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# RENEWABLE ENERGY SOURCES

Edited by
MICHAEL A. LAUGHTON

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# Watt Committee Report Number 22

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# Foreword

Ever since the oil price increases of the 1970s triggered a wide-spread awareness of the problems of over-dependence on imported energy supplies, there has been increased interest in industrialised countries in the possibilities of obtaining power from locally available renewable resources. Today, after considerable R & D effort, renewable resources are now regarded as capable of supplying a significant proportion of energy in the long-term future. In addition, recent years have seen the growth in importance of environmental issues, which in turn are influencing the energy scene.

The Watt Committee on Energy has always been interested in environmental questions concerning energy. Notable examples were the two *Watt Committee Reports* entitled *Acid Rain* (No. 14) and *Air Pollution, Acid Rain and the Environment* (No. 20), published in 1984 and 1989 respectively. As the latter neared completion, the Watt Committee Executive considered what further studies might be initiated in this area; one of the results was the appointment of the working group that planned the recent Consultative Conference entitled Technological Responses to the Greenhouse Effect', which will be the subject of a further report, due to to be published soon.

During these years, there has been a marked increase in the level of public concern with environmental issues. One of its effects has been a growing awareness of the contribution that might be made by greater exploitation of renewable energy sources—frequently described as alternative energy sources, or 'the renewables'. Conventional large-scale power generation has been widely thought objectionable because it is polluting, causes damage to life and to valued buildings, emits radiation or generates more heavy goods traffic. Whether or not all these objections are valid, there is no doubt that many of the renewables are comparatively free of them. Thus there is justice in the linkage, vague though it is, that public opinion tends to see between the renewables and environmental improvement, although electrical power generation from renewables is not free from other objections.

One of the renewables that seems to be almost entirely free of objections is passive solar design of buildings. This was the subject of *Watt Committee Report* No. 17. In principle, the technique is very ancient, and the methods of applying it today are well known. Its adoption, however, has to overcome the public ignorance of what can be done, the attitudes created by a century or two of cheap energy and the indifference expressed in institutional structures. Much the same is true of electricity generation by small-scale hydro-electric schemes, which was dealt with in *Report* No. 15. The Watt Committee's studies of these subjects received financial support from the Department of Energy. It is not only Government action that affects the decisions of energy suppliers and users, however—more important is the effect of informed public opinion.

The development of public opinion on energy matters is a primary concern of the Watt Committee. As a body representing the professional community, and as a registered charity, it is both authoritative and impartial. This was its standpoint when, in 1986, it appointed the working group on Renewable Energy Sources, whose results are published here.

This report, like the others, is the result of study by a working group leading to a Consultative Conference. The views expressed at the Conference were taken into account in preparing the final text of the report, and in a rapidly changing scene the group found it necessary to go through several stages of revision, especially with regard to the economic assessment of the renewables. The group has tried to grapple with the concepts that apply to renewables as a whole. Expertise has been given freely byall members of the group, and an exceptionally heavy burden has been imposed on the Chairman of the group, Professor Michael Laughton. On behalf of the Watt Committee, I am grateful to him and to them all, and in the period of consolidation that must be expected to follow the restructuring of the electricity supply industry I hope that their results, published here, will assist the public to assess the actual and potential role of the renewables.

**G.K.C.PARDOE**
*Chairman, The Watt Committee on Energy*

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**Part 1**

# INTRODUCTION TO THE REPORT

# Section 1

# Introduction and Summary

## 1.1 INTRODUCTION

This report by the Watt Committee concerns the current status of the technology and opportunities for the exploitation of renewable energy sources. Both technical and economic aspects are covered, primarily in relation to the existing pattern of demand and the organisation of energy supply in the United Kingdom.

As such the Report complements other recently published reports, particularly those by the International Energy Agency (*Renewable Sources of Energy,* OECD, Paris, March 1987), the UK Department of Energy (*Renewable Energy in the UK: The Way Forward,* Energy Paper Number 55, HMSO, London, June 1988) and the House of Lords Select Committee on the European Communities (*Alternative Energy Sources: Report with Evidence,* HL Paper 88, HMSO, London, June 1988). Although there are inevitably areas of overlap with these publications, nevertheless this Report provides an independent and integrated set of contributions from experts which provides fresh information, opinions and comparative analysis of this complex subject. The approach adopted has been mainly one of a general engineering viewpoint, stressing technology, economics and systems integration, but including also discussions of legal and environmental issues as appropriate.

## 1.2 BACKGROUND

During the period of work of the Committee's Working Group the energy supply scene saw the drifting down of oil prices on the international markets along with growing expectations that such low prices will prevail until the end of the century. It was the steep oil price rises of the 1970s coupled with the realisation of undue oil and hence OPEC supply dependence which turned attention initially towards energy efficiency and also to the development of alternative sources. Subsequently, in the aftermath of the Chernobyl nuclear accident, safety, or rather the potential consequences of power plant failure, has become a matter of public concern. More recently, environmental questions related to the transformation of energy, especially the carbon dioxide-linked 'greenhouse effect' and the polluting effects of acid rain, have received growing public and political attention and thus are assuming greater importance in the planning and operation of energy supply systems.

Constraints imposed by such considerations are felt nowhere more so than in electrical power systems which constitute the main potential outlet for energy derived from renewable sources. Although some renewable resources can contribute energy effectively directly in the form of heat, it is through the medium of electrical energy that most contributions can be made.

Finally in this period the test discount rate has been changed from 5% to 8% for the public sector since the completion of the bulk of the work on the Report. In addition the decision was taken to privatise the electricity supply industry. It was considered appropriate not to treat privatisation aspects in the main body of the Report because the consequences are still in the future at the time of writing. On the other hand with such a major change to the electricity supply industry forthcoming the Working Group believe that some comment, albeit speculative, is appropriate and hence include a discussion in this Introduction.

## 1.3 STRUCTURE OF THE REPORT

Each renewable source of energy is considered in turn in separate sections, viz. tidal, wave, wind, small-scale hydro, geothermal, OTEC, solar thermal and photovoltaics, and biofuels. Three overarching sections follow on environmental considerations, the problems of integrating intermittent resources into a public electricity system and, finally, the economics of exploitation of renewable sources of energy. These last two sections are a particular feature of the Report and cover in considerable detail the analysis of both the novel planning and operational problems caused by the addition of large-scale and distributed intermittent sources to an electricity supply system and the appropriate methodology of economic appraisal.

With the study being focused on the United Kingdom, large-scale hydro was considered to be inappropriate, even though opportunities wider than those within the UK were considered for the other renewables.

### 1.3.1 The status of the respective technologies

A common theme is the technical virtuosity that is necessary both in power conversion and transmission and in the necessary civil engineering works in often hostile environments. Such advanced engineering needs are far from the Third World technological image often associated with this area of energy resource exploitation.

All technologies require further research, design and testing to a greater or lesser degree, but the emphasis in need is different from one technology to another. The potential exploitation of tidal power, small-scale hydro, ocean thermal energy conversion and biofuel processes involves mostly tried and tested technologies, whatever the severity of the engineering tasks, whereas some aspects of offshore wave and solar power are still searching for the most appropriate overall system and associated component ideas. Most areas have unanswered scientific questions, particularly concerning engineering materials, which need addressing before efficient designs can be realised; rigorous field testing of the emerging technologies is still largely a subject for the future.

Naturally with new engineering advances learning occurs only from experiences which inevitably include failures. From the evidence out of California, for example, it appears that only comparatively recently have turbines for onshore wind farms been successfully designed in appropriate sizes (less than 1 MW) which withstand the rigours imposed by the operating cycle of stresses. Much further research work remains to be done on the dynamics of cyclic stall, blade profiles, composite lightweight materials for the turbine blades, and integration with individual diesel sets in small power systems; however, some wind turbine designs have now been satisfactorily proven in three or more years' commercial operation and, even though full-life fatigue testing remains, wind energy conversion may now be considered to be a rapidly maturing technology.

The feasibility of tidal power has also benefited from the efforts of industrial engineering design teams in the preparation of proposals for the exploitation of the Severn and Mersey estuaries. Here the engineering problems are well understood with relevant experience gained by manufacturers in other types of project. No significant new technology is required for its development and so specific designs could be realised immediately should these schemes be implemented.

Small-scale hydro power in the mini- and microrange have likewise seen design developments around well-developed technology and established manufacturing facilities. The greatest steps in innovative design have taken place in the application of microelectronics for control purposes, the use of off-the-shelf components and the imaginative exploitation of modern plastics and composites. Again, in this case if institutional barriers (as described later) could be removed, there are resources which could be immediately employed in addition to those already exploited.

With wave power, on the other hand, progress is still in a comparatively early stage, much of it of an investigative kind in university laboratories. One promising technology relates to developments of shoreline wave schemes, which exploit the amplification of wave effects in natural or artificial gullies, and are now showing genuine promise for their use in remote coastal communities with smallscale isolated electricity supplies.

Meanwhile for offshore wave power there are no agreed designs. In view of the size of the resource the engineering challenge will always retain a high profile, as is evidenced by the some 300 schemes proposed. Here the problems appear to be formidable with the range of energies involved, and the scope for university research beyond the initial stages is limited. Success will only be achieved by the greater involvement of engineering companies with offshore design and construction experience in order that ideas may be taken through to the prototype demonstration stage. Such a pattern of activity has happened in the development of wind power which, as a result, now stands at the threshold of commercial success.

Geothermal energy R & D also are activities demanding high levels of financial support, although here much of the expenditure is in meeting the costs of drilling. The Hot Dry Rock technology is still under development and further knowledge needs to be gained of many aspects of hydrofracturing in deep rock structures.

Finally, for the UK, there are the technologies concerned with biomass and solar energy. Five biomass technologies involving the processing and use of dry wastes from domestic and industrial sources, straw and forestry wastes or the digestion of wet wastes and the recovery of methane in prefabricated digesters or in landfill sites, are already demonstrably successful and in commercial use. The technologies allow the use of biofuels in larger-scale electricity generating plants without difficulty should the commercial vision of their potential allow. The Working Group noted that, with regard to the development of equipment generally in this field, the record of the United Kingdom does not compare favourably with other developed countries.

Solar thermal technologies and photovoltaics have greater potential applications in large-scale electrical power generation only in regions of the world with high solar radiation levels. In most other parts increased use would be through the more widespread adoption of active systems for heat and hot water, through passive heating systems *vis-à-vis* buildings, to the professional low power markets of telecommunications, cathodic protection, navigation, and a range of consumer products. Normal commercial interests ensure that the required research and development processes are being undertaken with regard to photovoltaic technology and its applications, particularly in the consumer product markets. This Report draws attention, however, to the need for the wider-scale technology transfer of solar thermal technology in the case of building design and codes of construction. Again in these respects this technology for buildings is available, but apart from water heating in sunnier countries, the applications on a significant scale in northern Europe, including the United Kingdom, are as yet comparatively limited.

The section on ocean thermal energy conversion (OTEC) is included for the sake of completeness *vis-à-vis* worldwide technologies. At present OTEC is demonstrable only on a very small scale, but it is also centred around well-understood plant engineering so is technically achievable without great difficulty. Further investigations need to be carried out, however, on specific cold water pipe, heat exchanger, mooring and power transmission problems before realisation. Although having no relevance to the United Kingdom's domestic energy supply needs, the technology may well make a significant contribution in other warmer, oceanic areas of the world for offshore electric power generation and manufacturing facilities.

### 1.3.2 Prospects for the use of renewables: extent and economics of the exploitable resources

The extent of any exploitable resource depends, of course, on the price that the consumer is willing to pay and so any discussion of the resource base cannot be divorced from assumptions concerning price levels. A characteristic of renewable sources, as of other sources of energy, is that there is a technical resource base and a smaller economic base, which increases in size towards the technical base as the price paid for energy rises. The summary here will be confined to the renewable resources available within the United Kingdom with costs quoted in 1987 terms using a 5% test discount rate unless otherwise stated. It is convenient to measure potential contributions to the energy supply mainly in terms of the UK demand for electrical power and energy, which in 1987 were 52·5 GW maximum demand and 256 TWh respectively. In addition to giving views of costs in respective sections, the Report gives a picture of electricity generation costs based on an independent survey and an analysis of the results which are given in full in Section 13.

United Kingdom tidal power is estimated to have an economic resource of about 45 TWh/year, or approximately 17% of annual demand, which could be exploited at 6 p/kWh or less (1984 prices). Of this by far the largest contribution would come from the Severn Barrage (seaward of Weston to Cardiff) which would generate an average of 17 TWh/year over a large number of years. The design life of the project would be 120 years, but with reasonable maintenance this could be considerably extended. The total installed generating capacity from the 216 bulb set turbine generators would be 8640 MW and the capital cost is estimated at £8260 m in 1988 money with an additional cost of £850 m required for grid strengthening and stability. The cost of electricity at the barrage boundary would range from 1·7 p/kWh at 2% discount rate to 7·2 p/kWh at 10% discount rate. (The above figures are taken from the 1989 report *The Severn Barrage Project: General Report,* Energy Paper Number 57, published by HMSO.)

Such levels of expenditure would make the project difficult to promote wholly within the private sector. It seems, therefore, that this exceptional tidal scheme has to be regarded as a public sector project, the more so because of the widespread regional development consequences.

The same can be argued with respect to the smaller Mersey Barrage scheme which would have an estimated capital cost of £500 million and an output of 1·3 TWh/year at 3·5 p/kWh. Again the regional benefits would be considerable and so to judge such projects on the same commercial terms as other small private generation schemes is not wholly satisfactory.

Of the other technologies small-scale hydro has the lowest unit costs of any conventional or renewable source at unit sizes over 25 kW and depending on the site. The total contribution to UK energy demand would be small, however, comprising only some further 2 TWh/year maximum in addition to the 4 TWh currently supplied.

On a larger scale, wind power is at present the most favoured source and plans have been made to build experimental wind farms at three sites in the UK. Onshore the maximum size of the technical resource which could be used is related to environmental factors and to the maximum allowable penetration of wind power into the national electricity supply. This is estimated to be about 45–50 TWh/ year, or about 20% of demand, although higher limits are thought possible. Generating costs would be down to 2–3 p/kWh at the most attractive sites, the main savings being gained from the reductions in output from low merit coal- or oil-fired plant. At this level of generating cost, power from the best sites is cheaper than that from any conventional power station. Widespread adoption of wind power, however, would necessitate the use of less attractive sites with lower wind speeds, giving rise to higher generating costs. This sensitivity is discussed further and quantified in Section 13. Larger offshore resources are estimated to be available at generating costs of 4–8 p/kWh, although the technology is some years behind the onshore technology.

With relatively small unit sizes and large wind farm space requirements, the rate of build-up of the contribution of wind power to the UK electrical power scene will probably not be as rapid as is hoped for, with environmental considerations playing a major restraining role. In the opinion of the Working Group, however, wind energy is now economically attractive, machines in the range of 500–1000 kW being the most economic size in the future.

The same cannot yet be said of offshore wave power. Although a large technical potential exists of some 50 TWh/year, no offshore energy conversion scheme has yet promised electrical energy below 9·8–17·2 p/kWh according to the Department of Energy. Recent designs of a circular version of the Lanchester Sea Clam may offer a way forward in this respect. Shore-line schemes, however, based on the tapered channel leading to either lagoons or oscillating water columns, look capable of supplying energy at costs of 4–5 p/kWh, thus partly replacing the more expensive energy available from local small-scale fossil fuel conversion.

Biomass has been seen in the UK primarily as a means of providing heat, but this view does not find support elsewhere. In the USA, for example, about 4% of electricity production comes from biomass (which is more than the 3% from nuclear sources) where power plants from 10–70 MW are in operation. The UK view of how this resource should be used is thus somewhat anomalous, although with privatisation pending there is now a significant growth in interest in the possibilities of small private power stations embedded in the low voltage system well suited to the exploitation of biomass resources. Appraisals of the potential contribution to electrical energy production indicate some 40 TWh per annum could be obtained from municipal and industrial wastes by combustion and from landfill gas sites at costs below 7 p/kWh. Such a transformation of wastes would represent 16% of national demand for electrical energy and so, with the addition of possible combined heat and power schemes, confirms the large potential contribution of energy from this source (in sharp contrast to the 1% produced at present).

Electrical power using hot dry rock technology could be generated at 3–7 p/kWh if the technology proves to be feasible, contributing some 2–3% of UK energy demand through economic electrical power and CHP schemes for up to 200 years depending on the depth of drilling. Well drilling rates for numerous small power stations would limit the rate of installation of such plants so that any significant contribution to electrical energy supplies would only be achieved over a long period, reaching perhaps 4·7 TWh/year by 2030 (1·8% of current electrical demand).

What is not possible to predict from these results, however, is the rate at which renewable energy sources will penetrate the UK electricity market over the next few decades. Such penetration will depend on the rate of growth of electricity demand, the rate of replacement of old power stations and the effect of privatisation of the electricity supply industry. The latter is discussed below, but with regard to growth, new power demand is forecast to grow at only 1·8% per year over the next decade; even this rate may prove to be too high with a static population size and with the increasing attention being paid to the efficient use of electricity where considerable savings are possible (*Efficiency of Electricity Use: Report with Evidence,* HL Paper 37, HMSO, London, April 1989). Excluding such major schemes as tidal barrage developments, a contribution of approximately 1% (around 500–600 MW) of the United Kingdom's requirements for electricity by the year 2000 and perhaps of 15–20% by 2030 would be the working Group's most optimistic guess of developments.

### 1.3.3 Environmental considerations

Renewable energy sources can reduce pollution by displacing conventional thermal generation in electricity supply. In practice the anticipated slow take-up of the renewable technologies will not have a significant effect on pollution reduction for many decades to come unless government policies force the pace. Renewables can introduce environmental impacts of their own however, of visual intrusion, noise, interference to radio and TV signals (wind turbines), toxic emissions (biofuels), interference with fish populations and water flow (mini-hydro), conflict of land use and other disturbance to the natural habitat. No satisfactory method of comparative assessment in this area exists; nevertheless the Report tries to cover the subject briefly but systematically in Section 11.

### 1.3.4 Institutional barriers

The barriers facing use of renewable resources and small private generation schemes within the present institutional structures are discussed in several sections. Two difficulties of common concern relate, firstly, to the low prices paid and the absence of long-term contracts for the purchase of electricity from private suppliers by the public supply industry (Area Boards) and, secondly, to the excessive level of local taxation on associated plant, such as wind turbines, which are not utility-owned. In the case of small-scale hydro, inequitable water charges are also levied, the net effect being the cessation of development of this resource.

The first problem may disappear with privatisation in England and Wales because it derives from the 1983 Energy Act and relates to the CEGB Bulk Supply Tariff; the second problem means that local rates are paid at a level ten times that of the CEGB, but hopefully this inequality may be removed by the new rating provisions to come into force in April 1990.

Other barriers exist because of the absence of legislation. Wind rights and geothermal heat rights, ownership of foreshore and areas of port jurisdiction (tidal), for example, have not been clarified for would-be entrepreneurs and will impede the greater commercial exploitation of these renewables.

### 1.3.5 Commercial prospects

Section 13 presents a picture of the cost structure of the renewable sources of energy available within the United Kingdom from which the immediate commercial potential, if not prospects, can be deduced. Against an average break-even price of 3·5 p/kWh paid to the CEGB for the electricity produced, small hydro, wind, geothermal, shore-line wave and tidal power can all provide power more cheaply under the assumptions given. As noted above, the take-up of these new technologies will inevitably be slow, however, in a market-place where there is low growth and already much investment in established technologies and patterns of fuel supply. Perhaps 10% of the UK electricity market could be captured by renewables in 25 years, more if the Severn tidal scheme proceeds.

Although in the United Kingdom's industrialised society exploitation of renewable resources is still in a comparatively early stage, the prospects for the export of the technologies elsewhere in the world must not be forgotten. In many developing countries high rates of growth in electricity demand occur because their societies and industries are still in the initial electrification stage. Here renewable technologies can make faster inroads into the supply structure. These opportunities for trade are discussed further in the various sections.

## 1.4 PRIVATISATION OF THE ELECTRICITY SUPPLY INDUSTRY

The new privatised electricity supply industry in England and Wales will comprise two 'conventional' power generating companies (National Power and PowerGen), a nuclear generating company (Nuclear Electric), a transmission company (National Grid Company) and 12 distribution companies. Not only will the low voltage power distribution function be assigned to the distribution companies, formerly the Area Boards, they will also have the right to generate up to 15% of their power requirements themselves if they so wish.

This latter facility is seen to be especially significant for the use of renewable resources which are of relatively low power density, occur on widespread sites and under most circumstances are more likely to be connected to LV distribution than to HV transmission networks.

While the full consequences of these developments cannot yet be foreseen in their entirety, nevertheless a potentially greater diversity of electricity generation and supply may be anticipated; however, in terms of daily operation, system economic despatch, as exercised by the National Grid Company (NGC), will be authorised only for power stations in excess of 100 MW capacity connected to the transmission system. This lower limit on size is greater than that of most stations using renewable sources other than tidal power stations, so, effectively, renewable sources of generation will not be under the central system control. Indeed in order to hold an Electricity Generation Licence companies producing electricity for supply to others, using their own lines or those of the grid or distribution networks, must have at least one station with a capacity of 50 MW or more. Again this requirement is set too high for most renewable energy sites.

Much of the electricity supply derived from renewables would thus belong to the category of small intermittent, and probably private, generation which would be bought under different terms by the electricity supply companies as and when available. To the distribution companies such energy supplies might appear in effect as negative loads in operational considerations.

Plant operated under central control will be despatched not according to *cost* as hitherto but in ascending *price* order according to an offer price of energy. From 1990 the UK electricity supply system will operate according to many contracts covering both basic energy demands and capacity requirements. Each contract will specify a price for energy supplied (kWh) and a price for capacity (kW). NGC will have sufficient details of these contracts and be able to despatch power in an order related strictly to the lowest price available. Generating companies will be able to offer prices different from their contracts if they so wish the day before. For intermittent sources such as wind, specific site contracts of this nature are inappropriate and so, regardless of the size of the station, many renewables will not fit into this trading pattern. Again this will result in low voltage supply contracts with the distribution companies.

Although a tranche of energy to be supplied by renewables† will be safeguarded within the larger tranche of energy to be supplied from non-fossil fuels, it is evident that such contracts were not formulated with the characteristics of renewable sources in mind. Whereas the outputs from the more predictably available sources such as hydro, geothermal, biomass and tidal could be contracted for, those from wind and wave energy can be neither predicted nor depended upon on a site-by-site basis and so cannot be operated satisfactorily according to this form of contract. As described in Section 12, firm power statistical assumptions can only be made about many sources *on a total system basis*. These assumptions can then be incorporated into operating and capacity planning practices.

