Matching Renewable Electricity Generation With Demand

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Academic Study

Matching Renewable Electricity Generation with Demand

Full Report

Contract QLC 11/1

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Produced by The University of Edinburgh

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This investigation was commissioned by the Scottish Executive as an academic study of Scotland's renewable energy resource. The work reported was carried out in the Institute for Energy Systems at The University of Edinburgh by Thomas Boehme, Jamie Taylor, Dr. Robin Wallace and Prof. Janusz Bialek.

Disclaimer

This report presents the results of an academic study on matching renewable energy resources with demand for electricity in Scotland. The results do not imply or form recommendations for the final locations or developments of renewable energy projects, individual or total generating capacities, or performance of specific technologies.

This report is submitted in good faith only. The University of Edinburgh will not accept responsibility or liability for third party use or interpretation of the findings.

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Glossary

agl	above ground level
AGLV	Area of Great Landscape Value
ASACS	Air Surveillance and Control System
asl	above sea level
BETTA	British Electricity Trading and Transmission Arrangements
BGS	British Geological Survey
BODC	British Oceanographic Data Centre
BWEA	British Wind Energy Association
CAA	Civil Aviation Authority
CFD	Computational Fluid Dynamics
CHP	Combined Heat and Power
CO_2	Carbon dioxide
CORINE	European programme to COoRdinate INformation on the Environment
DE	Defence Estates
DN	Distribution Network
DNO	Distribution Network Operator
DTI	Department of Trade and Industry
DTM	Digital Terrain Model
EDINA	Centre based at Edinburgh University Data Library offering data, information and research resources. ('Edina' is the ancient and poetic name for Edinburgh.)
EEA	European Environmental Agency
EMEC	European Marine Energy Centre, Ltd. (Orkney)
ETSU	Energy Technology Support Unit, now Future Energy Solutions
EU	European Union
EWEA	European Wind Energy Association
EWTR	Electronic Warfare Tactics Range
FREDS	Forum for Renewable Energy Development in Scotland
GH	Garrad Hassan Ltd.
GIS	Geographical Information System
GSP	Grid Supply Point
HS	Historic Scotland
IOS	Institute of Oceanographic Sciences
LAT	Lowest Astronomical Tide
LFS	Low Flying System
LNR	Local Nature Reserve
Long Term Development Statement	Summarises the planned performance and operating characteristics of a distribution system over several financial years, usually five or six.
LPC	Lifetime production costs
MCA	Marine Consultation Area

MCT	Marine Current Turbines Ltd.
MHW	Mean High Water
MLW	Mean Low Water
MoD	Ministry of Defence
MSL	Mean Sea Level
NATS	National Air Traffic Service
NNR	National Nature Reserve
NOABL	Mass consistent flow model, developed by Science Applications Inc., USA
NPPG	National Planning Policy Guideline
NSA	National Scenic Area
O&M	Operation and Maintenance
Ofgem	Office of Gas and Electricity Markets
OPD	Ocean Power Delivery Ltd
OS	Ordnance Survey
PEXA	Practice and Exercise Area (military)
POL	Proudman Oceanographic Laboratory
PV	Present Value
QUB	Queen's University Belfast
Ramsar site	Wetland site designated under the Ramsar Convention (Ramsar, Iran, 1971)
rms	root mean square
RETS	Renewable Energy Transmission Study
SAC	Special Area of Conservation
SEEF	Scottish Energy Environment Foundation
SEGIS	Scottish Executive Geographic Information Service
Seven Year Statement	Summarises the planned performance and operating characteristics of a transmission system over seven financial years.
SNH	Scottish Natural Heritage
SP	Scottish Power
SPA	Special Protection Area
SRTM	Shuttle Radar Topography Mission
SSE	Scottish and Southern Energy
SSR	Secondary Surveillance Radar
SSSI	Site of Special Scientific Interest
TN	Transmission Network
TNO	Transmission Network Operator
TNUoS	Transmission Network Use of System
TTA	Tactical Training Area
UKHO	UK Hydrographic Office
UoE	The University of Edinburgh
WAsP	Wind Atlas Analysis and Application Programme
WHS	World Heritage Site

1 Introduction

This report was prepared by the Institute for Energy Systems in the School of Engineering and Electronics at The University of Edinburgh. It was commissioned in May 2004 as an academic study by the Scottish Executive, Meridian Court, Glasgow, under reference QLC11/1. The subject of the report is an appraisal of the extent to which Scotland could meet forty-percent of its demand for electricity in the year 2020 from renewable resources.

1.1 Context

Scotland has extensive renewable energy resources that might be developed to reduce carbon dioxide (CO_2) production by future electricity generation. The resources are geographically dispersed and variable. Demand for electricity is also variable and largely remote from the resources. This report describes the method and findings of a study that explored the extent, location and availability of onshore-wind, offshore-wind, wave, and tidal-current energy relative to the timing, location and extent of demand for electricity.

1.1.1 Scotland's Future Demand for Electricity

In March 2003, the Scottish Executive aspired to the target of Scotland generating forty-percent of its electricity from renewable sources by the year 2020 (Scottish Executive 2003). Demand for electricity is forecast to increase slowly in the period up to that time. Based on a predicted one-percent annual increase from 32.4 TWh in 2003, demand could exceed 38.4 TWh by 2020. Supplying forty-percent of this demand from existing hydro-generation, consented and new renewable sources would require an annual production of over 15.3 TWh.

Allowing for the consequences of changing rainfall patterns and hydrology over the next fifteen years, the plant capacity factor of the existing 1.3 GW of hydro generation could be as low as 25%. There is potential for another 200 MW of large and small-hydro capacity. Total annual hydro contribution might then be 3.3 TWh, leaving nearly 12 TWh to come from new renewable sources such as wind, wave, tidal-current and biomass. Based on an assumed average plant capacity factor of 30%, this would require the development of over 4.5 GW of new renewable energy capacity by 2020. By the end of 2005, there was about 500 MW of existing wind capacity at stations accredited by Ofgem under the Renewables Obligation (Scotland) Order. In addition the Scottish Executive has consented more than 1 GW of onshore-wind, offshore-wind, hydro and biomass plant which is planned or under construction. Some further capacity has been consented by local authorities. With the assumed 30% plant capacity factor another 3 GW of new renewable energy-generating capacity would need to be identified, consented and constructed.

This broadly accords with estimates from the FREDS Future Generation Group report "Scotland's Renewable Energy Potential: Realising the 2020 Target" (Scottish Executive 2005). In that report Scottish demand in 2003 was taken as 35 TWh, increasing to about 43 TWh in 2020 based on an annual increase of one percent. The figures used in this study were somewhat lower as they are based on the information published in the Seven Year Statements and are slightly offset by embedded generation satisfying local demand and not using the transmission system. Historical demand time-series and scaling factors used in this study led to an average annual demand of about 41 TWh which endorses the projections in the FREDS report.

1.1.2 Scotland's Renewable Energy Resources

Scotland is at the end of long wind-fetches over the Atlantic Ocean and therefore has some of the best wind and wave energy resources in Europe. Its landmass separates the basins of the Atlantic Ocean from the North Sea and consequently has good tidal-current resources around its headlands and coastal channels. At present, the major renewable-energy sources in Scotland are hydro and onshore-wind. In the future, these could be joined by offshore-wind, wave tidal-current and biomass.

Onshore- and offshore-wind, waves and tidal-currents were selected for the study as they have significant potential for growth and could considerably broaden the mix of energy sources used in Scotland. Garrad Hassan (2001a) predicted an exploitable capacity in Scotland by 2025 as shown in Table 1.1. The figures were based on *lifetime production costs* (LPC) below seven pence per kilowatt-hour. In the case of onshore-wind the exploitable capacity was additionally constrained by a *socially acceptable limit* which was based on experience in Denmark. This set a maximum average density of wind-generation at 150 kW per square kilometre in any planning authority's area.

Technology	Exploitable capacity (GW)
Onshore-wind	11.5 ❶
Offshore-wind	25.0 ❶
Waves	14.0 ❶
Tidal-currents	7.5 ❶
Large hydro	1.5
Biomass ❷	0.6 ❶❸

Table 1.1 Exploitable renewable energy capacity in Scotland by 2025.
Notes: ❶ Figures are taken from Garrad Hassan (2001a); ❷ Includes forestry residues, energy crops and agricultural wastes; ❸ Scottish Executive (2005) assumes a potential of 450 MW.

Data for hydro-power has been added to Table 1.1 for comparison and assumes a small growth from the currently installed capacity of around 1.3 GW. Large hydro power and biomass can generally be considered to be dispatchable while the other sources in the table are variable. Tidal-currents have the benefit of being fully predictable with some secondary influence from weather conditions. Hydro and waves can be forecast from weeks to days ahead, whilst for wind detailed forecasts are, as yet, generally shorter-term.

1.1.3 Matching Renewable Electricity Generation with Demand

The figures in Table 1.1 suggested at the time that forty-percent of Scotland's electricity demand could be met from any of the first four renewable energy sources considered, or from a combination of them. However, such a conclusion would have been based solely on *installed-capacity*.

The level of demand for electricity in Scotland varies hourly, daily and seasonally as well as regionally. To meet the aspirational forty-percent target, renewable energy resources that vary with time and that are geographically dispersed over land and sea must be able to concurrently match or exceed that portion of demand for electricity at each moment in time. The timing and location of these resources is important, both in absolute terms and in relation to the timing and location of the demand. The objective of the study was to provide a detailed exploration of the *temporal* and *spatial* factors that govern the match between renewable electricity generation and demand for electricity. The degree of matching was considered at two timescales: *long-term* and *hour-by-hour*.

The four renewable energy resources and technologies studied in this context were onshore-wind, offshore-wind, wave and tidal-current, as they are the most variable and the most abundant. A Geographical Information System (GIS) was used as the database within which the renewable resources, along with most of the physical constraints on their development, were mapped. This allowed the visualisation and representation of statistically averaged wind, wave and tidal-current resources by location. The extents and locations of each of the four resources that were left after exclusion of all constrained areas were set in rough economic merit order by area. Farms and arrays of generators were located at suitable development sites and the time-series of their electricity production were estimated on an hourly basis over three years. This permitted regional and national comparison with demand, and allowed exploration by scenario of the extent to which forty-percent of Scotland's demand for electricity could be met by renewable resources.

1.1.4 Electricity Supply Infrastructure

The energy resources must either be near to the load demand or, if remote, there must be corresponding capacity in the electricity network to accept and deliver the energy. Without any constraints imposed by the electricity distribution and transmission systems, Scotland could be considered as a single land and sea area with a broad portfolio of renewable resources that could meet local and remote demand for electricity. At the time of writing however, the network is heavily constrained by existing power flows, and future access to the network in geographically remote areas will be expensive to secure. The location and volume of the renewable energy capacity identified in this study to be necessary to provide 40% of Scotland's 2020 demand for electricity would require network reinforcement at the levels recognised in numerous studies (see for example: DTI 2003b, DTI 2003c & Sinclair Knight Merz 2004). Future investment may release much of the network constraint through upgrades of identified sections of the transmission system, to allow accommodation of up to 4.8 GW of additional consented generation (Scottish Executive 2005). Evolution of the thermal plant mix in Scotland and operation of the Scottish electricity system within the context of BETTA and new network rules are not expected to reduce this capacity.

During the course of the present study, transmission and distribution network models were completed that allowed scenario analysis of network power flows within the existing system. Their modification to reflect future reinforcements was agreed to be too speculative and may be the subject of a separate and later study. The present study therefore concentrated on analysis of the location and availability of the renewable resources relative to the location and timing of demand, as if the network would impose no restriction. This provides the most fundamental appraisal of the extent to which the renewable resource can provide 40% of demand, but it must be emphasised that progress towards this goal will require release of current constraints through network reinforcement.

1.2 Report Structure

After this introduction, the study and its results are presented in six further sections and an appendix, as detailed below.

Section 2 – Analysis

Describes the general methodology adopted for the study, the analysis models that were developed and the input data that was used. The data describes the renewable resources themselves, the many constraints that affect generating plant location, and the parameters used in the relative financial analysis.

Section 3 – Electricity Generation

Separate sub-sections are presented for onshore-wind, offshore-wind, wave and tidal-current energies. For each of the four technologies, the nature, location and extent of the available resource is described and quantified. The characteristics of generic energy converters are discussed and the constraints that affect placement philosophy are identified.

Section 4 – Electricity Demand

The creation of disaggregated demand profiles at regional grid supply points is described. Data was derived from half-hourly system demand of the years 2001, 2002 and 2003 and scaled to anticipated levels in 2020. The future demand profiles take account of daily and seasonal variation.

Section 5 – Energy Delivery Scenarios

A *scenario* based methodology was used as a means of concisely specifying various mixes of renewable-energy sources. Eleven scenarios were modelled based on resource time series from 2001, 2002 and 2003. Six *technology scenarios* explored the development of the resource in combinations of up to 6 GW of onshore-wind, 3 GW of offshore-wind, 3 GW of wave and 0.75 GW of tidal-current devices. The selection of each resource was based on the nationally most cost-effective or energetic sites. Five geographical or *area scenarios* tested the nature of the resources in each of ten regions by allocating capacities of each technology evenly in each area. The balance or match between generated and consumed electrical energy was calculated nationally and disaggregated by area. This section of the report describes the analysis methodology in detail and defines the key figures for each scenario.

Section 6 – Results and Discussion

This section contains the results that are tabulated as spreadsheets and shown as graphs. The resources were appraised in a number of ways and are reported in terms of the *plant capacity factors* that they would bring about; their *long-term local matching* to demand; their *hour-by-hour matching* to demand; and *coincident hours* between their production and demand levels. Graphical results are presented for each of the technology and plant-mix scenarios and the implications of the results are discussed. Furthermore, geographical, physical, resource and time-series limitations are identified.

Section 7 – Conclusions

The report concludes with an appraisal of the extent to which Scotland's renewable resources can individually, or in combination, supply forty-percent of demand for electricity in 2020.

Appendix

The Appendix contains eleven A4-sized maps covering the study area at a scale of approximately 1:3,150,000. The main GIS datasets are displayed together with information which illustrates the approach taken in the study.

2 Analysis

2.1 Approach

The four renewable energy resources studied were onshore-wind, offshore-wind, wave and tidal-current, as they are the most abundant (Garrad Hassan 2001a) and the most variable. Existing hydro-generation and projected new hydro and biomass resources were not included in this investigation. They are likely, however, to make an important contribution to meet the forty-percent target set for 2020.

The *study area* was chosen to cover all of the component Scottish landmasses and surrounding sea and ocean areas. The maps in this report all depict the same study area which is defined in terms of the British National Grid. The south-west corner is at *easting* 0 km and *northing* 500 km, and the north-east corner is at easting 500 km and northing 1,250 km. The basic unit of area was 1 km^2 and is generally referred to as a ‘cell’. The study area thus comprised an array of 750 rows by 500 columns, a total of 375,000 1 km^2 cells.

This study presents *scenarios* relating to a range of possible future portfolios of renewable energy generation in Scotland. Renewable generation was compared with demand on an hour-by-hour basis. Tidal currents are predictable over long periods of time, however, wind and waves vary throughout the year as well as inter-annually. Therefore the resource data should ideally be taken from as many years as possible so that generation siting decisions reflect long-term average conditions. The notional year for the study was 2020, but the input data was drawn from the years 2001, 2002 and 2003 as these were the most recent years for which concurrent time-series of meteorological resource data and electrical demand data could be obtained. The demand was scaled up by one-percent per year to allow for anticipated growth in electricity consumption by 2020, but renewable resource data was *not* modified to anticipate any possible effects of climate change.

2.2 Model Outline

The process that was used to model renewable electricity generation used ArcGIS, a Geographical Information System (GIS), along with a number of other computer applications. The GIS program produced maps and was used to establish spatial relationships between resource, generation and electrical load datasets. The spatial units used within the GIS were the 1 km^2 cells that make up the study area. Datasets from various sources were assembled in the GIS database. Figure 2.1 illustrates the conversion of GIS datasets to a common raster (image) format with a resolution that corresponds to the 1 km^2 cells of the study so that logical and numerical operations can be carried out.

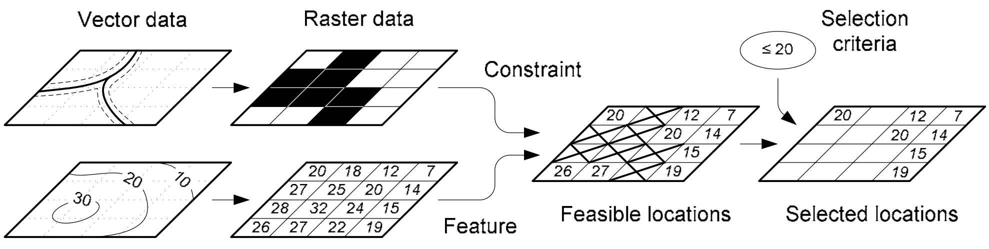


Figure 2.1 Vector and raster data processing in a GIS.

By overlaying datasets and performing mathematical and logical operations on them it is possible to create new spatial datasets. One dataset often contains the primary information with others acting as constraints. For example, the marine renewable resource could be the feature which is constrained by water depth. Figure 2.2 shows a number of constraint datasets that were used within the study. These maps are also included in a larger format in the Appendix.

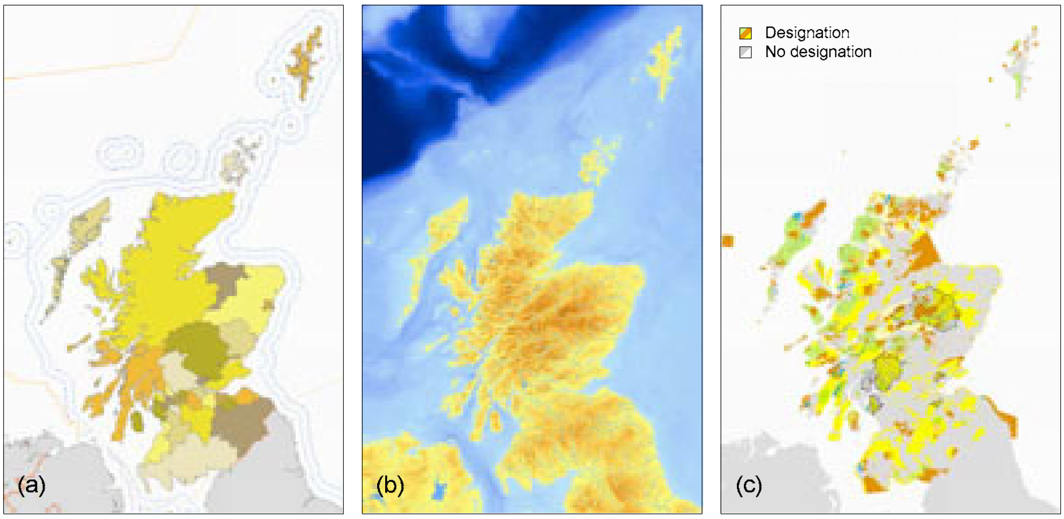


Figure 2.2 Examples of GIS datasets.
(a) Scotland political; (b) Scotland physical; (c) Natural and cultural heritage areas.

Figure 2.3 is a diagrammatic representation of the first part of the modelling process: the production of time-series of renewably generated electricity. The logical flow illustrated in Figure 2.3 involved the progressive creation of a *resource map*, a *cost map* and a *generation map*. These maps are 2-dimensional arrays of numbers that correspond to the 1 km^2 cells of the study area.

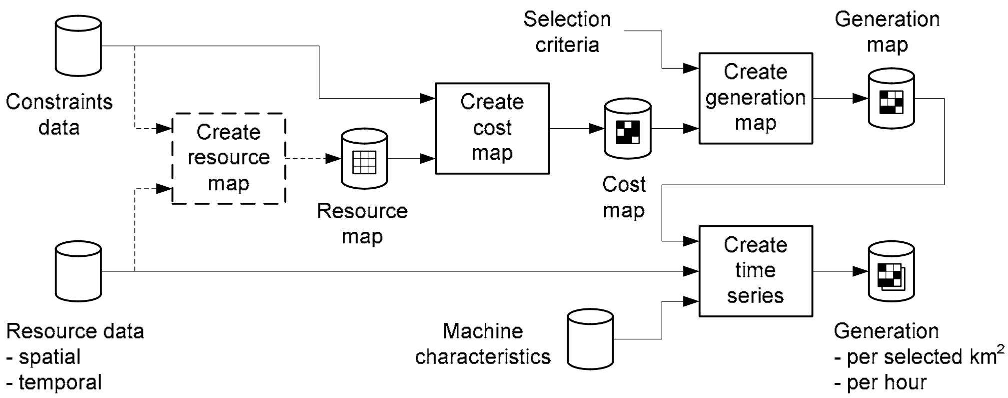


Figure 2.3 Modelling of costs and generation.

Resource maps were prepared from wind, wave and tidal data. They indicate the average long-term strength of the resource within each cell. The cost map was created from the resource map using various constraints and costing formulae to create relative rather than absolute costs for the selection process. The procedure for creating the cost map was as follows:

- Remove cells with absolute constraints (e.g. land slope too steep, water too deep, urban area);
- Calculate the annual energy output for the remaining cells in the map;
- Calculate the initial lifetime production costs per cell, excluding the cost of grid connection;
- Remove cells that are relatively too expensive;
- In consultation areas, where there is a defined limit to the allowable generating capacity within a certain area, remove cells that exceed the limit, starting with the most expensive ones;
- Calculate the density of occupied cells to determine the optimum grid connection option;
- Estimate final lifetime production costs including grid connection.

As an example, Figure 2.4a shows a map of areas with absolute constraints and with consultation status for developing onshore wind projects. Lifetime production costs, shown in Figure 2.4b, were calculated for unconstrained areas and, in the case of onshore-wind, for the best ten percent of cells in consultation areas.

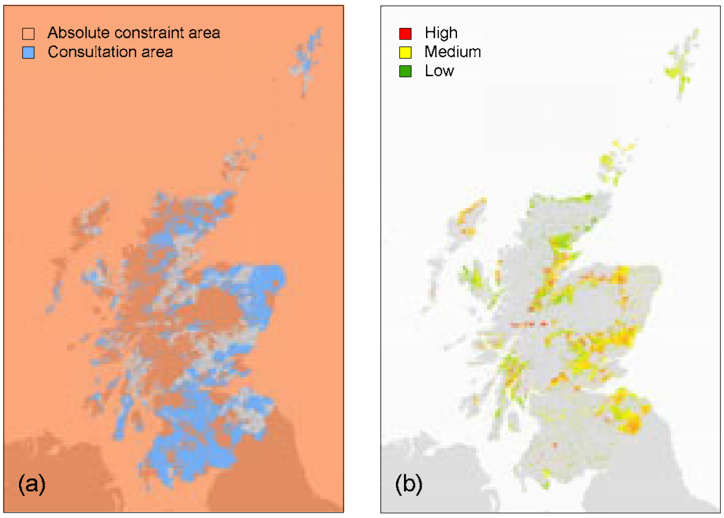


Figure 2.4 Examples of constraint and cost maps for onshore-wind.
(a) Absolute constraint and consultation areas; (b) Lifetime production costs.

With additional selection criteria (e.g. cheapest 750 MW) the generation map was created. For the selected cells, *time-series of resource* (e.g. wind speed or wave height and period) were transformed into *time-series of electrical power* using the electricity generation characteristic of a particular machine.

The final output (lower right of Figure 2.3) consisted of one file for each of the four renewable technologies. Each file contains *generation* time-series for any 1 km^2 cell that has generators assigned to it. The time-series list the hourly averages of the total power generated within that cell. *One hour* was used as the time step throughout the study because longer time series with higher sample rates are generally not available. The time-series modelling of energy conversion and the exploration of scenarios was largely done within Matlab, Visual Basic and Excel.

Once the generation time-series for each of the four technologies had been produced, the aggregate renewably generated power could then be compared with the concurrent electrical demand. This is further described in Section 5. In fully realistic studies that take account of the network characteristics, power-flow restrictions would reduce the number of renewable generators that could be connected at any time. To evaluate most freely the coincidence between the renewable energy and demand for electricity, the simplified case of an idealised network with zero impedance was used. This allowed all renewable energy generators to form an idealised ‘best’ mix of technologies to match the 40% demand target.

2.3 Input Data

A large amount of data was used within the modelling process and this section gives an overview of the datasets employed. Further details of the renewable energy sources are given in Section 3 and on the electrical load demand in Section 4.

2.3.1 Resource Data

The resource datasets are the most crucial part of the study and Table 2.1 summarises the principal sources for this information.

Dataset	Source	Format	Parameter	Onshore wind	Offshore wind	Waves	Tidal currents
Long-term resource							
NOABL database	BWEA	raster	average per km^2	✓	-	-	-
Atlas of UK Marine Renewable Energy	DTI	raster	long-term averages by area	-	✓	✓	✓
Admiralty charts	UKHO	point	peak velocities	-	-	-	✓
Tidal stream atlases	UKHO	point	spring and neap tide velocities	-	-	-	✓
Resource time-series							
Hourly wind measurement data	Met Office	table	speed, direction, gust, 24 stations, 10 years	✓	✓	-	-
3-hourly UK Waters model	Met Office	table	95 points of wind and wave data, 4.5 years	-	✓	✓	-
TotalTide prediction software	UKHO	table	tidal level and current predictions	-	-	-	✓
Tidal-stream atlases	UKHO	chart	tidal-current predictions	-	-	-	✓

Table 2.1 Resource datasets.
Key: ✓ used; - not used.
BWEA: British Wind Energy Association, DTI: Department of Trade and Industry, UKHO: UK Hydrographic Office.

2.3.2 Machine Selection

Once the resource time-series had been prepared they were transformed into time-series of electrical power from groups of wind, wave and tidal-current generators, by means of generic power conversion characteristics. Details of the generic machines are given in Section 3.

2.3.3 Geographical Information

The energy resource depends on the location. Wind blows more strongly at high altitudes or over a flat sea, waves are more powerful in deep water and tidal-currents are accelerated in narrow channels. Height (altitude) and water-depth (bathymetry) contours describe this topography within the GIS. Major geographical datasets are listed in Table 2.2.

Elevation data was converted for input to wind-modelling software and combined with bathymetry data to construct a digital terrain model (DTM) of Scotland with 100 m resolution. The main source for bathymetry was the 'DigBath250' vector dataset from the British Geological Survey (BGS). This has contour intervals of 10 m for depths from 0 to 200 m, 20 m for depths between 200 m and 400 m and 100 m for depths greater than 400 m. Certain areas (east of England, north of Ireland and south of the Faeroe Islands) were not covered by the purchased DigBath250 bathymetry data and were filled in from the British Oceanographic Data Centre's (BODC) '1 minute' raster dataset.

In certain areas, there are differences of depths in shallow water between the bathymetry datasets and the Admiralty charts, which can exceed 10 m (for example in Yell Sound in Shetland and in the Pentland Firth). This could have caused some inaccuracies in the placement of offshore-wind turbines and tidal-current converters. There are further differences between the positions of coastlines between BGS (World Vector Shoreline) and Ordnance Survey (Strategi), but these are generally less than 1 km.

Dataset	Source	Format	Parameter	Onshore wind	Offshore wind	Waves	Tidal currents
Coast line, coarse	BODC	line	footprint	✓	✓	✓	✓
Coast line, detailed	OS Strategi	line	footprint	✓	✓	✓	✓
Territorial limits	e.g. UKHO	line	footprint	✓	✓	✓	✓
Planning authority boundaries	OS Strategi	line	footprint	✓	✓	✓	✓
Cities, towns and villages	OS Strategi	line	footprint	✓	-	-	-
Lakes, rivers	OS Strategi	line	footprint	✓	-	-	-
Height contour lines	OS Panorama	line	footprint	✓	✓	-	-
Elevation for Ireland	SRTM	raster	footprint	✓	✓	-	-
Water depth, detailed	BGS DigBath250	line	footprint	-	✓	✓	✓
Water depth, coarse	BODC 1' atlas	raster	spot heights	-	✓	✓	✓

Table 2.2 Geographical datasets.
Key: ✓ used; - not used.
BODC: British Oceanographic Data Centre, OS: Ordnance Survey, UKHO: UK Hydrographic Office, SRTM: Shuttle Radar Topography Mission, BGS: British Geological Survey.

New information can be derived from the GIS datasets. To evaluate potential marine energy sites economically, the distance to the shoreline and the distance to the nearest *grid supply point* were calculated in the GIS. Ground slopes and radar *viewsheds* around airfields were calculated from the 100 m digital terrain model. An additional model with a reduced resolution of 1 km as shown on Map 02 was used for further processing.

2.3.4 Natural and Cultural Heritage

Renewable energy developments can have a major impact on landscape and biodiversity. The 'National Planning Policy Guideline 6' issued by the Scottish Executive (2000) states that projects should not be developed when they compromise the interests of a protected site. In some areas developments are prohibited or undesirable, in others only a certain maximum number of generators may be acceptable. The available datasets are listed in Table 2.3, with some of them shown on Map 03.

In accordance with publications from Scottish Natural Heritage, in particular SNH (2001), the environmental designations were separated into *high* and *medium* sensitivity. The high sensitivity areas were treated as *absolute constraints*, with no renewable developments allowed within them. This interpretation is more strict than SNH (2001) which does not completely rule out developments in National Park and certain SSSI areas. The high sensitivity *natural and cultural heritage areas* which were treated as absolute constraints include:

- Natura 2000 sites: Special Areas of Conservation (SAC), including candidate sites, and Special Protection Areas (SPA);
- Ramsar sites, Sites of Special Scientific Interest (SSSI), National Nature Reserves (NNR), Local Nature Reserves (LNR), Marine Consultation Areas (MCA);
- National Parks and Regional Parks;
- World Heritage Sites;
- National Scenic Areas (NSA);
- Scheduled Ancient Monuments.

Dataset	Source	Format	Parameter	Onshore wind	Offshore wind	Waves	Tidal currents
Ramsar site	SNH	polygon	footprint	●	●	-	-
Special Protection Area (SPA)	SNH	polygon	footprint	●	-	-	-
Special Area of Conservation (SAC)	SNH	polygon	footprint	●	●	●	●
Site of Special Scientific Interest (SSSI)	SNH	polygon	footprint	●	-	-	-
National Nature Reserve (NNR)	SNH	polygon	footprint	●	-	-	-
Local Nature Reserve (LNR)	SNH	polygon	footprint	○	-	-	-
Marine Consultation Area (MCA)	SNH	polygon	footprint	●	●	●	●
World Heritage Site	SNH	polygon	footprint	●	-	-	-
National park	SNH	polygon	footprint	●	-	-	-
Regional park	SNH	polygon	footprint	●	-	-	-
Country park	SNH	polygon	footprint	○	-	-	-
Garden and Designed Landscape	SNH	polygon	footprint	●	-	-	-
National Scenic Area (NSA)	SEGIS	polygon	footprint	●	●	●	-
Local landscape designations	Landmark	polygon	footprint	○	○	-	-
Areas of great landscape value (AGLV)	SNH	polygon	footprint	○	○	-	-
Scheduled ancient monuments	HS	polygon	footprint	○	○	-	-

Table 2.3 Natural and cultural heritage areas.
Key: ● absolute constraint area; ○ consultation area; - not used.
SNH: Scottish Natural Heritage, SEGIS: Scottish Executive Geographic Information Service, Landmark: Landmark Information Group, HS: Historic Scotland.

Garrad Hassan (2001a) included Green Belts in the high sensitivity category. However, it was not possible to source a consistent dataset for this designation and SNH (2001) does not recommend classifying Green Belts as wind farm exclusion zones.

The medium sensitivity areas included:

- Country parks and Historic Gardens;
- Local landscape designations, including some further Areas of Great Landscape Value (AGLV) in the Highlands;
- ‘Search areas for wild land’.

At the time of writing, the ‘wild land’ areas (SNH 2001) had not yet been further refined, otherwise they would certainly be highly sensitive. *Listed buildings* were not used as they are believed to be mostly in urban areas which were not available for development. The local landscape designations compiled by the Landmark Information Group, and referred to in Table 2.3, replaced the outdated AGLV dataset with the exception of the Highlands (in accordance with information from collaborators and partners).

2.3.5 Aviation Interests

Wind farms may impact on aviation as physical obstructions, and rotating blades may affect communication, navigation and surveillance (DTI 2002). Generally a 30 km consultation radius applies to civil airfields, while military technical sites will be examined on a case-by-case basis. Developers need to consult the Civil Aviation Authority (CAA) and the Ministry of Defence (MoD) with regard to wind farm proposals.

Table 2.4 shows the datasets used within the study. Locations of airports and radars were used for GIS viewshed calculations while the surveillance radar maps and the low flying system mostly describe consultation areas.

