in ECU per square metre swept rotor area against rotor diameter.

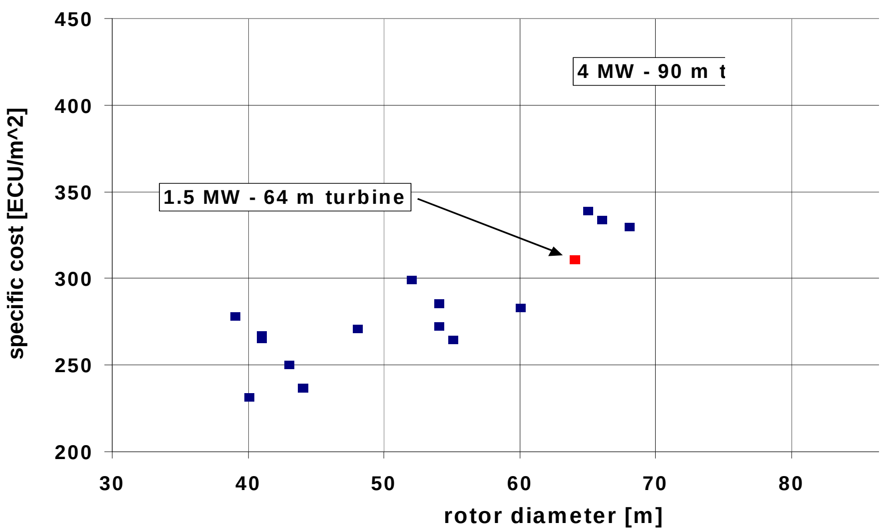


Figure C.3-1: Trend in investment cost of commercial wind turbines (excl. tower) for ratings of 500 kW to 1.65 MW

[2]Tower costs have been estimated to be 22% of the total cost for wind turbine and tower.

The trend clearly indicates that multi-megawatt machines will become expensive if current technology is extrapolated. Therefore it is likely that within a medium to long time scale innovative solutions are found which will reduce the cost considerably.

For the time being and for the comparison of the EU sites here simply the extrapolated trend is considered by assuming specific costs of approx. 400 ECU/m^2 for the 4 MW - 90 m machine. This leads to total costs of the wind turbine (excl. tower) of about 2.55 M ECU.

C.4. Reliability data for the wind turbines

For both reference machines the same reliability properties are assumed. The failure rate of 1.02 events/year is also considered for the Opti-OWECS design solution [C.4-1]. This is about 45% lower than current state-of-the-art in the 500/600 kW class and can only be achieved by careful design and an (onshore) track record. Nonetheless, the assumption is regarded reasonable if the different time scale of the two reference offshore wind farms is taken into account. OWECS employing megawatt machines are likely to be erected by the begin of the next century whilst wind farms with multi-megawatt turbines, e.g. with rating of about 4 MW, are more likely in 5 to 10 years from now.