The prospects of renewables gaining a larger part of the reserved non-fossil fuel tranche are somewhat questionable for other reasons. At present most renewable forms of electricity generation are not available in sufficient amounts to displace the contracted capacity of any single nuclear power station. The minimum quota which the Distribution Supply companies will have to purchase may tend to bind the companies by taking the maximum nuclear capacity available, which will thus be shielded from competition. The costs of nuclear stations make it unlikely that any new stations will be built without the guarantee of longterm contracts. Without such commitment the private investors would be exposed to the risk of not even covering their fixed costs. In

† This tranche of energy reserved for renewable resources can apparently be filled also by imported renewable energy, specifically from French hydro stations. Two obstacles preventing significant exploitation in such a way are (i) the limited capacity of the interconnector between France and England, and (ii) the total lack of identification of the power flow through the cross-channel link with the output of any particular French power station.

this way competition is reduced to very little and only at the point of time of the investment. (Such a lack of long term contracts with the Area Boards for the output of the proposed Fawley B coal-fired station led to its recent cancellation by the CEGB.)

With cheap electricity being available from France, the net effect could be to freeze renewable energy sources out of the larger unreserved nonfossil quota. In such circumstances the forecast made by the CEGB to Sub-Committee B of the Select Committee on the European Communities in its inquiry into Alternative Energy Sources, that renewables could contribute up to 7% of the likely UK electricity demand before the year 2005 and up to 17% by 2030, looks decidedly optimistic unless renewables compete for the energy otherwise supplied by fossil fuels or the government makes more use of the fossil fuel levy and promotes renewables.

Here the argument becomes one of whether renewable-derived electricity can be generated at costs below that generated from imported coal. Such coal is at present the international marginal energy source. Although a relatively small amount of coal is traded on the world markets (approximately 140m tonnes), prices are relatively immune to increases caused by greater demand because of the considerable resources available, i.e. cheap imported coal has low price elasticity. Again, however, the matter of long-term contracts being made for entire station outputs intervenes and so the question remains, as for nuclear stations, whether renewables can supplant not just part of a station output but an entire station output.

In one respect privatisation for several reasons should lead to plants with smaller unit sizes than has been the custom hitherto. Such a trend should benefit many renewable source developments but not others such as large tidal schemes.

In Section 13, on the Economics of Renewable Energy Sources, the sensitivities of electricity generating costs to possible changes in assumptions about basic factors for the various types of renewable sources are calculated. In particular the effects on generation costs (p/kWh) of increasing discount rates above the nominal 5% attached to central government funding in the past are shown. With interest rates governing private capital supply being much higher than 5%, the attractiveness of electricity generation projects with relatively high capital costs should decrease. Costs of renewable sources of power are dominated by initial capital costs, so it might be anticipated that renewable along with nuclear power will be more disadvantaged by commercial lending rates than coal- or oil-fired power stations which have lower capital costs and higher running costs.

In conclusion it is apparent that the Working Group do not believe that privatisation will work to the unmixed benefit of renewable resource development. New institutional and financial factors would seem positively to harm the prospects of increasing the proportion of electricity supplied by such means, whereas the government's intention might be otherwise.

## 1.5 CONCLUSIONS AND RECOMMENDATIONS

Costs of coal and oil have not risen in line with earlier expectations, neither has electricity demand. These circumstances coupled with the realisation that renewables do not afford soft technological options have not served the cause of their development well. On the other hand growing environmental pressures coupled with a decreasing public support for nuclear power may serve to promote investment in some renewable schemes.

It is evident that in the long term the UK has a technical abundance of renewable energy resources and, if all this could be utilised through a sustained programme of research and development, there would be far more than could ever be used domestically. The Working Group notes, therefore, that the substantial exploitation of these resources can occur only in a European context, which implies considerable transmission of electricity by undersea cable into a larger European grid.

The large peak power output of the Severn Barrage scheme has often been associated with such an idea, albeit to cross-channel links to France, but in view of the disposition of renewable resources elsewhere in the country, particularly in the north-west, other links across the North Sea would have to be considered. This would be a subject for much further study.

The classification of the respective technologies as economic or otherwise has not featured strongly in the Report because such assessments depend strongly on the costs of alternative forms of energy supply. These in turn depend on the degree of subsidy received within the existing supply system and the expected rate of return on the investment. In the case of the UK electricity industry a rate of return on capital has existed which is much lower than the nominal 5% test discount rate and, under the same circumstances, renewables with their high capital costs per kWh of energy output would have artifically high economic attractions.

To evaluate renewable options on a basis other than that enjoyed by existing conventional plant, however, is also artificial. The cases of eccentric local tax rates and low purchase prices for electricity generated by private suppliers have been noted. These and other unfortunate barriers and influences serve to distort the rate of market penetration of the new emerging renewable technologies. In addition future costs will be dictated largely by higher private financial market discount rates and periods of capital recovery shorter than technical lifetimes. Both figures, although resulting in higher priced electricity, are at present unknown. Indeed it should be emphasised that estimates of future costs and opportunities for the emerging renewable technologies as a whole entail at present much uncertainty because of the absence of a sufficient number of proven schemes, a situation which will change over the next few years.

One major weakness of short-term commercial analyses emerges in the case of the Severn and other tidal power schemes. Discounting the long-term future in investment appraisal techniques does not give proper weight to the value of such schemes where, if the initial capital is recovered in, say, 25 years, the output of electrical energy for the next 100 or 200 years is at practically zero cost. In such cases of long-term investment to the great benefit of the nation there must remain a role for public funding if private capital will only initiate short-term ventures.†

On the other hand government support through the selective funding of research and development in universities, polytechnics and industry has been highly effective in the promotion of some ideas through their initial stages. Further support of industry has also brought an enhanced state of awareness through demonstration of the possibilities of using some renewable resources. The role of government in the third stage of utilisation in the electricity supply industry is as yet at a fairly early stage, and thus at a low level, apart from the provisions made for renewables in the electricity privatisation legislation.

† This opinion is, of course, part of long established economic theory, viz. The sovereign (government) has the duty of erecting and maintaining certain public works which it can never be for the interest of any small number of individuals to erect and maintain; because the profit could never repay the expense to any small number of individuals though it may frequently do much more than repay it to a great society', Adam Smith, The Wealth of Nations, March 1776.

The Working Party recommend specifically

—the continued government support for R & D activities of all renewable technologies consistent with a long-term national energy policy;
—the preparation of a detailed geographic survey of domestic onshore and offshore resources for all renewable energy types;
—the removal of institutional barriers which distort the market for renewable energy, particularly biased taxes and electricity prices;
—legislation to clarify rights of ownership of renewable resources such as wind and heat and to remove unnecessary obstacles and penalties in the use of water;
—the encouragement of passive solar technology by 'gentle legislative pressure' of appropriate building practices and building codes;
—the treatment of the very large projects such as the major tidal power schemes as public sector projects in view of their very wide regional impacts, thus attracting a measure of public funding (whatever the degree of private financing and ownership) and measuring their return by normal Treasury rules for public sector investments rather than by private sector measures of short-term profitability;
—support for the development of manufacturing industry in those technologies deemed economic for exploitation, taking note of comparable government support elsewhere and openness or otherwise of markets to foreign suppliers;
—that the government should watch the development of these embryonic and hence vulnerable technologies in a market-place dominated by the big utility companies and in which there is an overcapacity, in order to take further appropriate action if necessary;
—that the government should in particular consider the position of Scotland where the very high surplus generating capacity coupled with the availability of some low cost hydro is resulting in uneconomically low prices being offered for electricity from renewable sources. In addition there are no non-fossil fuel/renewable obligations for Scotland in the Electricity Bill. This situation is unfortunate in view of the high concentration of wind and wave resources there coupled with the already limited transmission capacity between Scotland and England. Questions arise as to the appropriate development and indeed ownership of what have hitherto been thought, incorrectly perhaps, to be national resources.

# Section 2

# The Place of Renewable Energy as an Energy Source

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## 2.1 INTRODUCTION

This section provides a background to the status of renewable energy technologies achieved within IEA countries by the late 1980s. Many statements are derived from the findings of an extended study (*Renewable Sources of Energy,* IEA/OECD, Paris, 1987, ISBN 9 264 12941 1) published by the IEA in 1987. The study was prepared over a period of several years in close collaboration between the IEA and a number of leading experts in their respective fields. It is an attempt to give a critical and comprehensive review of the technological and economic status of renewable energy technologies. It includes information on all IEA member countries, and on major developments in non-member countries where available.

To begin with, let me refer to some principles of general energy policy and energy research and development policy which have been agreed upon and have been confirmed recently by the governments of IEA member countries. These principles are supposed to be guidelines for all energy and energy RD&D related decisions by member governments.

## 2.2 IEA RENEWABLE ENERGY RD&D POLICIES

Renewable energy technologies are certainly not yet a cornerstone of primary energy supply in industrialised countries. Nevertheless, they have attracted much attention during the past 15 years. In IEA countries, after the experience of two severe oil supply crises within less than one decade, the common general and central energy policy objective remains to maintain security of energy supply in both the short and long term as a basic condition for economic prosperity. Energy policy has, therefore, to consider carefully all aspects of energy supply and consumption. Although every country in this regard has a responsibility on its own, the history of the last 15 years has revealed that a collaboration among countries with similar interests is very important. The most prominent feature in the situation of the industrialised countries in the energy supply sector during this period was, and to a certain degree still is, their dependence on imported oil, the oil price and availability thus being of crucial importance for any national economics. The impact of high or low oil prices, respectively, cannot be derived from simple models as most complex and sometimes unpredictable economic processes are involved. It can be assumed, however, that the currently low oil prices have stimulated economic prosperity in consumer countries whereas they have been rather harmful to the producers. Likewise, other options in the energy market have become less competitive and attractive inhibiting the short and medium term prospects of energy technologies which, for different reasons, should be strongly supported. This, in particular, applies to renewable energy technologies.

The governments of the IEA countries have, therefore, affirmed and extended their earlier decisions on common energy policy rules—including the RD&D (research, development and demonstration) sector—that will, on a co-operative basis, help to achieve and maintain the basic objective of a steady and secure primary energy supply. These energy policy aims include promoting a free international energy trade, benefiting and avoiding detriments from the currently lower energy and oil prices, and improving preparation for the expected increase of the oil price in the 1990s and for possible unexpected disruptions in energy supply. The continued development of indigenous energy resources and energy technologies—in energy production and conversion as well as in consumption and in the end-use sector—must be a most prominent objective of energy policy in the future. It is of special interest that in a meeting communiqué of IEA energy ministers, RD&D for renewable energy sources, among other areas, has been given special attention and the need for enhanced international collaboration has been emphasised. At the same time environmental considerations in energy politics have become more and more important and the effect of global warming and climatic change through emission of carbon dioxide and other 'greenhouse gases' has now become an issue of major concern. Energy ministers affirmed the need for early actions in this area. Renewable energy technologies, generally being considered to be environmentally benign, thus find themselves in a most encouraging position as far as the fundamental line of RD&D policy in IEA member countries is concerned. This, however, does not always tie in with the recent development of government RD&D budgets devoted to them, as we will see later.

## 2.3 STATUS AND PROSPECTS OF RENEWABLE ENERGY SOURCES IN IEA COUNTRIES

The IEA, which for their government-supported work has already been following for some years the principles mentioned above and recognising the growing importance of additional energy carriers and of environmental protection measures in energy production, has been promoting international co-operation in renewable energy technology projects over a period of more than ten years, thereby providing the legal frame for this collaboration by means of Implementing Agreements (IA) and stimulating the national authorities' interest. It may be fair to assume that for at least some of the examples of technologies which will be described, this IEA-initiated international collaboration has been quite instrumental in the attainment of their current status.

It may be useful to recollect that, when after the first substantive oil price increase about 1974 the public and private sector in IEA countries made the first committed effort to develop the renewable energy sources and technologies systematically and many IEA member countries were initiating their renewable energy programmes, most of these technologies were in the conceptual stage or existed in first-generation forms. Only large hydro-electricity generation and wood (biomass) fired boilers for steam and electricity generation had been proven technically mature and used commercially for a long time.

Since then major efforts to develop renewable energy technologies have been made. Much successful research, development and demonstration work has been accomplished from the design of photovoltaic cells to the development of geothermal drilling techniques. New materials have been developed with the thermal, optical and physical properties required for lower cost and higher performance. New components have been tested and substituted for less effective ones. Extensive systems analysis has been performed with thousands of systems studied under both controlled laboratory conditions and typical field operation conditions. Throughout the world, teams of scientists and engineers in universities, industry and government laboratories have created a solid technology base and expertise in the extremely broad array of disciplines that make up renewable energy technologies.

Today, renewable energy sources are used in most countries, and, in some, these sources contribute significantly to the national energy supply. In all IEA countries their contribution to the energy supplies is growing as R&D efforts are reaching fruition and market penetration increases. Renewable energy (excluding hydroelectric generation) provides between 1% and 5% of total primary energy requirements in Australia, Austria, Canada, Denmark, Sweden and Switzerland. In Ireland, peat resources provide about 8% of the country's primary energy requirements and in Portugal biomass resources cover about 7% of those requirements. In absolute terms in the United States, the energy contribution from renewable energy sources amounts to about 64 million metric tons of oil equivalent per year, which is, on the other hand, roughly equivalent to the total energy requirements of the Netherlands.

To give some numbers and an idea of how the contribution of renewable energies to the national energy balances of the IEA countries has developed, Table 2.1 shows the total renewable energy production as a percentage of the total primary energy requirements (TPER) for the years 1973 to 1986. These numbers all include hydroelectric power generation, which is a true and in many cases economic renewable energy source, but being mature and commercial is generally not included in RD&D considerations or programmes.

The high values shown for Canada, New Zealand, Norway, Sweden and Switzerland are mainly due to hydropower electricity generation. In Norway, hydropower accounts for as much as *c.* 55% of that country's TPER. The IEA total numbers show a generally slightly increasing tendency over the years with some uncertainties in recent years for future extrapolation.

On the other hand, compared with the mid 1970s, expectations concerning the pace of development are now more realistic. Fuel costs, far from rising as fast as expected, have in fact recently fallen drastically, affecting all alternatives. Better assessments of the time needed for development and market penetration exist. These factors, combined with budgetary constraints, have weakened some governments' support and industry interest in developing renewable energy technologies.

The important intrinsic factors for renewable energy technologies that will decide which place these sources can take in future within a highly competitive energy world, are

- —the available resource base;
- —the technical status of the technology used to turn the resource into usable forms;
- —the type and quality of energy supplied.

Resource assessments are important for governments to estimate the potential contribution to national primary energy requirements as well as for special renewable energy projects to be economically successful.

The combined potential of all renewable energy sources is thought to be enormous and virtually untapped after 15 years of rapid technology development. Summarising some particularly good examples of assessment of these potential resources that have been reported for IEA countries gives a rough indication of the magnitude:

- —active solar, between 1% and 2%, and biomass, over 7% of total energy requirements in all IEA countries;
- —geothermal, hundreds of thousands of MWh equivalents;
- —wind, 2 million GWh annually in European countries.

Unfortunately, at the IEA no detailed assessments or estimates on Third World or eastern countries exist. It

**Table 2.1 IEA renewable energy production as percentage of total primary energy requirement**[a]

| | 1973 | 1974 | 1975 | 1976 | 1977 | 1978 | 1979 | 1980 | 1981 | 1982 | 1983 | 1984 | 1985 | 1986 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Canada | 24·34 | 25·70 | 24·10 | 23·94 | 24·04 | 24·99 | 24·76 | 25·12 | 26·96 | 27·05 | 27·94 | 28·62 | 29·09 | 29·72 |
| USA | 3·52 | 3·98 | 4·07 | 3·65 | 2·75 | 3·37 | 3·38 | 3·47 | 3·39 | 4·15 | 4·46 | 4·18 | 3·69 | 3·82 |
| Australia | 4·43 | 4·93 | 5·32 | 5·30 | 4·42 | 4·70 | 5·02 | 4·26 | 4·54 | 4·25 | 3·89 | 3·82 | 4·29 | 4·44 |
| Japan | 5·20 | 6·06 | 6·46 | 6·28 | 5·37 | 5·18 | 5·66 | 6·25 | 6·33 | 6·04 | 6·25 | 5·12 | 5·84 | 5·30 |
| New Zealand | 37·92 | 36·29 | 40·30 | 34·57 | 32·33 | 35·91 | 41·34 | 41·20 | 42·16 | 37·61 | 39·89 | 37·63 | 35·30 | 36·40 |
| Austria | 17·78 | 21·22 | 22·79 | 18·83 | 22·79 | 22·22 | 22·98 | 24·07 | 25·96 | 26·65 | 26·33 | 24·42 | 25·44 | 25·74 |
| Belgium | 0·31 | 0·34 | 0·23 | 0·17 | 0·23 | 0·24 | 0·27 | 0·41 | 0·57 | 0·58 | 0·66 | 0·71 | 0·71 | 0·73 |
| Denmark | 0·03 | 0·03 | 0·03 | 0·03 | 0·03 | 0·02 | 0·03 | 0·04 | 0·04 | 0·04 | 0·08 | 0·10 | 0·11 | 0·21 |
| W. Germany | 1·30 | 1·54 | 1·58 | 1·20 | 1·50 | 1·52 | 1·44 | 1·52 | 1·70 | 1·74 | 1·67 | 1·57 | 1·47 | 1·53 |
| Greece | 3·97 | 4·42 | 3·67 | 3·17 | 2·98 | 4·32 | 4·88 | 4·68 | 4·79 | 4·86 | 3·11 | 3·65 | 3·41 | 4·10 |
| Rep. Ireland | 1·98 | 3·00 | 2·31 | 2·74 | 2·95 | 2·97 | 2·96 | 2·97 | 3·17 | 3·09 | 3·04 | 2·67 | 2·88 | 2·87 |
| Italy | 7·03 | 7·05 | 7·91 | 7·08 | 9·06 | 8·05 | 7·83 | 7·85 | 7·74 | 7·72 | 7·74 | 7·79 | 7·53 | 7·43 |
| Netherlands | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Norway | 55·43 | 58·33 | 57·96 | 56·99 | 50·70 | 51·84 | 54·66 | 52·15 | 57·06 | 58·33 | 62·55 | 60·40 | 58·44 | 53·98 |
| Portugal | 20·07 | 20·60 | 16·37 | 12·09 | 23·28 | 23·09 | 22·04 | 15·79 | 10·42 | 12·64 | 14·55 | 17·19 | 18·88 | 14·44 |
| Spain | 11·88 | 11·68 | 9·72 | 7·82 | 13·80 | 13·28 | 14·65 | 9·59 | 7·30 | 8·67 | 8·96 | 10·15 | 9·96 | 8·32 |
| Sweden | 28·28 | 28·63 | 27·50 | 24·70 | 24·59 | 26·41 | 26·64 | 27·75 | 27·27 | 26·47 | 29·49 | 29·91 | 29·15 | 24·89 |
| Switzerland | 27·78 | 29·31 | 34·38 | 27·46 | 34·71 | 30·81 | 30·40 | 30·29 | 32·75 | 34·19 | 31·71 | 27·48 | 27·59 | 27·04 |
| Turkey | 2·39 | 2·93 | 4·82 | 6·22 | 5·81 | 6·23 | 7·16 | 7·61 | 8·31 | 8·63 | 6·86 | 7·94 | 6·77 | 6·04 |
| United Kingdom | 0·46 | 0·50 | 0·55 | 0·56 | 0·56 | 0·56 | 0·55 | 0·57 | 0·62 | 0·65 | 0·75 | 0·70 | 0·76 | 0·76 |
| IEA total | 5·66 | 6·22 | 6·40 | 5·89 | 5·59 | 5·94 | 6·11 | 6·23 | 6·42 | 6·84 | 7·17 | 6·94 | 6·81 | 6·73 |

[a] Source: country submissions.

can be assumed from geographical and social reasons, however, that in many of these countries considerable potentials exist, especially for biomass and solar energy, that could be exploited if adequate technologies are applied. This certainly would help not only to improve the living conditions of these peoples but also to save their environment.

In fact, it has been found by the IEA study mentioned earlier that the technical and economic status are two of the most important factors for introduction of a technology into the market. The economics of a renewable energy technology are of course not an intrinsic factor but highly dependent on actual energy prices, which can change rapidly. The combined technical and economic status of a technology can be classified into one of the following four stages as is shown in Fig. 2.1:

(1) 'Economic' technologies which are well developed and economically viable at least in some markets and locations; further market penetration will require technology refinements, mass production, and/or economies of scale;
(2) 'Commercial-with-incentives': technologies which are available in some markets but are competitive with the conventional technologies only with preferential treatments such as subsidies; these technologies still need further technology refinements, mass production, and economies of scale;
(3) 'Under-development': technologies which need more research and development to improve efficiency, reliability or cost so as to become commercial; this would include materials and systems development, pilot plants or field experiments to resolve operational problems and environmental impacts and demonstration plants to illustrate performance capabilities and to establish cost and performance capabilities of specific applications;
(4) 'Future-technology': technologies which have not yet been technically proven, even though they are scientifically feasible; applied R&D on components would fit into this stage, as would bench-scale model development at laboratory levels to establish the technical viability of the technology.

For a technology to be classified under one of these stages, most of its recent applications should have reached this stage, and this list represents the results of the more detailed technical and economic analysis of the study.

ECONOMIC (in some locations)

- Solar water heaters, replacing electricity, or with seasonal storage and for swimming pools
- Solar industrial process heat with parabolic trough collectors or large flat-plate collectors
- Residential passive solar heating designs and daylighting
- Solar agricultural drying
- Small remote photovoltaic systems
- Small to medium wind systems
- Direct biomass combustion
- Conventional geothermal technologies (dry and flashed steam power generation, higher temperature hot water and low temperature heat)
- Tidal systems*

COMMERCIAL-WITH-INCENTIVES

- Solar water and space heaters, replacing natural gas or oil
- Electricity generation with parabolic trough collectors
- Non-residential passive solar heating and daylighting
- Biomass liquid fuels (ethanol) from sugar and starch feedstocks
- Binary cycle hydro-geothermal systems

UNDER-DEVELOPMENT

- Solar space cooling (active and passive)
- Solar thermal power systems (other than parabolic trough collectors)
- Photovoltaic power systems
- Large-sized wind systems
- Biomass gasification
- Hot dry rock geothermal
- Geothermal total flow prime movers
- Wave energy systems

FUTURE-TECHNOLOGIES

- Photochemical and thermochemical conversion
- Fast pyrolysis or direct liquefaction of biomass
- Biochemical biomass conversion processes
- Ocean thermal energy conversion systems
- Geopressured geothermal
- Geothermal magma

**Fig. 2.1.** Current status of renewable energy technologies. (*Only one tidal system, which was built in 1968, is presently operating commercially (in a non-IEA member country). All other tidal projects are either proposed or in a demonstration stage, and would be considered to be 'Under-development' until built and proven 'Economic' at a specific site under today's conditions.)