Dataset	Source	Format	Parameter	Onshore wind	Offshore wind	Waves	Tidal currents
Civil airfields	OS Strategi	point	viewshed point	●/○	●/○	-	-
Military airbases	DE	point	viewshed point	●/○	●/○	-	-
Military radars	DE	point	viewshed point	●/○	●/○	-	-
NATS en route interference areas	NATS	polygon	footprint	○	○	-	-
Low Flying System	DE	polygon	footprint	●/○	-	-	-
Met Office radars	Met Office	point	viewshed point	●/○	●/○	-	-

Table 2.4 Aviation interest datasets.
Key: ● absolute constraint area; ○ consultation area; - not used.
OS: Ordnance Survey, DE: Defence Estates, NATS: National Air Traffic Service.

Civil Airfields Airfields are issued with safeguarding maps, extending to radii of 15 km and 30 km, within which consultations must be made regarding developments. Radar viewsheds were calculated for all civil airfields in Scotland, assuming a radar height of 15 m and turbine tip-heights between 80 m and 120 m (with the latter being chosen for the final analysis). As an example, Figure **2.5** shows the results for Edinburgh Airport with a 100 m horizontal resolution. Areas within a 15 km radius seen by the radar are treated as absolute constraints while those within a 30 km radius are treated as consultation areas.

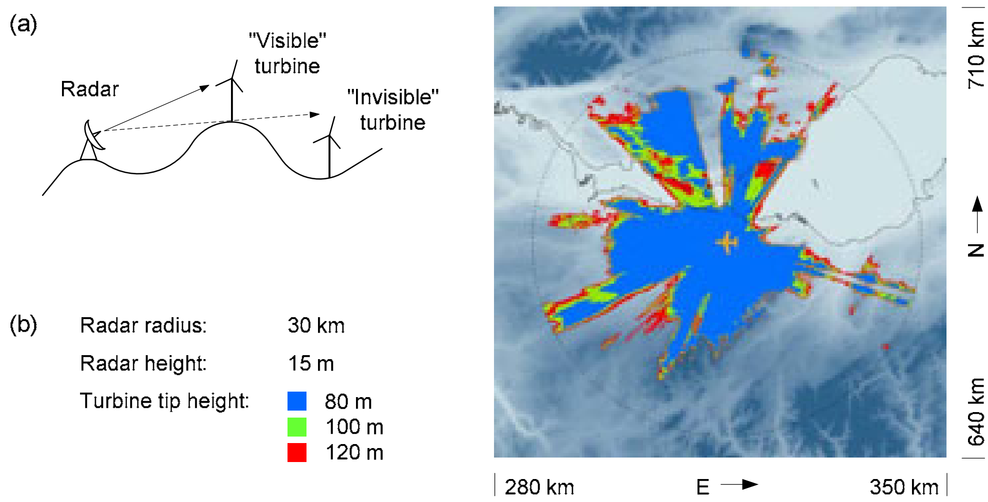


Figure 2.5 Radar viewshed calculation.
(a) Principle of viewshed calculation; (b) Edinburgh airport sample calculation, turbines in the coloured areas are visible to the radar. Map based on Ordnance Survey data.

En route (or area) *radars* are operated by the National Air Traffic Service (NATS) who provides maps indicating areas where there is a probability or a potential that turbines will interfere with the radar. Within the study, areas of high sensitivity were assigned consultation status while those with lower sensitivity were not used (see Map 04). The dataset corresponding to 120 m tip height was used throughout as no data was available for the greater tip heights of offshore turbines.

Military Airfields According to the Defence Estates there are four military airfields in Scotland (Benbecula, Lossiemouth, Leuchars and West Freugh). As no further information was available, they were treated as civil airfields with the same safeguarding radii.

Air Defence There are three ground-based Air Surveillance and Control System (ASACS) radars in Scotland (at Saxa-Vord on Shetland, South Clettraval on South Uist and Buchan in Aberdeenshire) and one in Northumberland (Brizlee Wood) whose operation could be affected by wind-turbine developments in Scotland. DTI (2002) describes a consultation radius of 74 km within which the developer has to prove that there will be no adverse impact. As absolute constraints have not been published, 74 km radius viewshed areas were assigned consultation status.

Low Flying System The UK Low Flying System (LFS) includes the open airspace over land and extends up to 3 nautical miles (5.6 km) offshore. Low flying of military fixed-wing aircraft covers levels between 250 and 2,000 feet (DTI 2002). Within tactical training areas (TTAs) the range goes down to 100 feet. Two of the three TTAs are in Scotland, one in the Highlands (area 14 T, see Map 04) and one in the Scottish/English border region (area 20 T). There are already wind-turbine developments within these areas, but projects will be carefully scrutinised before approval is given. Within the study, these areas are considered to be consultation areas. According to the Defence Estates there are some regions within area 20 T which are less desirable for low-flying. For these the consultation constraint was lifted within the study. A further Electronic Warfare Tactics Range (EWTR) can be found in the Scottish Borders region (area 13). As it is likely that no permission will be granted for wind-power developments in this area, it was considered an absolute constraint.

Met Office Radars Aviation safety depends on accurate weather forecasting for which the Met Office uses *weather radars* and *wind-profiling radars*. The former scans a narrow airspace between the horizon and one-degree of elevation, hence wind-turbines may interfere with operation. There are two weather radars in Scotland (at Stornoway in the Western Isles and Hill of Dudwick in Aberdeenshire). A third (Corse Hill in East Renfrewshire) is under decommissioning and will be replaced by two others which may be located in Stirling and Fife. Wind-profiling radars determine the variations in direction and speed with altitude. There is one in operation on South Uist in the Western Isles. The Met Office will most probably object to wind-turbine developments within a radius of 5 km and possibly object within 10 km radius. Within the study, these viewshed areas were assigned absolute and consultation constraint, respectively.

2.3.6 Land and Sea Use

Renewable energy developments may interfere with other forms of land and sea space usage. Table 2.5 shows relevant data sources that were consulted during the study. In particular, marine devices may block navigational channels. The best information freely available was the study carried out by Anatec UK Ltd., as published in Garrad Hassan (2001a). In the present study the data was only used as a first indicator, as its resolution is only 10 km and areas of water depth greater than 100 m which may be of interest for wave-energy converters were omitted. Military activities take place in Practice and Exercise Areas (PEXA), but no general guideline exists to date on sensitivities. MoD will have to be contacted on a case-by-case basis. Potential renewable energy sites do not lie within Scottish *ammunition dumping grounds*, although a study by Fisheries Research Services, Aberdeen, published in SNH (2004b), shows that hundreds of explosives per square kilometre are commonly found outside the charted areas, even up to 40 km away (see also Map 05).

The Eskdalemuir seismological station has often been quoted as an obstacle to onshore-wind developments in the Borders area. Based on the most recent information available, Map 05 shows a 10 km radius exclusion area and a 17.5 km radius consultation area around the station. For wind resource calculations, surface roughness information for Scotland was derived from the European land cover database CORINE CLC90.

Dataset	Source	Format	Parameter	Onshore wind	Offshore wind	Waves	Tidal currents
Navigational risk	Anatec	raster	footprint	-	✓	✓	✓
Practice and Exercise Areas (PEXA)	UKHO	polygon	footprint	-	-	-	-
Ammunition dumping areas	UKHO	polygon	footprint	-	✓	✓	✓
Pipelines	Kingfisher	line	footprint	-	-	-	-
Undersea cables	Kingfisher	line	footprint	-	-	-	-
Eskdalemuir seismological station	OS	point	10/17.5 km radius	✓	-	-	-
CORINE land cover (CLC90), 250 m	EEA	raster	footprint	✓	✓	-	-

Table 2.5 Land and sea use datasets.
Key: ✓ used; - not used.
Anatec: Anatec UK Ltd., UKHO: UK Hydrographic Office, OS: Ordnance Survey, EEA: European Environmental Agency.

2.3.7 Power System Data

Power system information was taken from the *Seven Year Statements* (SP 2001 – SP 2004 and SSE 2002 – SSE 2004) for the transmission network and the *Long Term Development Statements* (SP 2003, 2004 and SSE 2002, 2004) for the distribution network.

Both Scottish Power and Scottish and Southern Energy supplied coordinates of the electricity substations in their area. These were used to calculate the distances from potential generation sites to the nearest grid supply point.

Both power companies supplied demand information for their respective area and for some selected grid supply points. The processing of this is described in Section 5.

2.3.8 Financial Parameters

Capital and Operation & Maintenance cost information for 2010 was taken from Garrad Hassan (2001a) and some more recent device-specific publications, and broken down into typical costs as shown by example in Figure 2.6. More detailed cost information is given in Section 3.

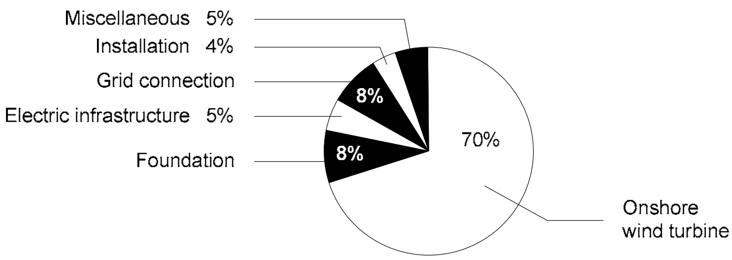


Figure 2.6 Example project cost breakdown for onshore-wind.

The costs were input into a discounted cash flow model. In line with previous studies, a project lifetime of twenty-years and a discount rate of 8% were assumed for all technologies. The latter reflects a *public-sector* rather than a *private-sector* rate of return which would require a discount rate of at least 15%. The effects of inflation were ignored, and costs are based on 2005 prices. From the discounted sums of energy production and annual expenses, the *lifetime production costs* (LPC) were calculated as:

$$LPC\,(\text{p/kWh}) = \frac{\text{Investment} + PV(\text{Expenses})}{PV(\text{Energy production})}. \qquad (2.1)$$

The figures calculated for lifetime production costs serve for comparison between sites (but not technologies) and for the ranking of sites in order of lowest cost first.

Grid connection costs from Garrad Hassan (2001a) were updated to 2005 levels. They include capitalised operation and maintenance (O&M) costs. In the cases of Shetland, Orkney, and the Western Isles it was assumed that all projects in each of these areas would share the capital costs of undersea cable connections to the mainland in a manner similar to that published by Sinclair Knight Merz (2004). The GIS calculated an internal non-monetary *least cost distance* between a project and a grid connection point to suggest the best route. Only approximations were possible for the *friction surface* describing relative costs for crossing a particular distance. As an example, for onshore wind a value of 1 was used for land and a value of 10 for water and sea areas and natural heritage areas with ‘high sensitivity’ designation. The GIS then favoured sites that are close to grid supply points and chose cable routes around protected areas.

Power stations in Scotland which are connected to the transmission network pay Transmission Network Use of System (TNUoS) charges. These charges are determined annually by National Grid and vary regionally. The arrangement of the zones can be changed every five years. Within the study the selection of renewable energy sites was rank-ordered based on economic merit. This includes estimates of the capital costs of connection but *excludes* the annual TNUoS charges that may apply. The three reasons for this exclusion follow.

Firstly, TNUoS charges may change considerably over time due to network reinforcement or addition of new power plants (SEEF *et al* 2005). Hence it is difficult to estimate what the future charges will be in every region for deployment of a particular technology. Secondly, TNUoS charges vary considerably for different zones across the UK but they are relatively flat in Scotland ranging from about 12 £/kW in South Scotland to about 23 £/kW in the Northern Highlands (National Grid 2005). Finally, the DTI is considering special dispensation for up to 10 years in areas of high renewable energy potential which would otherwise face comparatively high transmission charges. Such dispensation would effectively further flatten the charges across Scotland. Since these matters were not resolved at the time of writing it was agreed to exclude TNUoS charges from the study.

3 Electricity Generation

Wind, waves and tidal-currents have the potential to generate significant amounts of electrical energy. The nature and geographical distribution of the resource needs to be well understood for the successful design and implementation of energy converters. The characteristics of the machines that are likely to be to able to make a major contribution to energy production by the year 2020 must be established.

3.1 Onshore-wind Energy

3.1.1 Resource Characteristics

Wind is the result of the uneven heating of the earth's surface by the sun. Besides the pressure gradient and gravitational forces, the wind is also strongly influenced by the Coriolis force (due to the earth's rotation), the inertia of air and its friction with the earth's surface. Locally, the wind is further modified by topography and coastlines as well as by weather conditions.

The wind-speed varies over time, with seasonal and diurnal patterns. Figure 3.1 shows the wind-speed measurements of a wind turbine on Orkney during the year 2003. In Scotland the wind-speeds in summer are generally lower than in winter. Wind-speed also varies from one year to another, with a ten year period generally being considered to be representative of the local wind climate. Wind blowing across a large land mass is influenced by the daily solar radiation cycle, particularly during summer, creating a rise in wind-speeds around midday. There are also short-term variations or *turbulences* with timescales from seconds to minutes.

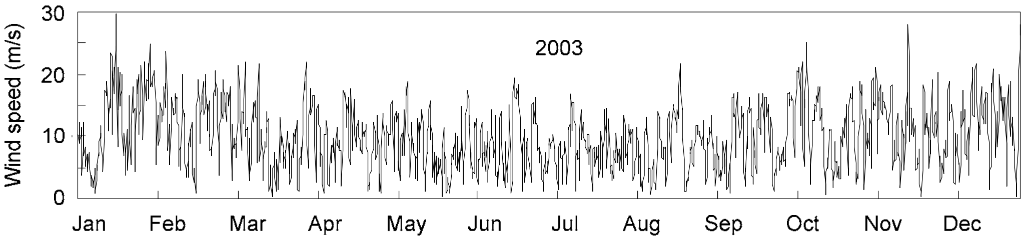


Figure 3.1 Wind-speed measurement at an onshore location.
Location: Burgar Hill, Orkney; 60 m measurement height; 4 hour averages.

The factors that influence wind-speed generally also influence direction. In Scotland the prevailing wind is from the south-west. The statistical variation of wind-speed and direction can be graphically represented by a *wind rose* (see Map 06). Because of the friction between wind and the earth's surface, the wind-speed increases with height above ground level. For neutral stratification of the atmosphere the profile was approximated by the *logarithmic power law* taking into account the *surface roughness length* z_0:

$$\frac{v(z)}{v(z_r)} = \ln\left(\frac{z}{z_0}\right) \Big/ \ln\left(\frac{z_r}{z_0}\right), \tag{3.1}$$

where $v(z_r)$ is the wind-speed at reference height z_r and $v(z)$ the wind-speed at height z. Values for the surface roughness vary from 0.0002 m for a calm open sea, to 1 m for large cities.

3.1.2 Resource Assessment

The most comprehensive estimation of the UK onshore-wind resource was done by Newton & Burch (1992), Burch *et al* (1992), and Burch & Ravenscroft (1992) using the mesoscale numerical wind-flow model NOABL. A similar approach based on the 'Wind Atlas Analysis and Application Program' *WAsP* from Risø National Laboratory in Denmark was used for this study. The program extrapolates wind measurements horizontally and vertically to estimate the local wind climate. The models are based on flows in the atmospheric boundary layer and take into account *orography*, surface roughness, and obstacles. ('Orography' strictly refers to the study or description of mountains, but is used in the context of wind energy to refer to the description of height variation across any area of land.) In order to compute the wind climate in each onshore 1 km^2 cell, the study area was first divided into a series of twenty-one overlapping 100 km by 100 km *wind simulation areas* as shown on Map 06.

Orography WAsP needs surface elevation maps with height contours. The former were derived from Ordnance Survey *Panorama* vector tiles. They were assembled into 120 km by 120 km maps; the calculations were carried out for the central 100 km by 100 km region (Map 06). Due to restrictions in computing power, the resolution of height contours had to be increased to 50 m. Horizontally, the contours were allowed to deviate at most 50 m from the Ordnance Survey data. To improve the results of the final analysis, high resolution maps with 10 m horizontal and vertical resolution were used in the 10 km by 10 km area around wind measurement sites.

Surface roughness Using the GIS, surface roughness information for Scotland was derived from the European land cover database CORINE CLC90 which has a resolution of 250 m. Roughness was assigned to each landscape type, with the few 'NO DATA' squares (missing information in the database) set to 0.01m (short grass). An average value was then calculated for each square kilometre, except for areas around wind measurement sites where a resolution of 250 m was retained.

Obstacles WAsP can take into account the influence of trees or buildings that are near to the meteorological instruments. 360 degree photographic panoramas were sourced for wind measurement sites. These were evaluated along with 1:10,000 OS raster maps to determine the effects of obstacles. As available wind data is already corrected in a rather crude way for these effects, and as these correction factors are not always known for historical datasets, the data was used as delivered by the Met Office with no additional obstacles modelled in WAsP.

Atmospheric data Hourly wind-speed, wind direction, and maximum gust records for 24 meteorological stations across Scotland were purchased from the Met Office. The period of time covered was 1994 through 2003, except for South Uist, Skye Lusa and Port Ellen which have missing records at the beginning. The majority of the record sets (21 out of the 24) were obtained to represent the wind climate within each of the 100 km by 100 km wind simulation areas. The other three records were used for backup. The stations are shown in Table 3.1 and on Map 06. All values are either from measurements at 10 m above ground level (agl) or were corrected to this height. Wind direction is represented from true-north in multiples of ten degrees. Wind-speed and gust data are stored as integer values in knots. The Met Office was not able to provide estimates for the data quality before the purchase. Where data was missing for up to three subsequent hours it was interpolated. For larger gaps it was predicted from one or two neighbouring stations. Some stations, in particular Strathallan, Eskdalemuir, and Dunstaffnage had large numbers of records with zero wind-speed due to sheltered or less sensitive anemometers. These records were recalculated including data from two neighbouring stations.

The met station assigned to each of the twenty-one 100 km by 100 km simulation areas provided the wind source data for modelling (Table 3.1 and Map 06). WAsP was used to calculate the average wind-speed at 80 m height for each square kilometre within a simulation area. Neighbouring areas overlapped by ten kilometres so that *scaling factors* for each area could be calculated and used to smooth transitions at the boundaries and to improve the overall consistency. As a result, the transitions were reduced to below 3% except between Orkney and Shetland where a higher difference was justified by the differing wind climates.

Area	SW corner Northing (m)	SW corner Easting (m)	Associated Met station	Backup Met station	Scaling factor
1	1,150,000	390,000	Sella Ness		0.926
2	1,060,000	380,000	Lerwick		0.955
3	970,000	300,000	Kirkwall		0.820
4	880,000	80,000	Stornoway		0.983
5	880,000	170,000	Altnaharra	Aultbea	1.056
6	880,000	260,000	Wick		0.959
7	790,000	50,000	South Uist		0.794
8	790,000	140,000	Skye Lusa		0.971
9	790,000	230,000	Kinloss	Aviemore	1.011
10	790,000	320,000	Dyce		0.938
11	700,000	50,000	Tiree		0.811
12	700,000	140,000	Dunstaffnage	Tulloch Bridge	0.967
13	700,000	230,000	Strathallan	Tulloch Bridge	0.971
14	700,000	320,000	Leuchars		1.012
15	610,000	50,000	Port Ellen		0.853
16	610,000	140,000	Machrihanish		0.866
17	610,000	230,000	Salsburgh		0.848
18	610,000	320,000	Charterhall		0.943
19	520,000	140,000	West Freugh		0.908
20	520,000	230,000	Dundrennan		0.942
21	520,000	320,000	Eskdalemuir		0.967

Table 3.1 Onshore wind simulation areas.

The final results were compared to the NOABL dataset which was scaled from 45 m to 80 m height using roughness information. Overall the *initial* results of the WAsP calculations were about 5% higher than those of the NOABL studies referred to above. This difference is consistent with the findings of Halliday *et al* (1995). Comparison of the results with wind and production data from operational wind turbines in the Shetland, Orkney and Borders areas led to the adoption of the final scaling factors above which also compensate for WAsP's resource overestimation in mountainous terrain. Figure 3.2 and Map 06 show the calculated average wind speeds at 80 m agl across Scotland for 1994 through 2003. According to the DTI (2004b), wind speeds during the years 2000 to 2003 were observed to be lower than the long-term average. Note that wind speeds in the 'low' category for Scotland in Figure 3.2 are still higher than those at many Central European sites.

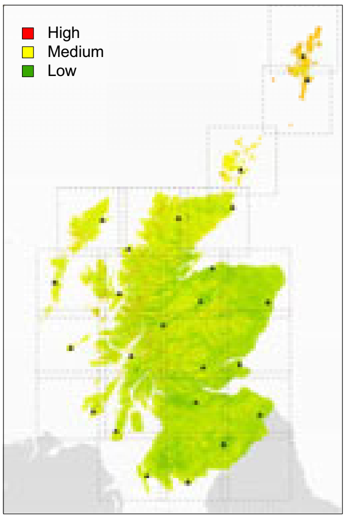


Figure 3.2 Onshore-wind resource map.
Results based on WAsP simulations with data from 21 met stations.

3.1.3 Energy Converter

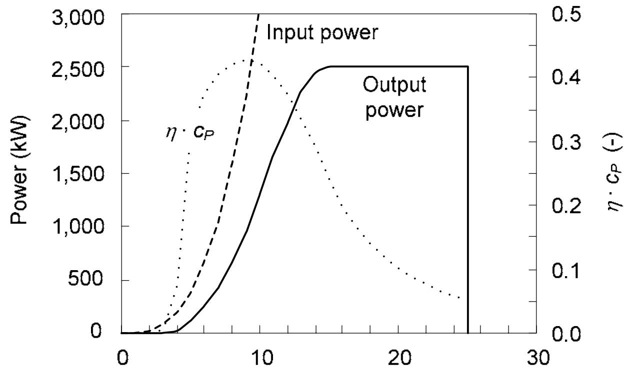
When an air mass with velocity v and density ρ (standard value: 1.225 kg/m^3 at +15°C) passes through the rotor of a horizontal axis wind turbine with area A, power coefficient c_P (maximum 0.593) and an overall efficiency η, then the extracted power may be calculated from

$$P = \frac{1}{2} c_P \, \eta \, \rho \, A \, v^3 \, . \tag{3.2}$$

The basic characteristics of the chosen *reference* wind turbine were as follows:

- Horizontal axis, 3-bladed, upwind design;
- 2.5 MW rated power, variable-pitch blades, variable rotational speed;
- 80 m rotor diameter and 80 m hub height;
- Rotor alignment by active yawing through 360°;
- 25 m/s cut-out wind speed.

Figure 3.3 shows the power curve of the machine (adapted from a Nordex N80/2500 turbine).



(a)

Wind (m/s)	Power (kW)	Wind (m/s)	Power (kW)
0	0	11	1,658
1	0	12	1,984
2	0	13	2,269
3	0	14	2,450
4	15	15	2,500
5	120	16	2,500
6	248	...	...
7	429		
8	662	24	2,500
9	964	25	2,500
10	1,306	26	0

(b)

Figure 3.3 Reference onshore 2.5 MW wind turbine.
(a) Curves of wind input and output power against wind-speed; (b) Table of generated power against wind speed.

Three of these turbines were placed in a 1 km^2 cell, giving 7.5 MW per km^2 installed capacity. For calculation of the indicative lifetime production cost, average project costs of 600 £/kW were assumed for Scotland with 8% of this amount representing nominal grid connection costs. Actual grid connection costs were estimated from GIS cost distance as described in Section 2.3.8. Land rental was assumed to reduce annual revenues by 2%. Insurance was set to an annual fee of 1% of capital expenditure and O&M costs were 0.55 p/kWh (e.g. EWEA 2004).

3.1.4 Generation

The average wind-speed assigned to each 1 km^2 cell of the onshore-wind resource map allowed an initial selection of potential sites for wind generation. Inappropriate sites were filtered out by reference to *absolute* and *consultation* constraints (discussed in Section 2.2) including:

- Natural and cultural heritage sites;
- Aviation and radar interference areas;
- Cities, towns and villages; lakes; cells with an average slope greater than 15%.

For the remaining 1 km^2 cells the lifetime production cost was calculated. This figure included the grid connection cost and, in the case of the islands, a share of the undersea cable connection. The cells were ranked according to the lifetime production cost and groups of the 'cheapest' (for example the cheapest 1,500 MW out of all of the onshore wind generating capacity) were selected for scenario calculations. Time-series of wind-generated power were needed for all potential onshore sites. The first stage of this process was to use the *WindFarmer* program from Garrad Hassan to compute a *flow matrix* for each cell of interest. This matrix transforms 'input' wind-speeds and directions at the *associated met station* (at 10 m agl) to 'output' wind-speeds (at 80 m agl) at the 1 km^2 cell. The time-series of wind-speed for each selected cell was then generated from the Met Office time-series data.

Wind-speed time series were converted to power time series using the power curve shown in Figure 3.3. The generated power for each cell had to be reduced in order to allow for the following factors.

High wind cut-out To avoid damage or excessive wear, onshore wind turbines are generally designed to be shut down in wind-speeds that exceed 25 m/s. Turbulences and gusts can force the operation of the cut-out procedure, but as the study was based on hourly wind data this could not be accurately modelled. Each Met Office hourly wind data record included the maximum gust that occurred during the hour. However, this is measured at 10 m height whereas the wind turbine hub height is 80 m and generally many kilometres away. Extrapolating the gust values for the height difference and for the distance would not have been meaningful. A compromise used here was to trigger shut-down when a wind-speed of 25 m/s was reached and then wait subsequently until it fell below 22 m/s before re-starting generation. From the data used in the study, a wind-speed of 25 m/s at 80 m hub height was exceeded in Scotland for an average of 19 hours per turbine per year and the subsequent average waiting time for cut-in was 9 hours per year. Assuming a 35% plant capacity factor, the corresponding annual production losses were estimated to be 0.6% and 0.3%, respectively.

Downtime Onshore-wind turbines in projects in Europe are now commonly available (generating or waiting for sufficient wind-speed) for 98% of the time. For the remaining 2% of time they are either awaiting or undergoing repair or they are shut-down for scheduled maintenance. Equivalent production losses of 2% were used in the study.

Electrical losses Transformers and low voltage interconnections within a wind park typically cause losses from 2 to 3%. The lower number was used for the study. Losses for the grid connection were not considered, as feed-in at remote corners of the network can actually reduce transmission losses by supplying electrical energy locally.

Wake losses On average, individual turbines in wind farms spend some time in the wake of other turbines and therefore intercept less wind. Flat terrain causes wakes to propagate a long distance down-wind and the wake losses to other machines can approach 8%. Scotland's hilly terrain helps to 'mix' and re-energise the wind so that this effect is reduced. In the study, wake losses were taken into account by reducing power output linearly in proportion to turbine density. The density was defined by the number of occupied cells within a 5 km by 5 km square. The reduction was set to zero if only the centre cell was occupied (3 turbines in total) and to 7.5% if all 25 cells were occupied (75 turbines in total).

Directionality Modern wind turbines have yaw systems which actively align the rotor to face the wind and so there are practically no losses caused by changes of wind direction.

High wind cut-out and subsequent cut-in were applied on an hour-by-hour basis in the calculation of the generation time-series. Downtime, electrical and wake losses were implemented by applying global reduction factors to the final time-series figures.

3.2 Offshore-wind Energy

3.2.1 Resource Characteristics

Compared with land, oceans have relatively smooth surfaces and so there is generally less reduction in wind-speed near to the surface. This characteristic is referred to as low *wind shear*. The atmosphere far offshore tends to be more stable than onshore due to the absence of large obstructions and because of lower vertical temperature gradients. Diurnal patterns of wind-speed variation are relatively flat and turbulence intensity tends to be low, so that dynamic machine loading is less and reduced tower heights may be considered. However, as a result of the less turbulent conditions, the machines in an offshore wind-farm generally need greater spacing to allow the wakes of up-wind turbines to be re-energised.

Figure 3.4 shows simulated wind-speeds at an offshore location north of Orkney derived from Met Office *hindcast* data. The location is only 60 km from the onshore measurement site of Figure 3.1 and the storm peaks are very similar.

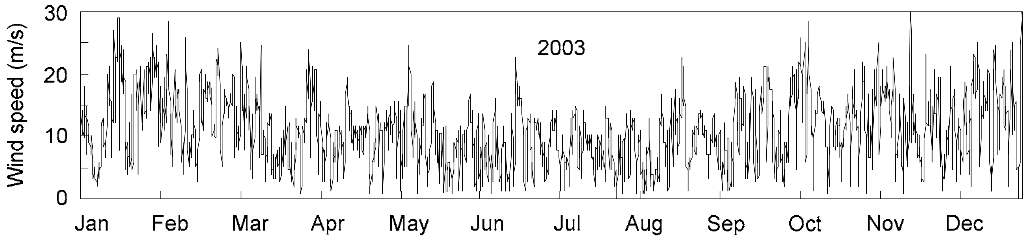


Figure 3.4 Wind-speed simulation for an offshore location, based on Met Office hindcast data. Location: 59.50°N, 2.58°W (north of Orkney); 80 m height; 3 hour values.

3.2.2 Resource Assessment

In comparison with the number of onshore Met Office stations, there are relatively few maintained offshore wind measurement points around Britain. Off Scotland there are four 'island systems' (North Rona, Sule Skerry, Foula, Muckle Holm) and a number of moored buoys. Due to the frequency of severe weather conditions and their relative inaccessibility, the datasets from these stations are much less complete than those of their mainland counterparts. Furthermore as these stations are all well to the north of the Scottish mainland, they are of little use for predicting conditions in potential offshore-wind areas such as the east coast or the Solway Firth.

Therefore the primary resource information for offshore-wind was the Met Office *UK Waters Wave Model* which has wind information included with the wave data. Hindcast averages of wind-speed and direction are provided eight times a day for a height of 10 m above sea level (asl). Data from 29th March 2000 through to 9th November 2004 was obtained for 95 simulation *grid-points* (shown on Map 08). Hindcasting is a well-established technique whereby *archived* weather data is later used as the input for a detailed meteorological model of weather conditions in some required area. In recent years the temporal and spatial resolution of hindcast data has greatly improved. The UK Waters Wave Model now has a spatial resolution of one-ninth of a degree of latitude by one-sixth of a degree of longitude, an area typically around twelve kilometres square. The start date of the data used for the study corresponds to the date at which the frequency of data archiving increased to allow 3-hourly hindcasts to be made.

For distances well offshore (more than 30 km from the coastline) the hindcast wind data could be directly applied to any potential wind turbine location, with interpolation between two or more points where necessary. However, the comparatively shallow waters needed for offshore-wind turbine foundations generally require them to be relatively close to the shore. At these distances from the coastline the models do not describe the wind resource robustly (DTI 2004b).

To overcome this problem, the UK Waters hindcast offshore-wind data was used to provide input to WAsP (see Section 3.1.2) which was then able to correct for *coastal discontinuity* and to make more accurate predictions for nearshore locations. The local wind climate was established from 2001 through 2003 data. The 11 simulation areas, 150 km by 100 km in size, shown in Table 3.2 and Map 07 were created to cover potential offshore-wind locations around Scotland. The roughness of land areas can have a stronger influence on wind regimes over the coastal sea than the orography. As combined orography and roughness maps were readily available from the onshore-wind simulations (see Section 3.1.2), the appropriate parts were used for offshore-simulations as well. A total of 124 three-hour periods were missing within the four and a half year hindcast dataset, but these were filled by prediction from data from 'backup' meteorological stations within the simulation area (see Table 3.2).

Figure 3.3 and Map 07 show that, as with onshore-wind (Map 06), neighbouring offshore-wind simulation areas have 10 km overlaps. These again allowed calculation of scaling factors that were used to reduce transitions between areas. The resulting long-term averages compared very well with the data published in the UK Marine Renewable Energy Atlas (DTI 2004a), with differences generally being smaller than 5%.

Area	Name	SW corner Northing (m)	SW corner Easting (m)	Simulation Grid-point	Backup Met station	Scaling factor
1	Shetland	1,070,000	370,000	59.94°N, 1.75°W	Lerwick	0.933
2	Orkney	930,000	290,000	59.50°N, 2.58°W	Kirkwall	0.858
3	Cape Wrath	950,000	150,000	59.06°N, 5.08°W	Altnaharra	0.810
4	Lewis	860,000	30,000	58.17°N, 7.58°W	Stornoway	0.781
5	Moray Firth	840,000	260,000	58.17°N, 2.58°W	Wick	0.876
6	Uist	770,000	20,000	57.28°N, 7.75°W	South Uist	0.781
7	Aberdeen	750,000	330,000	57.28°N, 1.75°W	Dyce	0.903
8	Tiree	680,000	20,000	56.39°N, 7.58°W	Tiree	0.778
9	Fife	610,000	310,000	56.39°N, 1.75°W	Leuchars	0.805
10	Islay	590,000	80,000	55.50°N, 5.92°W	Machrihanish	0.843
11	Solway Firth	500,000	160,000	54.61°N, 4.25°W	Dundrennan	0.924

Table 3.2 Offshore-wind simulation areas.