### 2.3.1 Economic renewable energy technologies

*Active solar water, swimming pool, space heating and industrial process heating systems* are presently economic primarily in areas with good solar energy resources and high fuel costs. Systems serving larger energy demands tend to be more economic. Millions of simple solar water heating systems have been sold in IEA countries, mainly in the sunniest regions. Fewer space heating systems have been installed. Residential installations account for the majority, but many successful commercial installations exist as well. The widespread requirement for hot water and space heating in both sectors and the general availability of solar energy throughout IEA countries indicates a significant potential for further penetration of the technology. R&D is concentrating on improving efficiency, reliability and durability of components, reducing the materials-intensiveness of solar collectors with new materials and improving energy storage capabilities, especially for space heating

*Passive solar designs,* combined with conservation techniques, can economically provide a large share of the energy needed for residential space heating, and many cost no more than conventional designs. Passive solar can be adapted to a wide range of climatic conditions; thus the potential for the application is great in most IEA countries. The extent of present diffusion of the use of these techniques cannot be known exactly but is felt to be a very small fraction of its economic potential. Dissemination of information on the technology to the public and building industry is most important for increasing the penetration rate of this technology.

*Wind technologies* are fairly advanced for *small- and medium-sized installations* (up to 500 kW). Small- and medium-sized wind power systems offer a promising alternative in high resource areas, such as some coastal areas or areas with unusually high wind conditions. Over 10 000 wind machines have been installed in the last decade, the bulk of these in 'windfarms', although only recently have such installations begun to be economic without subsidies. Development of small-to-medium sized turbine technology is relatively mature; however, this size of wind system could benefit from mass production. Further R&D should concentrate on improving wind capture potential, reliability, life expectancy and availability to substantially reduce costs and enhance performance, thereby increasing the number of sites where wind systems would be economic. More accurate site-specific assessments of wind energy potential would spur market interest in countries and regions where there is potential but little market penetration to date.

*Biomass technologies* for providing *heat and combined heat and power plants* based on wood, peat and municipal wastes are in widespread use with many applications. Hundreds of small-scale systems for electricity generation, industrial process energy and district heating with wood, peat, refuse-derived fuel, industrial waste and straw are presently in operation in numerous IEA countries. These plants are especially attractive for agricultural or forestry industries since biomass transportation costs are minimised. Wood stoves for residential heating are widely used, in fact, so much so that in some areas they are causing concern for environmental degradation of air quality caused by emissions. R&D is being conducted to develop energy crops which increase biomass supplies, to densify biomass fuels, and to develop lower cost collection and handling equipment.

*Anaerobic digestion* to produce methane is widely used in many IEA countries. This use is increasing because of process improvements and advances in the feedstocks which can be utilised and in feedstock pretreatment. Dissemination of information on how and where this technology is applicable and economic could further expand the use of this technology.

In some of the best geothermal fields, costs for *electricity generated by geothermal hydrothermal* technologies (using high temperature steam or flashed hot water) are half the cost of oil-fired generation and three-quarters of the cost of nuclear or coal generation. At the end of 1986 approximately 5500 $MW_e$ were operating worldwide. New plants are being constructed, and some existing installations are being expanded.

In addition, *low-grade geothermal heat* contained in warm and hot water aquifers is being exploited economically for *space heating and district heating*. Most uses of the technology where the resource is adequate are less costly than or equal to oil heating costs. At the end of 1984 a capacity of over 7000 $MW_{th}$ was installed worldwide. The primary limitation to increased use of geothermal direct heat is geographical.

*Tidal power systems* are economic when compared to total cost of conventional oil generation but still almost twice as expensive as coal-fired generation. However, there is presently only one tidal energy power station in operation. Because the technologies for construction of tidal systems are well developed, economy of scale is one of the most important factors for the utilisation of tidal energy. Tidal power projects are therefore likely to be quite large in comparison with other renewable energy projects. Proposals for tidal power projects estimate a required capital investment in excess of a few thousand million dollars.

### 2.3.2 'Commercial-with-incentives' renewable energy technologies

Two *solar thermal* technologies, *parabolic troughs* and *solar ponds* for the production of industrial process heat, are much further advanced developmentally than the other solar thermal technologies. However, only a few systems had been installed before tax advantages in the United States were eliminated and oil prices dropped. Improved manufacturing economies would make the most impact on increased penetration.

*Solar water and space heating replacing natural gas or oil heating systems* has experienced some market penetration in Japan without incentives, but elsewhere with the assistance of government incentives, which offset the added cost (presently up to 1·5 to 2 times more expensive than the alternative). This industry has declined significantly in countries where these incentives have been removed.

### 2.3.3 'Under-development' renewable energy technologies

*Active solar space cooling* technology still requires substantial R&D despite many advances in the technology to date. R&D is concentrating on increasing the efficiency of energy conversion equipment, such as desiccant-dehumidification cooling, absorption cooling, and hybrid systems. With success in making these improvements, the efficiency of solar cooling systems is expected to increase by a factor of two which could make them economic in good resource areas by the year 2000.

*Passive solar space cooling techniques* lag behind passive solar heating techniques in terms of research and use. Their usefulness also appears more limited since they are more dependent on local climatic conditions. Use of this technology in all types of structures still needs R&D emphasis.

A number of *solar thermal technologies* (parabolic dishes and troughs, central receivers and solar ponds) are based on different system concepts for receiving and converting the solar energy to useful energy. A decade of development has brought the specific costs of present systems for electricity generation to a factor of two to six times higher than conventional alternatives except for troughs, the cost of which are only two to four times higher.

*Photovoltaic electricity generation* development has succeeded in bringing generating costs to around 10 times the present costs of conventional generation. Reaching the economic stage is projected to occur by the mid-1990s. Only remote applications and consumer products have seen any market penetration, and in 1984 worldwide photovoltaic shipments totalled about 25 MW. Photovoltaic technology development currently is taking a variety of approaches in order to produce more efficient cells at less cost.

Demonstrations of *large-scale wind systems* have proved to be three to six times more expensive than conventional generation. Many technical problems must be overcome by R&D in the areas of blade design construction and testing, aerodynamics and atmospheric physics and materials. Other areas of R&D which could enhance the potential of both large and small systems are development of load following diesel-hybrid systems, offshore wind energy stations, and techniques for improving interconnection with electric grids to reduce surge problems.

In the area of *biomass gasification,* several technologies are being developed, and low BTU gasification techniques have reached demonstration stages. In general the costs presently exceed the cost of conventional sources by a factor of 1·5 to 2·5, although this technology is marginally competitive in some agricultural applications.

Testing of a *geothermal* total flow prime mover has been completed in several countries. Recent Hot Dry Rock technology developments have shown that reservoirs can be created and that this technology can produce hot water. Progress is still needed in demonstrating the heat capacity of the reservoirs.

A variety of designs for *wave energy conversion devices* are being developed and tested. Some experience with costs of these types of systems indicates that they are around twice as expensive as diesel generation. Full-scale testing is occurring in two recent, privately constructed projects in Norway with projections of costs being close to competitive with conventional generation. R&D is concentrating on ways to improve energy conversion efficiency and system design, integration and components.

### 2.3.4 'Future-technology' renewable energy technologies

Biomass technologies such as *fast pyrolysis, direct liquefaction and biochemical conversion* are being pursued because of the large biomass resources available and because they promise to produce liquid and gaseous fuels and energy-intensive petrochemical substitutes. Some of these products could be available commercially around the year 2000. Technologies to tap *geopressured geothermal* and *magma* sources of geothermal energy are being developed in order to greatly expand the amount of resource which is considered economically useful. The very large potential offered by these energy sources is offset, at least initially, by the high costs of developing the technologies. Magma R&D is at the level of development of equipment and materials capable of withstanding the very high temperatures that will be encountered. Geopressured geothermal resources development requires combining systems to capture dissolved methane with others to extract heat. *Ocean thermal energy conversion technologies* are being developed because the potential resource is very large.

## 2.4 GOVERNMENTAL SUPPORT TO RENEWABLE ENERGY RD&D

This section will not go into detailed discussion of the very important issue of governmental support to renewable energy RD&D, which has been instrumental for many of the renewable energy technologies just discussed to reach their current status. For governments, one instrument among others to promote and accelerate the pace of development for any technology is the direct funding of research, development and demonstration. As an example of continuous public support to renewable energy technologies with varying priorities, Fig. 2.2 shows the cumulative direct funding of RD&D by the IEA member governments. The diagram provides a breakdown of RD&D expenditure by technology. It can readily be seen that during a definition phase until *c.* 1980 the total budgets of IEA member countries for renewable energy RD&D increased steadily, then declined sharply after 1981 to level out at about the 1978 level of effort. Comparison between this and Fig. 2.3, which gives expenditures excluding US budgets, shows that this decline is mostly due to the major expenditure cuts in the United States. However, both diagrams reflect a general tightening of government budgets and changing national policies after 1980. It is believed that the changes of the relative contributions for the different renewable energy technologies are primarily because of either successful cost reduction for some technologies, revised estimates of potential energy contributions, or high costs associated with further development for other technologies.

The cumulative government funding for renewable energy RD&D between 1977 and 1989 amounted to no less than US $\$11\times10^9$ (1989 prices) and in 1989

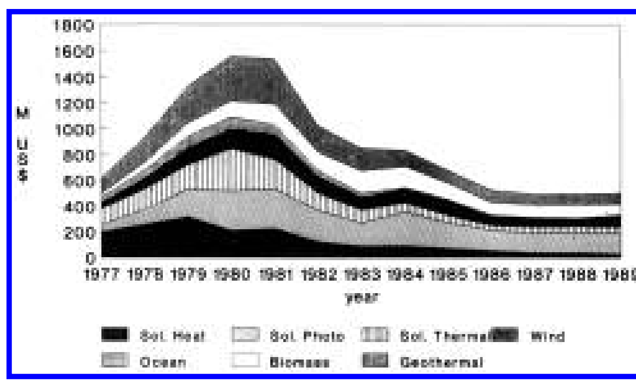


**Fig. 2.2.** Government renewable energy RD&D budgets (million 1989 US dollars equivalent) for all IEA countries including USA, 1977–1989.

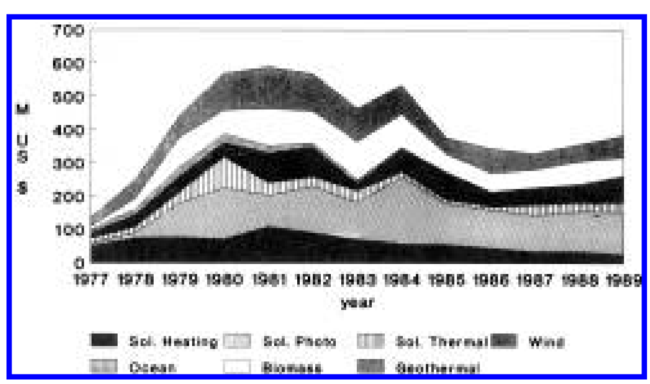


**Fig. 2.3.** Government renewable energy RD&D budgets (million 1989 US dollars equivalent) for all IEA countries excluding USA, 1977–1989.

IEA countries allocated about 7% of their overall R&D budgets to renewable energy technologies. This means that by the late 1980s total IEA members' expenditure on renewable energy R&D was in the range of that devoted to coal technology development.

After the Chernobyl accident and due to the recently considerably increasing concern over global warming, most governments again revised their mid- and long-term planning for renewable energy RD&D budgets and in the future we may find again a marked increase of these budgets. To date, however, and this is mainly due to the still comparatively low oil and energy prices, no distinct change of mid-term tendency could be detected. There are exceptions, however, as in the case of the Federal Republic of Germany, where the renewable energy RD&D budget increased from DM88 m in 1986 to DM175 m in 1989.

Substantial additional support in the form of grants, favourable loans and tax incentives has also been given to encourage the use of certain developing renewable energy sources. It should be noted that the proportion of energy RD&D budgets devoted to renewable energy sources by many of the smaller economies is substantially above the overall IEA average, a fact that tends to reflect a more emphatic commitment to indigeneous resource development. On the other hand, the ten countries with individual budgets of more than US $15 million account for nearly 90% of all government expenditures on renewable energy.

## 2.5 CONCLUSIONS

Summarising, it can be concluded that a future energy world (probably much more diversified than today) will offer many chances to renewable energy technologies. The place they will take in these markets is highly dependent on their technological and economic status at that time, on the comfort they offer to potential users, and of their particular environmental merits or benefits. Renewable energy technology can and must be advanced by efforts of governments by means of the various instruments they have for their disposal, and the economy of the different technologies will greatly depend on the price of concurrent energy carriers such as oil, coal and electricity, depending on which one is to be replaced.

In industrialised countries, renewable energies other than hydropower and biomass will probably not exceed a share of 3–5% of the national total primary energy requirements (which is quite a lot in absolute terms), and biomass may contribute up to 7% of this quantity. This, however, is not true for non-industrialised countries with large rural areas, where large potentials of especially solar and biomass exist and no reliable potential assessments are available to date. Therefore, there are many chances for renewable energy technologies all over the world to create markets, to help people towards a better and more comfortable life and to improve the overall environmental influence of energy use in the world.

## APPENDIX 2.1

## Some other IEA energy indicators

### OECD Energy price and economic indicators

| | % Change in real price of landed crude oil | % Change in real price of energy to final users | % Change in consumer prices | % Change in real GDP |
|---|---|---|---|---|
| Annual average 1960–73 | 1·0 | 0·6 | 3·9 | 4·5 |
| 1973 | 3·2 | −0·6 | 7·8 | 5·8 |
| 1974 | 166·1 | 25·9 | 13·5 | 0·7 |
| 1975 | −4·2 | 6·9 | 11·3 | −0·2 |
| 1976 | −1·0 | 5·4 | 8·6 | 4·7 |
| 1977 | −0·5 | 5·5 | 8·9 | 3·5 |
| 1978 | −11·2 | −2·0 | 7·9 | 4·0 |
| 1979 | 23·6 | 8·5 | 10·3 | 3·1 |
| 1980 | 45·8 | 13·2 | 14·0 | 1·3 |
| 1981 | 14·1 | 8·3 | 10·8 | 1·5 |
| 1982 | −2·2 | 3·0 | 7·9 | −0·3 |
| 1983 | −12·9 | −0·8 | 3·6 | 2·5 |
| 1984 | −1·1 | −1·4 | 5·0 | 4·5 |
| 1985 | −3·7 | −1·8 | 4·8 | 3·0 |
| 1986 | −54·8 | −15·2 | 2·2 | 2·5 |

### TPER/GDP Ratio for IEA countries

| | 1973 | 1979 | 1984 | 1985 | 1986 | Average annual growth rate |
|---|---|---|---|---|---|---|
| Canada | 0·88 | 0·85 | 0·78 | 0·78 | 0·76 | −1·1 |
| USA | 0·76 | 0·71 | 0·60 | 0·59 | 0·57 | −2·1 |
| North America | 0·77 | 0·72 | 0·62 | 0·61 | 0·59 | −2·0 |
| Australia | 0·49 | 0·50 | 0·47 | 0·46 | 0·44 | −0·8 |
| Japan | 0·41 | 0·37 | 0·31 | 0·29 | 0·29 | −2·7 |
| New Zealand | 0·42 | 0·48 | 0·49 | 0·50 | 0·56 | 2·3 |
| Pacific | 0·42 | 0·39 | 0·33 | 0·32 | 0·31 | −2·3 |
| Austria | 0·38 | 0·37 | 0·33 | 0·33 | 0·32 | −1·3 |
| Belgium | 0·47 | 0·42 | 0·35 | 0·35 | 0·35 | −2·1 |
| Denmark | 0·33 | 0·31 | 0·24 | 0·26 | 0·25 | −2·0 |
| W. Germany | 0·38 | 0·36 | 0·31 | 0·31 | 0·30 | −1·7 |
| Greece | 0·39 | 0·41 | 0·42 | 0·44 | 0·43 | 0·8 |
| Rep. Ireland | 0·51 | 0·49 | 0·42 | 0·44 | 0·46 | −0·8 |
| Italy | 0·41 | 0·38 | 0·34 | 0·34 | 0·33 | −1·5 |
| Luxembourg | 1·14 | 0·88 | 0·63 | 0·64 | 0·63 | −4·5 |
| Netherlands | 0·44 | 0·42 | 0·35 | 0·35 | 0·36 | −1·5 |
| Norway | 0·47 | 0·44 | 0·41 | 0·39 | 0·38 | −1·6 |
| Portugal | 0·41 | 0·48 | 0·50 | 0·48 | 0·48 | 1·3 |
| Spain | 0·31 | 0·35 | 0·33 | 0·33 | 0·31 | 0·1 |
| Sweden | 0·43 | 0·42 | 0·39 | 0·41 | 0·40 | −0·6 |
| Switzerland | 0·24 | 0·25 | 0·24 | 0·25 | 0·25 | 0·5 |
| Turkey | 0·63 | 0·56 | 0·55 | 0·55 | 0·56 | −0·8 |
| United Kingdom | 0·44 | 0·40 | 0·34 | 0·35 | 0·34 | −1·9 |
| Europe | 0·40 | 0·38 | 0·34 | 0·34 | 0·34 | −1·3 |
| IEA total | 0·56 | 0·53 | 0·46 | 0·45 | 0·44 | −1·9 |

**Development of TPER, production and self-sufficiency by product in the IEA (Mtoe and per cent)[a]**

| | 1973 | | | 1979 | | | 1986 | | |
|---|---|---|---|---|---|---|---|---|---|
| | TPER | Prod. | % | TPER | Prod. | % | TPER | Prod. | % |
| Solid fuels | 677·8 | 654·2 | 96·5 | 761·7 | 770·9 | 101·2 | 874·3 | 881·8 | 100·9 |
| Oil | 1 737·8 | 652·6 | 37·6 | 1 813·5 | 704·1 | 38·8 | 1 513·6 | 797·7 | 52·7 |
| Natural gas | 678·8 | 690·2 | 101·7 | 719·6 | 697·0 | 96·9 | 665·3 | 614·6 | 92·4 |
| Nuclear | 38·9 | 38·9 | 100·0 | 116·3 | 116·3 | 100·0 | 237·7 | 237·7 | 100·0 |
| Hydro and others | 187·8 | 187·8 | 100·0 | 221·6 | 221·6 | 100·0 | 237·6 | 237·6 | 100·0 |
| Total | 3 321·1 | 2 223·8 | 67·0 | 3 632·3 | 2 509·9 | 69·1 | 3 531·6 | 2 769·4 | 78·4 |

[a] Source: IEA, 1987.

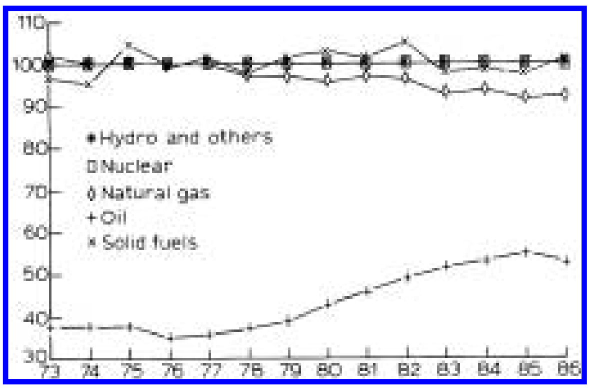


**Fig. A2.1.** Self-sufficiency by product in the IEA (per cent).
Source: IEA, 1987.

**IEA electricity generation by fuels**

| | 1973 | | 1979 | | 1987 | | 1988 | | 1995 | | 2000 | | 2005 | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | Output (TWh) | Share (%) | Output (TWh) | Share (%) | Output (TWh) | Share (%) | Output (TWh) | Share (%) | Output (TWh) | Share (%) | Output (TWh) | Share (%) | Output (TWh) | Share (%) |
| Solid fuels | 1454·7 | 36·6 | 1804·0 | 37·1 | 2518·1 | 43·4 | 2603·2 | 43·2 | 3015·0 | 42·6 | 3375·1 | 42·2 | 3008·6 | 48·3 |
| of which coal | 1447·2 | 36·4 | 1791·6 | 36·8 | 2501·7 | 43·2 | 2585·1 | 42·9 | 2983·3 | 42·1 | 3332·3 | 41·7 | 2973·5 | 47·8 |
| Non-solid | | | | | | | | | | | | | | |
| oil | 1001·3 | 25·2 | 957·9 | 19·7 | 508·8 | 8·8 | 556·3 | 9·2 | 545·0 | 7·7 | 537·5 | 6·7 | 243·6 | 3·9 |
| natural gas | 494·2 | 12·4 | 575·4 | 11·8 | 574·8 | 9·9 | 560·1 | 9·3 | 881·8 | 12·5 | 1169·8 | 14·6 | 912·3 | 14·7 |
| nuclear | 173·2 | 4·4 | 513·8 | 10·6 | 1110·7 | 19·2 | 1218·0 | 20·2 | 1350·6 | 19·1 | 1443·3 | 18·0 | 942·2 | 15·1 |
| hydro/others | 848·5 | 21·4 | 1013·0 | 20·8 | 1083·7 | 18·7 | 1090·7 | 18·1 | 1290·0 | 18·2 | 1471·5 | 18·4 | 1118·7 | 18·0 |
| Total | 3971·9 | 100·0 | 4864·2 | 100·0 | 5796·1 | 100·0 | 6028·3 | 100·0 | 7082·5 | 100·0 | 7997·3 | 100·0 | 6226·3 | 100·0 |

Sources: Energy Balances of OECD Countries (1973, 1979, 1987 and 1988); Country submissions (1995, 2000 and 2005).

## IEA Government RD&D Budgets in 1989 United States Dollars[a]

| | 1975 | 1977 | 1979 | 1981 | 1982 | 1983 | 1984 | 1985 | 1986 | 1987 | 1988 | 1989 | Average 1989 exchange rates unit per $ |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Canada | 299·1 | 332·3 | 407·0 | 448·0 | 463·0 | 530·6 | 602·6 | 490·0 | 473·6 | 382·0 | 353·9 | 352·9 | 1·1840 |
| USA | 2573·8 | 4651·0 | 5890·4 | 4469·6 | 3450·6 | 3239·3 | 2702·6 | 2701·5 | 2410·8 | 2127·5 | 2252·4 | 2280·0 | 1·0000 |
| Japan | 1017·4 | 1263·0 | 1706·5 | 2621·1 | 2624·0 | 2637·7 | 2660·9 | 2797·3 | 2864·6 | 2484·3 | 2032·0 | 2722·2 | 137·9740 |
| Australia | n.a | 45·8 | 74·2 | 108·6 | n.a | 125·9 | n.a | 116·8 | n.a | 58·5 | n.a | n.a | 1·2648 |
| New Zealand | 6·8 | 6·8 | 11·4 | 16·5 | 14·9 | 14·0 | 16·6 | 15·5 | 8·5 | 2·9 | n.a | n.a | 1·6740 |
| Austria | 10·3 | 33·0 | 34·8 | 35·2 | 38·3 | 36·3 | 39·9 | 38·0 | 23·2 | 20·3 | 24·7 | 13·4 | 13·2300 |
| Belgium | 175·2 | 141·5 | 118·6 | 128·5 | 118·3 | 106·5 | 113·5 | 104·1 | 94·1 | 79·0 | 66·2 | 46·3 | 39·3996 |
| Luxembourg | n.a | n.a | n.a | 8·3 | n.a | n.a | n.a | n.a | n.a | n.a | 0·1 | n.a | 39·3996 |
| Denmark | 17·6 | 29·1 | 47·0 | 22·6 | 21·7 | 21·2 | 19·2 | 18·0 | 24·5 | 24·5 | n.a | 33·3 | 7·3100 |
| FRG | 1003·3 | 1077·9 | 1266·6 | 1387·7 | 1770·2 | 1041·2 | 1039·8 | 987·2 | 725·0 | 556·9 | 504·2 | 493·4 | 1·8800 |
| Greece | n.a | 1·4 | 6·8 | 40·5 | 9·3 | 8·5 | 10·8 | 14·4 | 12·6 | 9·6 | 9·5 | 19·8 | 162·0833 |
| Rep. Ireland | 2·3 | 3·8 | 7·8 | 10·9 | 9·2 | 5·8 | 2·3 | 3·3 | 3·4 | 2·2 | n.a | n.a | 0·7056 |
| Italy | n.a | 359·1 | 495·8 | 874·9 | 672·5 | 787·6 | 1040·5 | 971·5 | 915·7 | 742·0 | 779·7 | 615·9 | 1371·6871 |
| Netherlands | 114·4 | 167·6 | 181·7 | 190·6 | 157·5 | 157·2 | 135·3 | 184·3 | 135·1 | 131·6 | 117·5 | 132·0 | 2·1209 |
| Norway | 27·4 | 38·0 | 53·4 | 41·8 | 37·2 | 30·9 | 29·4 | 29·3 | 34·6 | 35·1 | 42·0 | 45·5 | 6·9033 |
| Portugal | n.a | n.a | n.a | 5·3 | 5·3 | 6·5 | 10·4 | 9·8 | 6·8 | 7·4 | 6·0 | 7·0 | 157·0995 |
| Spain | 88·5 | 74·2 | 105·7 | 116·5 | 106·5 | 242·8 | 250·2 | 75·2 | 48·8 | 49·0 | 61·3 | 51·5 | 118·3976 |
| Sweden | 94·0 | 106·7 | 176·9 | 235·5 | 188·6 | 168·8 | 150·1 | 137·6 | 106·4 | 86·0 | 88·9 | 90·8 | 6·4462 |
| Switzerland | 23·9 | 51·8 | 80·8 | 80·7 | 76·2 | 78·5 | 77·1 | 82·7 | 83·1 | 87·4 | 89·9 | 101·1 | 1·6355 |
| Turkey | n.a | n.a | n.a | 1·6 | 2·4 | 3·5 | 3·0 | 2·9 | 3·1 | 3·5 | 4·7 | 4·2 | 2119·9610 |
| United Kingdom | 612·2 | 525·6 | 636·5 | 678·7 | 617·1 | 658·1 | 611·0 | 581·8 | 460·2 | 401·3 | 400·1 | 334·1 | 0·6114 |
| IEA Total | 6066·2 | 8908·5 | 11302·0 | 11523·0 | 10382·8 | 9901·0 | 9515·3 | 9361·3 | 8434·2 | 7290·9 | 6833·1 | 7343·3 | n.a |
| EC | n.a | 205·3 | 278·1 | 300·3 | 542·7 | 583·5 | 495·6 | 626·3 | 596·7 | 592·9 | n.a | n.a | 0·9082 |

[a]Millions except for Italian and Japanese currencies which are in billions.
Source: Country submissions; OECD Economic Outlook.

## World crude oil price

| | |
|---|---|
| 1985 (average) | US $27·56/barrel |
| July 1986 (low point) | US $10·69/barrel |
| Dec. 1986 | US $14·12/barrel |
| 1987 (average) | US $18·15/barrel |
| 1988 (average) | US $14·67/barrel |
| 1989 (average) | US $17·50/barrel |
| May 1990 | US $16·45/barrel |

Present tendency: slightly increasing

Impacts of low oil prices and general energy developments

- General economic benefit in consumer countries
- Difficulties in producer countries and dependent economies
- Future development of new indigenous resources inhibited
- Full potential of energy conservation not achieved
- Alternatives to oil inhibited
- Growing demand for electricity
- Difficulty of non-oil energy supply industries—call for subsidies (coal)
- Slowing down of energy RD&D funding
- Growing importance of environmental and safety concern in energy production

## Part 2

# TYPES OF RENEWABLE ENERGY SOURCE

# Section 3

# Tidal Energy

## 3.1 TECHNOLOGY

There are two types of technology involved in extracting energy from the tides. The first is based on the capture of tidal energy as potential energy within a basin. The second is based on the direct extraction of the kinetic energy of tidal streams. The latter is a relatively diffuse source and, although the subject of numerous technical papers, has been developed only at very small scale, for example for lighting navigation buoys. Therefore this section discusses the concept of tidal power extracted by turbines installed in barrages which enclose inlets or estuaries and thus develop a substantial differential head.

In its most basic form, the technology of tidal power is simple: the rising 'flood' tide enters the basin through gated openings or 'sluices' and through the turbines idling in reverse (Fig. 3.1). At high tide, all openings are closed until the tide has ebbed enough to develop a useful head across the barrage. The turbines are then opened and generate electricity for several hours, until the difference in level between the emptying basin and the next flood tide has dropped to the minimum at which the turbines can operate. Shortly after, the tide level and basin level will be equal, the sluices are opened and the cycle repeats.

There are several alternative methods of operation available. These include:

— modifying the design of an ebb generation scheme so that, at around high water, the turbines are used as pumps to raise the level of water in the basin. By pumping at low head and then using the same water at higher head, a net gain in energy may be achieved;
— generating during both the flood and ebb tides. The 240 MW barrage at La Rance in France was designed both to operate in this manner and to pump in each direction. It is now operated mainly as an ebb generation scheme with pumping at high tide;
— schemes involving two basins, one being filled at high tide, the other being emptied at low tide, so that there is a near-continuous difference in level between the two. This difference can then be exploited by one set of turbines located between the two basins.

Studies (Refs 1 and 2) have shown that the method of operation which results in the lowest unit cost of energy is either simple ebb generation or ebb generation with pumping at high tide. No clear difference has yet

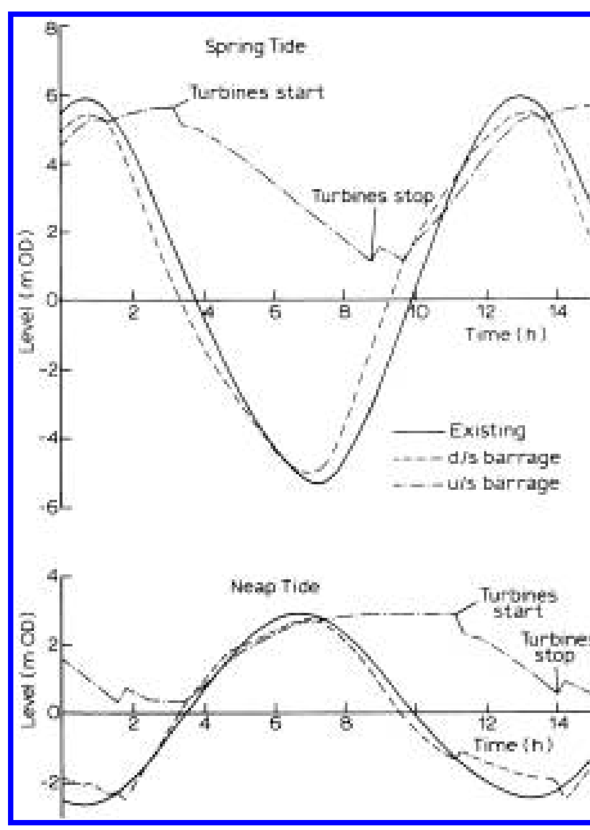


**Fig. 3.1.** Single tide: ebb generation.

been established. However, ebb generation produces electricity for 5–6 h during spring tides, and about 3 h during neap tides, out of a tidal cycle lasting just less than 12½ h. Thus a tidal barrage produces two blocks of energy each day, the size and timing of which follow the lunar cycle. Figure 3.2 shows a typical output over a spring tide to neap tide cycle.

If the output of the tidal barrage is fed into a well-developed grid system, then the power stations with the highest avoidable running costs, such as gas turbines or older coal-fired plant, can be either shut down or throttled back in order to absorb the tidal power in a way that maximises its value. The predictability of the output from a tidal barrage means that this absorption can be planned as far ahead as necessary.

If the grid system is not sufficiently developed to be able to absorb this predictable but intermittent energy, then two-way generation, which produces two smaller blocks of energy per tide at around 10 to 15% greater unit cost, may be preferable. This is discussed in more detail later in the section dealing with system effects.

## 3.2 COMPONENTS OF A TIDAL BARRAGE

The principal components of a tidal barrage are:

(1) Turbo-generators. Two types are favoured. The first is the 'bulb' turbine, so-called because the generator is enclosed in a steel watertight bulb upstream of the runner which is normally of four-bladed axial flow type. For large units, say 20 MW or above, the runner is directly coupled to the generator. For small units the option is becoming available of inserting a two-stage epicyclic gearbox to increase the speed of the generator by about 10:1. This reduces access and cooling problems around the generator. The Rance barrage[3] has 24 turbines with 5·4 m diameter runners and 10 MW direct-coupled generators. The second is the 'rim-generator' or 'Straflo' turbine which is marketed by Sulzer-Escher Wyss of Zurich. This type has the generator rotor mounted on the rim of the runner blades so that generator cooling and rotational inertia are improved at the expense of difficult sealing

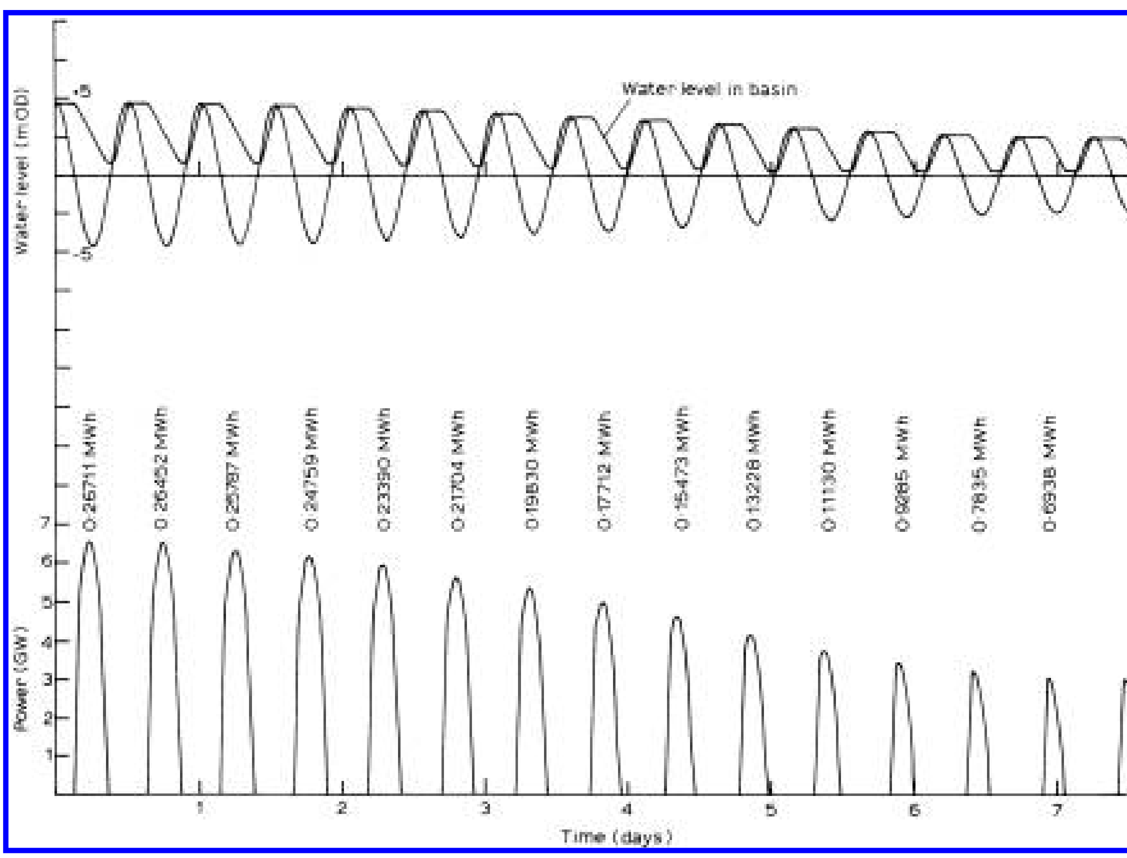


**Fig. 3.2.** Operation over a spring-neap tide cycle.

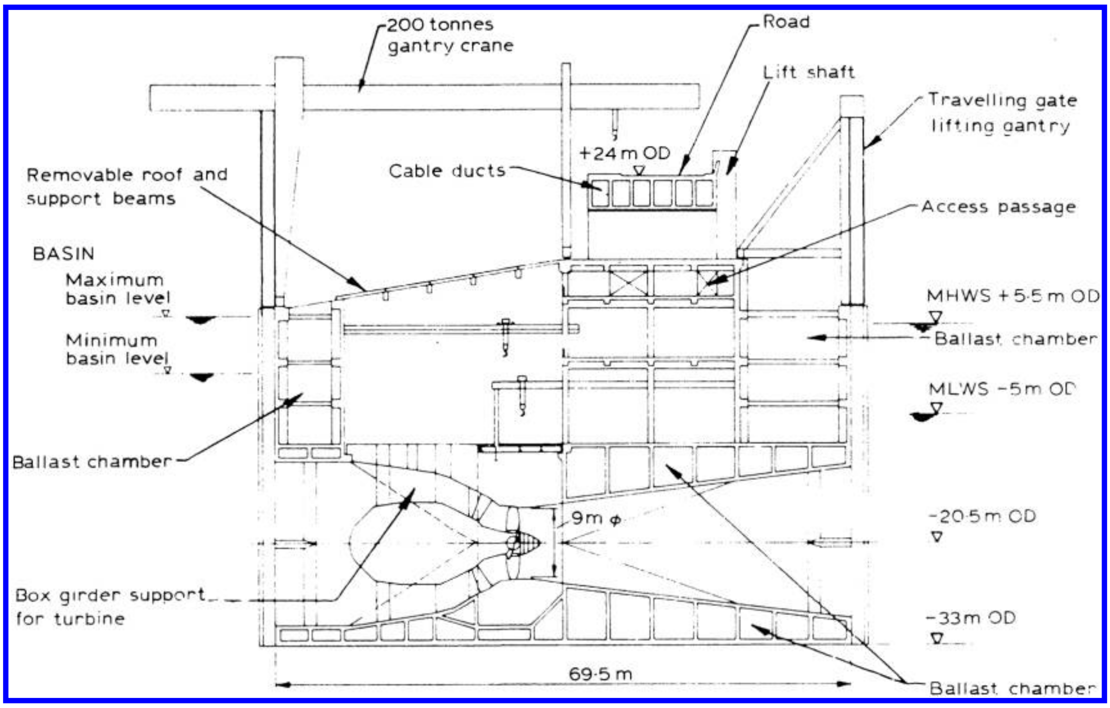


**Fig. 3.3.** Preliminary design of precast concrete caisson.

arrangements. A 7·6 m diameter, 20 MW Straflo machine was commissioned in 1984 at Annapolis Royal, a small tidal inlet off the Bay of Fundy, Canada.[4]

(2) Some form of structure housing the turbines and forming hydraulically efficient water passages upstream and downstream of the runners. This structure could be built of precast concrete (Fig. 3.3) or steel boxes floated into position, or perhaps could be built *in situ* within a temporary island of dredged sand fill, suitably protected during the construction period.
(3) Sluices, which can be designed around either vertical-lift wheeled gates (Fig. 3.4) or radial gates.
(4) One or two ship locks and possibly a small boat lock, depending on the amount of commercial shipping using the estuary.
(5) Either embankments or plain concrete boxes (caissons) floated into position, thus completing the barrage linking it to the shore and providing a route for transmission cables and access for operation and maintenance.

An important feature of tidal power is that no significant new technology is required for its development. Apart from the Rance barrage, which celebrated 20 years of generally very successful operation in 1986, relevant experience has been gained by designers, manufacturers and contractors on other types of project. For example, bulb turbines up to 8·4 m in diameter and with up to 54 MW capacity have been built for low-head or run-of-river schemes in Europe, Japan and the United States. Concrete caissons weighing up to 1 million tonnes have been towed into position and placed accurately for oil field development in the North Sea. Large embankments

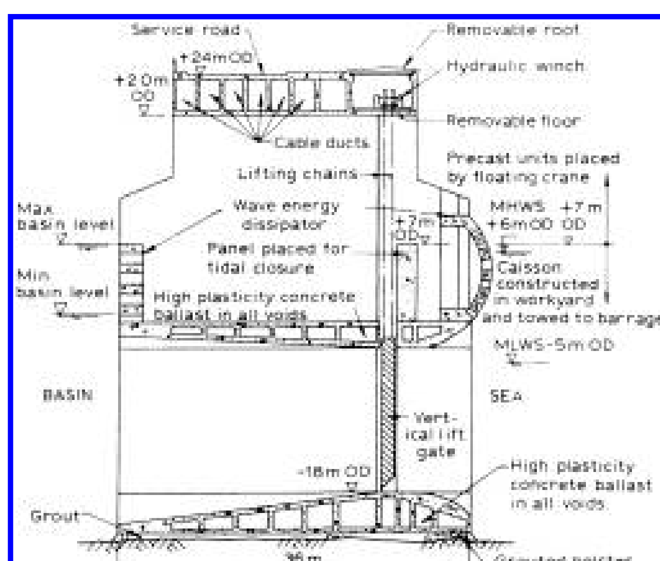


**Fig. 3.4.** Preliminary design of vertical-lift gate sluice caisson.

have been built in water up to 30m deep to close off an inlet of the sea in Hong Kong to form a freshwater storage reservoir.[5] Useful experience has also been gained during the building of the storm surge barrier at the mouth of the Oosterschelde in the Netherlands. Less fortunate but nevertheless valuable experience was gained during the building of the Thames barrier.

However, there is little relevant experience of large-scale construction offshore in the tidal ranges which are of interest for tidal power. The spring tidal range in the Netherlands is typically about 3·5 m whereas the range in the Severn estuary can exceed 12 m. The greater tidal range results in four main problems when towing and placing large caissons:

— stronger currents make towing more difficult;
— the length of time that currents are slack is short;
— preparation of foundations is difficult;
— the obstruction caused by the part-complete barrage results in strong currents in the remaining gaps, and also significant differential heads on the caissons immediately after they are first placed.

For the proposed Severn barrage, these aspects have been studied in considerable detail, with the aid of computer models of the tidal flows, and technically feasible solutions have been developed.

### 3.3 EXPLOITABLE RESOURCES IN THE UK

Of the UK estuaries, only the Severn estuary has been studied in detail so far, although studies are in progress of the feasibility of a tidal power barrage in the Mersey estuary. Preliminary studies, relying on the methods of assessment and cost estimates developed during the work carried out for the Severn Barrage Committee between 1978 and 1981, have been carried out for the Department of Energy on six large estuaries[6] and nine small ones.[7] These studies did not concentrate only on estuaries with large tidal ranges, but covered a variety of water depths, basin shapes and so forth, so that the importance of these factors could be understood.

The results, together with the published results of studies carried out elsewhere, have been used to develop a parametric method of estimating the performance and cost of a tidal barrage at any location.[8] This has been applied to a number of inlets and estuaries on the west and south coasts of England and Wales. The principal conclusions of these studies are that:

— the total resource that could be exploited at a unit cost of electricity of 6 p/kWh (at 1984 prices) or less is about 45 TWh/year;
— the Severn estuary, Solway Firth and Morecambe Bay are the prime sites for large-scale development. The time of high water of the last two is about 5 h after the Severn, so they would produce electricity out of phase with the Severn;
— the Mersey estuary could produce electricity at about the same cost as the Severn, and at about one-tenth the capital cost (£500 m) would be a less difficult project to finance;
— there are a few small estuaries which could be developed to produce electricity at about 4 p/ kWh, perhaps slightly less. With capital costs around £50 m, the investment required would be two orders of magnitude less than that required for the Severn barrage, although their electricity output, correspondingly smaller, would not be significant in national terms.

### 3.4 ECONOMIC APPRAISAL

The unit costs of electricity discussed above are based on a discount rate of 5% and 1984–85 prices. This discount rate is that currently recommended by the Treasury for public sector investments. Unit costs based on this, while useful as a basis of comparison of different methods of generating electricity, do not take into account:

— the very long operating life to be expected from a tidal barrage. Given careful design and construction, the main structure should last 100 years or more, while the slow-turning turbines should last 40 years without major repairs;
— the value to the nation of diversity in sources of electricity;
— the value of the benefits of a tidal power project, which are mainly the fuel saved at thermal power stations;
— the higher discount rates (or internal rates of return) used in the private sector when assessing whether to invest in a project.