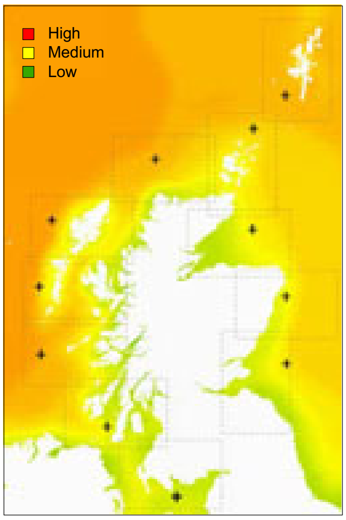


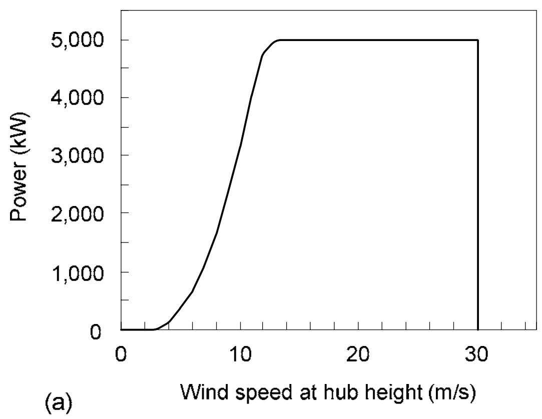
Figure 3.5 Offshore-wind resource map.
Data derived from the Atlas of UK Marine Renewable Energy Resources (DTI 2004a).

3.2.3 Energy Converter

Offshore wind-turbines are in principle built in the same way as their onshore counterparts. Certain aspects such as noise emission or visual intrusion may be less critical, winds may be less turbulent, tower heights for a given capacity may be lower and it may be easier to move very large components at sea. However, the corrosive effect of the maritime environment is much higher, foundations and cable-laying are more complex and costly, and installation and access for maintenance are more demanding. At present offshore machines are largely modified onshore types, but in the future they are likely to evolve into more specialised designs. The parameters chosen for the study were:

- Horizontal axis, 3-bladed, upwind design;
- 5 MW rated power, variable-pitch blades, variable rotational speed;
- 126 m rotor diameter and 80 m hub height;
- Rotor alignment by active yawing through 360°;
- 30 m/s cut-out wind speed.

Figure 3.6 shows the power curve of the machine (adapted from a REpower 5 MW turbine).



(a)

Wind (m/s)	Power (kW)	Wind (m/s)	Power (kW)
0	0	11	4,017
1	0	12	4,755
2	0	13	5,000
3	0	14	5,000
4	126	15	5,000
5	352	16	5,000
6	648	...	...
7	1,081		
8	1,638	29	5,000
9	2,335	30	5,000
10	3,170	31	0

(b)

Figure 3.6 Reference 5 MW offshore wind turbine.
(a) Power curve; (b) Tabulated values of generated power against wind-speed.

Only one 5 MW turbine was permitted in any 1 km^2 cell, giving 5 MW/km^2 installed capacity. For the indicative lifetime production cost calculations, a capital cost of 960 £/kW was assumed for a water depth of 10 m and nominal costs of grid connection. Cell-specific foundation and installation cost fractions were calculated as water depth dependent, while grid connection costs were calculated dependent on cost distance. Sea area rental was assumed to reduce annual revenues by 2%. Insurance was set to an annual fee of 1.5% of capital expenditure and O&M costs were 0.65 p/kWh (e.g. EWEA 2004).

3.2.4 Generation

The main constraint for offshore-wind developments is water depth. At present a depth of 30 m is considered to be the limit for economic feasibility. However, for sensitivity analysis up to 40 m was allowed in the scenario calculations. Map 07 shows these areas along with deeper water regions down to 40 m and 50 m. In line with Garrad Hassan (2001a) wind farms were placed at least 5 km offshore. All areas closer to the shore were therefore excluded from further analysis.

Further sites were removed due to absolute and consultation constraints including:

- Natural and cultural heritage sites,
- Aviation and radar interference areas,
- Areas of very high navigational risk.

Navigational risk which was ranked 'very high' was used as an absolute constraint against placement of generating plant. 'High' navigational risk was treated as a consultation constraint to avoid constraining out some potential development in the Firth of Forth. This seems a reasonable decision because in places the coarse 10 km resolution of the navigational risk dataset tends to broaden the apparent shipping lanes. Likewise, Military Practice and Exercise Areas (PEXA) were not considered as constraints in the study due to the lack of available guidance information.

For site selection, the average wind speeds as predicted by WAsP based on the Met Office hindcast input were used. The calculations beyond this were carried out in the same manner as for onshore-wind. Reduction factors included the following:

High wind cut-out The offshore turbine modelled had a cut-out speed of 30 m/s compared with 25 m/s for the onshore machine used in the study. It was assumed that the wind has to fall below 26 m/s before the turbine would resume operation. A high-wind shutdown is more likely to happen in the north of Scotland than in the south. On average across all of the offshore locations suggested by this study, 30 m/s at 80 m hub height was exceeded for only 0.2 hours per turbine per year with a subsequent waiting time for cut-in of 0.1 hours per year. The corresponding annual production losses were practically negligible. This result is likely to be optimistic since the hourly wind data was derived from three-hourly hindcast records which effectively mask gusts that can force a shutdown.

Downtime Availability figures for offshore wind projects were predicted to reach or exceed 94% by 2010, and so a corresponding 6% loss of production was assumed. Advances in technology and service concepts will be necessary to actually achieve this figure throughout all projects.

Electrical losses As for onshore-wind, losses in transformers and interconnections within offshore wind-parks were estimated at 2% of production.

Wake losses Low surface roughness offshore and less vertical wind movement than on land, allow wakes to propagate over comparatively long distances. The associated power losses in existing offshore wind farms have been reported to be in the range of 5% to 15%. Therefore power losses due to wakes were increased linearly from zero if only the centre cell in a 5 km by 5 km square was occupied (1 single turbine) to 10% if all 25 cells were occupied (25 turbines in total).

Directionality As with onshore wind turbines, there are no losses associated with the change of wind direction. As long as the actual wind speed is above the cut-in level, the automated yaw system of the turbine will change the nacelle's direction to always face the wind.

High wind cut-out and subsequent cut-in were implemented on an hour-by-hour basis during the calculation of generator time-series, whilst downtime, electrical and wake losses were applied in the form of global reduction factors.

3.3 Wave Energy

3.3.1 Resource Characteristics

When winds start to blow over calm water, they create waves that are small and short. If the winds continue to blow, the waves get bigger and longer and they also travel faster. A typical speed for a mid-spectrum Atlantic wave is 55 km/h (35 mph) and so it would take several days to cross the ocean from west to east. As such waves arrive in shallower coastal waters, they begin to lose energy due to friction with the sea bed and through breaking. *Sea-states* are highly complex, but can generally be thought of as being made up of waves of different periods, heights and directions combining together. The wind-sea interactions that are responsible for the waves seen at any point may have occurred hours or days ago and over distances of thousands of kilometres. Superimposed on top of a short-period *wind-sea* from local winds, there may be an *old-wind sea* of half-a-day ago from an adjacent sea area along with long-period *swell* from distant storms of several days ago.

Figure 3.7a shows the variation in *wave height* for a site 120 km north-west of Lewis, predicted over a one year period from hindcast data. Figure 3.7b shows the variation in *wave power* over a shorter period along with the corresponding hindcast wind power record for the same site. There is visible correlation between wave and wind, but there are clearly times (such as around 23rd February) when high wave power levels must be due to more distant winds. It is important to note that none of the traces shown in the figures give any indication of wave or wind *direction*.

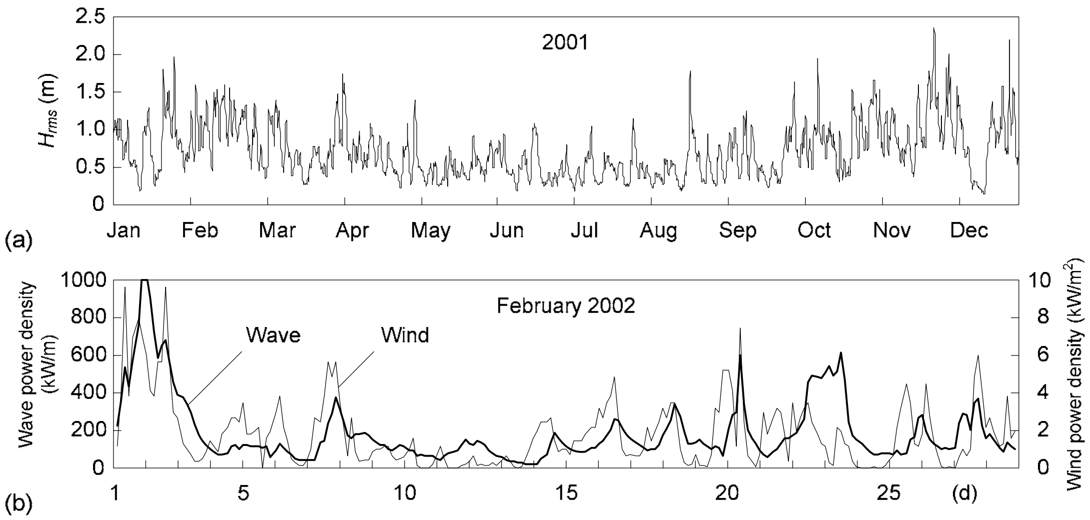


Figure 3.7 Wave height and power density at 59.06°N, 8.42°W.
(a) Three-hourly hindcast values of wave height in 2001;
(b) Comparison of wave and wind power density during February 2002.

Whatever the means used to record or predict a wave climate, the complexity of any particular sea-state is usually described by using a simplifying set of statistical parameters. A sea-state can then be thought of as being composed of a *spectrum* of *regular* waves of different heights, periods and directions. The two most important parameters are wave height and wave period.

The height parameter is used to represent the average of the heights of the constituent waves. In this study the *root-mean-square (rms) wave-elevation* parameter H_{rms} was used. H_{rms} is equivalent to the standard deviation of the water surface about the mean position. Oceanographers often use the parameter H_s (significant wave height) which is now defined as being 4 times the H_{rms} value.

The period parameter is used to represent the average of the periods of the constituent waves. In this study the *energy period* parameter T_e was used because it has a robust definition. The T_e of a spectrum of waves having a certain H_{rms} and power density is equivalent to the period of a *regular* wave that has the same values of H_{rms} and of power density. This is useful because the power density of a spectrum of waves is generally easy to calculate.

A curve can be drawn for any measured sea-state to show how energy is distributed across the wave frequency spectrum. Such spectra can also often show the relative contribution of swell (at low frequencies) or local wind-sea (higher frequencies). With a long fetch and steady wind conditions, it is possible to estimate the wave spectrum from knowledge of wind-speed by using parametric spectra such as the *Pierson-Moskowitz* or the *Jonswap*.

Wave recording buoys are often equipped to measure horizontal surge and sway motions as well as heave motions so that wave *directionality* can be calculated. Swell from a distant source may have a very narrow angular range whereas locally generated waves may approach from a wide range of angles as winds shift and change speed.

The *power density* of a wave is proportional to the square of its height multiplied by its period. If ρ is the density of water (1,025 kg/m^3) and g the acceleration due to gravity (9.81 m/s^2), then the wave power density in deep water (in watt per metre of wave crest) is given by:

$$P_W = \frac{\rho g^2}{4\pi} H_{rms}^2 T_e . \tag{3.3}$$

As an example, a sea-state with H_{rms} = 1 m and T_e = 10 s has a power density of nearly 79 kW/m.

3.3.2 Resource Assessment

Off Scotland, the areas that have historically been of most interest as potential wave energy generation sites are in the Atlantic approaches to its western coasts, because these areas are at the ends of very long fetches that stretch out in the directions of the prevailing wind systems.

Early UK wave energy researchers used data from Ocean Weather Ship ‘India’ which kept more or less permanent station in the deep Atlantic, 700 km west of the Western Isles, from 1947 to 1975. Estimates of the overall average power density at that location varied between 80 kW/m (Leishman & Scobie 1976) and 91 kW/m (Mollison, Buneman and Salter 1976). Crabb (1978) later reported systematic calibration errors in the ‘India’ data and reduced the mean figure to 78 kW/m.

In 1976, in response to interest in wave energy generation, the Institute of Oceanographic Sciences (IOS) began a wave measurement programme by installing a ‘waverider’ buoy about 18 km west of South Uist in 42 m depth. The long-term average wave power density was estimated at 48 kW/m (Crabb 1982).

These assessments were for specific areas and gave no explicit indication of the general wave climate. Winter (1980) used two years of data from the Met Office depth-dependent wave-forecasting model to hindcast directional wave power climates around the western approaches to the UK from Land’s End to Shetland and also in the Moray Firth. He found close agreement between the Met Office model and the IOS measurements made at South Uist.

In 1992 Queen’s University Belfast made calculations of the UK *shoreline* and *nearshore* wave energy resource using a Met Office wave prediction model. Included in the study were 14 representative locations to the west of the UK and Ireland and one location to the east of Shetland. Five of the locations were in areas of relevance to the present study and were modelled for the period February 1983 to July 1986.

The wave energy resource data used by Garrad Hassan (2001a) in their assessment of Scotland's renewable resource was interpolated from data for 29 offshore grid points that was obtained from the Norwegian company Oceanor. The data covered a period of nine years and was derived in part from information and techniques developed under 'Eurowave', a collaborative European research project during the 1990s. The interpolation process used for the Garrad Hassan work also used inshore waters data produced by the Queen's University Belfast project referred to above.

The calculations in the present study were based on Met Office hindcast data that recently became available with improved temporal and spatial resolution. The *UK Waters Wave Model*, referred to in Section 3.2.2 above, has a spatial resolution of 1/9th degree latitude by 1/6th degree longitude (each record thus represents conditions in an area of about twelve kilometres square), and a time-resolution of 3 hours. Data from 29th March 2000 through to 9th November 2004 was obtained for 95 simulation *grid-points* shown in Map 08.

Source	IOS (1976-1978)	Winter (1977-1979)	QUB (1983-1986)	GH (1992-2000)	UoE (2000-2004)
Fair Isle	-	-	-	50.5	37.5
Islay	-	-	29.3	27.7	16.0
Malin Head	-	-	53.1	54.9	30.0
North Rona	-	-	-	60.4	45.0
NW (DB2)	-	57	75.8	65.8	43.5
Shetland (DB3)	-	45	66.9	52.0	39.0
South Uist	48	52	71.6	56.4	45.0

Table 3.3 Comparison of average wave power density (kW/m) estimates from various sources. IOS: Institute of Oceanographic Sciences (Crabb 1982); Winter (1980); QUB: Queen's University Belfast (1992); GH: Garrad Hassan (2001a); UoE: University of Edinburgh (present study).

Table 3.3 compares wave power estimates for 7 locations, taken from the studies discussed above, with values from the present study. It is notable that the latter figures are lower than those of the other studies. With the exception of Garrad Hassan (2001a) the studies were based on 3 or 4 years, time periods too short to establish a long-term wave climate, and some variation was to be expected. According to the classic work of Pierson and Moskowitz (1964) the wave power density of a *fully developed* sea is proportional to the 5th power of wind-speed and so the wave resource is very sensitive to year-to-year variations in wind climate. According to the DTI (2004b), wind-speeds during the years 2000 to 2003 were observed to be significantly lower than the long-term historical record. They quantify the *windiness* of the period as 93.6% of the long-term value, which on a simple 5th power analysis would correspond to wave power density levels being 72% of the longer term value. This *could* explain the relationship between previous estimations and the present calculations.

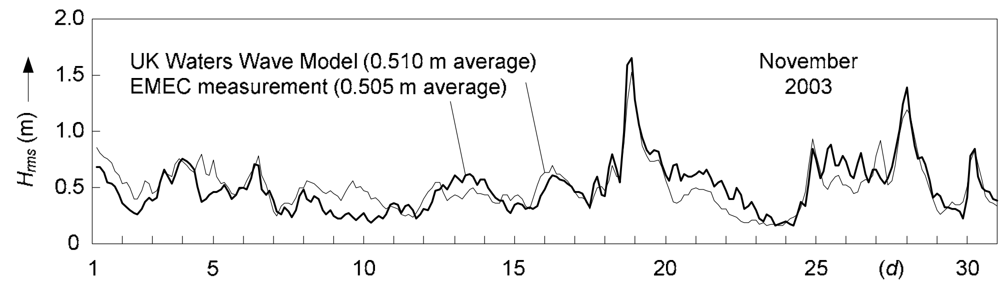


Figure 3.8 Comparison of measured and simulated rms wave elevation values. Measurement: three-hourly at the European Marine Energy Centre on Orkney; data courtesy of EMEC Ltd. Simulation: derived from Met Office hindcast data for the nearest grid-point. Distance between EMEC buoy and grid-point: 9 km.

Variations in the UK wave climate may also be linked to the *North Atlantic Oscillation*, but a brief comparison has found no clear correlation. The wave resource values calculated for the study are in very close agreement with the wave power densities published in the Atlas of UK Marine Renewable Energy Resources (DTI 2004a) which derive from the same Met Office data. Figure 3.8 compares wave heights calculated from the Met Office hindcast data with buoy measurements from a nearby location for the month of November 2003. There is good agreement, particularly between the average values for the month.

Wave data records The Met Office UK Waters Wave Model data was supplied in the '1D Integrated Variables' format for the 95 grid-points shown in Map 08. The wave information in each three-hourly record is listed as 13 spectral density values, each of which corresponds to one of the frequency bins illustrated in the spectral density histogram of Figure 3.9. The units of spectral density are such that the area of each column represents the energy at its nominal frequency, so that the sum of all columns represents the total energy in the sea-state. A second array lists the associated wave direction for each bin. The Met Office records include wind hindcast data that was used in calculating the offshore-wind resource (see Section 3.2.2), and so the 95 grid-points were chosen to give good coverage for wind as well as for waves. The record for each grid point also includes water depth.

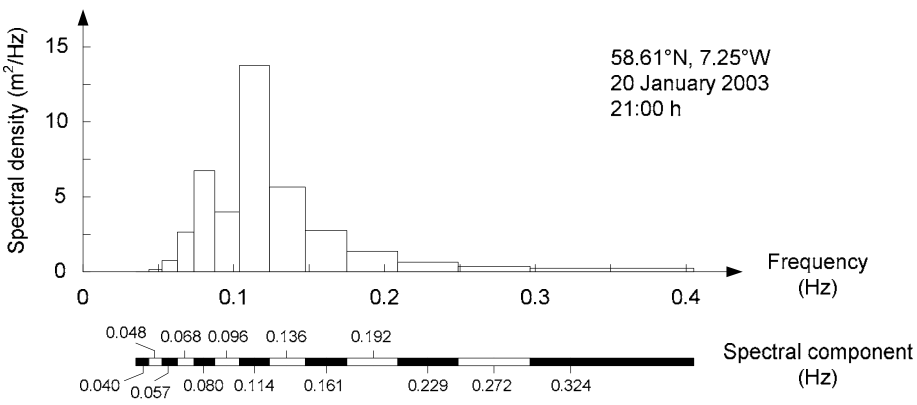


Figure 3.9 Energy spectrum from one record of the UK Waters Wave Model '1D' data. The nominal frequency of each bin is shown on the second horizontal axis.

Wave data preparation The preparation of the wave data was based on work by Tucker (1991) and the World Meteorological Organization (1998). With reference to the 13 bins shown in Figure 3.9, if i is used to represent the bin number, the ith bin has nominal frequency f_i, width df_i and spectral density $S(f_i)$.

Spectral moments are used in wave analysis. For the binned data, the nth spectral moment can be written as

$$m_n = \sum_{i=1}^{13} f_i^{\,n} S(f_i) df_i \ . \tag{3.4}$$

The rms wave elevation H_{rms} is then found from the zeroth spectral moment as

$$H_{rms} = \sqrt{m_0} \ . \tag{3.5}$$

The energy period T_e can be found from the ratio of two spectral moments:

$$T_e = \frac{m_{-1}}{m_0} . \tag{3.6}$$

If ρ is the density of sea water and g the acceleration due to gravity, the power density P_W per metre of crest length is

$$P_W = \rho g \sum_{i=1}^{13} c_g(f_i) S(f_i) df_i , \tag{3.7}$$

where $c_g(f_i)$ is the group velocity of the wave of frequency f_i in water depth h. In shallow water (depth less than half of a wavelength) this is given by:

$$c_g(f_i) = \frac{g}{4\pi f_i} \tanh k(f_i)h \left(1 + \frac{2k(f_i)h}{\sinh 2k(f_i)h} \right). \tag{3.8}$$

In Equation (3.8), k is the so-called 'wave number':

$$k = \frac{2\pi}{\lambda}, \tag{3.9}$$

where λ is the wavelength which depends on water depth. In deep water it is

$$k_0 = \frac{(2\pi f_i)^2}{g} . \tag{3.10}$$

k can be found for any depth by an iterative solution of the following equation, using the above value of k_0 as an initial guess:

$$k(f_i) = \frac{(2\pi f_i)^2}{g \tanh k(f_i)h} . \tag{3.11}$$

A contiguous file of 3-hour parametric records was prepared from the 1D data set for each of the 95 grid-points used in the study. For general resource estimation, average power density values based on four years of data running from 1st April 2000 to 31st of March 2004 were calculated. For the electricity generation time series, three years of data from 1st January 2001 to 31st December 2003 were used.

For the preparation of maps and site selection in the Atlantic areas of interest, power density data was interpolated in a two-stage process. The first stage consisted of interpolation from the 95 grid points down to the nominal resolution of the UK Waters Model (approximately 12 km). The second stage consisted of interpolation from that grid down to the 1 km^2 cells that were used in the study.

Figure 3.10 shows the average wave power densities across Scotland according to the DTI (2004a) derived from UK Waters Wave Model data for the period 1st June 2000 to 30th September 2003.

Map 08 in the Appendix shows in addition the wave power densities in areas of interest for wave power developments calculated in this study from data covering 1st April 2000 to 31st March 2004.

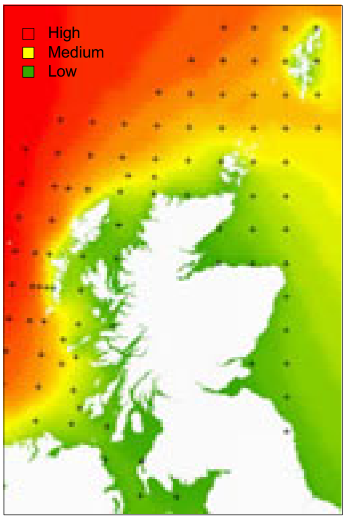


Figure 3.10 Wave energy resource map.
Data derived from the Atlas of UK Marine Renewable Energy Resources (DTI 2004a).

3.3.3 Energy Converter

The present study was concerned with notional installations having aggregate capacities at the gigawatt level. The offshore deep-water wave resource is considerably more energetic than the shoreline resource and there are more possible sites for energy conversion systems. Of the prototype deep-water wave energy devices that had recently been deployed, Ocean Power Delivery's 'Pelamis' device seemed to be the one nearest to commercial introduction. Furthermore it can be placed in a range of water depths commonly found around the Scottish coast.

Based on public domain information and after discussions with the device developer the characteristics of the 750 kW prototype were scaled up to represent anticipated future machines. The device parameters used for the study were:

- Semi-submerged, cylindrical structure consisting of 5 segments and 4 power modules, 180 m long;
- 1.5 MW rated power, power limitation through inherent design characteristics;
- Water depth range 50 to 150 m;
- Passive device alignment > ±90°;
- Packing: 3 rows of devices with 12.5 to each 1 km^2 cell (18.75 MW/km^2 capacity).

Table 3.4 shows the power-matrix of the notional wave energy converter. Each entry in the matrix gives the generated electrical power in kilowatts for a particular combination of parametric wave height and period. The combinations of H_{rms} and T_e values cover the full range of values found in the data records.

Rms wave elevation H_{rms} (m) \ Energy period T_e (s) — Output power (kW)	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19
3.0										1500	1500	1500	1500				
									1500	1500	1500	1500	1500	1453			
2.5								1500	1500	1500	1500	1500	1470	1319	1192		
							1500	1500	1500	1500	1500	1450	1350	1175	1039	900	
2.0						1500	1500	1500	1500	1500	1450	1320	1180	1008	865	750	635
					1500	1500	1500	1500	1500	1440	1277	1119	971	845	724	607	490
1.5				1450	1500	1500	1500	1460	1444	1253	1071	915	782	651	540	450	361
			650	1258	1470	1450	1467	1299	1136	968	826	688	567	462	378	314	251
1.0		95	427	871	1116	1170	1106	969	834	688	558	449	366	297	242	201	161
	0	53	241	525	730	769	709	605	493	397	317	254	206	168	137	114	91
0.5	0	24	108	237	336	358	326	274	222	178	142	114	93	75	61	51	41
	0	5	27	62	88	94	85	72	58	47	33	22	18	14	10	5	0
0.0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

Table 3.4 1.5 MW wave energy converter power matrix.

3.3.4 Generation

The creation of power generation time-series for the wave energy devices was a two-stage process. First, a power time-series was generated for each of the 95 grid-points of the hindcast wave resource data using values of H_{rms} and T_e to interpolate values for generated power from the power-matrix of Table 3.4. This set of time-series was then used to produce interpolated time-series at each 1 km^2 cell to which devices had been allocated. Inverse distance weighted values from up to four nearby grid-points were used.

Power limitation The chosen device has an inherent power limitation capability as described by the power matrix. H_{rms} and T_e combinations with blank entries in Table 3.4 did not occur in the dataset.

Downtime Once the technology is established, availabilities similar to those of offshore wind farms may be achievable. Maintenance will be carried out bi-annually in summer with little loss of production. An average 8% loss of production was assumed beyond 2010.

Electrical losses Production losses due to electrical interconnections within the wave farm were set to 2%.

Array losses The row of devices which faces the wave front will produce the highest power output. As devices are interleaved and as the attenuator type does not intercept all of the power, the array losses were set to 1%.

Directionality The nominal directional orientations for wave energy devices in each 1 km^2 cell were based on the all-year average direction of maximum incident wave energy. Moorings were assumed to allow devices to swing to either side of this mean position. However, an angular-attenuation factor k was calculated by the approximation

$$k = 0.8 + 0.2\left(\text{abs}\left(\cos\left(\theta_{nom} - \theta_{ss}\right)\right)\right)^{1/2} \qquad (3.10)$$

and applied to power calculations. θ_{nom} represents the nominal moored orientation of the device and θ_{ss} represents the direction of the sea-state. As examples, this function gives attenuation factors of 0.8, 0.88, 0.94, 0.97 respectively for seas whose mean directions are offset at respective angles of 90°, 80°, 60° and 45°.

3.4 Tidal-current Energy

3.4.1 Resource Characteristics

Tides are long oceanic waves which cause the sea level to change over periods of roughly half a day or a day (Pugh 1987). The rising tide is known as a *flood-tide* with a corresponding 'mean high water' (MHW) level. The falling tide is known as an *ebb-tide* with a corresponding 'mean low water' (MLW) level. The difference between the MHW and MLW levels is the *tidal range* and the average is the 'mean tide level'. The latter often serves as a datum for elevation measurements.

The moon provides the primary tidal force. It orbits the earth every 27.3 days around an axis of rotation which lies within the earth. The water masses on earth experience centrifugal and gravitational forces which tend to produce *tidal-bulges,* both on the side of the earth that faces the moon and on the opposite side. The shapes and phasing of the tidal bulges are complicated by the earth's daily rotation about its own axis and by the interaction of land masses and waters of varying depths. The earth-moon system and the earth rotate in the same direction, and so the earth's cycle with respect to the moon is 24 hours and 50 minutes. This is called the *lunar day*.

The sun has a similar influence on the water masses, with a diurnal period of 24 hours. Its enormous size is compensated by its great distance so that the solar gravitational force is about 0.46 that of the moon. When earth, sun and moon are in line (either a new or a full moon depending on their relative positions), then the forces combine to produce larger than average *spring-tides*. When the moon is in quadrature (half-moon), smaller than average *neap-tides* are produced. The basic earth-moon cycle repeats approximately every 29.5 days, or *lunar month*.

Tidal changes in water level are fed by very large horizontal movements of water having the same cyclic periodicity. Where the horizontal water motions are particularly pronounced, they are referred to as *tidal-currents*. As with the usually more apparent vertical motions, the intensities of the horizontal flows are very sensitive to the sizes of sea areas, the variations in water-depths (bathymetry) and the shapes of land masses.

Figure 3.11 shows the change of tidal-current velocities throughout a year for a site in the Fall of Warness (Orkney). The peaks during spring tides are clearly visible.

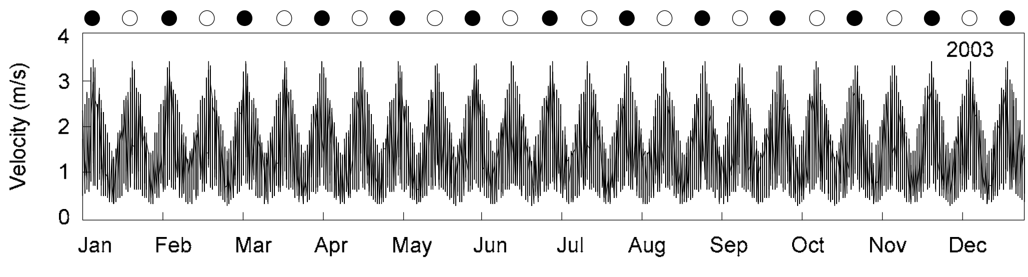


Figure 3.11 Absolute value of tidal-current velocity in the Fall of Warness (Orkney). Location: 59.135°N, 2.805°W, hourly values for 2003 computed with TotalTide. ● new moon; ○ full moon.

In restricted areas such as channels and narrow estuaries, tidal-currents are more or less bi-directional. In more open areas of sea, the direction of flow (which may be plotted in the form of a *tidal ellipse*) may be complicated by factors that include the Coriolis force. Tidal-currents are sensitive to bathymetry changes and to bottom friction. In general, current velocities reduce with depth, particularly near to the sea bed. In some cases, the near sea-bed and the free surface water motions may be significantly out of phase.

Because of their dependence on astronomical constellations, tidal-currents are deterministic and can be predicted with great accuracy into the future. However, weather has some additional influence. Wind can reinforce or weaken tidal motions, and water level is influenced by changes in atmospheric pressure.

3.4.2 Resource Assessment

Tidal *levels* can be predicted by summing up a number of *harmonic constituents,* each of which corresponds to a particular astronomical influence with its own characteristic frequency. Almost 400 constituents have been identified. The prediction of tidal-currents is made still more complex by their very high sensitivity to bathymetry and landmasses. The available sources of information include:

- Some Admiralty Charts with a resolution equal to or better than 1:200,000 contain *tidal arrows* indicating the direction and magnitude of the spring tide currents, sometimes for both the flood and the ebb tide.
- More information is attached to the *tidal-diamonds* that feature on some Admiralty Charts. For a number of selected points that are marked with diamond symbols, a table lists the hourly velocities up to six-hours before and six-hours after high water at a reference port, for average spring and for average neap tides. The values shown on the charts are obtained from short-term measurements and are applicable five metres below the surface. An example of a tidal diamond is shown in Figure 3.12a.
- *Tidal stream atlases* published by the United Kingdom Hydrographic Office (UKHO) cover specific areas in more detail. Each atlas contains thirteen hourly charts with spot values for spring and neap tidal velocities, and arrows to indicate the general direction of the currents. Scaling of the arrows may contain further information on the velocity rate. Each of the thirteen charts in any series represents a time in hourly intervals from six hours before high water at Dover to six hours after. A small extract from an atlas is shown in Figure 3.12b.
- The *'TotalTide'* software package was designed by the UKHO for mariners and allows prediction of tidal-currents at tidal-diamond locations at any time in the past or in the future.
- When tidal-currents are needed for an area where no measurements have been made, a complete *computational fluid dynamics* (CFD) analysis could be made. Because of the amount of data required to adequately describe the bathymetry of sea areas and the shapes of land masses, such studies are usually confined to smaller areas of a few hundred square kilometres. The data in the UK Marine Renewable Energy Atlas (DTI 2004a) is based on interleaved computer models with different resolutions. Such models perform well when given accurate boundary conditions, although at inshore locations the accuracy is generally lower. At the beginning of this project simulation models were not available at the correct resolution.
- For definitive information on current velocities, directions and depth profiles at any location, on-site measurements must be made. These should be carried out over a complete spring and neap cycle, and the results should be corrected for the effects of weather.