The evaluation of the benefits of a tidal power barrage has to be based largely on the value of the fuel saved. There will be greater uncertainty in this than in estimating the cost of the barrage, because it involves forecasting fuel costs and the overall plant mix for a period of at least 40 years into the future. The accuracy of such forecasts has generally been poor, as can be seen from the swings in oil prices over only the last 15 years, and the CEGB's difficulties in achieving the programme of building nuclear stations which they would like.

Historically in the UK, it has been difficult to justify the building of generating plant which has low running costs but high capital cost, for example the hydro schemes of the North of Scotland Hydro-electricity Board and the CEGB's Magnox stations. With the passage of time, these schemes produce the cheapest electricity as a result of a combination of increases in real costs of fossil fuel and inflation.

In this context, the interim conclusions of the Severn Tidal Power Group (STPG) are relevant.[2] They highlighted the fact that the unit prices offered by the Area Electricity Boards for the purchase of privately generated electricity are not based on marginal costs, and that the tariffs are valid for one year only, so that it is not possible to enter into a reasonable long term contract such as would be required by investors in a tidal power project. Thus, although the internal rate of return of the Severn Barrage was predicted to lie in the range 6 to 8%, and thus would be acceptable as a public sector project, this would not be attractive to private investors. STPG also pointed out the fact that private developers, raising funds in the open market, were effectively having to compete with a public sector industry whose investments were based on the Treasury's test discount rate. The proposed privatisation of the electricity supply industry should have important repercussions on these aspects.

### 3.5 ENVIRONMENTAL ASPECTS

When considering the environmental impact of a large tidal power project such as the Severn barrage, it must be borne in mind that its electrical output will be equivalent to that of about 2000 of the largest (90 m diameter) wind generators, and that, over its working life, the coal saved would equal the total planned production of the Selby coalfield (about 700 m tonnes).

The environmental impact of the Severn barrage has been and is continuing to be the subject of wide-ranging studies. Basically, a tidal power barrage is safe—it produces no toxic emissions or wastes, it does not involve plant running at high speeds or high pressures, has relatively little visual impact, and is quiet. Apart from the effects of changes in both tidal range behind the barrage and sediment movements on wading birds which, during their migrations, feed on worms and molluscs in the mud of the intertidal flats, the effects of a barrage will be limited to the estuary in which it is built.

The principal aspects of concern are probably the necessary reduction in tidal range behind a barrage, and associated reductions in the strength of ebb currents. The former will reduce the area available to waders and the reduction in the volumes of water entering and leaving the enclosed basin could increase the concentrations of dissolved or suspended pollutants discharged into the estuary from sewage works and industrial processes. The reduction in currents can be expected to result in sediments within the basin being much less mobile than at present, and is predicted to reduce the amount of sediment travelling seawards,[9] so that there will be a tendency for sediment brought through the barrage during the flood tide to remain in the basin.

The significance of this depends on the availability of fresh supplies to seaward of the barrage, and is site-specific. This could be more important for the Mersey barrage than for the Severn barrage, and is likely to be very important for small estuaries.

Large ships using the ports in an estuary, and relying on the largest tides to gain access through the port locks, could be adversely affected by the slight reductions in the levels of high water. On the other hand, small and medium-sized ships could benefit, because the time they lose passing through the barrage locks should be more than made up by the ease of navigation behind the barrage, and the timing of their arrivals and departures will not have to depend on the time of high water. The reduction in tidal range behind a barrage would make quays along the shore more practical, this being a much cheaper form of development than docks with entrance locks.

The reductions in tidal range and current strengths within the enclosed basin are seen as highly beneficial to the development of water-based leisure activities, largely because the large tidal ranges which are the source of the energy to be exploited also make sailing and boating difficult and, for example, make the sea at Weston-super-Mare almost inaccessible from the beach. The limiting of future water levels to the upper half of the present tidal range, a pronounced 'stand' at high water lasting 2–3 h, and a large reduction in the amounts of sediment in suspension should all make the enclosed basin much more attractive.

Two further aspects of the construction of a tidal barrage are seen as being beneficial. Firstly, a public road crossing can be added to a barrage at less cost than a separate bridge. The Rance barrage is a good example, its road providing a much shorter link between St Malo and Dinard than the route around the estuary. Secondly, a tidal barrage can be operated to control water levels in the enclosed basis. This will represent a substantial benefit in terms of flood prevention where the land around the estuary is low lying; large river floods can be accommodated by closing the barrage gates early on the previous high water and thus keeping basin levels lower than normal. In the same way, flooding that would be caused by exceptionally high tides or storm surges can be prevented. This benefit will become more important if the 'greenhouse effect' does cause sea levels to rise, because continual raising of long lengths of sea defence banks becomes progressively more difficult and expensive.

Aspects also being considered include land drainage, fish migration, changes in salinity, the effects of construction traffic, employment and so forth. So far, no insurmountable adverse impacts have been identified although much work remains to be done, some of it involving highly sophisticated computer modelling techniques.

## 3.6 WORK IN PROGRESS

The 1981 report of the Severn Barrage Committee[1] concluded that the technical feasibility of building the Severn barrage was proven, but that there was much uncertainty over its economics and its environmental impact. The Committee recommended that further studies of these aspects, together with more work on refining the engineering aspects, should be carried out immediately, and set out a comprehensive programme taking four years and costing £20 m which would enable government to make a fully informed decision as to whether to proceed with construction.

This recommendation was not accepted and no action was taken until 1984 when the newly formed Severn Tidal Power Group persuaded the government to fund half the cost of a study of the feasibility of building the barrage as a private development, together with some further work on engineering and environmental aspects. This study concluded that the barrage could not be built by the private sector alone, largely because of the uncertainty over income from electricity sales discussed above. Otherwise, the study generally confirmed the findings of the Severn Barrage Committee.

Since then, a further study is being undertaken by the Group. This will cost £4·2 m and is funded in equal parts by the Department of Energy, CEGB and STPG. The study is programmed to take about 18 months and will cover a wide range of engineering and environmental aspects. It is intended to be the first stage of a full five-year study, although there is no commitment yet to the further work.

Separately, an £800 000 study has been completed of the feasibility of a tidal power scheme in the Mersey estuary. This was funded equally by the Mersey Barrage Company, which is a consortium of a wide range of companies with interests in Mersey-side, and the Department of Energy. At the time of writing, the report has not been published, but plans have been announced for a further study costing £1·3 m.

The Department of Energy is funding a programme of 'generic' studies, i.e. studies of engineering and environmental aspects which are not site-specific. An example is the use of steel caissons fabricated in shipyards instead of caissons built of reinforced concrete which, because of their large draft, require purpose-built workyards.

Initial studies of small-scale tidal power have produced some encouraging results, and the building of such a scheme would provide some useful practical experience, including validating some of the computer-based predictive techniques being used or developed for studies of larger schemes.

## 3.7 INSTITUTIONAL BARRIERS

Forty years after the decision was taken not to build an 800 MW barrage at English Stones in the upper part of the Severn estuary, mainly because of fears for the South Wales coal industry, there is still a lack of commitment towards the development of tidal power which, in terms of resource size and density, predictability, proven technology, environmental impact and unit cost of electricity is arguably the best of the UK's renewable resources.

The Nature Conservancy Council (NCC) and the Royal Society for the Protection of Birds (RSPB) have both stated that they would object to the building of the Severn barrage. However, the former organisation is contributing to the work in progress and thus the study will benefit from the NCC's experience and expertise, while the NCC will be continuing to assess its own views as more information becomes available. The RSPB, on the other hand, has publicly announced its opposition to any tidal power developments involving estuaries. This seems premature, because it is not yet clear that the more stable sediment regime behind a tidal barrage would not increase productivity which would offset the reduction in intertidal areas available to wading birds.

Other institutions which have expressed concern about the effects of a tidal power scheme include the water authorities, the port authorities, and the Confederation of British Industry on behalf of industries discharging wastes into estuaries.

The building of a barrage on the sea bed, and the changes in low water levels that it would cause, would raise various legal questions concerning ownership of the foreshore, areas of port jurisdiction and so forth.

The local authority rates to be paid by the owners of a tidal barrage could be significant. However, the most important barrier to the private development of a tidal power project of significant size is the uncertainty of the value of the energy generated over a large number of years into the future.

## 3.8 EXPORT POTENTIAL

United Kingdom expertise in simulating the operation of tidal power barrages has contributed to the development of the 20 MW prototype Straflo turbine commissioned in 1984 at Annapolis Royal in Nova Scotia. In 1985, three UK firms carried out the engineering studies for a feasibility study of a 480 MW tidal power scheme in South Korea.[10] Otherwise, most work in this field has been carried out by French companies who have the benefit of the practical experience at La Rance.

The number of sites suitable for the development of tidal power is limited. The fundamental criterion is tidal range. UK studies have shown that a spring tide range of about 6 m is needed before a site has much chance of being economic. In addition, the width of the enclosed basin at the site of the proposed barrage should not be large in relation to its area, and the water depth should be enough to provide adequate submergence for the turbines without being too deep. Finally, the estuary should not be remote, otherwise transmission costs rise.

There are sites representing important energy resources in

—Alaska (Cook Inlet)
—Argentina (San Jose)
—Australia (north-west coast)
—Brazil (north coast) where plans have been announced to build a 36 MW pilot scheme in an existing flood control barrage on the Rio Bacanga at Sao Luis
—Canada (Bay of Fundy)
—China (Yellow Sea)
—France (Îies de Chaussée)
—India (Gulf of Cambay, Gulf of Katchch)
—South Korea (west coast)
—USA (Passamaquoddy Bay)
—USSR (Okhotsk Sea, Jugursk Bay)

Apart from the UK and the recently announced project in Brazil, activity, in the form of studies, is taking place at low levels in Canada and France. In India, after completion of feasibility studies, plans have been announced to take a 900 MW tidal power scheme in the Gulf of Katchch forward to detailed design. Symposia organised by the Institution of Civil Engineers and the Institution of Electrical Engineers to present the results of work carried out in the UK have been successful in attracting foreign delegates. The conclusion can be drawn that, if the UK were to build a tidal power project, even a small one, using the prefabrication techniques proposed, then this would generate enormous interest abroad and lead to export opportunities. Otherwise, the French practical experience, although dated in terms of the method of construction, leaves them as market leaders, with the Canadians second and the Brazilians and Indians now entering the market.

## 3.9 APPROPRIATENESS FOR DEVELOPMENT IN THE UK

The UK is blessed with a range of estuaries where tidal power schemes could be built and satisfy the Treasury's requirements for the rate of return for public sector investments. Overall, about 10% of our present electricity demand could be met in this way. Although building large projects such as the Thames barrier and the Humber bridge proved painful experiences, the history of more recent projects, such as the two latest AGR power stations and particularly the development of the North Sea oil fields, has been much more satisfactory. Thus severe delays or cost overruns should not occur during the building of the Severn barrage or a Mersey barrage. Once built, such projects would generate electricity at low cost for many decades. Thus they would be seen by future generations in the same light as the North of Scotland hydro-electric schemes are seen now, namely as a wise investment.

A difficulty arises from the different discount rates (which take risks into account) that are likely to be used by a private organisation considering building a barrage in order to sell the electricity to a utility, and a large, privatised, utility considering a tidal power scheme to add to its already established power generating system. There is no practical possibility that the electricity could be used by the owner of a tidal barrage in the same way that the output of a wind turbine or array of photo-electric cells could be used to avoid importing electricity from the grid and thus achieve greater value for the owner.

## 3.10 SYSTEM EFFECTS

As discussed in Section 3.1, in the absence of an effective grid system, the two blocks of energy produced each day by a tidal power scheme, which follow the lunar cycle, present difficulties of absorption by consumers. Two-way generation reduces this problem and has been chosen for a number of very small schemes in China which supply local communities which are not connected to the grid. One of the conclusions of the first major study of Severn tidal power, carried out between 1927 and 1933, was that a dedicated pumped storage scheme would be necessary to smooth the output of the 800 MW barrage then recommended. By 1945, a review of the 1933 report concluded that the grid system could absorb the barrage's output without the need for dedicated pumped storage.

The 1981 report of the Severn Barrage Committee concluded that there was no need for additional pumped storage, at least until nuclear plant output rose above base load, in which case the need for additional pumped storage capacity should be assessed within the whole system.

These conclusions were based on three main factors. Firstly, both the amount and timing of the output of the Severn could be predicted with good accuracy as far into the future as the CEGB could require. Secondly, by the time the barrage was built its maximum output of about 7000 MW would not be so large a proportion of the total demand as to embarrass the CEGB, although there could be times when the rate of start-up of the turbines would be limited. This would lose minimal tidal power. As a last resort, tidal power could be exported via the cross-Channel link.

In absorbing the output of the Severn barrage, the CEGB (or its successors) would plan to displace plant with the highest running costs first, thus obtaining maximum benefit. The need to cycle down coal-fired stations would incur a penalty in reduced efficiency, estimated at about 6% of the barrage's output. Thirdly, channelling energy through a pumped storage scheme loses 25% due to inefficiencies.

Although producing power intermittently, a tidal power scheme would reduce slightly the need for thermal plant. Studies carried out using the Department of Energy's computer model of the UK generating system (Ref.1) showed that the Severn barrage would save the need to build about 1500 MW of coal-fired plant but that about 400 MW of additional peaking plant such as old coal-fired plant, which would otherwise have been decommissioned, or gas turbines would be needed. The value of this displaced plant is relatively small.

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# Section 4

# Wave Energy

## 4.1 INTRODUCTION

The UK has a special position in wave energy. This arises from the pioneering work of a number of innovators in the early 1970s, which led to a substantial programme lasting some 10 years, and on which, at its peak in about 1981, the Department of Energy's expenditure was running at about £4 m per annum. The programme's objectives became clearly defined, and when, in about 1982, the Department decided that they had substantially been achieved, the decision to scale the programme down was quite logical. The objectives were:

(a) to establish the technology for extracting energy from ocean waves;
(b) to estimate the cost of this energy, if used on a large scale to supply UK needs.

The qualifying phrase in objective (b) is important. The Department of Energy's reason for sponsoring the programme was the hope that wave energy could economically provide a significant proportion of the country's electricity needs. This influenced decisions on the conduct of the research programme throughout. Devices and techniques which were only likely to be useful on the small or local scale were, in the main, only worked on if the work could support the programme's national-scale objectives. This, for instance, ruled out devices which could not even in principle be developed into a 2 GW power station. Because certain devices of this kind show promise as power sources for diesel substitution in remote island communities, work has continued (or begun) on them since the end of the main DEn programme, on a much more limited financial scale.

The DEn programme was reported in March 1985 in ETSU Report R26, *Wave Energy—The Department of Energy's R & D Programme 1974–1983*. The summary of this Report is reproduced (with ETSU consent) as Appendix 4.1. The Report forms the basis of much of this section.

## 4.2 TECHNOLOGY

The DEn programme concentrated on the following main areas. Where appropriate, we refer to other work under the same heading.

### 4.2.1 Wave data

This provides the basic design information. Because of the time scales of wave variability, it can take some years to build up a good statistical model of wave amplitude and directionality for a particular site. However, the combination of wind statistics (which are much more complete) with the Meteorological Office wind-wave forecasting method has enabled good working models, including directionality, to be developed for most areas of interest.

### 4.2.2 Conversion principles

Figure 4.1 (from Report R26, Fig. 4.1, p. 22) illustrates the main concepts considered in the DEn programme, for conver ting the slow movement of water to a more easily used and transmitted form, normally electricity.

In interfacing with the waves, any converter must be constrained so that wave forces are resisted. This gives rise to the concept of a 'frame of reference' against which the converter reacts (Report R26, p. 21).

Frames of reference can be achieved in a number of ways, including

— using the sea-bed for fixing or mooring;
— mounting several converters on a common frame or spine so that relative motion is obtained between them;
— using the inertial force due to the gyroscopic action of a flywheel;

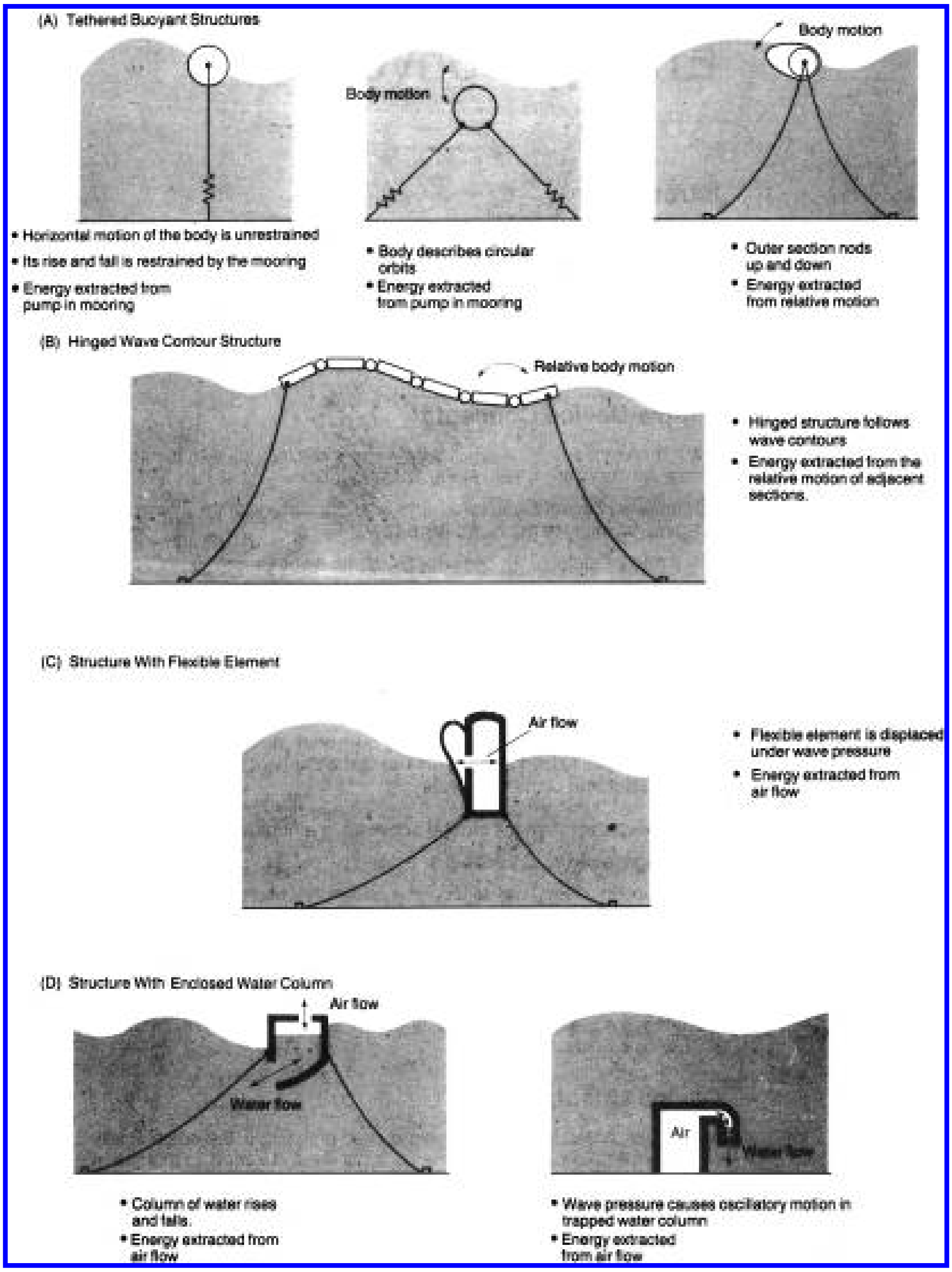


**Fig. 4.1.** Simple device concepts (from Report R26, Fig. 4.1).

—relying on the mass and inertia of the device.

One conversion principle which has been explored mostly outside the DEn programme is that of 'overtopping', where wave action causes water to flow over a dam where it is stored, and allowed to run out through a turbine when needed. This principle was proposed for Mauritius by A.N.Walton Bott, and it is currently being demonstrated in Norway in the Tapchan system. In the latter system, wave fronts enter a gently tapered channel, where their height becomes much enhanced.

### 4.2.3 Device design

Out of more than 300 device ideas that were considered during the DEn programme, some 12 received substantial financial support, and nine of these were continued through to the end of the main programme. Scale models were tested in wide wave tanks at Edinburgh University and at Wavepower Ltd, Southampton. Some testing at around one-tenth scale was carried out in The Solent and Loch Ness.

Figure 4.2 (Report R26, Fig.5.1, p.26) is a matrix which indicates the main features of the nine devices described in R26. The unit power ratings per device vary from 2·25 MW to 14·4 MW, and the corresponding weights from 10 600 tonnes to 120 000 tonnes.

Designs of these devices were produced using the results of model tests and theoretical work. Consulting engineers were given the task of assessing on a common basis the engineering viability, power output and costs of each of the designs.

Because most of the energy off the UK coast is in long wavelength waves, these designs, which are targeted at producing 2 GW over a reasonable length of coastline, are inevitably of massive units. Report R26 illustrates this by comparing a silhouette of each device with a background Tower Bridge.