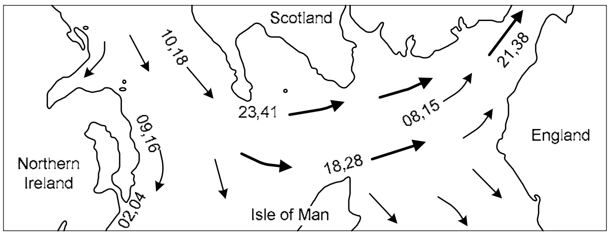
Directly measured information was not available for the study and a CFD analysis of the whole Scottish coastal area was well-beyond the available time and computing resources. Neither was the dataset nor the model used to compile the UK Marine Renewable Energy Atlas (DTI 2004a) available in the public domain. Accordingly, the tidal-current resource data used was based on UKHO information.

Figure 3.13 and Map 09 show the average spring-tide velocities across Scotland. Spring tidal-velocities of at least 2 m/s are commonly considered to be required for economic energy extraction. In collaboration with The Robert Gordon University, potential areas for tidal-current applications were identified. Where tidal-diamonds were available within a few kilometres of such a site, their data were included in the study. The phasing of some of this data, such as in the example shown in Figure 3.12a, is given with reference to sites other than Dover. In these cases the phasing was transformed to the Dover datum. In areas with no local tidal-diamonds, 'pseudo' tidal-diamonds were constructed using data estimated from the tidal stream atlases. Further spring tidal rates were obtained from Admiralty charts and from previous studies, in particular Black & Veatch (2004).

Tidal Streams referred to HW at ABERDEEN

		E 59°08.1'N 2°48.3'W		
			Rate (kn)	
Hours		Dir	Sp	Np
Before HW	6	150	6.2	2.4
	5	144	7.2	2.8
	4	141	5.8	2.3
	3	116	2.8	1.1
	2	350	0.3	0.1
	1	308	3.8	1.6
	HW	329	6.4	2.5
After HW	1	329	6.5	2.5
	2	320	4.9	1.9
	3	325	3.8	1.7
	4	324	1.2	0.5
	5	160	1.7	0.7
	6	153	5.7	2.3

(a)



(b)

Figure 3.12 Examples for a tidal diamond and a tidal stream atlas.
(a) Tidal diamond "E" on Admiralty Chart 2250 for the Fall of Warness (Orkney);
(b) Extract from tidal stream atlas NP 256 (UKHO 1992b), 2 hours before HW Dover.

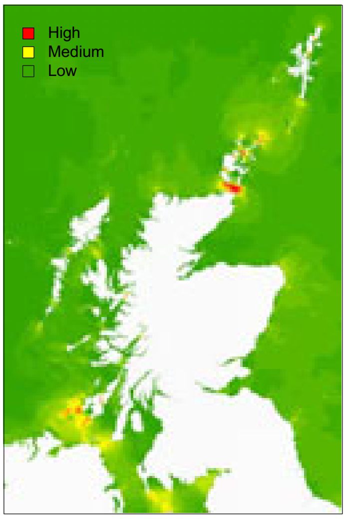


Figure 3.13 Tidal-current resource map.
Data derived from the Atlas of UK Marine Renewable Energy Resources (DTI 2004a).

For the study, the spring and neap tidal-current values at each site had to be transformed into three-year time-series of tidal-current velocities and directions. The first stage of this process was to produce a three-year reference time-series of tidal ranges for Dover using TotalTide. For each hour of the three-year period, the levels at the last high and low water times and those at the next high and low water times were used to calculate the short-term tidal range. This range was related to the known mean spring range of 6.0 m and the mean neap range of 3.2 m at Dover to establish the relative phasing within the spring and neap cycle. With the spring and neap tidal current velocities known for each tidal diamond, as well as the time to High Water at Dover, a velocity and a current direction could then be interpolated for each tidal diamond at every hour. Weighted tidal-current vectors from up to three diamonds were used to calculate velocity and direction at a site of interest.

3.4.3 Energy Converter

Traditionally, tidal power generation has been associated with the building of a dam or barrage at a site with sufficient tidal range and the generation of power by low-head hydro turbines either during ebb or flood or both. Because of the civil construction costs involved, and the potential impact on the environment, and in spite of there being several superb candidate sites no large plant has been built in the UK. In comparison to tidal-barrages, the direct use of tidal-currents avoids long-duration civil engineering activity and the environmental impacts are likely to be lower.

Several designs exist for tidal-current converters. At the time of writing the development of the horizontal-axis concept is more advanced than that of other proposed systems, and these machines therefore seem likely to be used for large-scale implementation in the near-future. Although there are many aspects of machine design and performance analysis that are quite distinct, horizontal-axis tidal-current machines extract power very much in the manner of wind-turbines, with the incident power being proportional to the cube of current velocity:

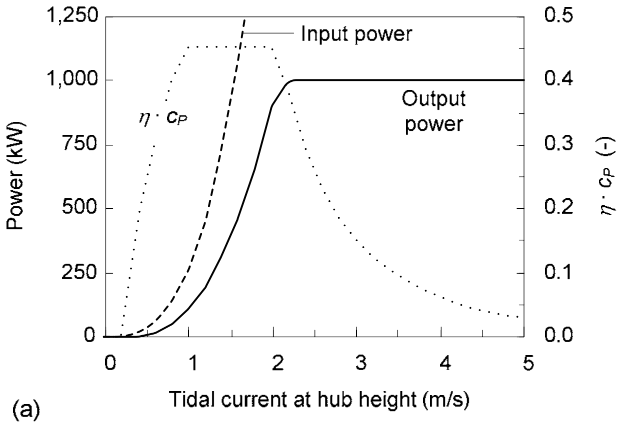
$$P = \frac{1}{2} c_P \, \eta \, \rho \, A \, v^3 . \tag{3.11}$$

The major difference is the much higher density ρ of seawater (about 1,025 kg/m^3) compared to air.

The key parameters for the projected 1 MW underwater turbine, which was conceived for the study, were:

- Horizontal axis, 2-bladed, twin rotor design. 18 m rotor diameter;
- Two 0.5 MW generators, variable rotational speed, blade pitch reversible;
- 5 m or more clearance to the sea bed, 9 m clearance to the sea surface;
- No yawing, but 180° blade pitch-reversal to capture bidirectional flows.

To reduce cost, the machine in the study did not have a yaw system. This requires the currents to be essentially bi-directional. Figure 3.14 shows the power curve of the machine (adapted from the MCT *SeaGen* design).



(a)

Current (m/s)	Power (kW)	Current (m/s)	Power (kW)
0.0	0	2.2	1,000
0.2	0	2.4	1,000
0.4	3	2.6	1,000
0.6	16	2.8	1,000
0.8	51	3.0	1,000
1.0	112	3.2	1,000
1.2	193	...	...
1.4	306		
1.6	457	4.6	1,000
1.8	650	4.8	1,000
2.0	892	5.0	1,000

(b)

Figure 3.14 1 MW tidal-current turbine power curve.
(a) Power curve; (b) Tabulated values of generated power against wind-speed.

The *optimum spacing* of tidal-current generators is subject to speculation and is likely to be site specific. Bryden & Couch (2004) suggest that up to 10% of the mean energy flux at a particular site could be intercepted by tidal-current generators without significantly changing the resource. Salter (2005) argues that higher fractions could be extracted from relatively long channels where the power losses already incurred by tidal-currents in overcoming bottom-friction are comparable with the energy to be extracted. For the notional machine, a *minimum* spacing of 1 km was assumed. When fifteen of these machines were placed along a line perpendicular to the main current direction, the lateral spacing was about 67 m. This gave an effective capacity of 15 MW per 1 km^2 cell. However, this machine density was only used in the most energetic areas of the Pentland Firth. Elsewhere, the axial spacing was increased to at least 2 km.

3.4.4 Generation

Due to the limited number of potential locations, the placement of machines was based on the suitability of sites from a physical and resource perspective, rather than being based on cost. It was assumed that the machines could be installed in water depths between 30 and 50 metres. All locations with spring tide rates of 2 m/s or greater and which were close to 1 km^2 in size or greater were considered. Narrow channels (such as Kyle Rhea) and lochs (such as Loch Linnhe) were excluded from the study due to the limited capacity for electricity generation at those locations (e.g. less than 5 MW).

For the 30 to 50 metre range of depths and the 2 m/s qualifying current, the total number of 1 km^2 cells in Scottish waters was of the order of 100. These cells were thinned out so as to normally stay within the ten-percent extraction limit. This left 26 cells in the Pentland Firth, 15 cells in the northern Orkney area, 5 cells in Shetland, and a further 34 cells in the south-west. The latter areas are known to be less energetic, but could make a valuable contribution to a balanced generation portfolio.

Some of the sites, in particular in the Pentland Firth, experience relatively high shipping densities which will be have to be taken into account before any project developments take place. However, as with offshore-wind, it was decided to not to attempt to constrain these sites with the low-resolution navigational risk dataset.

For the selected sites, the clearance between blade tips and the mean water surface was assumed to be 9 m. With 18 m rotor diameter the hubs are then 18 m below the surface. A 1/10th power law was applied to scale down the nominal near-to-surface velocities of the resource to values appropriate to the mean depths of the turbines. Based on resource time series and the conversion characteristic, power time series were calculated for each 1 km^2 cell. Further global reduction factors were applied to the turbine power output including the following.

High velocity cut-out Because of their predictability compared with winds and waves, the maximum velocities of tidal currents at any site will be known before installing the plant. Machines will be subjected to known stresses and will be designed to operate at all current velocities, probably using blade pitch-control to regulate power. Therefore a cut-out velocity was not set for the machines in the study.

Downtime The type of tidal current generator used in the study has the useful feature that its drive train can be raised above the surface of the water for maintenance. Tidal machines idle for several hours each day at slack water and the projects will be near the shore. Accordingly, access will be relatively easy and total downtime losses were set at 4% in the study.

Electrical losses As with the other technologies, the electrical losses due to interconnection within the tidal farm were set at 2% of production.

Wake losses Recent research (e.g. Bryden & Couch 2004) suggests that currents will only recombine after a long distance. In the study, wake losses of 5% were assumed. Future research is needed to obtain generally applicable figures.

Directionality Most turbine designs have no facility for yawing as tidal-currents in energetic areas are predominantly bi-directional. However tidal flow cycles usually have some small amount of angular deviation from the ideal. Within each 1 km^2 cell, the turbine orientations were set to the mean current direction. Whenever the tidal-currents deviated from this axis, a cosine correction was applied to the power output of the machine. For instance, a 5° off-axis current invoked a reduction of 0.5%, while 10° caused a loss of 1.5%.

4 Electricity Demand

Electricity cannot, at present, be economically stored in large volumes and has therefore to be generated as it is required. Short-term *demand forecasts* allow scheduling of *dispatchable* power stations on a minute-by-minute basis. The forecasts are based on records of historic load demands and trends (including transmission and distribution losses), weather forecasts, timings of major events (including television programmes), scheduled requirements at individual generating stations (for example maintenance activities), regional imports and exports through *interconnectors* and any load-control strategies that may be in place. Accurate long-term estimates of both power and energy requirements are crucial to effective power system planning and operation.

4.1 Scottish System Demand

There is a continuous increase in the demand for electricity, although in the UK and many industrialised countries, the *rate* of increase has declined in recent years (Weedy & Cory, 1998). The *seven year transmission statements* of Scottish Power (SP 2001 – SP 2004) and of Scottish and Southern Energy (SSE 2002 – SP 2004) list historical and predicted system demands, both in terms of system maximum demand (in MW) and of energy demand (in TWh). These are shown graphically in Figure 4.1.

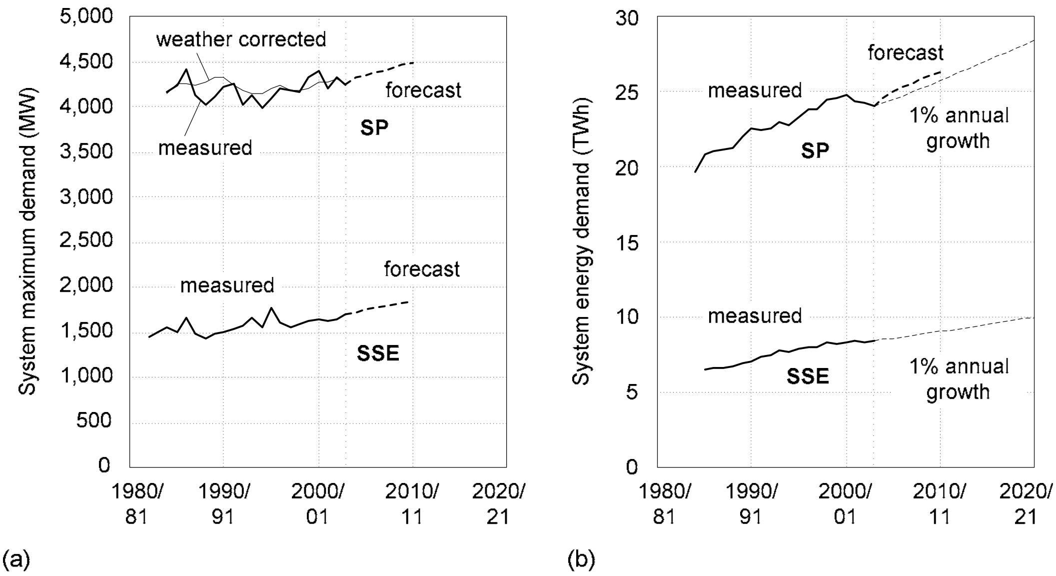


Figure 4.1 System demand in the Scottish Power and Scottish and Southern Energy areas. (a) System maximum demand; (b) System energy demand.

The *apparent* decrease of SP's energy demand is attributed to the increased usage of CHP plants, which locally reduce demand levels and, consequently, the usage of the transmission system. Nevertheless, it is anticipated by SP and SSE that the overall customer demand will rise in the future as indicated by the dashed lines. SSE specifies an underlying growth pattern between 0.5% and 4% per annum. For the development of a scenario for the year 2020, an annual growth rate of *one-percent* was assumed. This led to increases in energy consumption in the SP area from approximately 24 TWh in year 2003-2004 to 28.4 TWh in year 2020-2021. In the SSE area, the corresponding increase was from approximately 8.4 TWh to 10 TWh. Measures to reduce demand were beyond the scope of the study.

By definition, the system *maximum-demand* occurs once per year. In 2003/2004 in the SP area the maximum-demand of 4,227 MW was recorded in the evening of 20th December 2003. In the SSE area the corresponding figure was 1,694 MW on 28th January 2004. The minimum demand for both areas is of the order of 36% of peak demand. The load factor in 2003-2004 was 64.2% for SP and 56.8% for SSE.

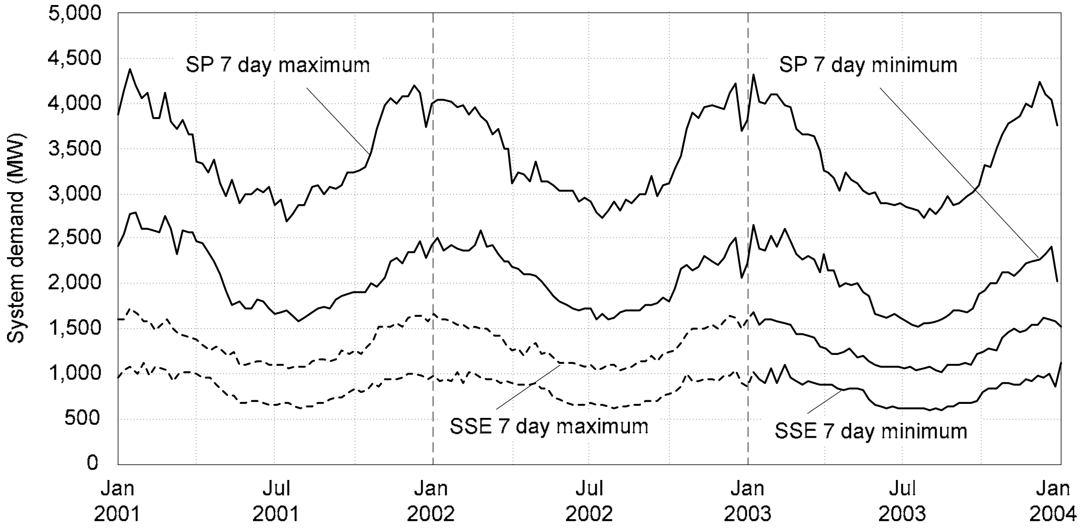


Figure 4.2 Annual load profiles for Scottish Power and Scottish and Southern Energy.
Weekly minima and maxima are shown; the 2001/2002 SSE values were predicted.

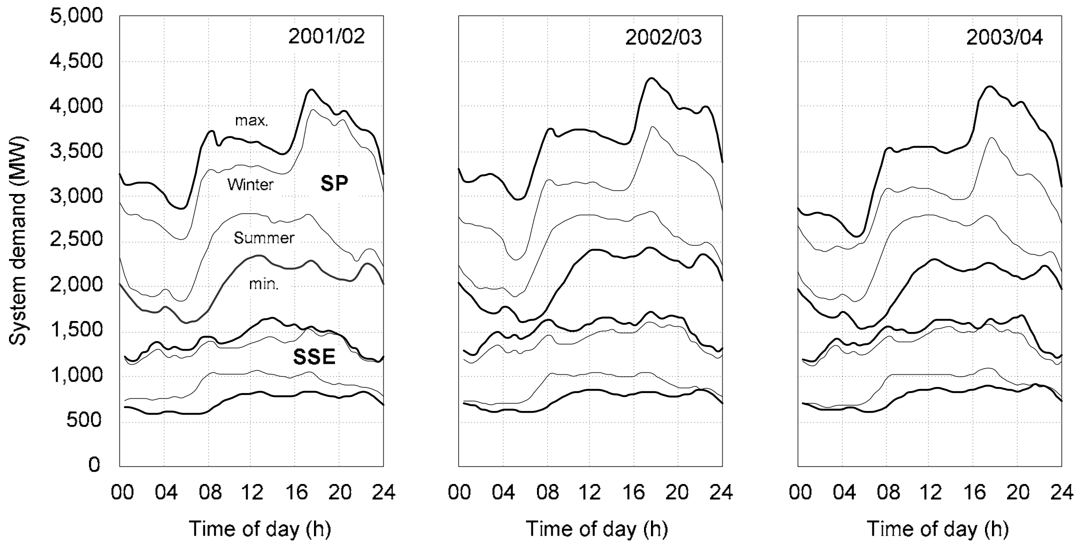


Figure 4.3 Daily load profiles for SP (top four curves) and SSE (lower four curves).
Each figure shows profiles corresponding to days of maximum demand (weekday), average winter demand, average summer demand and minimum demand (weekend).

Demand varies seasonally. In Scotland, the profile is highest in winter due to heating and lighting requirements. Figure 4.2 shows weekly minimum and maximum values within the areas of the two companies. The SSE values for 2001 and 2002 were predicted using the technique described below.

The daily demand profile also varies across the seasons as indicated in Figure 4.3. For each year, profiles are displayed for the days of maximum and minimum demand as well as for typical winter and summer days.

4.2 Demand Modelling

A *grid supply point* (GSP) is an electrical sub-station which connects a *distribution* system to a *transmission* system. It was assumed that all of the renewable-energy generators considered in the context of the study are connected directly to GSPs, and not to some part of the distribution system as *embedded generation*. The GSPs conveniently provide a finite number of nodes for the assessment of both the geographically-specific demands for electricity and the renewable energy supplied within specific areas.

Time-series of load-demands at each GSP are not available in the public domain. SP publishes measured 'maximum transformer loadings' (in MVA) and power factors for its GSPs, along with predicted values for future years. As there is embedded generation within certain parts of the distribution network, the figures cannot be strictly interpreted as demand. SSE publishes winter loads at each GSP which are useful for power-flow applications. In order to take *load diversity* into account, these '100% demands' at each GSP are *not* the measured peak demand but a scaled value. If all of the grid supply-point demand figures are added up, the sum will then just reach or slightly exceed the system maximum demand in the area.

The demand modelling within the study would ideally have used time-series of hourly demand for every GSP in Scotland for the years 2001 through 2003. However, this amount of data would have been excessively large for convenient handling and the electricity utilities are understandably reluctant to release it. It would also have needed exhaustive scanning for errors. Comparison of known individual GSP demand profiles suggested that time-series data from one GSP cannot be applied directly to another GSP if the only correlating information is the maximum demand. The method used in the study was therefore to appropriately scale the overall system demand pattern to each individual GSP. For this purpose, half-hourly system demand data was obtained from SP and SSE. The SP data corresponds to the period 1st April 2002 through 31st March 2004 and the SSE data to the period 1st January through 31st December 2003.

For the 'missing' SSE data corresponding to the period 1st January 2001 through 31st December 2002, the hourly demand was estimated as follows:

- *Monthly demand patterns*: Hourly averages were calculated from the 2003 data for each calendar month for each power company, separately for weekdays and for weekends (including bank holidays), giving a total of two sets of twenty four patterns.
- *Daily minimum and maximum*: The weekly demand *minima* and *maxima* published annually by SP were interpolated to provide daily values by assuming that the minima occurred on Sundays and the maxima in the middle of the weeks. The SSE values for 2001 and 2002 were based on the calculated ratio of the SP and SSE demands for 2003.
- *Daily demand curves*: The monthly demand patterns were assumed to represent the 15th day of each month. For other days, weighted average curves were calculated (separately for weekdays and weekends). The curves were time-shifted so that on weekdays the daily maximum was reached once and on weekends or holidays the minimum was reached.

As a quality check, the daily demand curve predictions for SP and SSE were calculated for the complete three year period 2001 through 2003. This allowed comparison with measured values where they were available. Table 4.1 lists the total energy consumption in the SP area for two complete business years. The predicted values match well both with the published and the measured figures.

Period	Published value	Calculated from measured hourly demand	Calculated from predicted hourly demand
01 Apr 2001 ... 31 Mar 2002	24.309 TWh	not available	24.797 TWh (+2.0%)
01 Apr 2002 ... 31 Mar 2003	24.247 TWh	24.207 TWh (-0.2%)	24.295 TWh (+0.2%)

Table 4.1 Model results for the annual energy consumption in the SP area.

As a further comparison, Figure 4.4 shows measured and predicted demand patterns for four-day, Friday through Monday periods during the winter and summer of 2003.

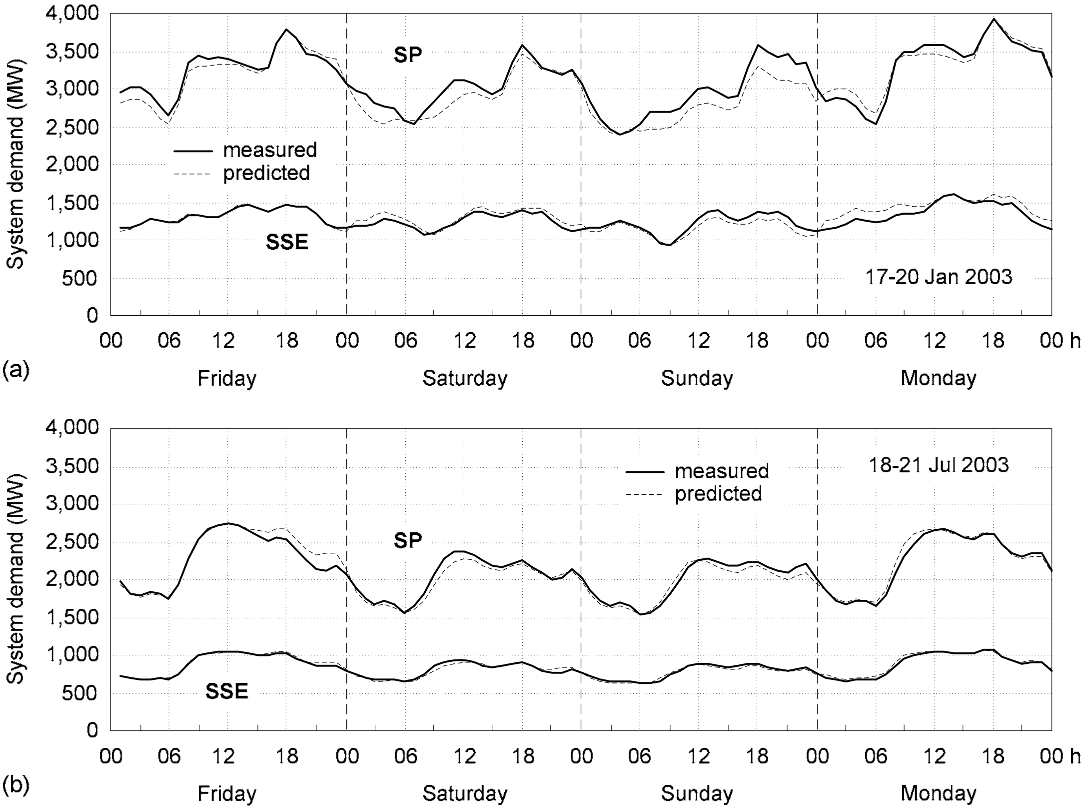


Figure 4.4 Measured and predicted hourly system demand for SP and SSE.
(a) Winter: Friday 17th to Monday 20th January 2003;
(b) Summer: Friday 18th July to Monday 21st July 2003.

The demand values finally used in the study were scaled up from the hourly values in relation to the anticipated load growth corresponding to the year 2020, assuming an annual growth in energy demand of one-percent. This process yielded *scaling factors* of 1.208, 1.196 and 1.184 respectively for the load data from 2001, 2002 and 2003. Scaling the time-series to 2020 predicted a peak power demand of 7.29 GW and an average energy demand of 41 TWh.

5 Energy Delivery Scenarios

A *scenario* based methodology was developed for the study as a means of concisely specifying various mixes of renewable energy sources. The balance between generated and consumed electrical energy is expressed both at a national level and in disaggregated form at area level by a number of key figures. This section of the report describes the analysis methodology in more detail and defines the key figures derived for each scenario.

5.1 Scenario Selection

Scenarios in this study are based on time series of renewable generation and demand. The temporal resolution of these was one hour. The total period of time was limited to three years, mainly because input data for offshore-wind and wave modelling was only available for 4.5 years of which the three full years, 2001 through 2003, were chosen for the time series analysis. Results were derived for each year individually and for the whole period. Due to the importance of seasonal variations in generation and demand, the winter and summer periods were examined separately. In this study the months of December, January and February represent winter, while June, July and August represent summer.

The creation of time series for renewable generation has been described in Section 3 for the four technologies considered. Time series for demand were derived as described in Section 4. These time series were used to compare, on an hour-by-hour basis or over periods of time, the electricity generated from a technology mix with the corresponding load demands. This process is illustrated in Figure 5.1.

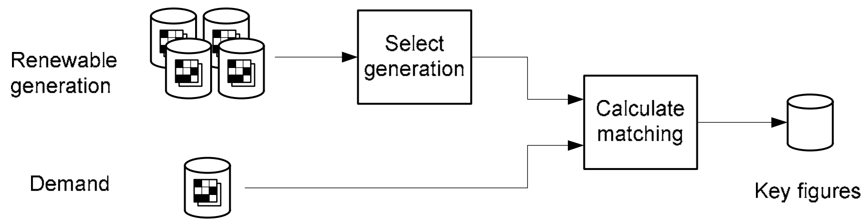


Figure 5.1 Model of scenario development.

Results of this study are presented as a series of scenarios. A scenario is specified by a particular mix of renewable energy sources. The *results* corresponding to each scenario follow from comparisons that are made between the time-series of renewable energy generation and of load demand. They are presented in the form of graphs and tables in Section 6.

Within the scenarios, each technology type was implemented by using incremental *placements* of capacity. The placements were ordered by relative cost rather than by location. However, as *clustering* as well as resource quality was taken into account in the calculation of relative cost, geographically adjacent groups of machines were likely to stay together in the same placement groups. The total plant capacity was increased between scenarios by a factor of two. The starting scenario contained 750 MW of plant with the subsequent ones containing 1.5 GW, 3.0 GW and 6.0 GW. The placements were *cost ranked*, so that in each case, the smaller placements were composed of the generators offering the cheapest energy and were sub-sets of the larger blocks.

Time series for a particular scenario were formed by summing the output of all cells which had been selected on the basis of relative lifetime economics. To examine different aspects of the expansion of renewable electricity generation, two types of scenarios were chosen. These *technology scenarios* and *area scenarios* are described in detail below.

5.1.1 Technology Scenarios

A series of scenarios was chosen to identify the effects and consequences of different mixes of generation technologies. The first group of scenarios was made up of *increasing capacities* of a particular technology, either onshore-wind, offshore-wind, wave, or tidal-current. The second group of scenarios comprised various *mixes* of the four technologies.

Onshore-wind The projected lifetime economics of all feasible onshore-wind developments in Scotland were identified. Detailed results in tabular form are given in Section 6 for the best blocks of 750 MW, 1.5 GW, 3.0 GW and 6.0 GW. To draw graphs indicating trends beyond these capacity limits, a number of further onshore-wind scenarios were made, ranging from 75 MW through to 9.0 GW.

Offshore-wind The capacity and projected lifetime economics of all offshore-wind sites were similarly identified and placed as for onshore-wind. The placements had capacities of 750 MW, 1.5 GW and 3.0 GW. The range of suitable shallow water sites in Scotland suggested that an installation of 6.0 GW would only be feasible with deep-water technology. Therefore no results were calculated at this level. For the presentation of the results in graphical form, some further runs with capacities down to 75 MW were made.

Waves An initial cost analysis determined the estimated lifetime production costs at suitable locations. As wave energy converters need to be arranged in lines facing the wave front, the final placement was done manually. The ranking between cells was then based on the production figures of all the cells with energy converters. Scenarios with 750 MW, 1.5 GW and 3.0 GW of plant were developed. The wave resource is much greater than these numbers would indicate, but due to potential conflicts with navigation it is unknown how much more of the resource can be exploited in areas not fully reported as shipping lanes. The resources may also be greater in real terms than estimated here if the average wind speeds return to customarily higher values than those in the years used to prepare the forecasts. Graphs in Section 6 show an expansion of up to 6 GW.

Tidal-current The number and capacity of tidal-current sites are limited by minimum spring tide velocities of 2 m/s and by the 30 to 50 metre range of water-depths. The fraction of the energy flux that can be exploited without significantly altering the tidal regime depends on the flow characteristics of the channel or sea-area and on the relative 'blockage' to flow caused by turbines. This aspect is likely to be very site specific. In the study, the main placement amounted to 750 MW and this was located manually in the most accessible regions. More tidal-current capacity will become available with later generations of devices that are able to operate in deeper waters. For graphical trend analysis, the capacity was varied from 75 MW through to 1 GW.

Technology mixes Two sets of *mixed portfolios* of generation technologies were also created. The first set comprised the four technologies always in the same relative proportions but with increasing total capacity. As onshore-wind is likely to dominate the renewable energy mix in the near future, it was assigned 75% of the total capacity. By 2020 the amount of installed offshore-wind and wave power plant may still be comparatively small and they were each assigned 10% of the total capacity of the mixes. As the total exploitable tidal-current resource is likely to be smaller than the wind or wave resources, a 5% contribution was assigned to it. Having assigned the *relative* contribution of each technology to the mixes, the *total capacity* was then increased from 750 MW to 6.0 GW in three capacity-doubling steps.

In the second set of mixed portfolio scenarios, the total capacity was kept fixed at 6 GW whilst the proportion assigned to onshore-wind was varied. Thus the contribution of onshore-wind was increased from 0 to 6.0 GW with the balance coming from a 2:2:1 mix of offshore-wind, wave and tidal-current. As with single-technology scenarios, further calculations were made to obtain data for a graphical representation.

Demand For comparison of renewably generated electricity with the load demand, the technology scenarios treated Scotland as a single area. Therefore only one demand time-series was needed for the calculations, the aggregated demand for Scotland. This meant that the SP and SSE three-year time series were added and scaled up to 2020 levels.

Figure 5.2a shows the maximum capacities for each of the four technologies placed: 6.0 GW of onshore-wind, 3.0 GW of offshore-wind, 3.0 GW of wave and 750 MW of tidal-current plant. Each 1 km^2 cell is highlighted to make it more visible. Figure 5.2b shows the corresponding map for area scenarios which are discussed in the next section. More details can be obtained from Maps 10 and 11 in the appendix.