Some device designs have been produced for other objectives; for instance, what can we do that would be useful to this community, using waves incident on their coastline? Designs for such purposes generally are installed at or close to the shore. This renders maintenance and power collection much simpler than with devices several kilometres offshore. Since the power needs of communities (e.g. farms) not

| DESIGN ASPECT | DEVICE | Bristol Cylinder | SEA Clam | Edinburgh Duck | Lancaster Flexible Bag | NEL OWC (floating terminator) | NEL OWC (bottom standing terminator) | Vickers OWC (bottom standing terminator) | Vickers OWC (bottom standing attenuator) | Belfast OWC |
|---|---|---|---|---|---|---|---|---|---|---|
| Frame of Reference | a Spine | | • | • | • | | | | | |
| | b Structure Inertia | | | | | • | | | | |
| | c Sea bed | • | | | | | • | • | • | • |
| | d Gyro | | | • | | | | | | |
| Interface | a None at all | | | | | • | • | • | • | • |
| | b Flexible Material | | • | | • | | | | | |
| | c Rigid | • | | • | | | | | | |
| Power Take off | a Pneumatic | | • | | • | • | • | • | • | • |
| | b Hydraulic | • | | • | | | | | | |
| Mooring and Anchoring | a Conventional Moorings | | • | • | • | • | | | | |
| | b Controlled Damping | • | | | • | | | | | |
| | c Tension Leg | • | | | | | | | | |
| | d Rock Anchor | • | | | | • | • | • | • | • |
| | e Conventional Anchor | | • | • | • | | | | | |
| Transmission | a Electrical – fixed | • | | | | | • | • | • | • |
| | b Electrical – flexible | | • | • | • | • | | | | |
| | c Hydraulic – fixed | • | | | | | | | | |
| | d Hydraulic – flexible | • | | | | | | | | |
| Hydrodynamic Configurations | a Point Absorber | | | | | | | | | ϕ |
| | b Attenuator | | | | • | | | | • | |
| | c Terminator | • | • | • | | • | • | • | | |
| | d Surface Piercing | | • | • | • | • | • | | | • |
| | e Submerged | • | | | | | | • | • | |

ϕ In its present form this device is not a true point absorber

**Fig. 4.2.** Device designs (from Report R26, Fig. 5.1).

connected to the grid are seldom very large, wave energy device ratings for such purposes could usefully be in the 20–500 kW range. Queens University, Belfast, are currently installing an oscillating water column in one of a number of natural rock gullies on the west coast of the island of Islay. This, and others like it, could meet the needs of farms and whisky distilleries for heating (varying frequency) electricity. The Norwegian Tapchan system and a Norwegian cliff-installed oscillating water column system are apparently aimed at the same market.

### 4.2.4 Mooring and anchoring

Again because of the DEn objective of harnessing large amounts of power, wave energy devices in their programme were deployed in deep water. About half of the devices in the programme were floaters. Mooring hundreds of such devices in the worst seas to be found anywhere, continuously, and in a way that allowed the wave energy to be captured, would need an extension of mooring technology well beyond what was available. Significant progress was made, discussed in Report R26.

In general, the cost of mooring and anchoring, or the provision of sea-bed attachment, together with the cost of the initial device installation would be a significant fraction of the overall capital costs. It could range from 10 to 15% for floating devices, and could be as high as 30% for devices fixed to the sea-bed. The latter systems would be virtually main-tenance-free whereas moorings require periodic inspection and replacement, thereby incurring an operational cost penalty.

### 4.2.5 Power conversion and transmission

Exploiting the low, variable frequency motion of waves, and coupling the power to a fixed frequency and fixed voltage grid system, is a challenging task which device designers have tackled in different ways. Various hydraulic and mechanical systems are proposed, but perhaps the largest number of designs use air as a working fluid. Either the air is rectified by valves, or it flows backwards and forwards through a turbine (such as the Wells turbine) which rotates in the same direction, irrespective of the direction of air flow.

Electricity, when generated in numerous small alternators, can be aggregated by a d.c. system. The present rapid developments in power electronics are making this technique more practicable and economic. They will also help in conditioning the power generated by isolated wave energy devices.

### 4.2.6 Availability and maintenance

In the severe environment of a wave power station, the view, often expressed, that things will break down (or break up!) in a short time and it will be very difficult to repair them, is understandable. Work in the DEn programme was aimed at quantifying this view.

The main points arising from this study of maintenance and availability were:

— a fixed device would be expected to have a higher availability than an equivalent floating device because maintenance crews could gain access to it and work in it in weather too severe for access to floating devices;
— a floating device which could not be repaired at sea is likely to be at a considerable disadvantage in terms of availability unless provision for sufficient spare devices is made;
— the present studies suggest that availability levels in the range 70–90% might be achieved with an annual maintenance cost equivalent to 1–2p/ kWh.

### 4.2.7 Other work since the end of the main DEn programme

The Department is currently supporting work by SEA Ltd towards a small-scale version of the CLAM device. The DTI have promoted a study of a small-scale demonstration of the NEL Breakwater device.

DEn has also been supporting the team at Queen's University, Belfast, to look at 'Shoreline' wave energy systems. In 1985 they funded a design and feasibility study. In 1987 they began funding Phase 2, the construction of a 40 m$^2$ oscillating water column chamber, capable of driving a biplane Wells turbine generator with a peak output of 180 kW. In the third phase, which is currently under negotiation, it is proposed to install the turbine generator and connect it to the island's electricity network.

As indicated above, there is some active demonstration work in Norway. Japan appears to have been continuing the unexciting Kaimei programme, sponsored by the International Energy Agency.

## 4.3 EXPLOITABLE RESOURCE IN THE UK

This was a topic of prime interest in the DEn programme. Figure 4.3 (Report R26, Fig. 3.8) shows how the eventual figure of 6 GW was arrived at. It should be borne in mind that this might be restricted by economics and environmental factors.

The scope for economic use of coastline devices by local communities in the UK may be fairly limited, perhaps 50 units each of 200 kW, or 10 MW total. Queen's University consider the resource to be much greater, in the order of 200–300 MW, with possible sites on nearly all the Scottish islands and the coast of Devon and Cornwall.

## 4.4 COMMERCIAL PROSPECTS

The DEn programme, after a very thorough and searching investigation, concluded that the cost of wave energy would be in the 8–14 p/kWh range (1982 values). At such costs, it would compare unfavourably with not only coal and nuclear electricity, but probably also with oil-fired electricity, and also with onshore and offshore wind power. This was the prime reason for scaling down the programme to a limited one aimed specifically at cost reduction. A figure of 5·5–6 p/kWh is being suggested for one new development.

The Norwegian coastline developments claim much lower unit costs in the 2·5–4 p/kWh range. They should be able to benefit from high availability due to easy access for maintenance, and from low costs of power distribution. However, some scepticism is inevitable.

So far, wave power has not been successful in competition with its nearest equivalent, wind power. Aerogenerators can be, and have been, installed at many sites both on the coast and inland. They can in principle be installed offshore. Wave power generators are as yet only likely to be useful at suitable coastal sites. It seems probable that they will have less environmental impact than large (20–25 m) aerogenerators, and thus may be more readily accepted in sensitive areas.

## 4.5 ENVIRONMENTAL ACCEPTABILITY

Naturally, the environmental impact of a large wave power scheme would be greater than that of a small scheme. It would also be different in character.

For the large scheme, off the west coast of Scotland:

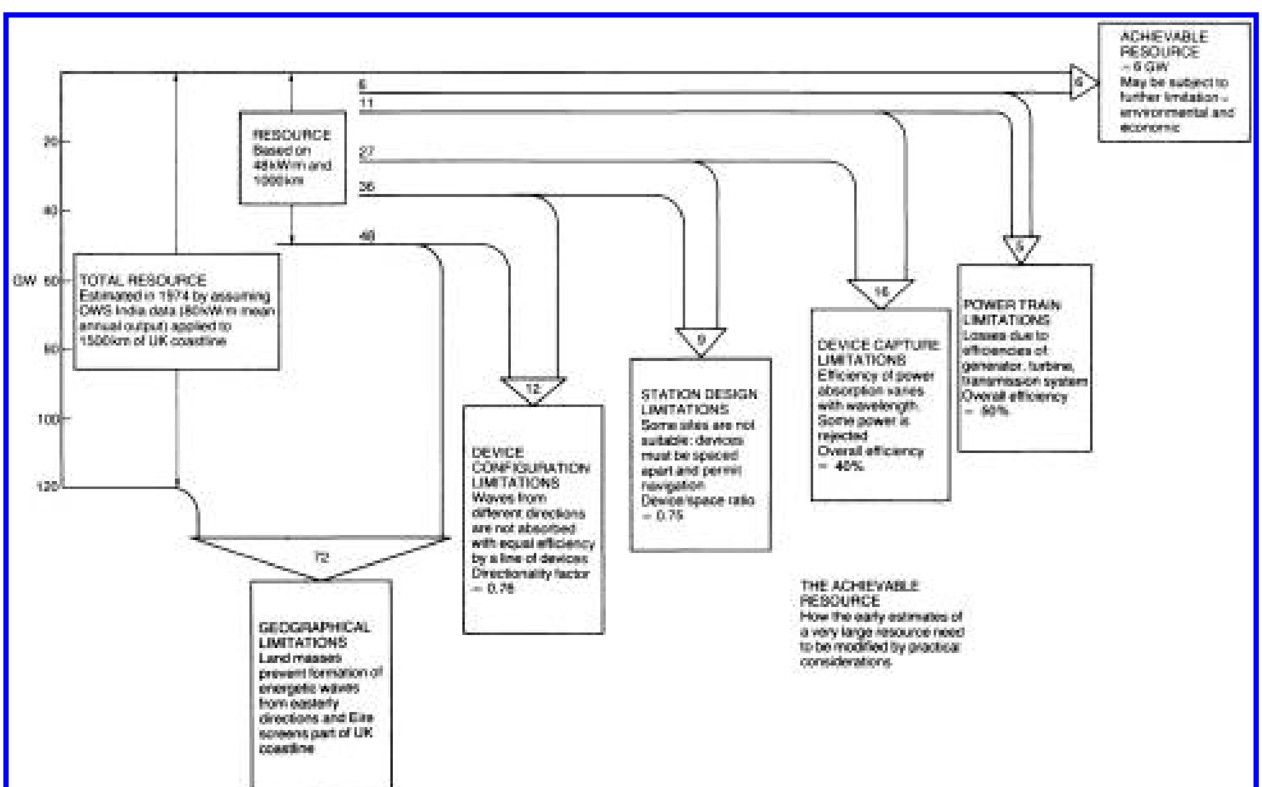


**Fig. 4.3.** The achievable resource (from Report R26, Fig. 3.8).

— the electricity transmission lines to the load centres in the south of Scotland would need careful placing;
— there would be a marked change in the shore wave climate, and hence of the ecology;
— there might be some noise, though if the power station is 20–30 km offshore this is unlikely to be serious;
— the construction activity would be considerable;
— predatory seabirds and seals might be encouraged, to the detriment offish stocks (though not with submerged devices like the Bristol Cylinder).

A small scheme, such as is proposed for Islay:

— might produce some noise;
— would need a Land Rover access track.

Otherwise there should be no environmental impact.

## 4.6 INSTITUTIONAL BARRIERS

Wave power has not yet progressed to the stage where the institutional objections have been formulated. However, a large offshore scheme might meet opposition from shipping and fishing interests, although the benefit of creating an inshore passage in relatively calm water should not be underestimated.

Fears are said to have been expressed that noise from mechanisms on large-scale wave energy schemes could frustrate the detection of sub-marines. We do not know whether there is any truth in this.

## 4.7 EXPORT POTENTIAL

There would no doubt be some opportunity for exporting the specialised mechanisms of wave energy devices. These might include air turbines, flexible bags, Duck gyros, electrical plant, mooring ropes, etc. Much of the capital cost of any wave energy system, large or small, would be in civil works construction, largely using local labour. This would appeal to overseas governments. There would be opportunities for UK consulting engineers.

## 4.8 APPROPRIATENESS FOR DEVELOPMENT IN THE UK

### *In favour*

— We have a resource assessed as technically capable of yielding 6 GW mean annual power.
— We have a useful quantity of wave data.
— We have a number of islands that depend on diesel generation, and have labour available for on-site work.
— We have a good industrial resource for all parts of a wave energy system.

### *Against*

— The UK has large resources of more easily exploited fossil energy, and at least one renewable source of similar scale (wind), which may be more economic.
— Several submarine power cables have been successfully laid in the last few years to offshore islands.

## APPENDIX 4.1 (ETSU REPORT R26)

### Introduction

The intensive phase of the Department of Energy's wave energy research and development programme ran from 1974 to 1983 and cost approximately £15M The basic objectives of the programme were to establish the feasibility of extracting energy from ocean waves and to estimate the cost of this energy, if used on a large-scale to supply UK needs.

### Programme Content

In order to meet these objectives, a comprehensive programme of work was carried out in the following main areas:

☐ **Wave Data**

Work on collecting and analysing wave data has advanced our knowledge of the wave climate considerably. The variable nature of wave energy is now better understood and the size of the resource is more firmly established

☐ **Conversion Principles**

The most suitable form of energy to which wave energy can be converted s electricity At present, the most cost-effective type of converter is likely to use wave motion to generate an air flow to drive turbines

☐ **Device Designs**

Over three hundred ideas for capturing wave energy were examined. The most attractive concepts were tested at small scale in wave tanks, and three were tested in sea conditions at one-tenth scale. Eight devices were taken to the stage where reference designs for a 2GW power station located off NW Scotland were produced and costed. This required the development of design codes for structures and a study of materials and construction techniques, and a great deal is now known about the sheer scale of the operations involved in building such stations.

☐ **Mooring and Anchoring**

Although mooring and anchoring technology has made advances in recent years, certain unique requirements of mooring systems for wave energy converters required special approaches. Significant progress was made on the design of 'compliant' mooring systems.

☐ **Power Conversion and Transmission**

The particular problems of aggregating power from thousands of individual generating sets and delivering it via a single transmission line to the Grid were studied in depth and suitable systems were designed.

☐ **Availability and Maintenance**

The economics of wave energy are heavily dependent upon the availability of devices and the cost of maintaining them. Mainly through the development of computer modelling techniques, the level and type of maintenance and repair resources required by wave power stations were determined.

### Size of the Resource

When the wave energy programme began, estimates suggested the potential resource around the UK coast was enormous. It is now evident from wave measurements and calculations which take account of geographical limitations and the overall conversion efficiency of the assessed wave energy stations that the technically achievable UK resource does not exceed 6 GW mean annual power This is equivalent to approximately 50 TWh of energy per annum or 20 Mtce per annum representing about 6% of the total current primary demand for energy in the UK. This achievable resource will probably be further limited in practice by environmental and economic constraints.

## Cost of Wave Energy

The cost of energy produced by the various devices was assessed by Consultants using cost data from the 2GW reference designs. The assessment concluded that there was only a low probability of any design achieving an energy cost below 8p/kWh (in May 1982 money values).

# Economics of Wave Energy

In January 1982, ETSU produced its 'Strategic Review of the Renewable Technologies' which made an economic analysis of all renewables including wave energy. It concluded that the overall economic prospects for wave energy looked poor when compared with other electricity-producing renewable energy technologies. An up-dated analysis in 1984 confirmed this conclusion.

In the light of the Strategic Review, the Advisory Council for Research and Development for Fuel and Power (ACORD) concluded in March 1982 that large-scale prototype work was not justified and that the programme should be reduced. The Department of Energy decided therefore to fund a small research programme to see if progress could be made which might justify larger-scale work in later years. Research work continues to be funded at the Universities of Edinburgh, Belfast and Lancaster and SEA Ltd. at Coventry.

## The Way Forward

The work carried out in the programme has indicated that constructing and maintaining wave power stations necessary for large-scale exploitation of the resource would present formidable tasks. The diffuse nature of the energy and its remoteness from industrial centres and consumers are major factors contributing to the unattractiveness of large-scale wave energy relative to other energy sources, renewable and conventional. Smaller scale wave energy might, however, have a brighter future in remote locations where the competition comes from expensive fuels such as diesel.

The Department is currently supporting work by SEA Ltd. directed towards a small-scale version of the CLAM device. In addition, the Department of Trade and Industry has supported a feasibility study of a small-scale demonstration of the NEL Breakwater device. These and developments overseas will be studied carefully; any re-assessment of the application of wave energy on a large scale must await the demonstration of its viability at these smaller scales.

# Section 5

# Wind Energy

## 5.1 INTRODUCTION

Fresh interest in wind power developed in the mid-1970s in the UK and in much of the Western World. This followed the oil price increases of 1973 and 1974 but was assisted by the great advances in materials and aerospace and computer technology. The mathematics necessary to analyse thoroughly the dynamics, aerodynamics and aeroelastics of medium and large wind turbines (WTs) are highly complex. Prior to this, development had been static for many years.

The modern development has followed two parallel paths, horizontal axis and vertical axis. The former is similar to the traditional windmill and is probably more developed than the vertical axis wind turbine. In theory both types can be similar in efficiency but they are fundamentally different in mode of operation. In the horizontal axis machine the blades rotate in a vertical plane, thus resulting in sinusoidally varying gravitational stresses, whilst the stresses due to the wind remain constant for a given wind speed if we neglect any variation of wind across the circular swept area. On the other hand, the gravitational stresses are constant for a vertical axis wind turbine but the aerodynamic stresses vary sinusoidally, peaking as the blades cross the wind upstream of the tower. Both types operate on the principle of aerodynamic lift with the velocity of the blades exceeding that of the wind. Figure 5.1 illustrates the mode of operation of the horizontal axis wind turbine and Fig. 5.2 that of the vertical axis machine. The other fundamental difference is that the blades of the horizontal axis turbine must be turned into the wind (the technical term is known as yawing) whilst the vertical axis wind turbine is omnidirectional.

Advocates of both types claim advantages but the proof will only be available when both are sufficiently developed and tried to prove which has the best long term economics. It could well be that size comes into this comparison, one of the claims of the vertical axis machine being that it can ultimately be developed to larger size due to the non-cyclic gravitational loads. It is thought that large wind turbines will have the advantage offshore where foundations will be expensive, but these machines are still in the experimental stage. On land more modest sizes could prove beneficial, perhaps somewhere between 250 kW and 2000 kW rated capacity, and appreciable experience is already available at the lower end of this range.

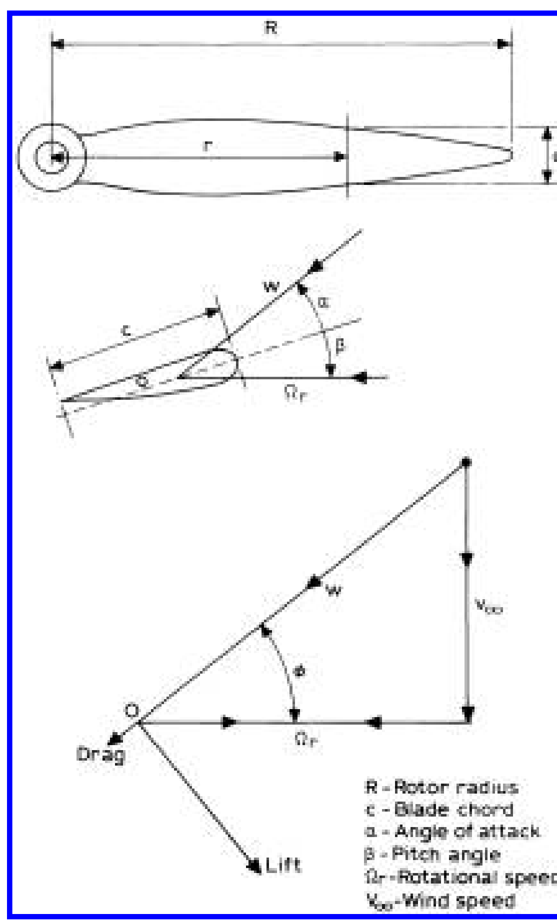


**Fig. 5.1.** Velocity diagram for horizontal axis wind turbine.

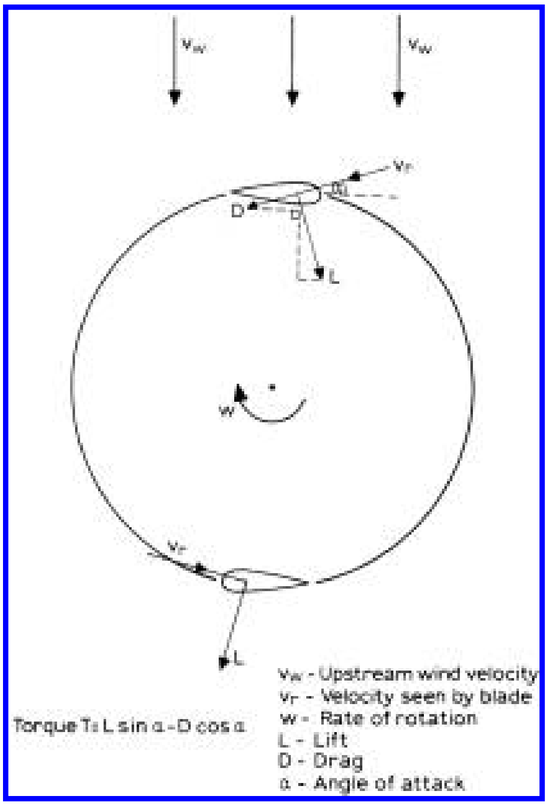


**Fig. 5.2.** Operation of vertical axis wind turbine.

In the United Kingdom both horizontal and vertical axis wind turbines are being developed with funding assistance primarily from the Department of Energy but also from the Department of Trade and Industry and the EEC.

## 5.2 STATUS OF TECHNOLOGY

Horizontal axis wind turbines (HAWTs) up to sizes of about 30m diameter have undergone a rapid phase of product development in the last 10 years or so. More than 14 000 with a total capacity of 1210 MW were installed and operating in California by the end of 1986: see Fig. 5.3. Well over 1000 machines, mainly small, are in use in Denmark. High availability is claimed for the best machines, in the order of 95%, coupled with low maintenance costs, probably less than 2% of the capital cost annually. However, it must be said that this is based on 2 or 3 years' operation and thus the validity of the designs for fatigue are not yet truly tested. Wind turbines are commonly designed for a 25-year life, during which time fatigue cycles exceeding $10^8$ will be experienced, with minimal inspection compared to aircraft standards which consider a fatigue cycle to consist of a take-off and landing. There are many important variants in the design of horizontal axis machines; the most important are the use of two or three blades (a few single-bladed machines exist in West Germany) and whether these blades are fixed or can pitch the whole or part of the blade. Pitching the blades enables power control to be achieved once the wind

**Fig. 5.3.** Californian wind farm (17 m diameter, 100 kW WT, US Windpower Inc.).

speed exceeds the rated value selected for the design, whereas power regulation on fixed blade WTs occurs in a natural (but uncontrolled) manner due to the aerodynamics of post-stall behaviour. Materials used for the blades include steel, aluminium, glass-reinforced plastic and epoxybonded laminated wood.

In 1984, the Wind Energy Group (WEG) installed a 25 m diameter three-bladed pitch-controlled wind turbine in the UK, and this was the forerunner to the installation of 20 such machines in California in 1988. In November 1987, the largest UK wind turbine was commissioned in Orkney. This has been designed and built by WEG, is 60 m in diameter and rated at 3 MW. The blades are of steel box section construction with GRP fairings. This wind turbine is on Burgar Hill, which is one of the windiest locations in the British Isles, hence the rather high rating of 3 MW. The one or two other giant, experimental wind turbines with ratings in the region of 3 MW are all approximately 100 m in diameter and sited on less windy sites. Reference 1 gives details of the development of WEG's horizontal axis wind turbines. The Glasgow-based firm of James Howden also developed three-bladed HAWTs and have installed WTs in Orkney, Carmarthen Bay, Sweden and Kent, and a 75-machine wind farm in California.

The main developments of verticial axis wind turbines are taking place in North America and the UK. In North America the Darrieus version is favoured; this machine has fixed curved blades, that is to say it cannot pitch or reef the blades to control power capture. It is therefore a stall-regulated machine (at high wind speeds the air flow will stall over the blade thus reducing lift and hence power capture). Significant numbers of Darrieus wind turbines have been built in Canada and the USA sized up to 300 kW rated capacity. In these machines the curved blades have been formed from extruded aluminium alloy. A large 64 m diameter Darrieus has been built in Canada but at this

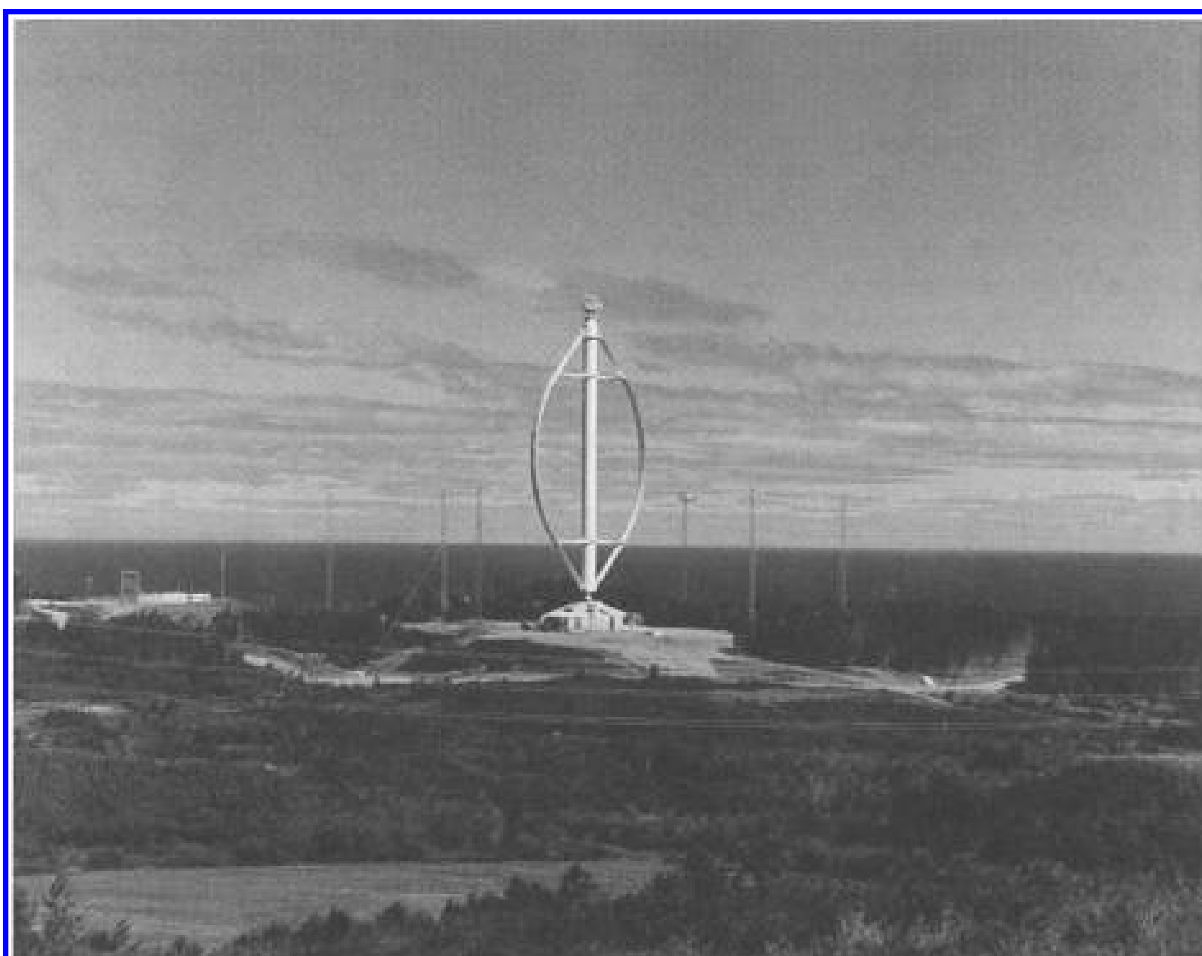

**Fig. 5.4.** 4 MW Darrieus WT, Project Eolé, Canada (photo by courtesy of National Research Council, Canada).

large size the curved blades are formed in short straight lengths using steel as the material: see Fig. 5.4. Reference 2 gives further details of the Darrieus WT development.

The vertical axis development in the UK is of a straight-bladed machine which on early models could control power capture by inclining its blades to the vertical. Hence they were not stall-regulated machines. Figure 5.5 illustrates the original concept conceived in 1975 by Dr Musgrove at Reading University, and Fig. 5.6 shows a 25 m diameter test bed development of the idea at Carmarthen Bay Power Station. Three years of testing of this wind turbine have demonstrated that its power capture can be controlled without blade inclination and all designs are now stall-regulated and with struts supporting the blades. A 500 kw machine has now been built at Carmarthen Bay.

Whilst some wind turbines are considered proven, much research and development remains to be done into various aspects, such as lightweight materials for the blades, the blade profiles, the dynamics of cyclic stall, and the integration of electricity-generating wind turbines with individual diesel sets, to mention but a few. The British Wind Energy Association (BWEA) has itemised the underlying R & D necessary and set out a programme in their publication *Wind Power for the UK*.[3]

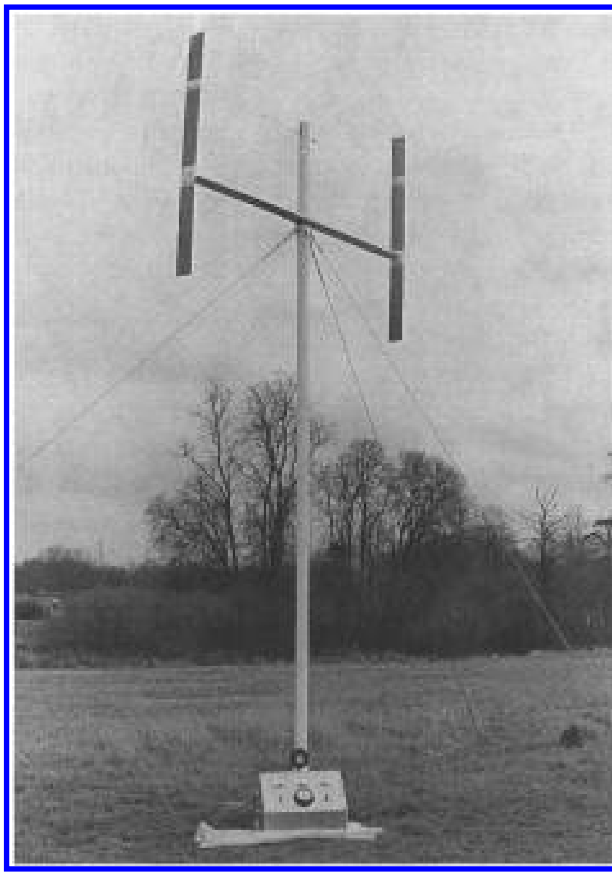

**Fig. 5.5.** University of Reading 3 m diameter vertical axis WT (1975).

### 5.3 EXPLOITABLE RESOURCE

The exploitable resource from the wind around the world is vast. Wherever the mean wind speed exceeds about 6 m/s there are possibilities for exploiting it economically, depending on the costs of competing sources of power. This is not limited to land-based wind turbines. Possibilities exist of installing large wind farms in shallow waters (perhaps limited to 30 m depth) around the coasts. Many areas of the world are subject to strong trade winds; Fig. 5.7 gives some indication of this resource. No reliable worldwide assessment of the exploitable resource has been made but many countries are making their own assessments based on varying criteria. These criteria take account of minimum distance from residential property (set by some at 500 m), visual acceptability, impact on farmland, and electrical transmission costs, to quote some of the principal ones.

Within the United Kingdom the CEC has estimated the gross resource on land to be 1760 TWh.[4] Environmental factors may reduce possibilities on land to a much lower figure, in the range 25–45 TWh/year.[5] A detailed assessment of the offshore resource[6] yielded an estimate of around 200 TWh—far more than could presently be accommodated in the UK. It has been suggested that around 20% of present capacity, about the same level as nuclear generation, could be assimilated into the system without difficulty. Economic penalties would be incurred with increasing levels of penetration.[7]

The Central Electricity Generating Board did an appreciable amount of research into probable costs of wind power and availability of sites within England and Wales. This has been published in their evidence to the Hinkley 'C' Public Inquiry and the following extract may be usefully quoted.

> The results of the preliminary resource estimate are shown in the table below for 30 m height, which is a tower height typical of medium size machines. In addition the variation of energy yield with windspeed is given in terms of an energy load factor, defined as the actual output in a year as a proportion of the output that would be achieved if the plant were always operating at maximum output. This parameter varies as the cube of the average windspeed.

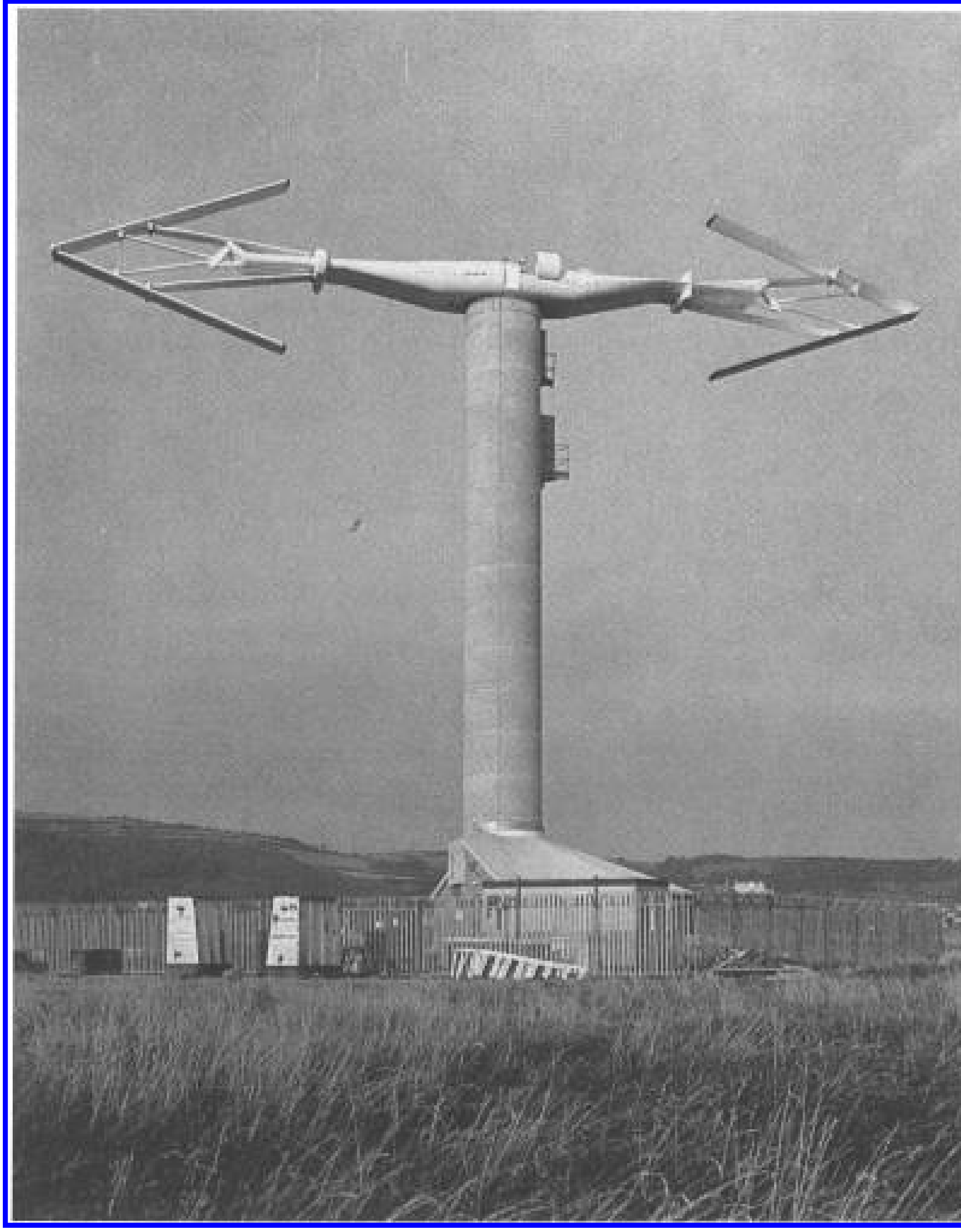

**Fig. 5.6.** 25 m diameter experimental vertical axis WT by VAWT Ltd at Carmarthen Bay Power Station.

It must be emphasised that this study was based on the total land area available in England and Wales; the actual usable areas are likely to be considerably less than this. Areas of high wind speed are mainly found at high elevations and therefore tend to lie in scenic regions including areas of outstanding natural beauty and national parks. The practical land area that could be used is uncertain. If 10% of the areas given in the above table could be developed with a typical planting density of 4 MW per sq km the total

**Estimated land areas and energy load factors with high average windspeeds**

| *Annual windspeed at 30 m height (m/s)* | *Land area with windspeed (sq km cumulative)* | *Energy load factor* |
|---|---|---|
| 9·0+ | 500 | 42% |
| 8·4+ | 2500 | 35% |
| 8·0+ | 7500 | 30% |

wind energy capacity of these regions would be about 3000 MW, with up to 1000 MW available at

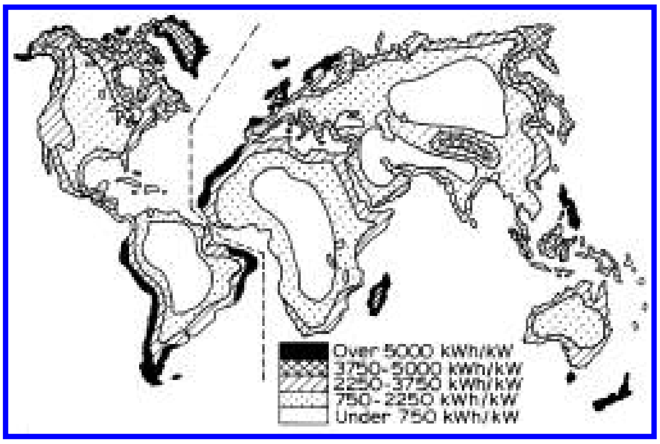


**Fig. 5.7.** Estimated worldwide distribution of wind energy sources (US Department of Energy).

windspeeds of 8·4 m/s and above. The total exploitable wind resource is hard to assess with any certainty.

The CEGB concluded that if £700/kW cost figures are achievable then on sites with mean annual wind speeds of 8·4 m/s or more at 30 m height, about 1000 MW of capacity could be installed, producing electricity at a comparable cost to PWR nuclear, and that this would have an equivalent firm capacity of 400 MW. If capital costs fall to £600/kW then a further 2000 MW of installed capacity on 8 m/s wind speed sites would be competitive with nuclear power. (This analysis was based on the use of a 5% return on investment as then required for a public sector organisation.)

## 5.4 ECONOMIC APPRAISAL

Where wind turbines can be installed in substantial numbers in wind farms the cost of electricity generated may be comparable with that from nuclear or coal-fired power stations, in the range of 2 to 4 pence/kWh at a 5% discount rate provided that targets for availability, lifetime and maintenance are met. The BWEA's publication *Wind Power for the UK*[3] estimates 2·1 p/kWh on a 9·4 m/s mean wind site. It is estimated that 1000 MW of wind turbines could be installed on sites with mean wind speed greater than 8 m/s on the UK mainland. A summary of the results of this calculation is appended at the end of this section.

The medium to long term economic prospects for wind-generated electricity in the UK look encouraging. Department of Energy assessments indicate that the total cost of land-based wind energy (capital cost of turbines plus costs of associated transmission systems plus maintenance costs) from series-ordered large production turbines operating from the year 2000 onwards could be in the range 2·5 to 3·2 p/kWh.[8] The Department's assessments show that over a wide range of scenarios land-based wind energy for grid supply shows better than unity benefit/cost ratios.[9]

Offshore wind power is estimated to be significantly more expensive due to the high cost of foundations and submarine electricity transmission. Estimated costs of 4½ to 5½ p/kWh are quoted, again for significant quantities at a 5% discount rate (the UK calculations are based on 200 large wind turbines).[10, 11]

## 5.5 COMMERCIAL PROSPECTS

The economic appraisal in Section 5.4 indicates good commercial prospects but these must be tempered by environmental acceptability and institutional and other barriers, as is the case with any power generation scheme. These are examined in the following sections. Nevertheless markets do exist and will continue to develop. These are of two types: the 'wind farm' and the 'stand alone' machine require different marketing and servicing. The only significant wind farm market to have developed to date is that in California where a combination of tax concessions, good purchase rates for electricity, and wind amplification due to geographic factors in areas well serviced by HV transmission lines (i.e. passes between deserts and valleys or valleys and coastal areas) created a bonanza for wind power. Not all projects succeeded but some proved themselves and their products, including two British and several Danish firms. It is a remarkable fact that despite the diversity of machines and companies, and the unplanned, unstructured growth of the industry, within 7 years a new source of electricity generation has been tapped, with very rapid production evolution year by year now resulting in high quality machines. In the Californian case all the factors were favourable. It is doubtful whether we shall see this repeated elsewhere; thus wind turbine manufacturers will wish to plan their export on the basis of a sound home market. It should be noted also that even in the 'windy' passes of California, annual mean wind speeds are lower than 8 m/s.

The stand alone market is generally for small machines (up to 100 kW) and is mostly in remote or island locations often with difficult access. Maintenance can therefore be a major problem; robust and simple designs are likely to succeed rather than sophistication to achieve high efficiency. Marketing and after-sales servicing probably require a suitable existing operation, such as agricultural equipment supply, rather than a newly established and dedicated operation. Much could possibly be achieved through judicious licensing of established local companies.

One thing is clear: the market for small and medium-sized machines is highly competitive, and for a supplier to remain in business it will need to keep abreast of rapidly developing technology and have the support of its home government.

## 5.6 ENVIRONMENTAL ACCEPTABILITY

As with most sources of power, wind power has its pluses and minuses as regards environmental impact. On the positive side, it is a non-polluting and renewable source. Public awareness of this fact is high.

On the negative side there are several factors to consider:

(a) visual intrusion;
(b) noise;
(c) interference to television and radio signals;
(d) conflict of land use;
(e) hazard to birds.

Let us consider these in turn.

*Visual intrusion* occurs. An individual wind turbine, or even a small group, can be regarded by many not as an objectionable intrusion but as an object of interest, a functioning structure no more at odds with the surroundings than, say, a motorway bridge. Large groups may create a different reaction and great care must be taken with their siting and layout. It is unlikely that layouts as in the Altamont Pass in California would be accepted in many parts of the UK. Public reaction needs to be tested, both by the construction of a few carefully planned wind farms within those countries wishing to adopt wind power as a significant supplier to the national grid and by the construction of single windmills to evaluate the concept of low density wind farms (a windmill every few kilometres instead of every few hundred metres).

*Noise* is of two kinds: mechanical noise from the transmission and aerodynamic noise from the blades or from the blades passing the tower. Good design should avoid both. Generally, the sound at a distance of 10 rotor diameters from the wind turbine is barely discernible above the general background for horizontal axis machines, and this distance is even less for vertical axis machines which have a lower rate of rotation and where the blades are much further from the tower. Some local authorities in the UK are already setting exceedingly stringent requirements for absence of noise. Williams, in his paper on wind turbine noise,[12] gives an extensive list of references for papers on this complex subject.

It can be concluded that noise ought not to be a major problem with well-designed wind turbines sited a sufficient distance from residential premises.

*Television interference* has been recorded on occasions but seems limited to about ½ km in range. The use of non-metallic blades partly resolves this problem except where lightning strike protection strips or mesh are used in the blades. Again good siting is the solution to this problem but if necessary local remedial measures can be taken, such as the installation of cable TV or a repeater station to avoid transmission through the wind turbines. This is the solution adopted at Goodnae Hills, Washington State.

*Conflict of land use* is not proven. It depends on public acceptance that agriculture can proceed unhindered to the base of the wind turbine towers, as is the case in the Altamont Pass, California, or on what restrictions on such close working will be required. Should agriculture be banned within an area of possible blade throw (up to 500 m) then effectively the whole wind farm will be denied to agriculture. More reasonably, farming would be restricted only in the relatively small area just below the blades, but many do not see this as a necessity and believe farming could go right up to the tower, particularly stock farming. Taking roads and areas below blades into account, land use is about 1–1½% of the total area, the rest continuing under agriculture.

*Hazard to birds* seems to be an insignificant issue. The effect on birds is being monitored at the wind turbine site in Orkney and no deleterious effect has been recorded. In the Netherlands this matter has also received careful study[13] and again no significant effects are recorded. In California certain rare species, e.g. the golden hawk which is California's state symbol, share their habitat with wind farms and perch on stationary windmill blades to assist their aerial predation.

## 5.7 INSTITUTIONAL AND OTHER BARRIERS

Institutional and other barriers vary greatly between countries and indeed within states of countries. They mainly occur under three headings:

—Taxation
—Payment for power generated
—Planning

### 5.7.1 UK

Until April 1990, local taxation in the form of rates was at a penal level on privately owned wind turbines and other private electricity generators (other than those used only for agricultural purposes). This however has now been rectified with the introduction of formula rating reasonably comparable to that for the large utilities. The result was no wind farms and relatively few planning applications.

The payment for power generated is, at the time of printing, somewhat confused due to the process of privatisation of the electricity supply industry. In some cases the operators of wind turbines may be able to benefit under the 1989 Electricity Act, from the Non-Fossil Fuel Obligation and the associated fossil fuel levy, but possibly only until 1998. There-after sales will have to be to the pool at the going rates for all generators. This may create considerable difficulties in financing projects on the open market with the requirement for high rates of return.