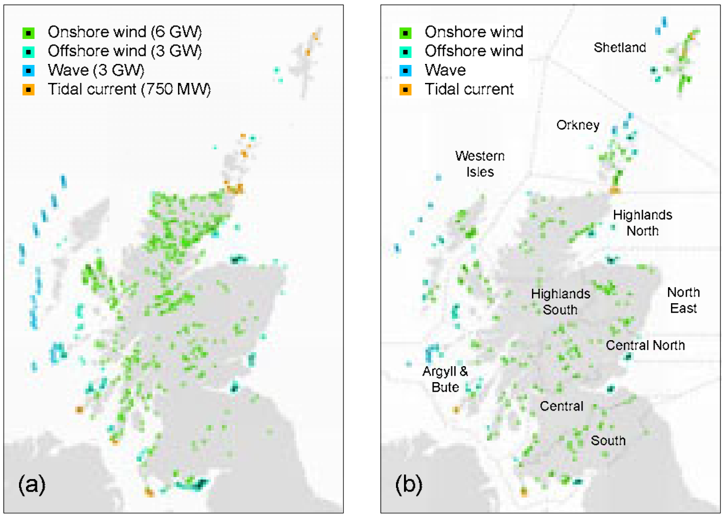


Figure 5.2 Energy converter placement for simulation scenarios.
(a) Technology scenarios; (b) Area scenarios.

5.1.2 Area Scenarios

The second series of scenarios was chosen to assess the regional characteristics of the resources. For the purpose of the study, Scotland was divided into ten areas: *Shetland, Orkney, Western Isles, Highlands North, Highlands South, North East, North Central, Argyll and Bute, Central* and *South*. Some of the boundaries between areas were based on actual boundaries between planning authorities. Where available, Ordnance Survey information was used to determine the sea boundaries between such areas. Another boundary corresponds to the division between the Scottish and Southern Energy area in the north and the Scottish Power area in the south of Scotland.

In principle the generator placements from the technology scenarios could have been used in the calculation of area scenarios. However, some areas might then have been represented by a small number of machines that were known to be amongst the most economic from a national perspective. This could then have led to anomalously high plant capacity-factors being calculated for the local area. To avoid this problem, and as all the areas are similar in size, equal generating capacities were placed in them.

The total capacities of the area scenarios were reduced compared to the technology scenarios. 3.0 GW of onshore-wind, 1.5 GW of offshore-wind, 1.5 GW of waves and 375 MW of tidal-current plant were placed. All areas can accommodate some onshore-wind power plant. Offshore-wind power plants are more likely to appear in the east and south of Scotland. Nevertheless it would technically be possible to develop projects in each area. Therefore 150 MW of offshore wind was placed into each area. In contrast, wave and tidal-current project developments are unlikely to be evenly distributed across Scotland. Wave power developments will most probably be confined to the northern and western areas including Shetland, Orkney, Western Isles and possibly Argyll and Bute. A quarter of the 1.5 GW total wave capacity was identified in each of these four areas. Tidal-current developments are promising in Shetland, Orkney, Highlands North, Argyll & Bute and South. 75 MW of plant was placed in each area, potentially slightly exceeding the exploitable resource in Shetland.

For the final area scenario, the performance of a mixed portfolio of technologies with a 75-10-10-5% split was examined: 4.5 GW of onshore-wind, 600 MW of offshore-wind, 600 MW of wave and 300 MW of tidal-current capacity.

For each area a particular time-series of load demand was applied based on the appropriate daily and annual patterns, from either Scottish and Southern Energy or from Scottish Power.

5.2 Terminology and Graphs

The presentation of results from the scenarios requires the use of specialised terminology and graphics. The following explanations and definitions may be helpful.

5.2.1 Generation and Demand Curves

As an example, Figure 5.3 shows six hours of output from a 40 MW wind farm connected to the network in the vicinity of a town. The wind farm and town are considered to form an area.

During the first hour there is perfect matching of turbine output and town demand. During the following four hours there is a local shortage of renewable energy. Plant connected elsewhere to the network provides the balancing energy. In the last hour production exceeds demand and the network allows electricity to be exported to another area. However, the generated energy is now higher than the network limit and the distribution network operator (DNO) curtails the wind farm output to a value below the rated power of the turbine. Note that for graphical distinction, in Figure 5.3 the average demands during each hour are represented by points which are joined by lines.

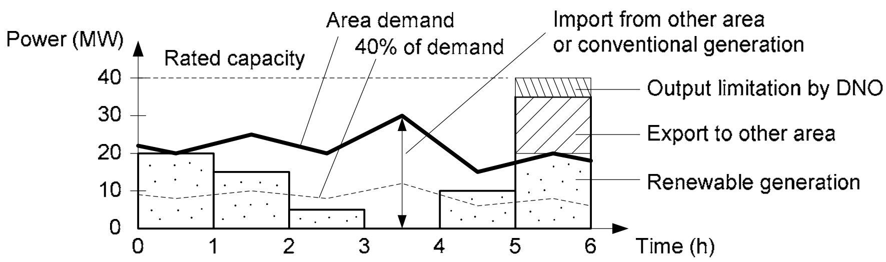


Figure 5.3 Simplified generation and demand curves for a fictitious area.

From the six hours of data some figures can be calculated which help to illustrate the definition of terms which follow:

- Total energy demand = (20 + 25 + 20 + 30 + 15 + 20) MWh = 130 MWh;
- Total renewable energy supply = (20 + 15 + 5 + 0 + 10 + 35) MWh = 85 MWh;
- Local renewable energy supply = (20 + 15 + 5 + 0 + 10 + 20) MWh = 70 MWh;
- Renewable energy export = 15 MWh;
- Renewable energy not supplied (100% target) = (10 + 15 + 30 + 5) MWh = 60 MWh;
- Renewable energy not supplied (40% target) = (3 + 12) MWh = 15 MWh.

5.2.2 Special Terms

Plant capacity factor The plant capacity factor of a generating unit is calculated as the total of the energy generated divided by the nominal or *nameplate* rating and the period of time:

$$Plant\,capacity\ factor\ = \frac{Energy\,supplied}{Rated\,capacity \cdot Period\ of\ time} \cdot 100\%\,. \qquad (5.1)$$

A plant capacity factor of 100% would indicate that the plant was working continuously at its full rating. During the six hours of the example shown in Figure 5.3 a value of 85 / (40 · 6) = 35% is reached. It is important to note that the plant capacity factor of a machine depends on its design and that the most economic plant does not necessarily have the highest plant capacity factor. A plant that is over-rated for the chosen site will have a low plant capacity factor, and a plant that is under-rated will spend longer operating at a capacity limited to the nameplate rating. For each of the four technologies used in the study a particular machine was used throughout, so that its performance at different locations could be compared. However, caution is required when plant capacity factors of different technologies are compared.

Long-term gross matching The ratio of generated and supplied renewable energy to demand gives *long-term gross matching*. For the example of Figure 5.3 a value of 85 / 130 = 65% is reached. Long-term gross matching figures tend to be favourable, as excess of production at a certain hour balances out shortfall at another. The figures are expressed as percentage values and can exceed 100%. A matching of 50% suggests that the total renewable energy produced over the time considered was half of the electrical energy supplied in that region. The stricter approach of using *long-term local matching*, as described below, was used in the study.

Long-term local matching The long-term local matching of an aggregated group of generators was calculated as the total of the renewably-generated energy that is used to satisfy local demand divided by the total energy demanded in that area:

$$Long-term\ local\ matching\ = \frac{Local\,energy\,supplied}{Energy\,demand} \cdot 100\%\,. \qquad (5.2)$$

For the example of Figure 5.3, the long-term local matching reduces to 70 / 130 = 54%. This definition emphasises the shortfall in energy required locally to meet demand and therefore was used throughout the study.

Energy export When renewable electricity production exceeds local demand, then the excess must be exported to other areas or the output of the machines must be reduced. In the example of Figure 5.3 there is one such hour requiring export. Relative to the total energy demand, the amount of exported energy is 15 / 130 = 12%. Note that this figure is the same as the difference between gross and local matching (with the discrepancy of 1% arising from the presentation of the results in integer format).

Output limitation With increasing penetration of renewable generators it is possible that at times the network operator may have to limit the plant output. In the present study, the network was assumed to be ideal and output limitation was not implemented.

Energy shortfall Shortfall is expressed as the percentage of total energy demand in any locality that is not supplied by the corresponding renewable-energy generators:

$$Energy\ shortfall\,(target\ \%) = \frac{Energy\ not\ supplied\,(target\ \%)}{Energy\ demand} \cdot 100\% \,. \tag{5.3}$$

When the *target demand level* to be supplied by renewable generators is 100%, then the sum of *energy shortfall* and *long-term local matching* add up to 100%. In the example of Figure 5.3, the energy shortfall (with 100% demand target) is 60 / 130 = 46%. This amount of energy must be supplied by other generators connected to the network. Had no renewable energy been produced at all during the six hours, then the energy shortfall would be 100%.

Within this study, a supply target of 40% of demand was used and figures are calculated relative to this:

$$Energy\ shortfall\,(40\%\ target) = \frac{Energy\ not\ supplied\,(40\%\ target)}{Energy\ demand} \cdot 100\% \,. \tag{5.4}$$

With the values from Figure 5.3, the energy shortfall (with 40% demand target) is now 15 / 130 = 12%. Despite the high long-term local matching value of 54% there is still this amount of energy which could not be supplied by the renewable generators to meet the 40% target on an hour-by-hour basis. Had no renewable energy been produced at all during the six hours, then the corresponding energy shortfall would be 40%.

Exceedance hours When energy shortfall is calculated on an hour-by-hour basis then the *absolute* hourly energy amounts can be represented in an *exceedance curve* as energy exceedance or shortfall against percentage of time.

In some cases it may be useful to know the number of hours when production exceeds a certain level of demand. In the example of Figure 5.3, 100% of demand is reached or exceeded for 33% of the time, 40% of the demand is exceeded for 67% of the time. For the scenarios in Scotland, the number of hours when the 40% demand level is exceeded was calculated and expressed as a percentage of time.

Coincident hours A long-term local matching value of 50% achieved with renewable energy sources suggests that the total renewable energy produced over a particular season or year is equal to half of the electrical energy consumed within the area. During any shorter time period, the generated energy could be well above or well below the local demand. The use of a single numerical value for matching masks this important information. It is therefore useful to present the statistics of matching in the form of a *coincident-hours* histogram which is an extension of the exceedance hours concept.

As the time series of six hours in the example in Figure 5.3 above is too short to produce a histogram, data from actual scenarios (with 26,280 time steps) is used to illustrate the concept. Figure 5.4a shows an idealised coincident-hours histogram for an imaginary situation where generated and demanded energy are always in balance. Each column in this bivariate histogram represents the relative amount of time during which a particular combination of generation *as a percentage of total capacity* and demand *as percentage of peak demand* is true. The combined heights of all of the columns represent 100%. On the diagonal of green columns capacity-factors and load-factors are matched (to within a 10% tolerance band). The blue area represents times when demand percentage is less than generation percentage and the red area represents times when it is higher. Note that if demand and generation axes were scaled to the same maximum value in MW, then the diagram would look different.

A different situation is illustrated by the coincident-hours histogram of Figure 5.4b for a 6 GW renewable mix across Scotland. Note that the height scale of the columns in both diagrams is different. It can be seen that demand never falls below approximately 30 % of its peak value. Generation, in contrast, varies between zero and total nameplate rating. The number of columns makes it somewhat difficult to compare scenarios, but the extremes are of greater concern. For example, the hours when generation is less than 10% of capacity *and* demand exceeds 90% of its peak value. This value is represented by the small red column at the very right of Figure 5.4b. Due to its importance, this *worst-case coincident hours* figure is listed in the spreadsheets of Section 6.

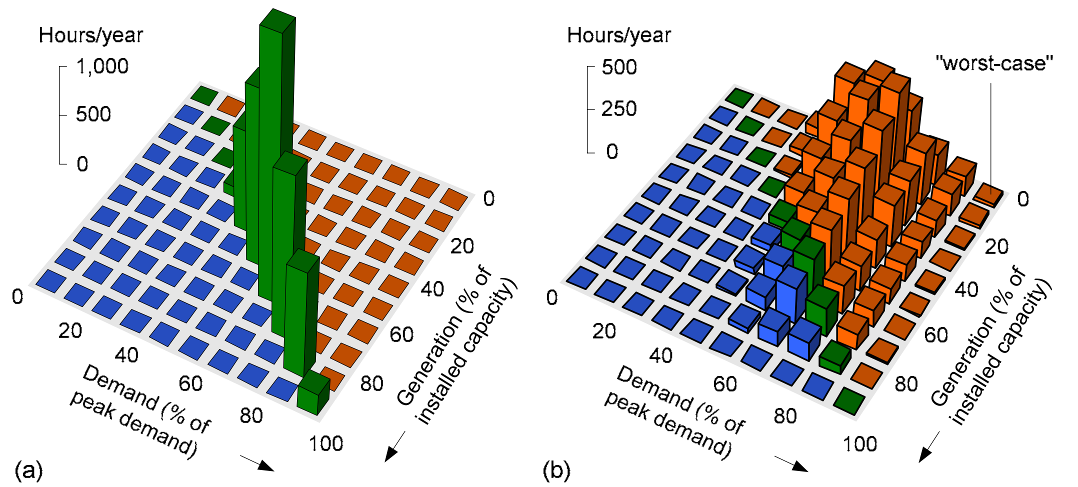


Figure 5.4 Coincident-hours histograms.
(a) Imaginary situation where generation and demand are always matched;
(b) Scenario with 6 GW broad-mix of technologies.

Power output variability Other statistical information that can be extracted from the data includes the *rate of change* of power output. When renewable output power reduces, for instance because the wind calms down, then balancing plant needs to be brought online. Likewise, the output of balancing plant can be reduced or the plant can be taken offline when enough renewable generation is available. Forecasting and system monitoring allow dispatching centres to act on these events, provided that spare balancing plant is available with output that can be changed at the required rate. The probability of a certain change of renewable output power (as a percentage of installed capacity) can be displayed in form of a histogram. For instance, a high-wind cut-out of a wind turbine represents a -100% change while a subsequent cut-in at strong winds can create a +100% change. An important parameter of the power output variability is the time difference between the two observations. Two different calculations were made in this study, one with a one hour time lag and another with a six hour time lag. The one hour results need to be interpreted with caution since the offshore wind and wave data originated from three-hourly records with interpolations in between. However, detailed time series analysis of wave power records suggests that there is little change from one hour to the next. Example histograms are shown in Section 6.3.

6 Results and Discussion

The numerical results of the six *technology scenarios* (four individual technologies and two mixed portfolios) and the five *area scenarios* are presented as three spreadsheets. The placement of devices and the division of Scotland into ten areas is shown on Maps 10 and 11.

6.1 Technology Scenarios

The numerical results from the technology scenarios are shown in Spreadsheet 1 which should be referred to throughout this section. The technology scenarios are referred to as *Tech 1* to *Tech 6* with suffixes *a* through *e* denoting increasing capacity in each scenario.

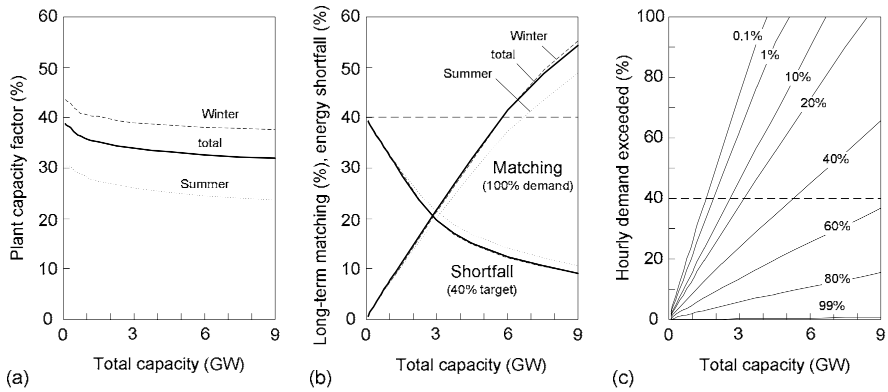


Figure 6.1 Example of key indicator graph (from Tech 1, onshore-wind).

A figure made up of three separate graphs is used to illustrate each of the technology scenarios. The figure above is shown here as an example. The horizontal axis used in each of the three graphs is always the same and shows increasing capacity of renewable plant. In certain cases, the maximum total capacity value shown on the graphs is greater than the corresponding figure on the Spreadsheet 1 to extend the view for trend analysis.

The left hand graph shows plant capacity factor, separated into curves for winter, summer and for the year as a total. These are all based on average values from the years 2001, 2002 and 2003.

The centre graph shows both long-term local matching and energy shortfall, as defined in Section 5.2.2. Note that the figures are not arithmetically complementary. Matching is shown relative to 100% of demand while shortfall is calculated relative to a 40% target.

The graph on the right may be used to read off a value for hourly 40% demand exceedance as follows. Choose a renewable capacity value from the horizontal axis and find its intercept with the dashed horizontal 40% line. Estimate the percentage exceedance time by interpolation from the family of lines that radiate from lower left. This means for example that 6 GW of plant would produce hourly power levels that exceed 40% of demand for around 45% of the time. A horizontal line is only drawn for the 40% case, but any other value could be used for comparison.

Spreadsheet 1 Technology scenario results.

Number	Area	Technology	Onshore wind	Offshore wind	Wave	Tidal current	TOTAL	Demand	Plant capacity factor						Long-term local matching						Energy shortfall (40% target)			Time when 40% of demand is exceeded			Coincident hours ❶	Energy export ❷
			MW	MW	MW	MW	MW		%						%						%			%			h	%
								❸	Su	Wi	01	02	03	total	Su	Wi	01	02	03	total	Su	Wi	total	Su	Wi	total	total	total
Tech 1a	Scotland	Onshore wind	750	0	0	0	750	Scotland total	29.0	40.8	35.5	37.1	36.2	**36.3**	5.6	5.6	5.5	6.0	6.0	**5.8**	34.4	34.4	**34.2**	0.0	0.0	**0.0**	29.7	0.0
Tech 1b	Scotland	Onshore wind	1500	0	0	0	1500	Scotland total	27.4	40.3	34.4	36.1	35.1	**35.2**	10.6	11.0	10.7	11.7	11.6	**11.3**	29.4	29.0	**28.7**	0.2	0.0	**0.0**	29.7	0.0
Tech 1c	Scotland	Onshore wind	3000	0	0	0	3000	Scotland total	26.0	39.0	33.1	34.8	33.7	**33.9**	20.2	21.3	20.6	22.5	22.3	**21.8**	21.4	19.7	**19.7**	13.4	16.1	**17.1**	28.3	0.0
Tech 1d	Scotland	Onshore wind	6000	0	0	0	6000	Scotland total	24.5	38.2	32.0	33.7	32.5	**32.7**	37.2	41.4	39.4	43.0	42.1	**41.5**	14.1	12.2	**12.4**	37.6	47.2	**44.6**	28.7	0.6
Tech 2a	Scotland	Offshore wind	0	750	0	0	750	Scotland total	20.9	46.5	32.3	35.3	34.7	**34.1**	4.1	6.4	5.0	5.7	5.7	**5.5**	35.9	33.6	**34.5**	0.0	0.0	**0.0**	20.3	0.0
Tech 2b	Scotland	Offshore wind	0	1500	0	0	1500	Scotland total	22.1	47.8	34.1	36.8	35.3	**35.4**	8.6	13.0	10.6	11.9	11.6	**11.4**	31.4	27.0	**28.6**	0.0	0.0	**0.0**	15.0	0.0
Tech 2c	Scotland	Offshore wind	0	3000	0	0	3000	Scotland total	22.6	48.1	34.6	37.2	35.5	**35.8**	17.5	26.3	21.6	24.0	23.5	**23.0**	23.4	15.1	**18.4**	8.7	23.9	**17.8**	13.7	0.0
Tech 3a	Scotland	Wave	0	0	750	0	750	Scotland total	17.6	48.6	32.6	35.1	32.5	**33.4**	3.4	6.6	5.1	5.7	5.4	**5.4**	36.6	33.4	**34.6**	0.0	0.0	**0.0**	20.7	0.0
Tech 3b	Scotland	Wave	0	0	1500	0	1500	Scotland total	17.5	48.6	32.4	35.1	32.4	**33.3**	6.8	13.3	10.1	11.3	10.7	**10.7**	33.2	26.7	**29.3**	0.0	0.0	**0.0**	20.7	0.0
Tech 3c	Scotland	Wave	0	0	3000	0	3000	Scotland total	16.5	46.7	30.7	33.9	30.5	**31.7**	12.8	25.5	19.1	21.9	20.2	**20.4**	27.7	15.4	**20.4**	6.3	16.9	**12.1**	19.0	0.0
Tech 4a	Scotland	Tidal current	0	0	0	750	750	Scotland total	29.7	29.7	30.5	30.0	29.6	**30.0**	5.7	4.1	4.7	4.8	4.9	**4.8**	34.3	35.9	**35.2**	0.0	0.0	**0.0**	22.0	0.0
Tech 5a	Scotland	Mix, 750 MW	570	75	75	30	750	Scotland total	27.8	42.8	35.4	37.5	36.4	**36.4**	5.4	5.8	5.5	6.0	6.0	**5.9**	34.6	34.2	**34.1**	0.0	0.0	**0.0**	17.3	0.0
Tech 5b	Scotland	Mix, 1500 MW	1125	150	150	75	1500	Scotland total	27.1	42.2	34.8	36.8	35.7	**35.8**	10.5	11.5	10.8	11.9	11.8	**11.5**	29.5	28.5	**28.5**	0.0	0.0	**0.0**	17.0	0.0
Tech 5c	Scotland	Mix, 3000 MW	2250	300	300	150	3000	Scotland total	26.0	41.3	33.8	35.7	34.6	**34.7**	20.1	22.6	21.0	23.1	22.9	**22.3**	20.9	18.2	**18.7**	10.9	14.0	**14.5**	18.0	0.0
Tech 5d	Scotland	Mix, 6000 MW	4500	600	600	300	6000	Scotland total	24.5	40.2	32.7	34.5	33.2	**33.5**	37.6	43.8	40.5	44.3	43.4	**42.7**	12.4	9.7	**10.4**	37.6	51.4	**46.4**	20.0	0.3
Tech 6a	Scotland	Mix, 0-40-40-20%	0	2400	2400	1200	6000	Scotland total	20.5	42.8	31.3	33.4	31.3	**32.0**	31.7	46.8	38.9	43.0	41.2	**41.0**	13.4	6.0	**8.8**	27.3	60.8	**45.6**	8.7	0.1
Tech 6b	Scotland	Mix, 12.5-35-35-17.5%	750	2100	2100	1050	6000	Scotland total	22.0	43.1	32.3	34.3	32.4	**33.0**	33.9	47.1	40.1	44.2	42.7	**42.3**	12.1	6.2	**8.4**	30.9	61.2	**47.7**	8.0	0.1
Tech 6c	Scotland	Mix, 25-30-30-15%	1500	1800	1800	900	6000	Scotland total	22.9	43.1	32.8	34.8	33.1	**33.6**	35.3	47.0	40.8	44.8	43.5	**43.0**	11.5	6.6	**8.3**	34.1	60.5	**48.9**	8.7	0.1
Tech 6d	Scotland	Mix, 50-20-20-10%	3000	1200	1200	600	6000	Scotland total	24.1	42.0	33.1	35.0	33.6	**33.9**	37.1	45.8	41.1	45.0	44.1	**43.4**	11.4	7.8	**9.0**	36.5	56.1	**48.2**	12.3	0.2
Tech 6e	Scotland	Mix, 100-0-0-0%	6000	0	0	0	6000	Scotland total	24.5	38.2	32.0	33.7	32.5	**32.7**	37.2	41.4	39.4	43.0	42.1	**41.5**	14.1	12.2	**12.4**	37.6	47.2	**44.6**	28.7	0.6

Notes: ❶ Coincident hours are given for demand ranging from 90% to 100% of peak demand and generation ranging from 0% to 10% of installed capacity, in hours per year; ❷ Amount of total electricity that would have to be exported, relative to area demand; ❸ Su = summer, Wi = winter, 01 = 2001, 02 = 2002, 03 = 2003, total = 2001-2003.

6.1.1 Tech 1: Onshore-wind

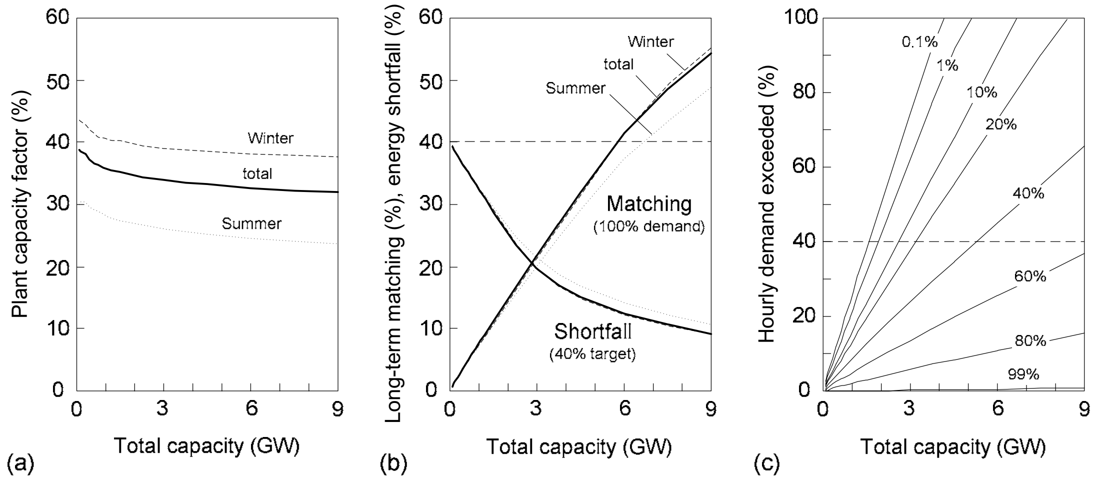


Figure 6.2 Onshore-wind, key indicators.

For the results shown in Spreadsheet 1, up to 6 GW of onshore-wind plant was placed in four stages. The best 750 MW was placed first, followed by three doublings of capacity up to a total of 6 GW and beyond. For the graphs shown in Figure 6.2, the range was extended from 75 MW up to 9 GW. The available land area and wind climate in Scotland could produce more than this total. Experience from Denmark suggests a maximum socially acceptable density of development of 150 kW/km^2. Such a level of development in Scotland would be equivalent to a maximum capacity of around 11.5 GW.

The *plant capacity factors* of the wind-turbines averaged over the three years 2001-2003, begin at a high of 36.3% for the first 750 MW of capacity, progressively falling to 32.7% for the entire 6 GW placement, as sites of lesser merit are included (Figure 6.2a). These capacity-factors for Scotland compare very favourably with typical European and global figures for wind turbines and not surprisingly show higher figures in winter compared with summer. The small downward slope of the curves suggests that there are many more sites suitable for economic exploitation.

The corresponding *long-term local matching* values start at 5.8% for 750 MW of placement and progressively increase to 41.5% of overall Scottish electrical demand for the 6 GW placement. From the 'matching' curve of Figure 6.2b it can be seen that to achieve a long-term match between only the onshore-wind resource and electricity demand, nearly 6 GW of capacity would need to be installed by 2020. The demand matching figures are very similar across the whole of each year and there is an inherent matching of onshore-wind production with Scottish demand across all seasons.

It must be emphasised that this does not imply that 6 GW of onshore-wind generating plant could supply the hour-by-hour demand at all times. There will be many hours when production is less than 40% of electricity demand. From the energy shortfall curve of Figure 6.2b it can be seen that 6 GW of onshore-wind would still leave a *shortfall* of 12.4% of total demand (or slightly less than a third of the 40% target). The hourly demand exceedance curves of Figure 6.2c show that 6 GW of onshore-wind plant would meet or exceed the 40% target for 44.6% of the time. For the remainder of the time, balancing energy would be required from dispatchable plant to meet the 40% target.

The results suggest that less than 6 GW of onshore-wind plant could, on average, supply 40% of the electricity demand in Scotland.

6.1.2 Tech 2: Offshore-wind

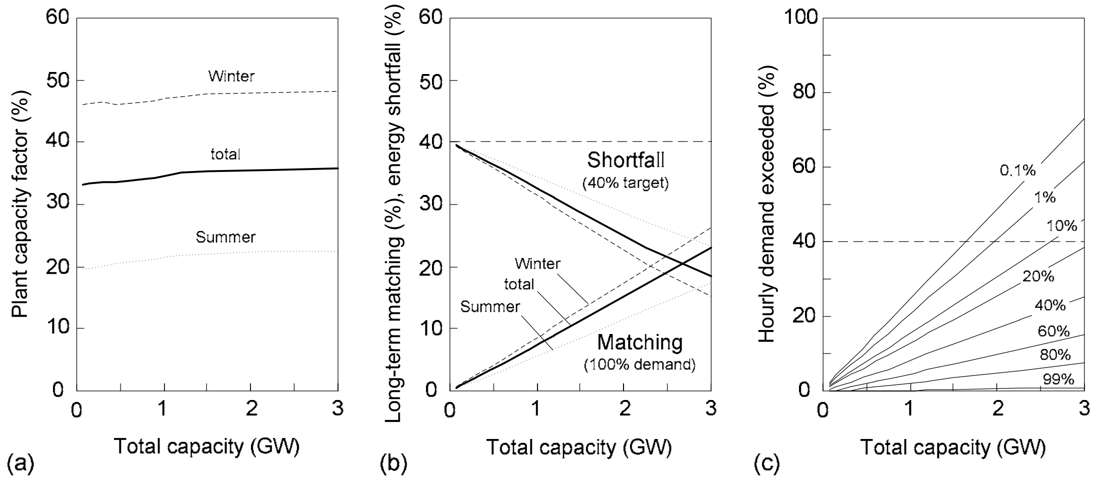


Figure 6.3 Offshore-wind, key indicators.

Up to 3 GW of offshore-wind plant was placed in three stages. The best 750 MW was placed first, followed by two doublings of capacity. Based on current technologies, the maximum water depth for installation was 40 m and the machines were sited at least 5 km offshore. Most of the suitable sites were found in east and south-west coastal areas and estuaries. There are likely to be fewer offshore-wind than onshore-wind projects, but individual offshore farms will be larger in terms of total capacity.

On Spreadsheet 1, the *plant capacity factors* of the offshore-wind-turbines averaged over the three years 2001 through 2003, begin at 34.1% for the best 750 MW and increase to 35.8% for the complete 3 GW placement. This small increase of capacity factor is due to higher wind resource sites in the north and west becoming *economically* feasible despite higher foundation and grid connection costs. Because of the differences in machines that are used onshore and offshore, these figures should not be directly compared. Nevertheless they highlight the attractiveness of the offshore resource from an energy generation point of view. The difference between summer and winter plant capacity factors is more pronounced at sea than over land.

The *long-term local matching* values start at 5.5% for 750 MW placement and progressively increase to 23.0% of overall Scottish electrical demand for the 3 GW placement. Offshore-wind plant with 1.5 GW capacity could *on average* provide 11.4% of total demand which is similar to the 11.3% from the same capacity of onshore-wind plant.

Again, this capacity of offshore-wind generating plant will not be able to supply the hour-by-hour demand at all times of the year. 3 GW of plant would leave a *shortfall* of 18.4% of total demand (or a little less than half of the 40% target). The exceedance curves in Figure 6.3c show that 3 GW of plant would exceed the 40% level for about 17.8% of the time.

Even though shallow-water sites are not abundant in Scotland, 3 GW of offshore-wind plant could be developed. This capacity would, on average, supply 23% of the electricity demand in Scotland.

6.1.3 Tech 3: Wave

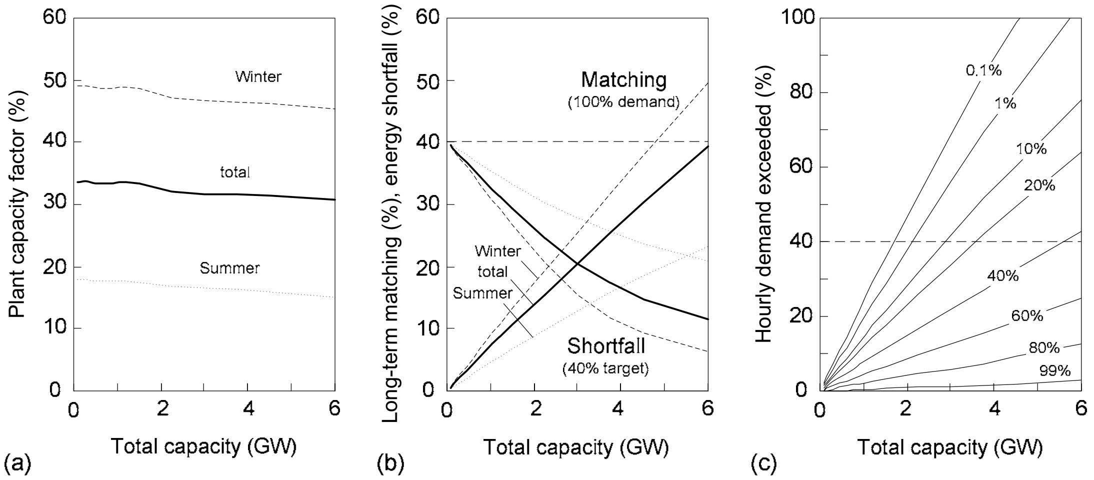


Figure 6.4 Wave, key indicators.

For the results shown in Spreadsheet 1, up to 3 GW of wave energy plant was manually placed in three stages, starting with the best 750 MW followed by two doublings of capacity. For the graphs shown in Figure 6.4, the range was extended up to 6 GW. The overall capacity is *not* resource limited, but the plant totals are based on conservative estimates of the amount of plant that might be installed by 2020.

Referring to the values shown in Spreadsheet 1, the *plant capacity factors* averaged over the three years 2001 through 2003, begin at 33.4% for the best 750 MW and fall to 31.7% for the full placement of 3 GW, as less economic sites are added. The differences between summer and winter plant capacity factors are far more pronounced than for either onshore-wind or offshore-wind, a pattern that is consistent over the three years. The figures show that wave power plants are especially suited to supply electricity during winter months but will produce well below average during summer months.

Consequently, the *long-term local matching* is generally a factor of two better in winter than in summer, as shown Figure 6.4b. The long-term local matching values start at 5.4% for the 750 MW placement and progressively increase to 20.4% of overall Scottish electricity demand for the 3 GW placement.

Appraisal of the hour-by-hour matching shows that 3 GW of wave energy plant would leave a *shortfall* of 20.4% of total demand (or half of the 40% target). Figure 6.4c shows that with such a capacity the 40% level would be exceeded for 12.1% of the time.

The characteristics of the wave energy converters were projected from existing first generation devices. The wave power levels calculated from the resource data for the years 2001 through 2003 (and thus the calculated output of the energy converters) are believed to be below the longer term averages.

The results suggest that 3 GW of wave energy plant could, on average, supply around 20% of the electricity demand in Scotland.

6.1.4 Tech 4: Tidal-current

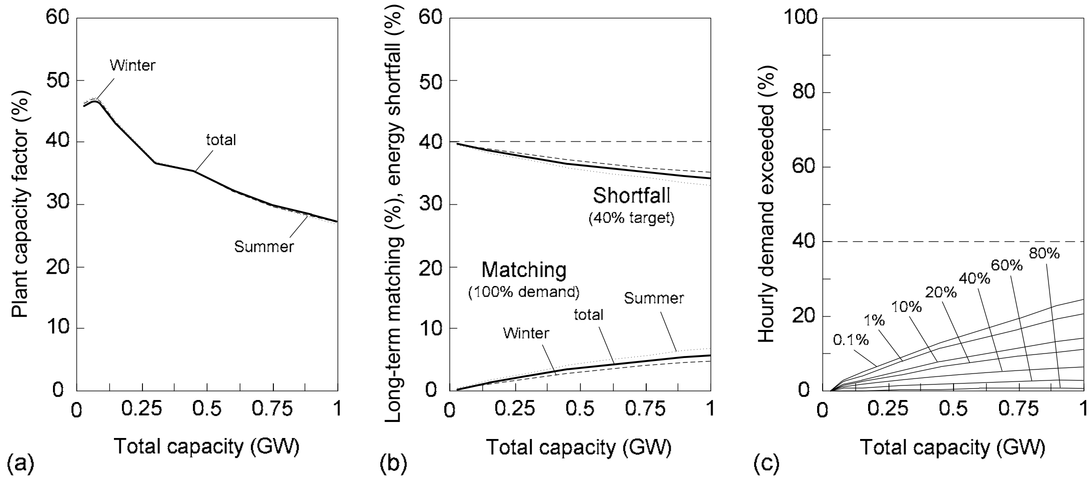


Figure 6.5 Tidal-current, key indicators.

For the results shown in Spreadsheet 1, 750 MW of tidal-current plant was placed manually. For the graphs of Figure 6.5, the range was extended up to 1 GW. The relatively modest tidal-current energy contribution in the study reflects the difficulty in finding sites with spring velocities of at least 2 m/s in water depths around 40 m. Further, first generation device technology was used to assess this potential, with an upper limit on channel energy extraction of about 10%. Further research may show that machines could be packed more densely in some places.

The *capacity factors* of 750 MW plant averaged over the three years 2001 through 2003 produce a figure of 30.0%, as shown in Figure 6.5a. The capacity factors are essentially the same in summer and winter. These are very high for the best sites in the Pentland Firth, but the steep slope of the curve in Figure 6.5a indicates that the number of "prime" sites is limited Once accurate measurements have been made, the tidal-current resource at any potential site will be almost entirely predictable. It should therefore be possible to configure optimal generating plant for any particular location.

Spreadsheet 1 and Figure 6.5b show that the *long-term local matching* value of the 750 MW placement is 4.8% of overall Scottish electricity demand. This number is small in the national context but regionally it could make a contribution exceeding the 40% level.

The hourly production of 750 MW of tidal-current plant would leave a *shortfall* of 35.2% of the total demand (or about 7/8 of the 40% target). This capacity is too small to reach the 40% demand level at any time of the year.

The tidal current resources were evaluated using machines based on first-generation shallow water devices and this has identified a relatively small number of good locations. More detailed measurements and modelling are needed to improve the accuracy of the results. While the phasing of tidal power delivery varies around the coastline, the opportunity to exploit phase differences is limited by the difficulty of finding suitably energetic sites whose patterns are complementary.

The results suggest that the completely predictable output of 750 MW of tidal-current plant could, on average, supply about 5% of the electricity demand in Scotland.

6.1.5 Tech 5: Mix with 75% Onshore-wind

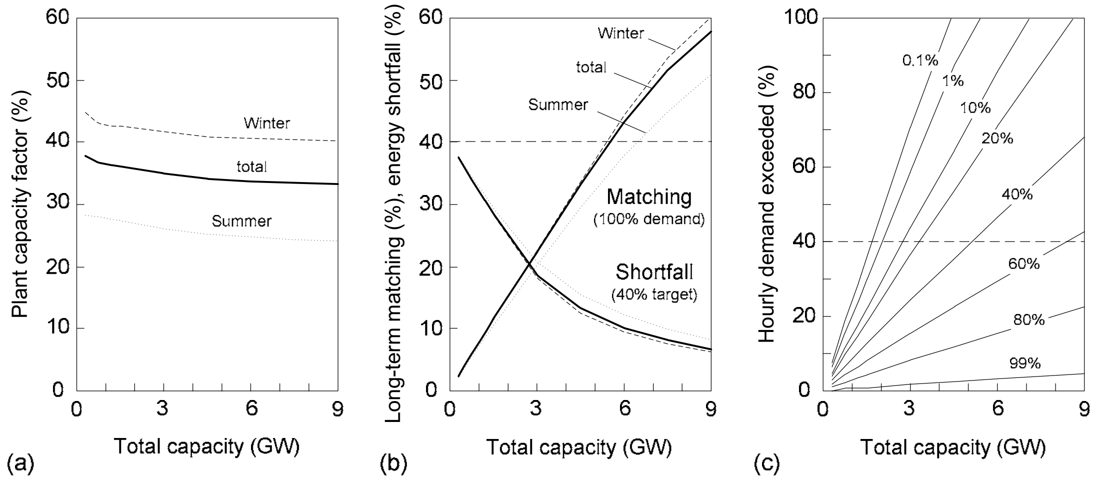


Figure 6.6 75-10-10-5% mixed portfolio, key indicators.

The first mixed portfolio scenario developed renewable-generating capacity with the relative contributions of each technology held constant at 75-10-10-5%, for onshore-wind, offshore-wind, wave and tidal-current respectively. For the results summarised in Spreadsheet 1, the total capacity was increased in four stages, starting with the best 750 MW followed by three doublings of capacity up to a total of 6 GW. For the results shown graphically in Figure 6.6 the total capacity was extended up to a maximum of 9 GW to illustrate trends. Note that there is a slight deviation from the given percentages in the 750 MW case to include integer numbers of 1 km^2 cells for each technology (Spreadsheet 1). Because of the chosen weighting, the simulation results in Figure 6.6 resemble those for onshore-wind alone.

In Spreadsheet 1, the *plant capacity factor* averaged across the plant portfolio for the three years 2001 through 2003, begins at 36.4% for the best 750 MW of mixed capacity, falling to 33.5% for the 6 GW as poorer sites are included.

The corresponding *long-term local matching* values start at 5.9% for 750 MW placement and progressively increase to 42.7% of overall Scottish electrical demand for the 6 GW placement. From Figure 6.6b it can be seen that to achieve a long-term local match between the mixed resource and electricity demand, about 5.5 GW of mixed capacity would need to be installed by 2020.

A mixed capacity of 6 GW would leave a *shortfall* of 10.4% of total demand (or one quarter of the 40% target). The 40% demand level would be exceeded for 46.4% of the time. This is a slight improvement compared with onshore-wind plant of the same capacity (Spreadsheet 1).

These findings accord with the projections of the FREDS Future Generation Group Report (Scottish Executive 2005) which identified a need for a total of 6 GW of renewable capacity to achieve the 40% target.

The results suggest that around 5.5 GW of mixed technologies plant could, on average, supply 40% of the electricity demand in Scotland. Existing and planned hydro and biomass plant will reduce the amount of capacity that would need to be installed from the four technologies considered.

6.1.6 Tech 6: Variable Mix

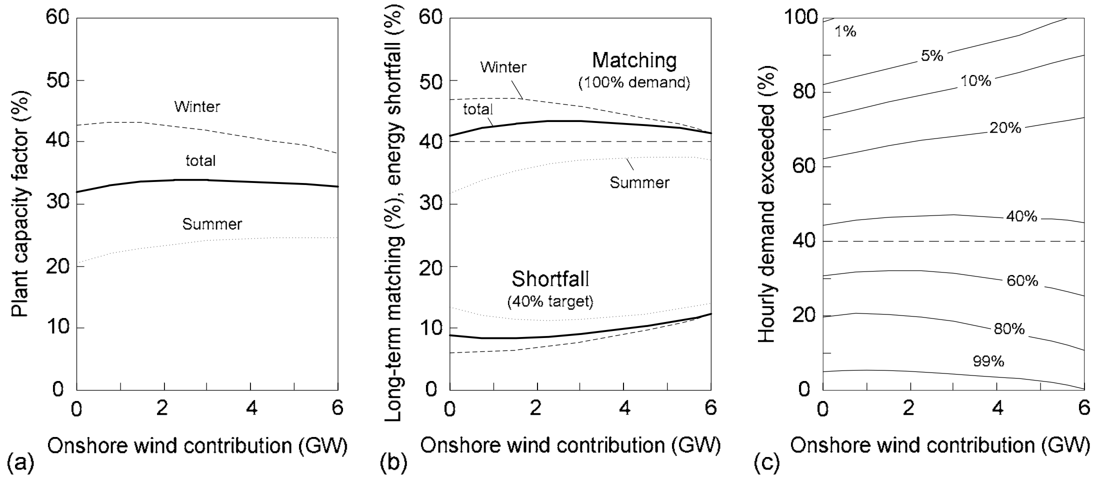


Figure 6.7 Variable-mix portfolio, key indicators.

Compared with the previous mixed-portfolio scenario, the combined capacity of the *Tech 6* portfolios were held constant at 6 GW whilst the relative proportion that is contributed by onshore-wind was varied from 0 up to 100% (0 MW, 750 MW, 1.5 GW, 3 GW and 6 GW) so as to give it increasing prominence in the mix. The balance of the renewably generated electricity from offshore-wind, wave and tidal-current was held in a fixed 2:2:1 ratio. The maximum contributions from these sources were therefore 2.4 GW, 2.4 GW and 1.2 GW respectively.

Note that the horizontal axis of Figure 6.7 is labelled as 'Onshore wind contribution'. The left side of each graph therefore corresponds to a mix of 2.4 GW offshore-wind, 2.4 GW wave and 1.2 GW tidal-current, with no contribution from onshore-wind. The right side of each graph corresponds to 6 GW of onshore-wind with no contribution from the other technologies. Compared with the previous graphs in this section, it is important to emphasise that the *total* installed renewable generating capacity remains constant in Figure 6.7.

The *plant capacity factor* in Figure 6.7a is given for comparison with previous results. The annual values are rather constant over the whole range of onshore wind capacities. To achieve higher values in summer it is useful to have a high onshore-wind capacity. The result is similar for *long-term matching*. The optimum may be reached with an onshore-wind contribution of about 3 GW. The *shortfall* curve and the exceedance hours both suggest that the hour-by-hour matching is better with a lower contribution of onshore-wind, e.g. only 1.5 GW. Figure 6.7c shows that lower levels of demand are more often exceeded with lower onshore-wind contribution while higher demand levels are more often exceeded with higher onshore-wind contribution. For example, a demand level of 10% (on the y-axis) is exceeded for about 92% of the time with no onshore-wind in the mix and for about 81% of the time with 6 GW of only onshore-wind. A demand level of 80% (on the y-axis) is exceeded for about 6% of the time with no onshore wind and for about 16% of the time with 6 GW of onshore-wind.

The results suggest that overall performance to meet demand targets could be optimised in a balanced generation mix.

6.2 Area Scenarios

Spreadsheets 2 and 3 list the results for the area scenarios. There is one scenario for each individual technology and one scenario for a renewable plant mix. Results are listed for each area which has an exploitable resource and for the resulting total capacity across Scotland. Demand is the aggregated hourly demand within the area. For comparison the table also lists average and peak demand in the area. As explained in Section 4, the demand time series were derived from the Scottish and Southern Energy (SSE) and the Scottish Power (SP) area demands and not from individual grid supply points within each area. Results are rounded to whole numbers since the area scenarios are based on further assumptions compared to the technology scenarios. Otherwise the spreadsheets are organised exactly as the one for technology scenarios above.

In the technology scenarios, plant placement was determined by cost ranking across Scotland, so that the most attractive sites were always developed first. As a result, each of the four technologies was unevenly spread across the ten areas of the study. The five area scenarios provide an opportunity to compare the performance of each of the four technologies geographically by forcing machines to be assigned to areas regardless of how their economic performance in that area compares with the national averages.

The nominal capacities of plant that were placed in each area should not be taken as an indication of the regional potentials or indicative of limits.

6.2.1 Area 1: Onshore-wind

The most economic 300 MW of plant was identified separately in each area. To allow plants to connect to a grid supply point in the area, one future GSP was assumed on Shetland and one on Orkney. On the Western Isles there already exists a single high-voltage transmission line from Harris to Stornoway, but connection to the mainland is at lower voltage.

The overall plant capacity factor for Scotland is 35% which compares to 33.9% in the 3 GW technology scenario. The increase stems from the inclusion of more energetic sites on the islands, Shetland notably with 44%. In all areas with good exposure to western winds the capacity factor is in the upper thirties. The eastern areas exhibit the lowest figures although these are still high compared to central Europe. The long-term matching depends on the demand in the area. Highlands South (SSE area) and South (SP area) have similar demand levels. The peak demand is ten to fifteen percent higher than the installed wind capacity and the long-term matching is 50% and 41%, respectively. In the Central area the 300 MW of wind capacity contributes relatively little to satisfy the high demand for electricity. In contrast, the low demand on the islands would make strong network connections to the mainland essential. This is also indicated by the high energy export figures in Spreadsheet 2.

6.2.2 Area 2: Offshore-wind

150 MW of offshore-wind plant was placed into each of the ten areas although this is unlikely to happen in the Shetland area where the water is generally too deep 5 km offshore around the islands. Around Orkney offshore-wind power plants would not be the first choice either but there are shallow regions that could be developed. All other areas have at least one region where developments could take place.

Plant capacity factors range from 33% for less exposed sites to 48% on Shetland. As for onshore-wind the amount of matching depends on the local demand. Again, the wind resource around the islands calls for a strong interconnection to the mainland. Without these, less exposed sites in the east and south with proximity to the electricity grid are financially more attractive.

Spreadsheet 2 Area scenarios 1 - 2.

Number	Area	Technology	Onshore wind	Offshore wind	Wave	Tidal current	TOTAL	Average demand (peak demand)	Plant capacity factor						Long-term local matching						Energy shortfall (40% target)			Time when 40% of demand is exceeded			Coincident hours ❶	Energy export ❷
			MW	MW	MW	MW	MW	MW	%						%						%			%			h	%
								❸	Su	Wi	01	02	03	total	Su	Wi	01	02	03	total	Su	Wi	total	Su	Wi	total	total	total
Area 1	Scotland total	Onshore wind	3000	0	0	0	3000	Scotland	27	41	34	36	35	35	21	22	21	23	23	23	20	18	19	13	14	16	24	0
	Shetland		300	0	0	0	300	34 (55)	33	51	43	45	45	44	80	82	80	85	82	82	6	5	5	80	83	83	22	311
	Orkney		300	0	0	0	300	25 (40)	27	45	37	38	39	38	75	82	78	82	83	81	8	5	6	75	83	81	30	384
	Western Isles		300	0	0	0	300	26 (43)	30	42	35	39	38	37	81	78	77	83	82	80	5	6	5	81	79	81	23	340
	Highlands North		300	0	0	0	300	111 (180)	28	40	35	38	36	36	59	60	60	65	62	63	11	11	10	59	63	64	26	36
	Highlands South		300	0	0	0	300	204 (332)	31	43	37	37	38	37	50	49	49	50	51	50	12	12	12	52	55	54	16	5
	North East		300	0	0	0	300	507 (826)	26	34	30	31	31	31	19	16	18	18	19	18	23	24	23	15	10	15	29	0
	North Central		300	0	0	0	300	359 (583)	27	34	31	31	30	31	28	23	25	26	26	26	21	22	21	28	27	28	33	0
	Argyll & Bute		300	0	0	0	300	94 (153)	23	46	35	38	36	36	60	70	65	68	68	67	9	7	8	62	73	68	12	48
	Central		300	0	0	0	300	3092 (4911)	23	36	30	32	29	30	3	3	3	3	3	3	37	37	37	0	0	0	30	0
	South		300	0	0	0	300	218 (347)	24	38	30	34	31	32	37	44	38	44	42	41	16	14	15	36	48	43	28	2
Area 2	Scotland total	Offshore wind	0	1500	0	0	1500	Scotland	26	51	38	40	39	39	10	14	12	13	13	13	30	26	27	0	0	0	12	0
	Shetland		0	150	0	0	150	34 (55)	32	60	46	50	49	48	69	84	76	82	81	79	8	4	5	72	85	80	13	135
	Orkney		0	150	0	0	150	25 (40)	27	55	41	44	44	43	69	84	76	82	80	79	8	4	5	71	85	80	22	184
	Western Isles		0	150	0	0	150	26 (43)	29	53	41	43	40	42	75	83	79	81	79	80	6	4	5	78	84	81	12	156
	Highlands North		0	150	0	0	150	111 (180)	26	50	38	40	40	39	40	55	47	51	51	50	16	10	12	41	61	52	19	3
	Highlands South		0	150	0	0	150	204 (332)	29	53	40	43	40	41	26	32	29	32	29	30	19	13	16	27	46	37	8	0
	North East		0	150	0	0	150	507 (826)	25	48	36	38	38	37	9	12	11	11	11	11	31	28	29	1	0	0	21	0
	North Central		0	150	0	0	150	359 (583)	22	45	34	33	33	33	11	15	14	14	14	14	29	25	26	4	0	2	18	0
	Argyll & Bute		0	150	0	0	150	94 (153)	25	53	39	42	37	39	44	64	54	59	53	56	13	7	10	47	69	58	5	7
	Central		0	150	0	0	150	3092 (4911)	21	44	34	33	32	33	1	2	2	2	2	2	39	38	38	0	0	0	27	0
	South		0	150	0	0	150	218 (347)	20	47	31	36	35	34	16	28	20	24	25	23	26	16	20	12	38	26	25	0

Notes: ❶ Coincident hours are given for demand ranging from 90% to 100% of peak demand and generation ranging from 0% to 10% of installed capacity, in hours per year; ❷ Amount of total electricity that would have to be exported, relative to area demand; ❸ Su = summer, Wi = winter, 01 = 2001, 02 = 2002, 03 = 2003, total = 2001-2003.

Spreadsheet 3 Area scenarios 3 - 5.

Number	Area	Technology	Onshore wind	Offshore wind	Wave	Tidal current	TOTAL	Average demand (peak demand)	Plant capacity factor						Long-term local matching						Energy shortfall (40% target)			Time when 40% of demand is exceeded			Coincident hours ❶	Energy export ❷
			MW	MW	MW	MW	MW	MW	%						%						%			%			h	%
								❸	Su	Wi	01	02	03	total	Su	Wi	01	02	03	total	Su	Wi	total	Su	Wi	total	total	total
Area 3	Scotland total	Waves	0	0	1500	0	1500	Scotland	15	45	30	32	30	30	6	12	9	10	10	10	34	28	30	0	0	0	15	0
	Shetland		0	0	375	0	375	34 (55)	15	48	32	33	32	32	82	98	94	95	92	94	2	0	0	87	99	96	7	265
	Orkney		0	0	375	0	375	25 (40)	12	43	28	30	28	29	85	98	94	97	94	95	1	0	0	91	99	97	14	347
	Western Isles		0	0	375	0	375	26 (43)	18	49	33	35	32	33	88	97	95	97	94	95	1	0	0	93	99	98	10	379
	Argyll & Bute		0	0	375	0	375	94 (153)	13	41	26	30	25	27	48	80	66	73	66	68	11	3	6	48	85	69	12	40
Area 4	Scotland total	Tidal currents	0	0	0	375	375	Scotland	32	32	33	32	32	32	3	2	3	3	3	3	37	38	37	0	0	0	23	0
	Shetland		0	0	0	75	75	34 (55)	24	24	25	25	24	25	54	41	47	47	47	47	9	13	12	57	43	50	17	8
	Orkney		0	0	0	75	75	25 (40)	46	46	46	46	45	46	74	68	70	70	70	70	7	8	8	75	70	72	15	69
	Highlands North		0	0	0	75	75	111 (180)	41	40	41	40	40	40	35	23	27	27	27	27	17	20	19	43	30	37	18	0
	Argyll & Bute		0	0	0	75	75	94 (153)	28	28	29	29	28	29	28	19	23	23	23	23	21	24	23	30	20	26	26	0
	South		0	0	0	75	75	218 (347)	21	22	22	22	22	22	9	6	7	8	8	8	31	34	32	0	0	0	27	0
Area 5	Scotland	Mix, 75-10-10-5%	4500	600	600	300	6000	Scotland	26	42	34	36	34	35	39	45	42	46	45	44	11	8	9	40	56	50	19	0
	Shetland		450	60	150	60	720	34 (55)	28	49	39	41	40	40	97	98	98	99	98	98	0	0	0	98	99	99	16	761
	Orkney		450	60	150	60	720	25 (40)	25	45	36	38	38	37	98	99	98	99	99	99	0	0	0	98	99	99	14	988
	Western Isles		450	60	150	0	660	26 (43)	27	44	34	38	36	36	94	96	96	97	96	96	0	1	0	96	96	97	14	809
	Highlands North		450	60	0	60	570	111 (180)	29	40	36	38	36	37	81	78	79	83	81	81	3	4	3	85	81	85	19	107
	Highlands South		450	60	0	0	510	204 (332)	30	44	36	38	38	37	63	65	63	65	65	64	8	8	8	65	68	66	14	28
	North East		450	60	0	0	510	507 (826)	25	35	30	31	31	31	31	29	30	31	32	31	18	18	17	30	32	32	28	0
	North Central		450	60	0	0	510	359 (583)	26	35	31	31	30	30	41	39	40	42	40	41	16	16	16	39	41	41	26	3
	Argyll & Bute		450	60	150	60	720	94 (153)	21	44	32	35	33	34	85	90	88	88	88	88	2	1	1	89	93	91	8	169
	Central		450	60	0	0	510	3092 (4911)	22	37	30	31	29	30	4	5	5	5	5	5	36	35	35	0	0	0	29	0
	South		450	60	0	60	570	218 (347)	23	37	29	32	30	30	55	62	57	62	60	60	9	8	8	56	64	61	25	19

Notes: ❶ Coincident hours are given for demand ranging from 90% to 100% of peak demand and generation ranging from 0% to 10% of installed capacity, in hours per year; ❷ Amount of total electricity that would have to be exported, relative to area demand; ❸ Su = summer, Wi = winter, 01 = 2001, 02 = 2002, 03 = 2003, total = 2001-2003.

6.2.3 Area 3: Wave

Even though each of the ten areas has some coastline, the wave resource is not equally distributed. At present, the resource off the western coastline is seen as the most worthy for exploitation. Therefore wave energy converters were only placed in the four areas with broad exposure to the North Atlantic wave climate.

The overall plant capacity factor is slightly lower than in the technology scenarios because machines off Orkney and Argyll and Bute deliver less electricity. The Western Isles, with the best wave climate in Scotland, and Shetland achieve factors exceeding 30%. The chosen capacities are much higher than needed for local demand and projects will only be developed when the transmission of the electricity to load centres is resolved.

6.2.4 Area 4: Tidal-current

Good sites for tidal current exploitation exist in the north and to some extent in the south of Scotland. Further sites with small capacities like 5 MW exist in other regions such as Skye, but these were not considered in the study. There are five areas where 75 MW of capacity each was placed. The Pentland Firth, known for its energetic currents, exhibits the highest plant capacity factors and this pushes the figures for Orkney (46%) and Highlands North (40%) up. In comparison, Shetland's 25% plant capacity factor is lower. Furthermore, 75 MW of capacity may actually overexploit the resource. Whether the figure of 29% in Argyll and Bute can be realised depends on the resource west of Islay being confirmed by measurements. The South reaches only 22% but is closer to load centres than other sites. The matching figures show that tidal current power can make an important contribution to the local electricity supply.

6.2.5 Area 5: Mixed Portfolio

As with the technology scenarios, a 6 GW mix with 75% onshore wind, 10% offshore wind, 10% wave and 5% tidal current plant was developed. Since not all four resources can be found in each area, the regional split differs from the above percentages. Compared to the corresponding technology scenario *Tech 5d* the total plant capacity factor changes from 33.5 to 35% and the long-term local matching from 42.7% to 44%. The time when the 40% target is exceeded changes from 46.4% to 50%. This shows that inclusion of the island areas, i.e. a more geographically dispersed generation mix, could improve the matching between generation and demand for electricity. Strong electrical interconnection between areas would be necessary to make full use of this feature of renewable energy.

6.3 Power System Implications

Excess and shortfall of generation With large capacities of renewable energy generation installed there sometimes will be a need to export electricity over interconnectors to England and Northern Ireland or to curtail production. There will be many times when the variable renewable production can only satisfy a fraction of electricity demand. The remainder must then be balanced by dispatchable plant and/or imports from other areas. Figure 6.8 shows exceedance curves for production excess and shortfall for two renewable scenarios. The dashed lines are for a 6 GW onshore-wind scenario (*Tech 1* scenario) while the solid lines are for an onshore wind dominated renewable mix of the same capacity (*Tech 5* scenario). The upper two lines are for a comparison to actual (100%) demand while the lower ones are for a comparison to 40% of demand. The lower half of the diagram describes production excess, the upper half production shortfall. The vertical scale is in power units (GW) and also in percentages of peak demand, with 100% corresponding to about 7.3 GW in 2020.

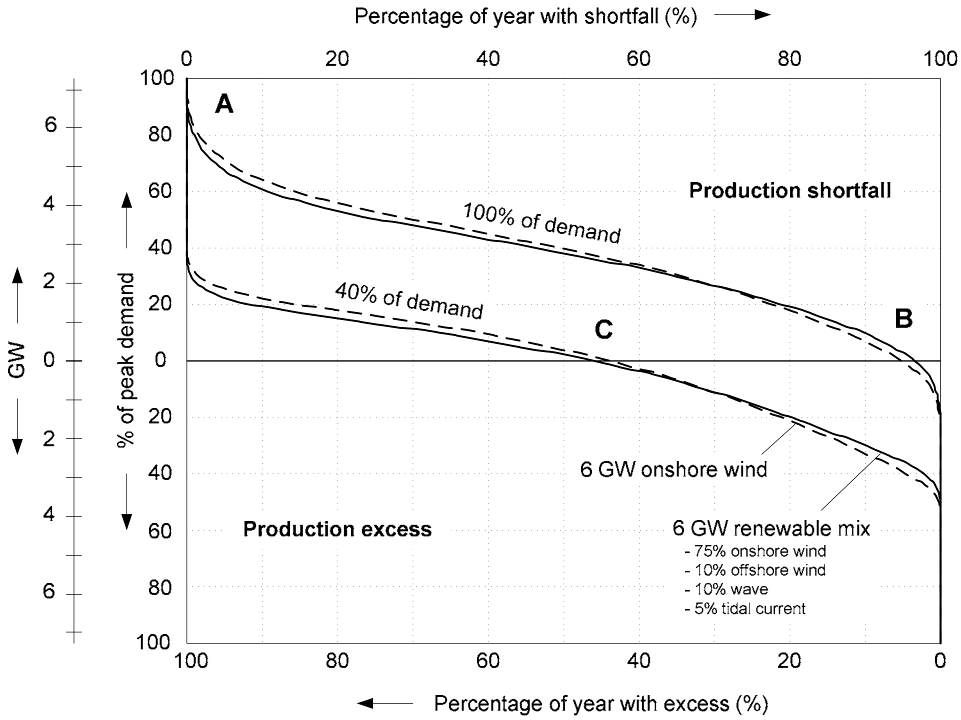


Figure 6.8 Production excess and shortfall for two scenarios.
(a) 6 GW onshore-wind only (dashed lines, *Tech 1*);
(b) Mixed 6 GW portfolio (solid lines, *Tech 5*).

Exceedance curves like the one above answer questions such as: "How many hours of the year does the shortfall (or excess) in production *exceed* a certain amount?" The interesting points in Figure 6.8, however, are at the extremes. The times when demand is close to peak demand and renewable generation is very low can be found in area 'A'. The scaling of the graph does not allow values in this region to be easily read, therefore the following values are taken from the numerical calculations. For 0.1% of the time (less than 9 hours in a year) the shortfall will exceed 92% (onshore-wind) or 89% (mix) of peak demand. The shortfall levels that will not be exceeded *at any hour* of the year are 98% for onshore-wind and 96% for the mix. Hence a mixed renewable portfolio is likely to produce more electricity at hours of high demand.

Area 'B' indicates where the curves relative to 100% of demand cross the zero line. 5% of the time onshore-wind production would actually be greater than total demand and export would be necessary. In case of the mix this time reduces to 3% of the year. Apparently there is a trade-off between the performance at both ends of the curves. From the supply point of view area 'A' is more crucial and therefore the mix performs better than the onshore-wind scenario.

Comparing production figures to 40% of the demand leads to the lower two curves. In area 'C' they cross the zero line. The time when production is greater than the 40% demand target is 44.6% for onshore wind and 46.4% for the renewable mix. The figures, which can also be found in Spreadsheet 1, suggest that the overall long-term average output of a mix of technologies is more stable than that of onshore-wind alone.

Coincident hours Area 'A' in Figure 6.8 is also described by a corner of the coincident-hours diagram discussed in Section 5.2.2. The number of hours per year when demand is higher than 90% of peak demand and generation is lower than 10% of nameplate rating is given in the 'Coincident hours' column of Spreadsheet 1 for each scenario. Comparing these *worst-case* values for the technology scenarios with 750 MW total capacity shows 30 hours per year for onshore-wind, 20 hours for offshore-wind, 21 hours for wave, 22 hours for tidal-current and 17 hours for the 75-10-10-5% mix.

This indicates that in terms of coincident hours the mix performs better than any of the single technology scenarios.

Evaluating these coincident hours for technology scenario *Tech 6* reveals that the lowest number of hours is achieved in mixes with low onshore-wind contributions. The number of worst-case coincident hours is below 9 for onshore-wind contributions up to 1.5 GW. In contrast, for a pure 6 GW onshore-wind scenario there would be 29 worst-case coincident hours per year.

As an example Figure 6.9 shows the coincident hour tables for both a 6 GW onshore-wind scenario and for a 6 GW mix. Notably the figures in the top row reduce with diversified technologies. This means it becomes more likely that at least a minimum amount of electricity is generated by the renewable generators. Given the possible dominance of onshore-wind in the renewable mix of 2020, inclusion of the other technologies reduces the risk that none of them can deliver any electricity at times of high demand.

(a)

0	0	0	63	473	587	522	288	165	29
0	0	0	27	233	366	474	260	121	15
0	0	0	11	142	285	398	225	83	7
0	0	0	6	84	222	321	203	89	4
0	0	0	2	56	171	283	146	87	8
0	0	0	1	40	137	249	131	69	5
0	0	0	0	31	118	221	130	90	5
0	0	0	0	18	91	212	153	80	8
0	0	0	0	7	56	148	130	66	5
0	0	0	0	0	7	30	42	25	1

Demand (% of peak demand) → (0, 20, 40, 60, 80, 100)

Generation (% of installed capacity) ↓ (0, 20, 40, 60, 80, 100)

(b)

0	0	0	51	374	442	348	164	109	20
0	0	0	33	278	447	546	292	128	20
0	0	0	15	181	339	458	252	99	10
0	0	0	6	102	253	371	240	97	5
0	0	0	2	54	182	323	170	99	6
0	0	0	1	44	149	274	146	90	6
0	0	0	0	32	121	240	162	99	8
0	0	0	0	17	79	207	171	94	9
0	0	0	0	1	28	88	108	58	3
0	0	0	0	0	1	2	2	2	0

Demand (% of peak demand) → (0, 20, 40, 60, 80, 100)

Generation (% of installed capacity) ↓ (0, 20, 40, 60, 80, 100)

Figure 6.9 Coincident hours of renewable generation and electricity demand.
(a) 6 GW of onshore-wind; (b) 6 GW of renewable mix with 75% onshore-wind, 10% offshore-wind, 10% wave and 5% tidal-current contribution.

Power output variability The frequency of power output changes is illustrated in Figure 6.10 for three proportions of onshore-wind in the *Tech 6* scenario with 6 GW total capacity. There are traces for onshore-wind alone, for a mix with 75% onshore-wind contribution, and for a mix with no onshore-wind contribution at all.

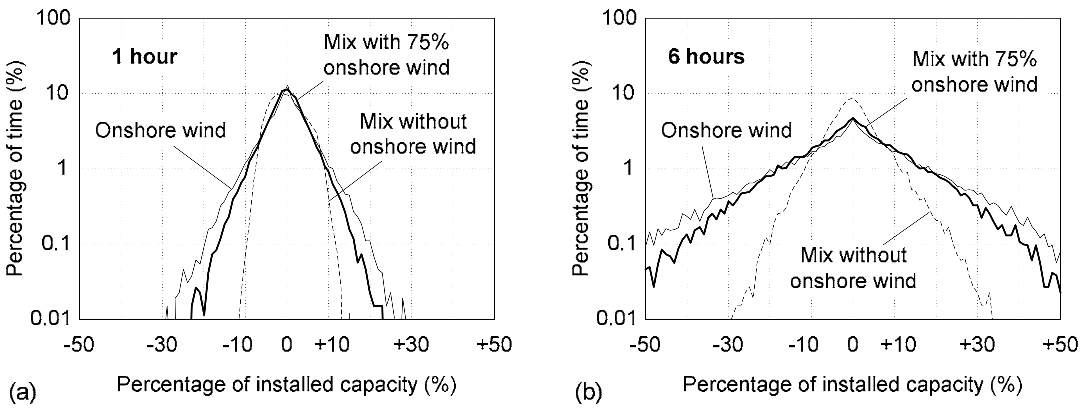


Figure 6.10 Power variation for three scenarios with 6 GW.
(a) One hour time lag; (b) Six hour time lag.

Figure 6.10a is for a time difference of one hour. Since the original offshore-wind and wave data was interpolated from three-hourly records, conclusions must be drawn with caution. The most likely change in power output is generally zero. This could be either because the generators produce no or rated power, both at the beginning and the end of the hour, or the power output did not change. This happens for 10% of the time. Small changes in power level, both to lower and higher output, are common, large changes happen much less frequently. +10% or -10% changes are observed for around 1% of the time. This figure applies for the whole of Scotland, regionally such changes will happen much more frequently.

Figure 6.10b shows that, on average, the change of power output is greater after six hours than after one. This is to be expected. Tidal-current devices, however, may show a big change in output power after one hour and, compared to the original value, only a small change after six hours. With the smaller contribution of tidal-current to the renewable mix this influence does not impact on the graph very much. Where offshore-wind and wave devices dominate the mix, the power output changes more gradually, i.e., compared to onshore-wind, small changes occur frequently and large changes occur less frequently, potentially leaving system operators more time to dispatch balancing plant.

Power system options Diversification of energy sources and their geographical dispersion increases the hour-by-hour matching with demand. Nevertheless there will still be many hours in a year when renewable output from wind, waves and tidal currents falls below the average and some form of dispatchable plant will be needed. Examples of available options in Scotland include the following.

- *Hydro-electric plant*: There is about 1.3 GW of installed hydro-electric plant in Scotland with a possible extension to 1.5 GW by 2020. The actual schedule of the plant not only depends on the availability of water but also on requirements like minimum and maximum discharge and the maximum change of flow rate. Hydro-electric plant essentially provides base electricity and therefore improves hour-by-hour matching and reduces the worst-case coincident hours. Scottish and Southern Energy provided *monthly* production figures for about 1 GW of the existing plant covering the years 2001 through 2003 which served to estimate the impact of hydro on the scenarios. Previous scenarios were repeated including an anticipated capacity of 1.5 GW of hydro plant operating as at present. This suggested that the 40% target could be reached with an additional capacity of about 4.4 GW of onshore wind or 4.3 GW of the 75-10-10-5% renewable mix. Worst-case coincident hours naturally reduce, but more detailed data on hydro plant output would be needed to obtain robust results.
- *Energy storage*: There are, at present, two *pumped-storage* plants in Scotland. Cruachan, operated by Scottish Power, has a capacity of 400 MW and Foyers, operated by Scottish and Southern Energy, has a capacity of 300 MW. Pumped storage can be used on a daily cycle for ‘peak shaving’ and ‘trough filling’, for system balance against small changes in demand and as standby. In the future existing or additional plant could be used to smooth the output of variable renewable sources.
- *Balancing plant*: Nuclear and coal power plant normally provide base electricity. However, fast-starting gas turbines offer the possibility to respond quickly and operate mainly during times of peak demand. With increasing variable generation such plant could provide necessary balancing. In the future, some biomass plant may also be able to operate in this mode.
- *Interconnectors*: Scotland currently has interconnections with England (2.2 GW) and Northern Ireland (500 MW). The limit for imports from England is actually lower than 2.2 GW due to voltage profile and stability issues (SP 2004). Future upgrades may further increase this capacity.

To enable any or all of the above, a *fully reinforced electricity network* will be required to transport energy from remote generators to load centres and to make balancing power available when and where needed.

6.4 Comments and Summary

In drawing conclusions from the study, particularly those inviting comparisons between technologies, there is a danger of comparing like with unlike. The study was strongly focussed on four variable, non-dispatchable renewable-energy generating technologies. Each of these technologies is at a different stage of development. Onshore-wind is relatively mature. Offshore-wind is new but largely based on the same technology as onshore-wind. Prototypes of deep-water wave energy devices have now been successfully deployed. Tidal-current energy on a large scale is a relatively new concept, but a prototype machine has operated for more than two years. Consequently the costs of producing electricity (or the lifetime production costs) are different for the four technologies. With the rich onshore-wind resource across Scotland, electricity from these projects is, *at present*, cheaper than for any project with the other three technologies. However, this situation could change with advances in technology and, for instance, with new sites for large-scale onshore-wind development becoming increasingly difficult to secure.

The nature of the resource information that was used for each technology in the study is also quite variable. The onshore-wind resource is based on measurements made at 24 stations over ten years. This was interpolated down to the scale of the 1 km^2 cells by using proven techniques. The data for offshore-wind is largely based on Met Office hindcast data which was again interpolated to the 1 km^2 cell level. The WAsP simulation in Scotland's rugged terrain, the necessary scaling of wind data to smooth discontinuities between areas and the use of a GIS for automatic site selection all introduce uncertainties. The overall validity of the results however is not affected. The wave data is entirely based on Met Office hindcast data, but was interpolated down to the 1 km^2 cells from a fairly coarse grid of points by using elementary techniques. The primary information source for the tidal-current resource was charts and tables that are intended for mariners and not for energy assessment. The tidal-current information in these publications is fairly sparse and generally based on fairly short measuring campaigns.

The final results as presented and the remarks made in the discussion are based on the joint products of machine specifications and resource estimations. In this context it must be clearly understood that the machine specifications are somewhat speculative. However, they reflect information in the public domain regarding future technology developments. It is likely that, as wave and tidal-current technologies mature and as detailed knowledge of the resource improves, the machine designs will evolve to be appropriate to the specific resource at each location. This process would have a strong positive influence on average capacity-factors and total production capacity.

The costs of connection of onshore-wind are lower on the mainland than they will be in the Western Isles, Orkney or Shetland and so the selection of capacity in order of economic merit tends to favour mainland sites where available. This does not imply that the renewable resource is lower or poorer in the islands. On the contrary, the area scenarios show clearly that the renewable resource in the island regions is significantly higher than on or near the mainland.

7 Conclusions

This study was commissioned to determine whether Scotland could meet 40% of its 2020 demand for electricity from renewable resources. By then annual demand for electrical energy in Scotland could be around 41 TWh with a peak power demand of around 7.3 GW. Supplying 40% (16.4 TWh) of the electricity required over the year from renewable resources suggests the need for around 6 GW of renewable capacity.

Current and planned hydro capacity in Scotland will contribute 1.5 GW to the 2020 energy mix. Onshore wind projects built to date, and consented but not yet operational, should contribute at least a further 1.5 GW. The balance of around 3 GW could be met by a range of technologies. Biomass has been assessed to have the potential to contribute up to 0.45 GW using existing technology. Information available before this study suggested that wave and tidal power, between them, have the potential to deliver over 1 GW, but that these are nascent technologies which need to be developed commercially. Onshore and offshore wind have potential to contribute significantly more.

Generated power must *match* demand for power on a second-by-second basis. Demand varies with time and with location across Scotland and so does renewable energy. This is particularly true for time-varying resources like wind, wave and tidal-current. Historical demand data was available for the study, but hourly production time-series were not available for existing renewable plant and could not be synthesised for consented or planned plant without detailed siting information. Instead a Geographical Information System and industry standard software were used to provide a consistent generic approach. This study has:

- mapped the location of onshore and offshore-wind, wave and tidal-current resources and the physical, environmental and planning constraints for their development;
- estimated connection costs between renewable plant and grid supply points;
- used an unconstrained electricity network as a basis;
- predicted the lifetime production costs of electricity generation which enabled the economic ranking of locations feasible for development;
- assembled and analysed resource time-series;
- converted the renewable energy resources to calculate hourly time-series of power levels by location for a consecutive period of three years;
- forecast hourly time-series of demand in 2020;
- developed individual and combined renewable technology scenarios to derive seasonal and annual key figures;
- calculated plant capacity factors and long-term matching data which describe the ability to meet, *on average*, the 40% target;
- estimated the extent to which portfolios of plant can meet the 40% target *on an hour-by-hour basis* by calculating hours of shortfall and hours of coincidence between production and demand.

Each of these steps is necessary to characterise the selected renewable resources, to increase confidence in them and to derive *maximum benefit* from the *minimum number of developments*.

Results in this summary are tabulated for generation from onshore and offshore-wind, wave and tidal-current generation, both individually and in a combined scenario with 75%, 10%, 10% and 5% respectively from each resource. To illustrate trends the scenarios are based on capacities of 3 and 6 GW where there was sufficient technically viable resource. The results do not imply that a combination of modelled with existing, consented or planned capacity will necessarily result in the same average and hour-by-hour figures. Hydro in particular could reduce the overall plant capacity factor and the long-term matching, but has the advantage of being dispatchable and offering storage.

1. After application of constraints it could be possible to develop renewable resources to capacities reaching or exceeding 6 GW for onshore wind, 3 GW for offshore wind, 3 GW for wave and 1 GW for tidal current, or any combination of these technologies. However, none of the resources studied is ultimately limited to the totals identified. There is significant additional onshore wind capacity available at less energetic sites. Offshore wind, wave and tidal current could be further developed in deeper waters.

2. The annual plant capacity factors derived from production time-series all exceed 30% and are in line with working experience. Generally they reduce as the capacity increases by adding sites of higher cost which are often less energetic. Seasonal values for the capacity factor indicate strong variations of wind and wave power over a year with significantly higher output in winter than in summer.

Plant capacity factor (%)	3 GW	6 GW
Onshore-wind	33.9	32.7
Offshore-wind	35.8	-
Wave	31.7	-
Tidal-current (750 MW)	(30.0)	-
75-10-10-5% mix	34.7	33.5

3. The long-term local matching is the best assessment of the extent to which renewable resources could meet 40% of annual demand for electricity in 2020, taking account of their time variation and that of the load. In the case of onshore wind, offshore wind and wave a 3 GW capacity of any one of these resources would *on average* match at least half of the 40% target demand. Extending onshore wind and the mixed technology portfolio up to 6 GW demonstrates that such a capacity would be able to supply, on average, at least 40% of the electricity demand in 2020.

Long-term local matching (%)	3 GW	6 GW
Onshore-wind	21.8	41.5
Offshore-wind	23.0	-
Wave	20.4	-
Tidal-current (750 MW)	(4.8)	-
75-10-10-5% mix	22.3	42.7

4. *This illustrates that Scotland could, in 2020, meet on average 40% of its demand for electricity from renewable resources with a total renewable capacity of around 6 GW*. It does not mean that the aspirational demand target is reached during each hour of a year. There will be periods of shortfall and periods of excess. The remainder of the study has quantified this.

5. Due to the variability of the renewable energy output, 40% of the actual demand level will only be met or exceeded for a fraction of the hours in a year. With 3 GW of renewable capacity this would happen between 12 and 18% of the total time. An increased capacity of 6 GW of onshore wind or the technology mix could meet or exceed 40% of demand for electricity for around 45% of time.

Hourly exceedance of 40% target (%)	3 GW	6 GW
Onshore-wind	17.1	44.6
Offshore-wind	17.8	-
Wave	12.1	-
Tidal-current (750 MW)	-	-
75-10-10-5% mix	14.5	46.4

6. The ongoing hourly match between renewably produced electricity and demand can be described by a histogram of coincident hours when production (arranged in 10% bins up to installed capacity) matches demand (arranged in 10% bins up to peak demand). At times of high production and low demand the excess energy would be exported or constrained off. At times of peak demand and insufficient production the shortfall in energy would need to be imported or sourced from balancing plant.

Coincident hours for demand > 90% and production < 10% (h/year)		
	3 GW	6 GW
Onshore-wind	29	29
Offshore-wind	14	-
Wave	19	-
Tidal-current (750 MW)	(22)	-
75-10-10-5% mix	18	20

7. Diversification of energy sources and their geographical dispersion improves the hour-by-hour matching with demand. Nevertheless there will be many hours in a year when renewable output from wind, waves and tidal currents falls below demand targets and balancing plant would be needed. A strong interconnected transmission system will reduce the need for local balancing plant and increase security of supply. Full development of the more remote onshore and most of the offshore resource would require completion of planned network upgrades in northern and western Scotland.

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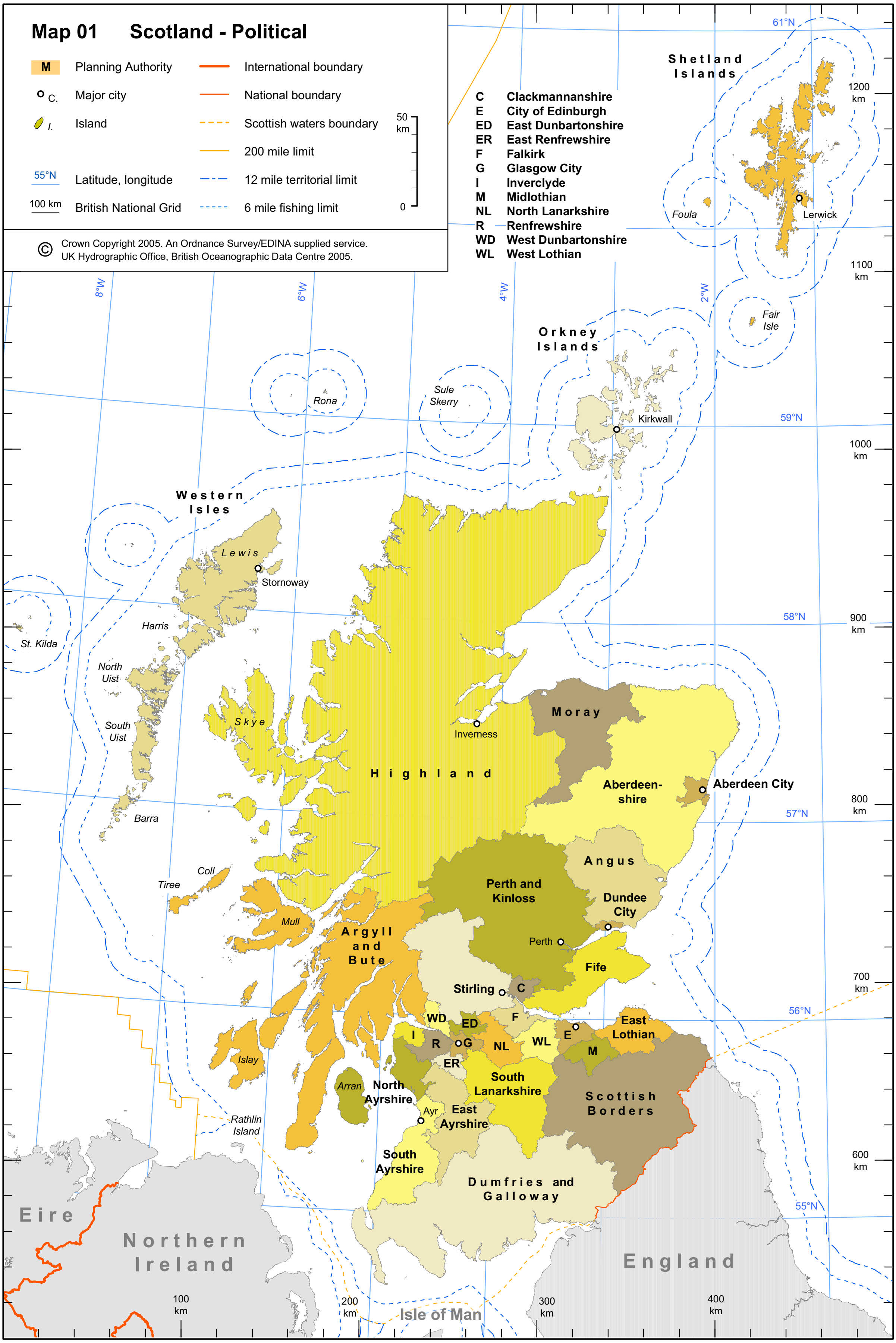
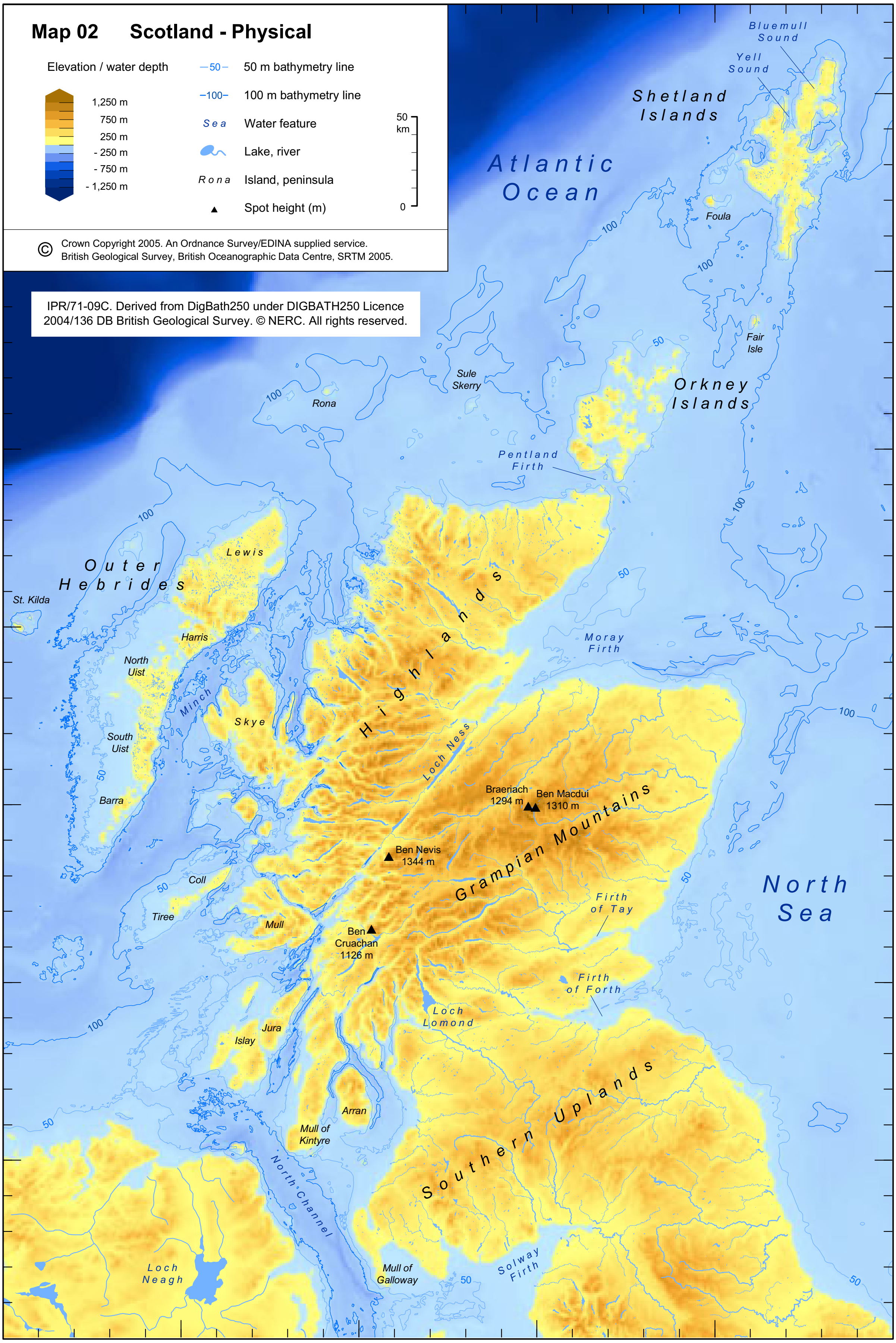

Map 01 Scotland - Political
M Planning Authority
C. Major city
I. Island
55°N Latitude, longitude
100 km British National Grid
International boundary
National boundary
Scottish waters boundary
200 mile limit
12 mile territorial limit
6 mile fishing limit
50 km
0
Crown Copyright 2005. An Ordnance Survey/EDINA supplied service.
UK Hydrographic Office, British Oceanographic Data Centre 2005.
C Clackmannanshire
E City of Edinburgh
ED East Dunbartonshire
ER East Renfrewshire
F Falkirk
G Glasgow City
I Inverclyde
M Midlothian
NL North Lanarkshire
R Renfrewshire
WD West Dunbartonshire
WL West Lothian
Shetland Islands
Foula
Lerwick
Fair Isle
Orkney Islands
Kirkwall
Sule Skerry
Rona
Western Isles
Lewis
Stornoway
Harris
St. Kilda
North Uist
South Uist
Barra
Skye
Highland
Inverness
Moray
Aberdeen-shire
Aberdeen City
Angus
Dundee City
Perth and Kinloss
Perth
Fife
Stirling
Coll
Tiree
Mull
Argyll and Bute
Islay
Arran
North Ayrshire
Ayr
East Ayrshire
South Ayrshire
South Lanarkshire
East Lothian
Scottish Borders
Dumfries and Galloway
Rathlin Island
Eire
Northern Ireland
England
Isle of Man
61°N
59°N
58°N
57°N
56°N
55°N
8°W
6°W
4°W
2°W
100 km
200 km
300 km
400 km
600 km
700 km
800 km
900 km
1000 km
1100 km
1200 km

Appendix 1


Map 02 Scotland - Physical
Elevation / water depth
1,250 m
750 m
250 m
- 250 m
- 750 m
- 1,250 m
50 m bathymetry line
100 m bathymetry line
Sea
Water feature
Lake, river
Rona
Island, peninsula
Spot height (m)
50 km
0
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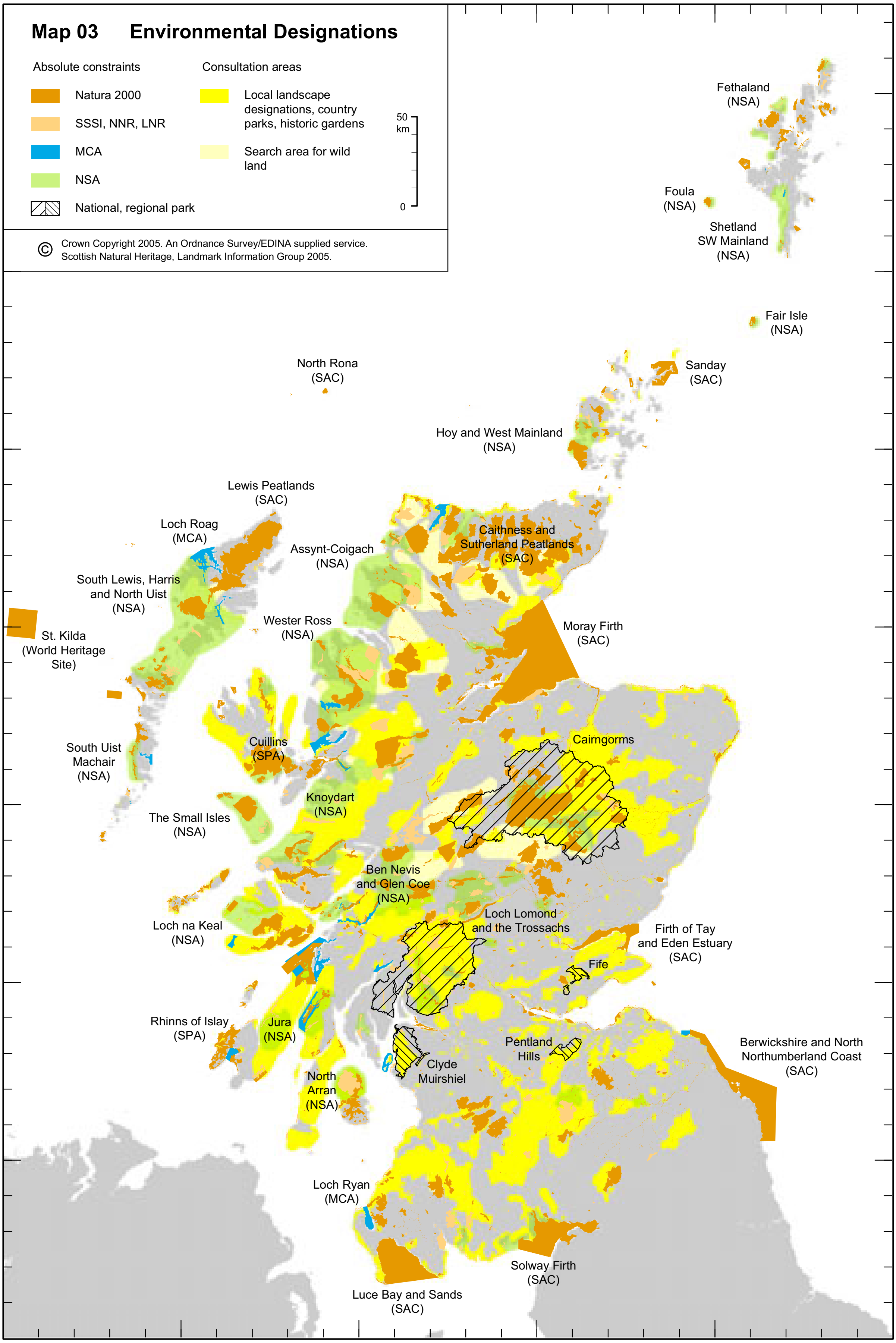
British Geological Survey, British Oceanographic Data Centre, SRTM 2005.
IPR/71-09C. Derived from DigBath250 under DIGBATH250 Licence 2004/136 DB British Geological Survey. © NERC. All rights reserved.
Atlantic Ocean
Bluemull Sound
Yell Sound
Shetland Islands
Foula
Fair Isle
Orkney Islands
Sule Skerry
Rona
Pentland Firth
Outer Hebrides
St. Kilda
Lewis
Harris
North Uist
South Uist
Barra
Minch
Skye
Highlands
Loch Ness
Moray Firth
Braeriach 1294 m
Ben Macdui 1310 m
Ben Nevis 1344 m
Grampian Mountains
Coll
Tiree
Mull
Ben Cruachan 1126 m
Firth of Tay
Firth of Forth
Loch Lomond
Jura
Islay
Arran
Mull of Kintyre
North Channel
Southern Uplands
Loch Neagh
Mull of Galloway
Solway Firth
North Sea

Appendix 2


Map 03 Environmental Designations
Absolute constraints
Natura 2000
SSSI, NNR, LNR
MCA
NSA
National, regional park
Consultation areas
Local landscape designations, country parks, historic gardens
Search area for wild land
50 km
0
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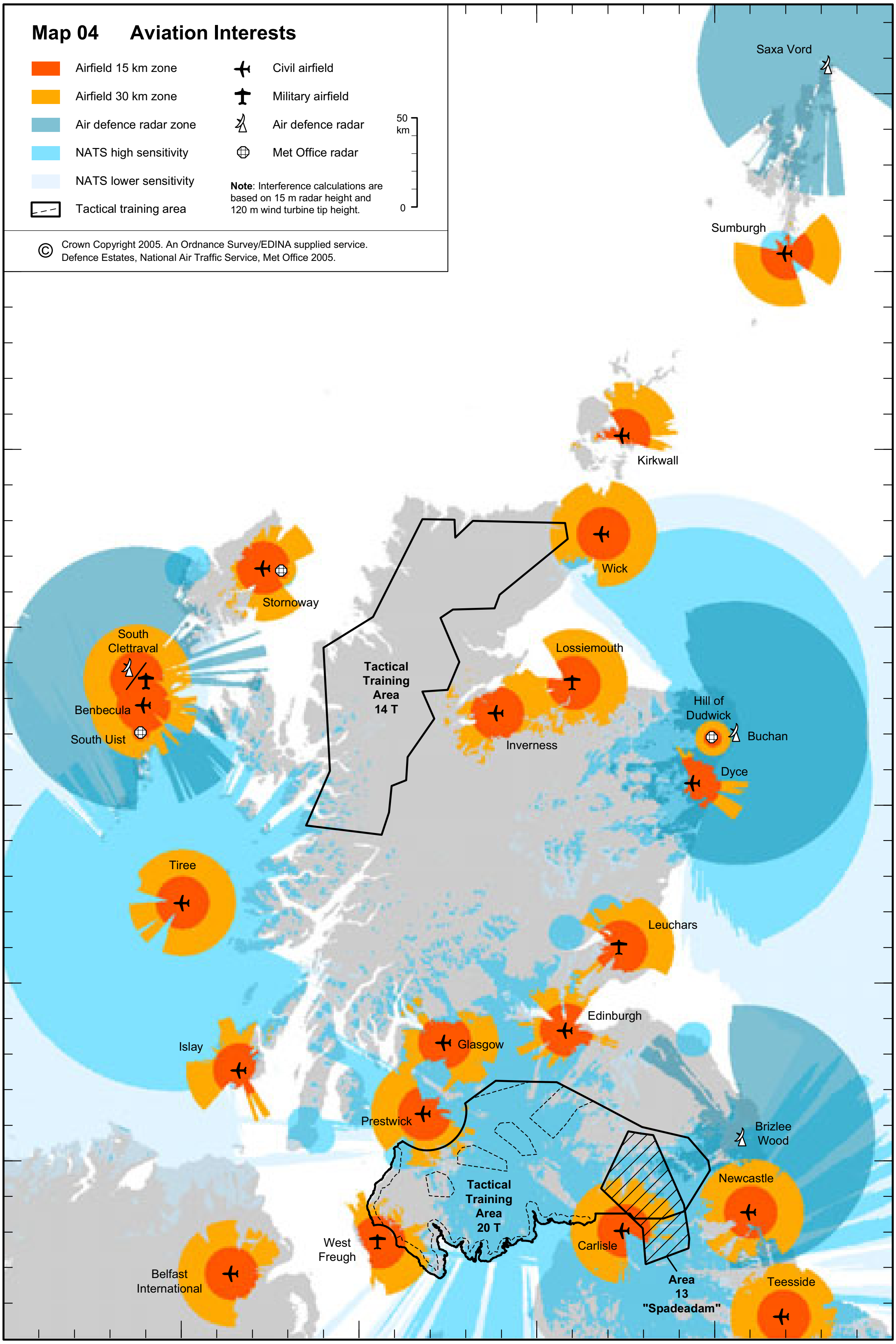
Fethaland (NSA)
Foula (NSA)
Shetland SW Mainland (NSA)
Fair Isle (NSA)
Sanday (SAC)
North Rona (SAC)
Hoy and West Mainland (NSA)
Lewis Peatlands (SAC)
Loch Roag (MCA)
Assynt-Coigach (NSA)
Caithness and Sutherland Peatlands (SAC)
South Lewis, Harris and North Uist (NSA)
St. Kilda (World Heritage Site)
Wester Ross (NSA)
Moray Firth (SAC)
Cairngorms
South Uist Machair (NSA)
Cuillins (SPA)
Knoydart (NSA)
The Small Isles (NSA)
Ben Nevis and Glen Coe (NSA)
Loch Lomond and the Trossachs
Loch na Keal (NSA)
Firth of Tay and Eden Estuary (SAC)
Fife
Rhinns of Islay (SPA)
Jura (NSA)
Pentland Hills
Clyde Muirshiel
Berwickshire and North Northumberland Coast (SAC)
North Arran (NSA)
Loch Ryan (MCA)
Solway Firth (SAC)
Luce Bay and Sands (SAC)



Map 04 Aviation Interests
Airfield 15 km zone
Airfield 30 km zone
Air defence radar zone
NATS high sensitivity
NATS lower sensitivity
Tactical training area
Civil airfield
Military airfield
Air defence radar
Met Office radar
50 km
0
Note: Interference calculations are based on 15 m radar height and 120 m wind turbine tip height.
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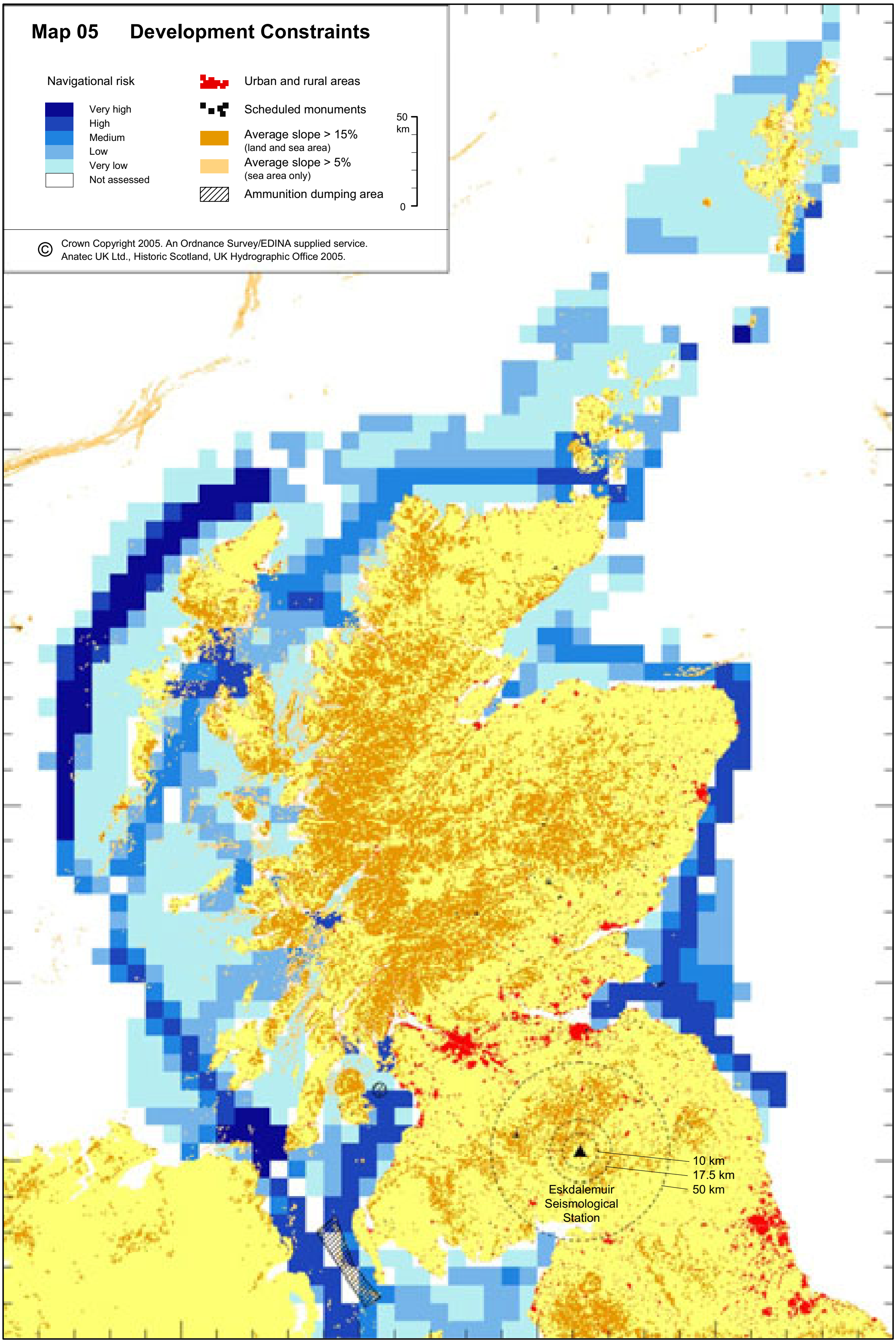
Saxa Vord
Sumburgh
Kirkwall
Wick
Stornoway
South Clettraval
Benbecula
South Uist
Tactical Training Area 14 T
Lossiemouth
Inverness
Hill of Dudwick
Buchan
Dyce
Tiree
Leuchars
Edinburgh
Islay
Glasgow
Prestwick
Brizlee Wood
Newcastle
Tactical Training Area 20 T
West Freugh
Carlisle
Belfast International
Area 13 "Spadeadam"
Teesside


Map 05 Development Constraints
Navigational risk
Very high
High
Medium
Low
Very low
Not assessed
Urban and rural areas
Scheduled monuments
Average slope > 15%
(land and sea area)
Average slope > 5%
(sea area only)
Ammunition dumping area
50
km
0
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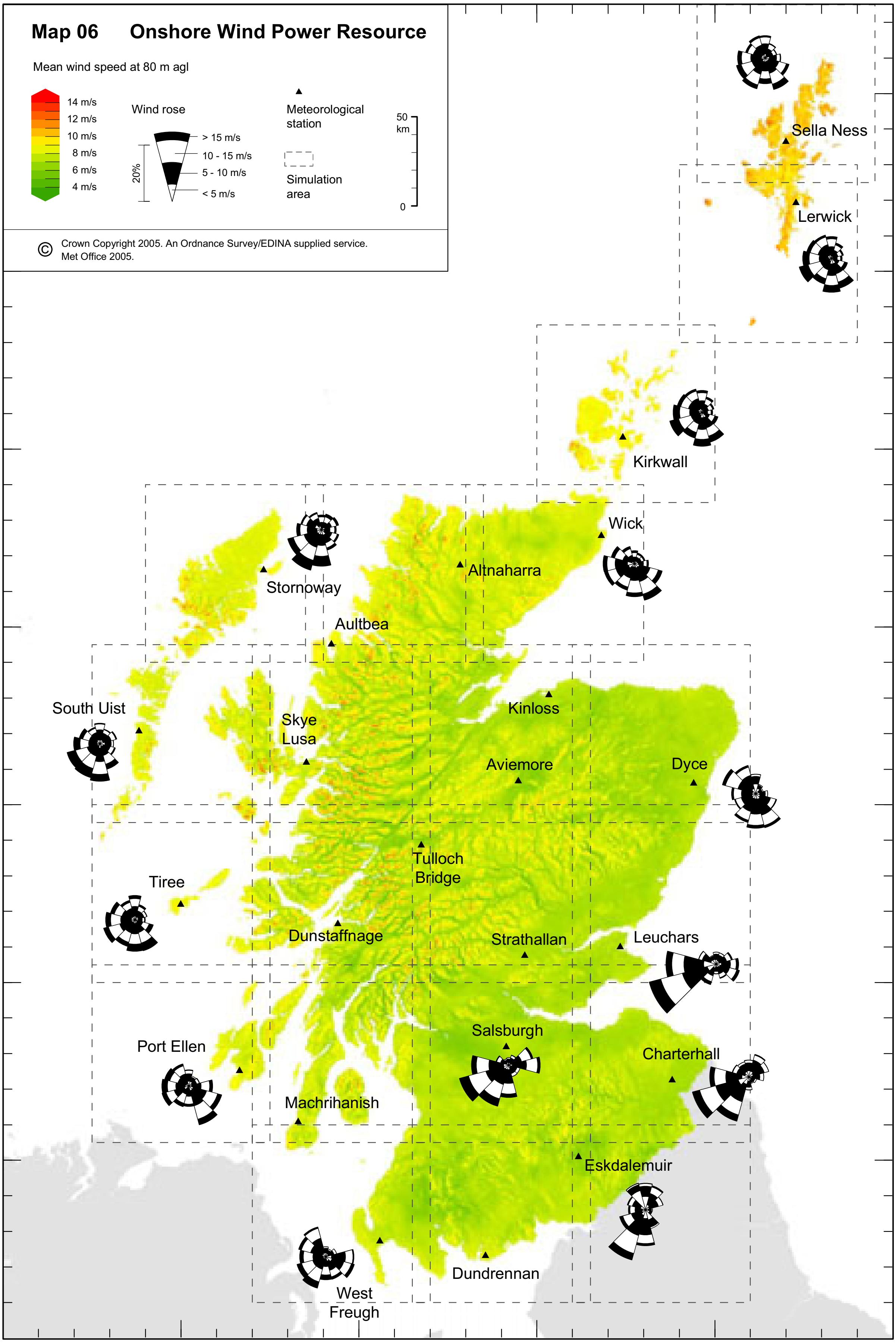
10 km
17.5 km
50 km
Eskdalemuir
Seismological
Station



Map 06 Onshore Wind Power Resource
Mean wind speed at 80 m agl
14 m/s
12 m/s
10 m/s
8 m/s
6 m/s
4 m/s
Wind rose
20%
> 15 m/s
10 - 15 m/s
5 - 10 m/s
< 5 m/s
Meteorological station
Simulation area
50 km
0
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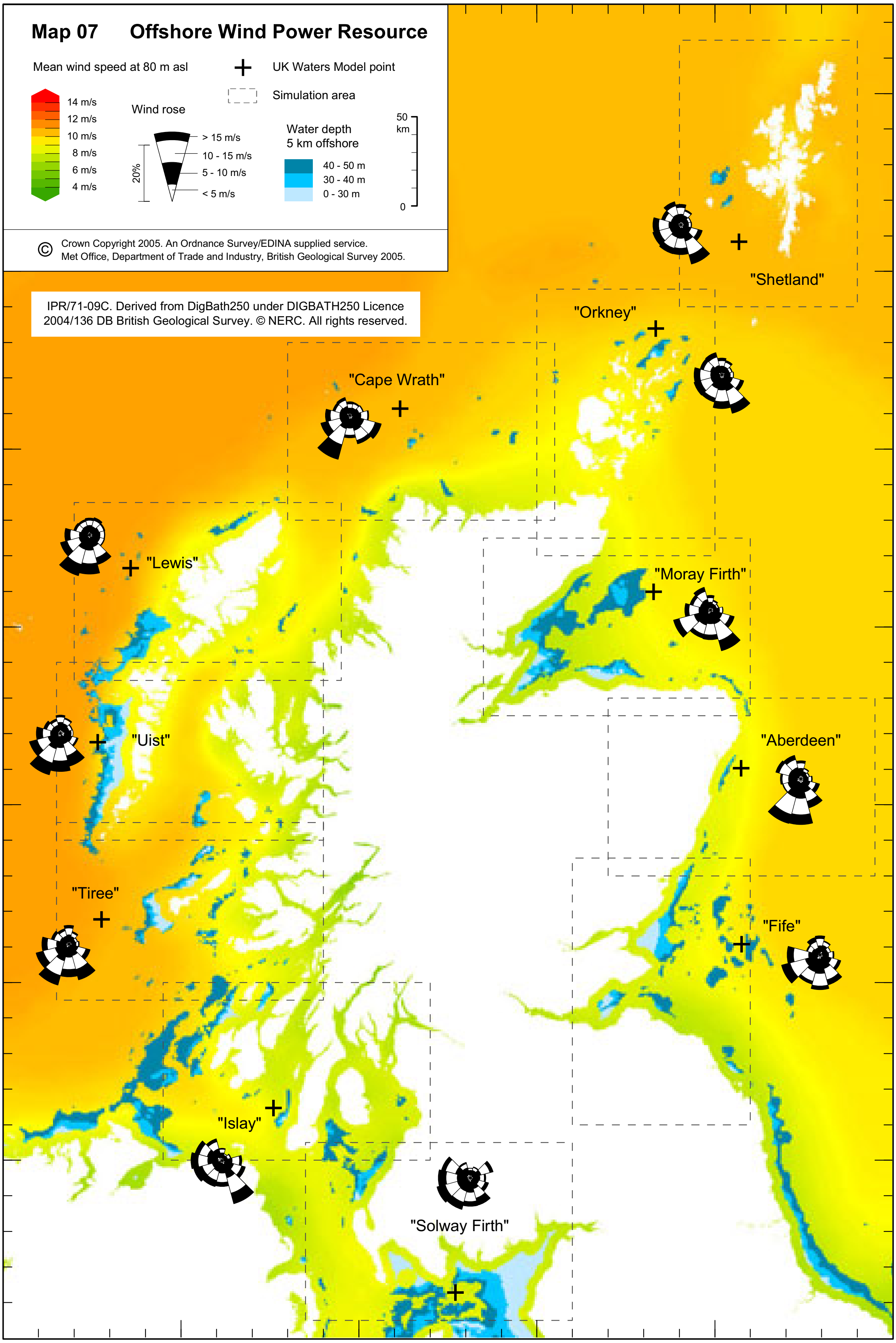
Sella Ness
Lerwick
Kirkwall
Wick
Altnaharra
Stornoway
Aultbea
South Uist
Skye Lusa
Kinloss
Aviemore
Dyce
Tulloch Bridge
Tiree
Dunstaffnage
Strathallan
Leuchars
Salsburgh
Charterhall
Port Ellen
Machrihanish
Eskdalemuir
West Freugh
Dundrennan


Map 07 Offshore Wind Power Resource
Mean wind speed at 80 m asl
UK Waters Model point
Simulation area
14 m/s
12 m/s
10 m/s
8 m/s
6 m/s
4 m/s
Wind rose
> 15 m/s
10 - 15 m/s
5 - 10 m/s
< 5 m/s
20%
Water depth
5 km offshore
40 - 50 m
30 - 40 m
0 - 30 m
50 km
0
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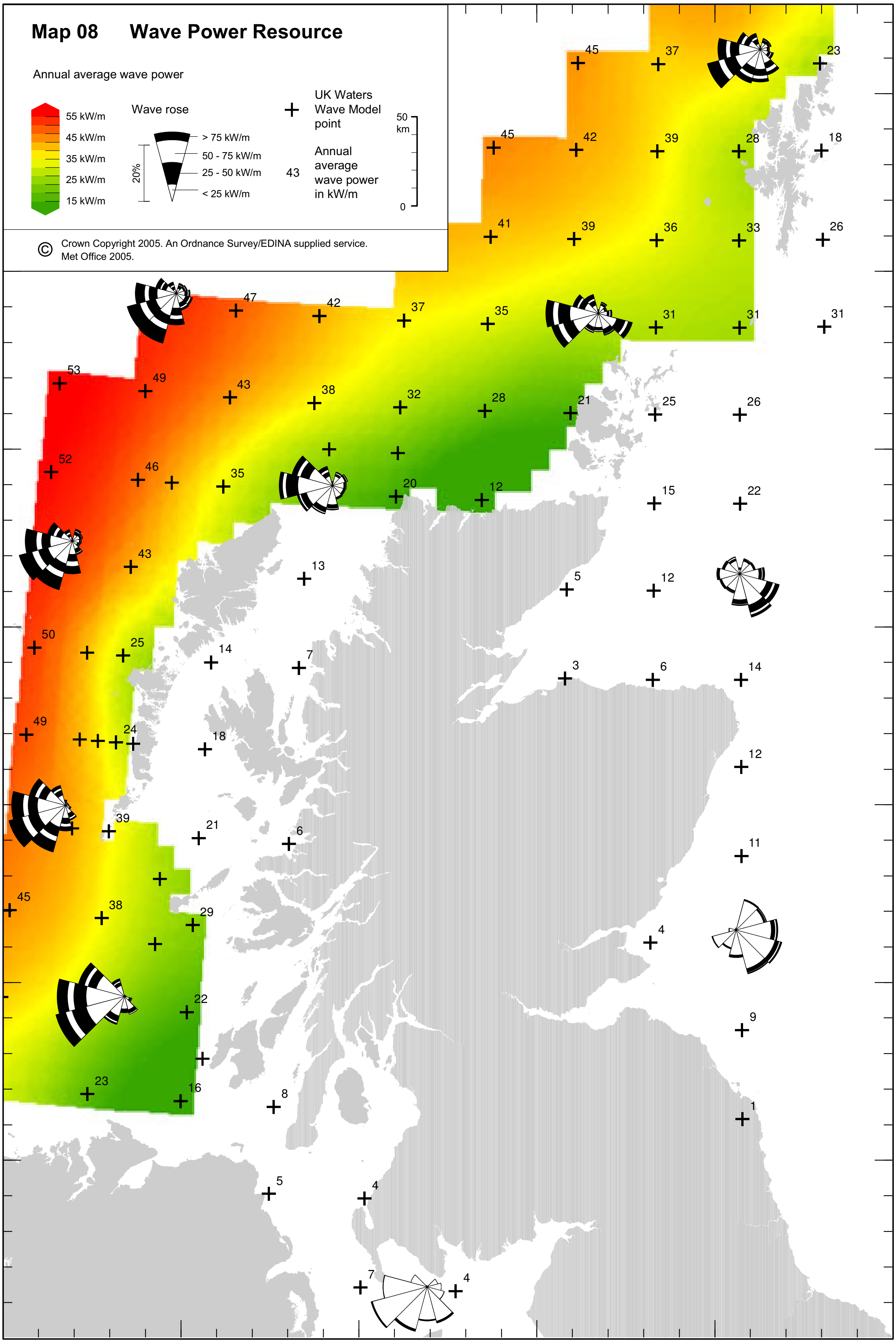
"Shetland"
"Orkney"
"Cape Wrath"
"Lewis"
"Moray Firth"
"Uist"
"Aberdeen"
"Tiree"
"Fife"
"Islay"
"Solway Firth"


Map 08 Wave Power Resource
Annual average wave power
55 kW/m
45 kW/m
35 kW/m
25 kW/m
15 kW/m
Wave rose
> 75 kW/m
50 - 75 kW/m
25 - 50 kW/m
< 25 kW/m
20%
UK Waters Wave Model point
43
Annual average wave power in kW/m
50 km
0
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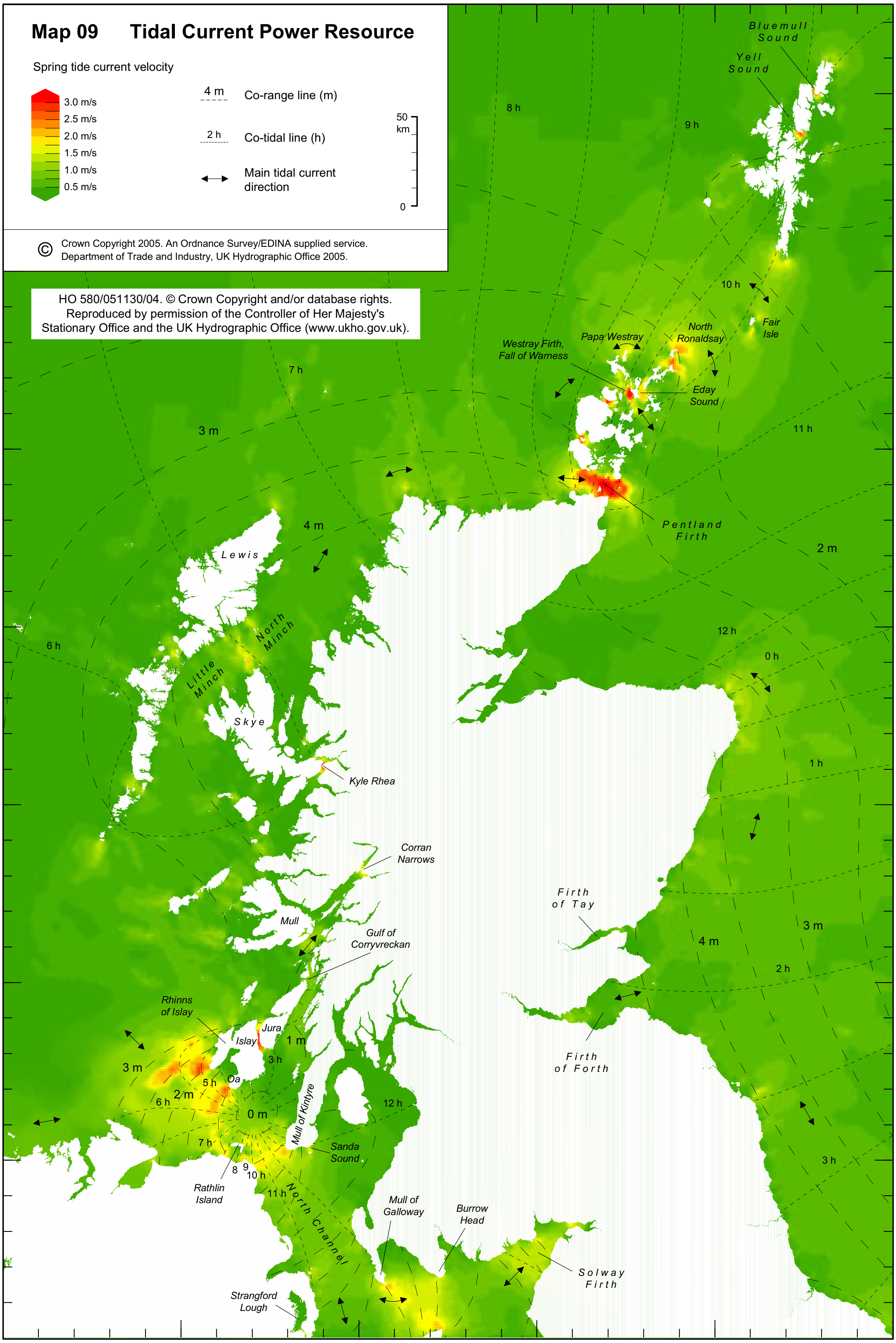
Map 09 Tidal Current Power Resource
Spring tide current velocity
3.0 m/s
2.5 m/s
2.0 m/s
1.5 m/s
1.0 m/s
0.5 m/s
4 m Co-range line (m)
2 h Co-tidal line (h)
Main tidal current direction
50 km
0
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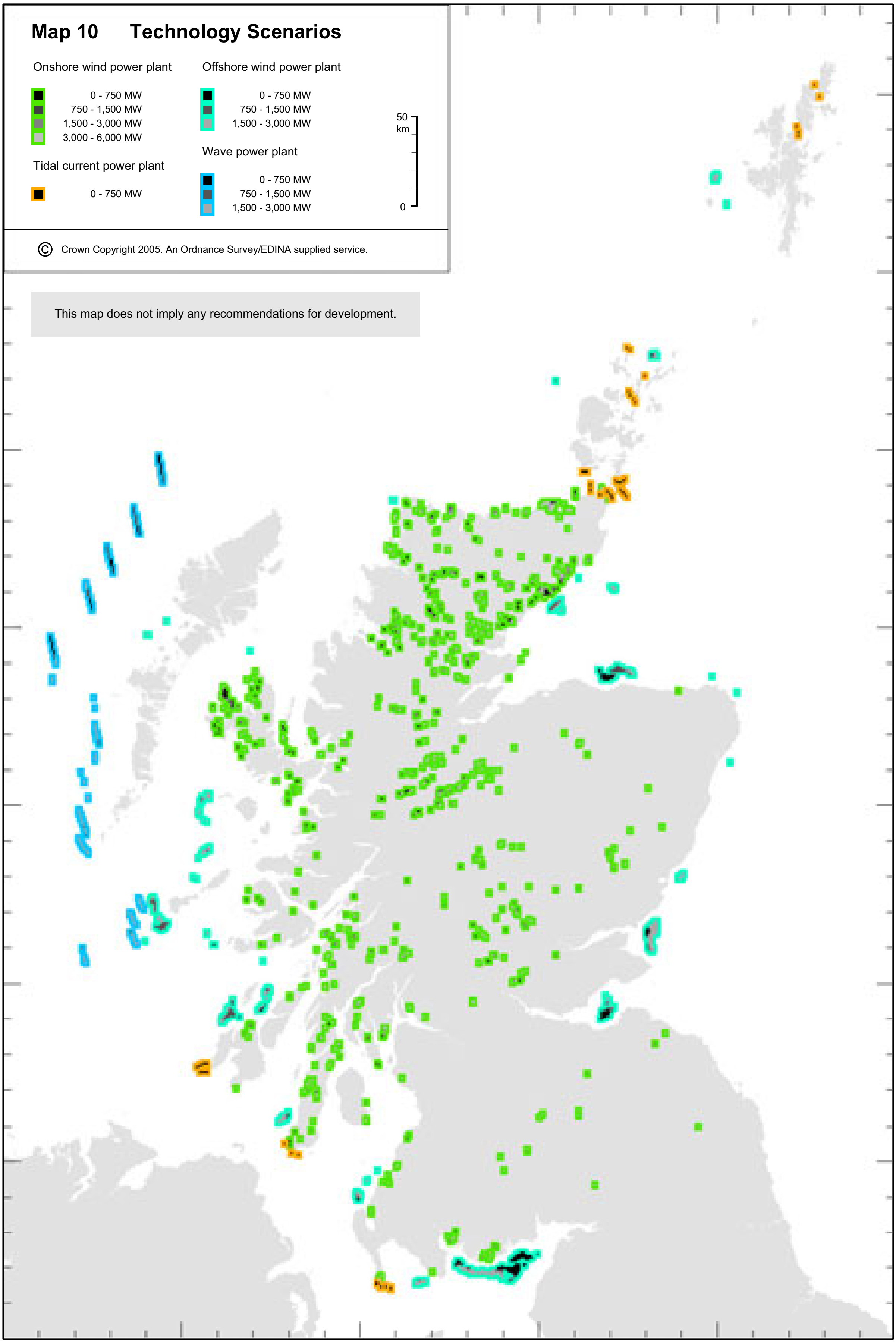
Bluemull Sound
Yell Sound
Fair Isle
North Ronaldsay
Papa Westray
Westray Firth, Fall of Warness
Eday Sound
Pentland Firth
Lewis
North Minch
Little Minch
Skye
Kyle Rhea
Corran Narrows
Mull
Gulf of Corryvreckan
Rhinns of Islay
Islay
Jura
Oa
Mull of Kintyre
Sanda Sound
Rathlin Island
North Channel
Mull of Galloway
Burrow Head
Solway Firth
Strangford Lough
Firth of Tay
Firth of Forth
8 h
9 h
10 h
11 h
12 h
0 h
1 h
2 h
3 h
7 h
6 h
5 h
3 m
4 m
2 m
1 m
0 m

Appendix 9


Map 10 Technology Scenarios
Onshore wind power plant
0 - 750 MW
750 - 1,500 MW
1,500 - 3,000 MW
3,000 - 6,000 MW
Offshore wind power plant
0 - 750 MW
750 - 1,500 MW
1,500 - 3,000 MW
Tidal current power plant
0 - 750 MW
Wave power plant
0 - 750 MW
750 - 1,500 MW
1,500 - 3,000 MW
50 km
0
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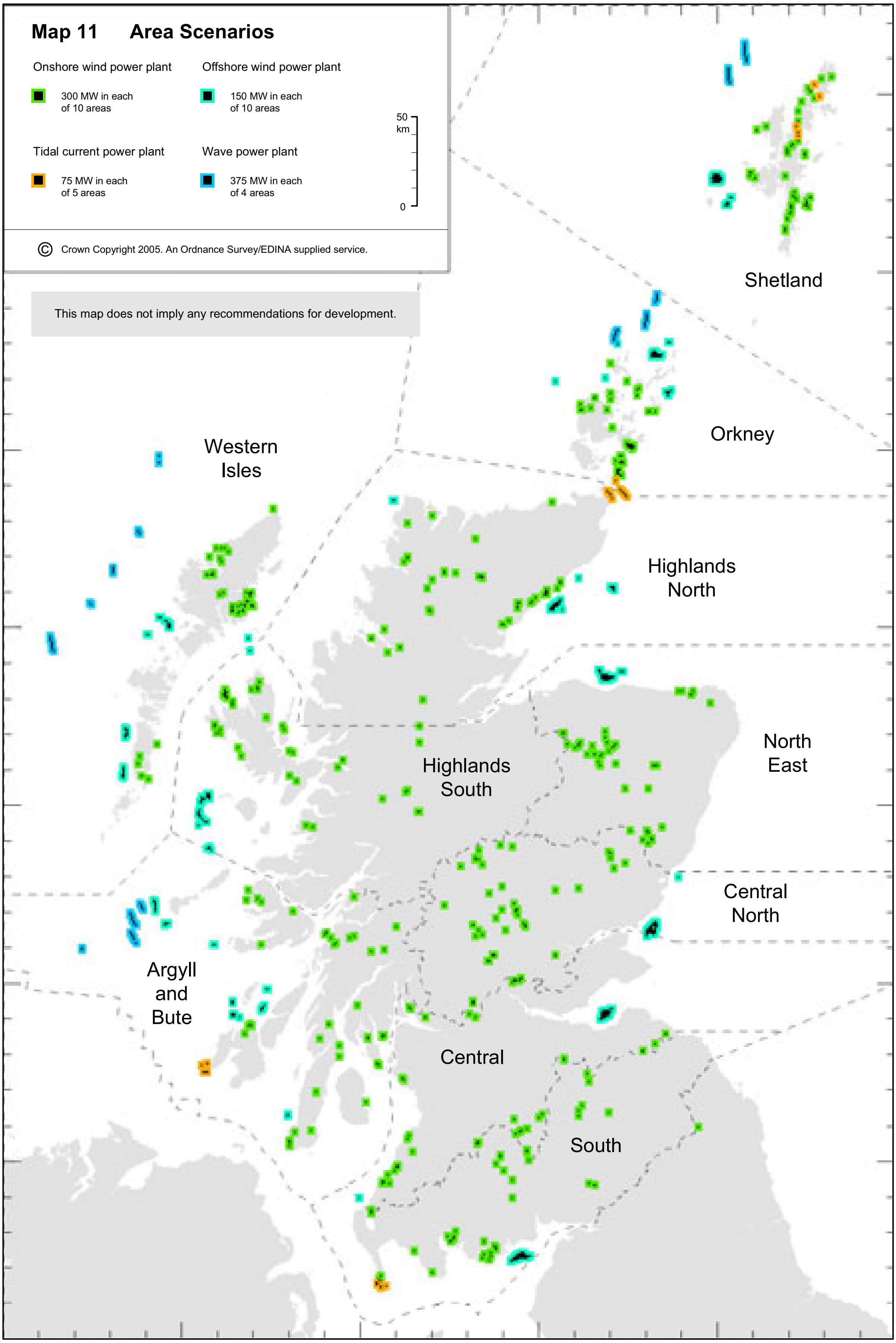

Map 11 Area Scenarios
Onshore wind power plant
300 MW in each of 10 areas
Offshore wind power plant
150 MW in each of 10 areas
Tidal current power plant
75 MW in each of 5 areas
Wave power plant
375 MW in each of 4 areas
50 km
0
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Shetland
Orkney
Western Isles
Highlands North
North East
Highlands South
Central North
Argyll and Bute
Central
South

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