### 5.7.2 USA

In the USA the position varies from state to state with California being the best known case. In that state there has been, till recently, 25% state and 25% federal tax concessions on the supply and installation of wind turbines. The utility companies have been required to purchase the power at their highest avoidable cost which has resulted in payments in the region of 8 c/kWh. It may also be said that planning considerations, until recently, have caused little constraint on the building of large wind farms in the areas behind San Francisco and Los Angeles. The result has been a bonanza for wind turbine manufacturers who had their products developed in time: up to the end of 1986 wind turbines had been installed with a total generating capacity of 1210 MW. Thus an American wind turbine industry has been able to develop on a sound home basis. These conditions have also been to the benefit of certain European manufacturers, particularly Danish but also two British companies which established wind farms there in the last two years of the tax concessions.

Whilst this section considers primarily wind turbine development in the UK, it is instructive to pick one of our European neighbours and briefly consider their development there.

### 5.7.3 The Netherlands

The Dutch wind turbine industry was given a major boost in 1986 when the Ministry of Economic Affairs launched a 4-year programme worth over £38 m. A total of £20·75 m has been allocated to 'market stimulation' whereby subsidies will be allocated on an installed kW basis to turbines which have been certified by the Dutch Test Station (ECN). A further £11·2 m has been allocated for grants to wind turbine manufacturers for industrial technology development. The remaining sum, £6·4 m, has been allocated to basic research activities in research institutes and universities and to support the continued operation of the ECN Test Station. The aim of this ambitious programme is to develop the Dutch industry, thus enhancing its ability to compete in the large wind turbine market both in the Netherlands and abroad.

## 5.8 EXPORT OPPORTUNITIES

The Watt Committee has not itself carried out a market survey but believes that a substantial market exists at present for small and medium-sized wind turbines, with rating up to about 250 kW, in stand alone conditions throughout the developing world and in remote areas of the developed world. The market for wind farms, other than the California situation, will depend on individual development where institutional and planning considerations are favourable and where the electricity generated will displace fossil fuels, particularly oil. As the production of wind turbines by established manufacturers grows and the price of power generated in wind farms reduces to the highly competitive figures quoted in Section 5.4, markets for wind farms are likely to develop in many parts of the world. There is, for example, considerable interest and potential in India where three wind farms are in operation using Danish wind turbines.

The Watt Committee considers export opportunities to be favourable in the medium term and that the government should continue to encourage the development of a UK industry for export having regard to the time needed for the development of wind farm export opportunities.

The removal of tariff barriers throughout the EEC in 1992 will offer both an opportunity and a challenge to enter the growing European market. The export market for large wind turbines (greater than 0·5 MW rated capacity) has not yet developed and will depend in turn on the development of these large machines which are still in the experimental stage and on their proven economics. Government support for this development will be necessary for some time due to the long lead time and high financial risk involved.

## 5.9 BRITISH WORK

There are several firms which have successfully developed small wind turbines and established export sales. Marlec Ltd have done exceptionally well, with sales of their 50 W machine exceeding 7000 over the past 5 years, over 70% being exported. Until the recent establishment of the Department of Trade and Industry test centre near Glasgow, operated by NEL, little government help was received by these companies which have developed in response to an existing demand.

For medium to large machines there have been three UK companies developing ranges of wind turbines. These are the Wind Energy Group (WEG), Howdens, and Vertical Axis Wind Turbines (VAWT). The first two are concerned with horizontal axis machines. All three have received support funding from the government and limited funds from the EEC.

The Wind Energy Group (and its earlier consortium) were the first to start and have developed their wind turbines from first principles. In the process they have carried out much research and development work, particularly into the turbines of 20 m and 60 m diameter in Orkney (Fig. 5.8) and into a 25 m commercial machine in North Devon. In addition they have exported twenty 25 m wind turbines to California and operate these through an associated company (Fig. 5.9). These machines have performed extremely well from the first. WEG have installed two 330 kW machines, one for National Power in Carmarthen Bay and one for US Wind Power in California.

Howdens initially took a licence from a USA company but later improved and developed this technology. Their first 'non-licensed' wind turbine was also built on Orkney and was 22 m in diameter (Fig. 5.10). More recently they have supplied a machine to the CEGB at Carmarthen Bay, a 750 kW wind turbine in Shetland and a 1 MW machine at Richborough in Kent. Howdens were the first UK company to export to California and have a wind farm of 75 machines with a total rated capacity of 25 MW (Fig. 5.11). Some difficulties with the fabrication of blades for the wind turbines delayed the effective start of operation of this wind farm.

VAWT have developed the variable geometry vertical axis wind turbine originally invented by Dr Peter Musgrove at Reading University. They have a 25 m diameter test bed machine operating at Carmarthen Bay and a 17 m, built in conjunction with their licencees, Davidson & Co. Ltd, on St Mary's in the Isles of Scilly. They have also provided the design for a 14 m diameter version built in Sardinia. Currently VAWT are commissioning a 35 m diameter, stall-regulated wind turbine at Carmarthen Bay. This will have a maximum output of 500 kW and will be owned and operated by National Power.

In parallel with these machine-specific developments, the Department of Energy and the Science and Engineering Research Council have been commissioning research work of a generic character, including work on materials, fatigue, blade profiles, resource availability and offshore application of wind power. The total government-funded wind power research and development budget amounts to about £5·2 m per annum, the Department of Energy contributing £4·5 m, SERC £0·3 m and DTI £0·4 m. In addition the CEGB programme of turbine construction and R & D reached a level of around £2½ m per year. It is difficult to arrive at the private sector expenditure on R & D as no published figures are available but it probably amounts to around 20% of the public sector figure.

New developments in wind-assisted ship propulsion have taken place during the past few years and the BWEA has been active in promoting further work in this area,[14] to encourage UK manufacturing and exporting opportunities. Despite a rapid drop in oil prices in 1985–86 there has now been the predicted inexorable rise. Expected fuel savings of 15–20% should be achieved for most medium-sized cargo ships fitted with optimum

**Fig. 5.8.** 60 m diameter, 3 MW WT at Burgar Hill, Orkney, by the Wind Energy Group.

**Fig. 5.9.** British WTs, 250 kW (Wind Energy Group), in Altamont Pass, California.

**Fig. 5.10.** 22 m diameter prototype WT by James Howden in Orkney.

WASP devices, and this now begins to represent an attractive cost reduction for fleet operators. One UK device, the Walker Wingsail, has already shown its worth on a British ship in 1986–87 and further developments of this and other cost-effective devices should be supported in a wind power research and development programme.

## 5.10 STRATEGIC CONSIDERATIONS

United Kingdom electricity generation is largely by coal-fired and nuclear power stations with oil-fired plant in reserve. There is also a small amount of hydro-power on the system. By far the largest proportion is coal-fired and on present plans for new power station building is likely to remain so in the next few decades. The introduction of wind generation, or any other renewable, into the system must increase the security of the system by adding to the diversity of generating plant. The CEGB has calculated[7, 15] that at least 20% of the system peak load could be accommodated from variable sources of supply, such as wind power, without

**Fig. 5.11.** Howden's Californian wind farm.

significant cost penalty in the operation of existing plant and with direct fuel savings which, in the case of coal, account for 60% of the cost of energy.

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## APPENDIX: GENERATION COSTS

The calculation for a typical British wind turbine on a good, windy site is summarised in Table A5.1. Such generation costs, around 2 pence/kWh, based upon actual operating experience overseas, are very favourable compared with other methods of generation including coal and nuclear power which are around 3 pence/kWh or more. Just how favourable the costs are depends upon many assumptions, such as future prices of fossil and nuclear fuels. However, they are sufficiently attractive now to justify a major programme of development and installation to meet British conditions.

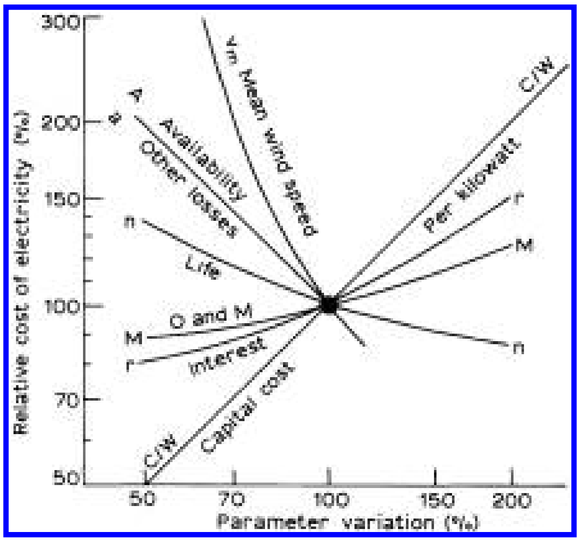


**Fig. A5.1.** Sensitivity of cost of electricity to various parameters. For each parameter, the 100% level is that given in Table A5.1. (Source: Ref. 3.)

**Table A5.1 Calculation of generation costs**

| | | |
|---|---|---|
| Capital cost per rated kilowatt | $C/W$ | 880 £/kw |
| Design life expectancy | $n$ | 30 years |
| Required real rate of return | $r$ | 5% |
| Annual charge rate | $R$ | 6·5% |
| Operation and maintenance | $M$ | 2% |
| Hours in a year | $h$ | 8760 h |
| Turbine rated wind speed (hub height) | $v_r$ | 13·3 m/s |
| Site annual mean wind speed (hub height) | $v_m$ | 9·4 m/s |
| Mean as fraction of rated wind speed | $v_m/v_r$ | 0·71 |
| Nominal load factor | $F$ | 0·45 |
| Machine availability | $A$ | 95% |
| Factor for other losses | $a$ | 90% |
| Generation costs | $G$ | 2·1 pence/kWh |

Source: Ref. 3.

# Section 6

# Small Scale Hydro-electric Energy

## 6.1 INTRODUCTION

Conventional hydro power uses the potential or kinetic energy of rainfall collected in a high level catchment as it runs towards one at a lower level, often the sea. As a power producer the technology has a long history of development, and it was hydro power which drove the first electricity power station to supply electricity to the general public at Godalming, Surrey in 1881.

Relying as it does on water, and hence rainfall, the resource is renewable, but does require terrain which produces an exploitable difference in height or 'head'. Heads of as little as a few feet can be exploited successfully, but require large volume flows to provide a useful quantity of energy.

Being rainfall-dependent, the resource is subject to fluctuations from season to season and year to year. Over a period of days or weeks typical Scottish run-off varies between (–)100% (i.e. none) and+400% of average values, whilst over a year typical variability would be (–)18% to+25%. Consequently the technology's firm output is only a fraction of its installed capacity unless storage is provided by high-level impounding of run-off.

Conditions suitable for hydro power development with high rainfall and steep mountainous terrain are not widespread in the United Kingdom, being largely confined to Scotland and Wales. Low head river resources are more widely scattered, but of relatively small energy significance.

In developed countries the larger hydro resources were among the first energy sources to be developed, and have largely been fully exploited. Consequently attention is now focused on smaller resources which are generally classified by size of scheme as shown in Table 6.1.

In less developed countries there are still considerable large-scale resources yet to be exploited, but the smaller schemes are nevertheless still of interest as possible low-cost, low-technology paths to electrification. It is in the mini and micro scale installations that technological progress is most evident because of the very tight constraint on economics caused by a relatively low energy density.

## 6.2 STATUS OF THE TECHNOLOGY

The harnessing of water for mechanical energy goes back centuries, initially for applications such as grinding cereals, and later for a wide range of industrial purposes. It has been used for the direct generation of electricity since 1881 and most modern schemes are installed for this purpose. The technology has developed from wooden water wheels (overshot, undershot and crossflow) through to the Francis, Kaplan, Pelton, Cross-flow and Turgo turbines of the 20th century, and whilst new materials and techniques are making an impact upon the civil works (particularly dams and penstocks), here too the technology is largely mature.

The investigation, design and construction of conventional hydro-electric schemes is well defined and understood, and can be costed with a reasonable degree of certainty. Similarly plant components, are readily available from a wide range of manufacturing sources.

Nevertheless there are areas of the technology where novel designs or methods are apparent, and these are concentrated at the mini and micro scale end of the spectrum where economic constraints demand an innovative approach. On the prime mover side there are novel low head designs based on reciprocating

**Table 6.1 Definition of hydro scheme size**

| | |
|---|---|
| Large | 50 MW and above |
| Small | 5 MW to 50 MW |
| Mini | 500 kW to 5 MW |
| Micro | 500 kW and below |

devices, together with a trend towards the use of off-the-shelf components and plastics for small impellar-type turbines. On the generation, protection and control side, the use of micro and power electronics is tending to simplify and cheapen the scheme. With regard to the civil works, these tend to be necessarily conservative in design given the cost and implications of any failure. Nevertheless use of components in novel materials such as plastics for pipelines is apparent.

None of these developments is revolutionary, in the sense that it creates extensive new opportunities, but it does gradually push out the boundaries of economic viability, particularly on the mini and micro scale fringes of the technology.

## 6.3 EXPLOITABLE RESOURCES

Francis[1] suggests that hydo resource potential falls into three broad categories, namely:

(a) Gross river potential—approximately the summation of annual run-off×potential head.
(b) Exploitable technical potential—which is all the potential in (a) above less that which it is technically impossible to exploit. Clearly, (b) tends towards (a) as technical developments take place.
(c) Economic exploitable potential—which is (b) less that energy which it is presently uneconomic to develop. As conditions change (e.g. the cost of capital and competing fuels), (a) may expand or contract, but cannot exceed (b).

To this classification scheme can now be added a fourth category, recognisable as an important addition in modern times, namely:

(d) Environmentally acceptable potential—which is all the potential in (c) less that which is considered to be undevelopable because of its environmental impact. As public sensitivity to environmental impact grows, the amount of economic, environmentally acceptable resource falls.

Over the last 70 years there have been several surveys and estimates of the potential for hydroelectric development in the UK, including those listed in Refs 1–9.

The Watt Committee on Energy working group on small scale hydropower reported on resource potential in March 1985 (Report No.15),[10] and developed estimates for technically and economically exploitable potential for the UK based on the available surveys. The estimates are shown in Table 6.2.

The WEC Survey of World Energy Resources,[11] published in 1986, gives a gross exploitable capability for Great Britain of 5600 GWh/year, whilst in May 1985 ETSU published estimates of technically exploitable potential for small-scale developments of 1800 GWh/year, and estimated that up to 90% of these could be economically viable at a 5% TDR.[12]

Since 1985 little has happened which materially affects the resource position. There have been no significant technical advances opening up new areas of exploitation, whilst competing fuel prices (largely coal or oil) have tended to fall in price, thus weakening the economic case. The run-of-river schemes proposed in recent years for development by the North of Scotland Hydro-Electric Board have been deferred due to lack of capital availability within the public sector borrowing requirement, but had in any case run into enough environmental opposition to add caution to the consideration of estimates of viable potential. With this in mind it would not be surprising if the total viable hydro-electric potential of the UK turned out

**Table 6.2 Total potential hydro-electric power in the United Kingdom**

| | Existing hydro-electric installations | | Further major developments proposed but not built | | Estimated small-scale (5 kW–5 MW) sites | | | |
|---|---|---|---|---|---|---|---|---|
| | | | | | Technically exploitable[a] | | Economically exploitable[a] | |
| | (MW) | (GWh/y) | (MW) | (GWh/y) | (MW) | (GWh/y) | (MW) | (GWh/y) |
| Scotland | 1 270 | 4 000 | 350 | 1 100 | 180 | 790 | 60 | 260 |
| Wales | 120 | 246 | 230 | 390 | 70 | 300 | 25 | 110 |
| England | 9[b] | 20 | — | — | 32 | 160 | 14 | 75[c] |
| N. Ireland | Negl. | 1 | 40 | 110 | 35 | 150 | 18 | 75 |
| Total | 1 399 | 4 267 | 620 | 1 600 | 317 | 1 400 | 117 | 520 |

[a] Power capacity estimated at 30% exceedance, which on most British rivers gives a 50% plant factor or thereabouts.
[b] Includes Kielder scheme (under construction).
[c] These values reflect the high utilisation factors of water supply schemes, which are typically 60%.

to be under 2 TWh/year, depending upon economic circumstances and given present regulatory procedures on development.

Throughout the world the 1986 WEC World Energy Survey estimates that annual hydro production totals over 1·8 million GWh, from both large and small-scale schemes. From the same survey, total exploitable capability exceeds 9·5 million GWh/year. Exploitable capabilities in excess of 100 000 GWh/year are available in Argentina, Brazil, Canada, Chile, China, Indonesia, Mexico, Norway, Turkey and the USSR.

## 6.4 ECONOMIC APPRAISAL

The economics of hydro power are absolutely sitespecific, and depend critically upon the topography, geology and hydrology of each individual site. These determine the size of the resource and the cost of development, which are themselves variable depending upon how the resource is developed—for example, with or without storage, at high or low load factor.

The costs of development do show some returns from increasing scale, but a very wide band due to site characteristics, as can be seen in Fig. 6.1.

For a typical small-scale scheme these costs can range from £700/kW installed to £2000/kW installed for 'green field' sites in Scotland[10] and from £540 to £2700/kW installed for low head or run-of-river schemes in England and Wales (September 1985 price levels).[1]

Based on a 5% discount rate these costs roughly translate to a capital cost of 16 to 70 pence per annual kWh from a scheme, and are capable of producing electricity at between 1·5 and 4·5 pence per unit (September 1985 price levels). A graph of viable potential at a given production cost for Scottish sites is shown in Fig. 6.2, and demonstrates that viable potential is a function of the economic scenario for the cost of capital and competing fuels.

Hydro power is capital-intensive, and usually long lived, with civil works typically lasting 100 years or more. With a zero fuel cost, and typically low maintenance and operation costs, the primary economic problems arise due to high interest rates and the demand for short payback periods. Generally speaking, unless the method of economic assessment used recognises the extremely long remunerative life of hydro works, the economic case will not look favourable. It is paradoxical that investment in hydro schemes looks extremely favourable in retrospect (i.e. existing schemes are very profitable now) but extremely uncertain in prospect, despite the greater maturity and experience of the technology now available.

## 6.5 COMMERCIAL PROSPECTS

In the present economic climate the commercial prospects for hydro development in the UK are not particularly encouraging. The high cost of capital, the

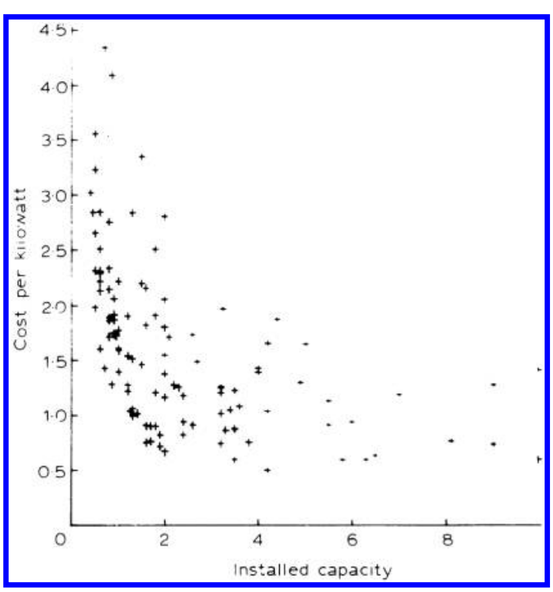


**Fig. 6.1.** Hydro capital cost distribution. (Cost,×10³ £; capacity, MW.)

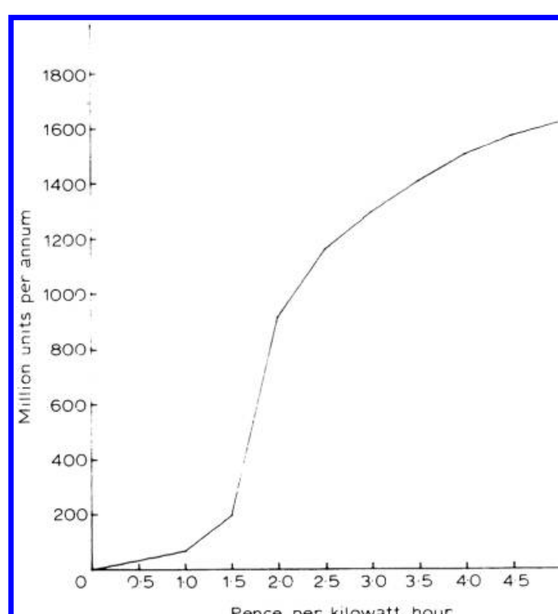


**Fig. 6.2.** Cumulative economic capacity.

present low cost of alternative fossil fuels, the small, generally inaccessible and dispersed nature of the resource, and the presence of some institutional barriers and environmental opposition combine to produce a stagnant domestic market. It seems unlikely that this situation will alter radically until there is a demand for new electrical generating capacity or until competing fossil fuel prices return to high levels.

### 6.6 ENVIRONMENTAL ACCEPTABILITY

The environmental impact of hydro-electric power schemes is entirely local to the installation, and arises from the physical impact of the works themselves, and upon the water level effects upon watercourses and catchments.

In the construction phase the excavation and deposition of spoil and the storage of construction materials and equipment are likely to have an adverse impact. Once constructed a number of scheme components can affect visual amenity, including the dam or intake, the pressure pipeline if not buried, the power station/substation buildings, the access roads, and high-voltage connections. In addition, in the operational phase the effects on water levels can be to expose unsightly silt margins and to remove water from the watercourses between intakes and power station.

Of the more significant environmental impacts, the most likely to generate serious opposition are:

(a) Interference with fish population, particularly salmon and trout, due to blockage of access to migratory fish, the diversion of water from spawning beds, and inadvertent pollution of water by silt or oil.
(b) Interference to access by man or other fauna (deer, birds) due to the works themselves (pressure pipelines) or to flooding of a catchment.
(c) The permanent occupation of land by scheme components, particularly the upper reservoir if a large area has to be flooded.
(d) Interference with the quality or flow of water downstream of the scheme.
(e) The visual intrusion of the scheme onto a landscape which is likely to be of high visual quality, perhaps supporting a large body of tourist or recreational interest.

The largest proportion of UK viable undeveloped hydro potential occurs in Scotland and Wales, in terrain which is considered to be of outstanding environmental quality. As a consequence the impact of environmental opposition on scheme development is considered to be relatively high, reducing the viable (i.e. economically exploitable) potential by as much as 50% in those areas.

### 6.7 INSTITUTIONAL AND OTHER BARRIERS

The institutional barriers special to hydro-electric development largely result from conflict with other water interests, and must be considered in conjunction with the site-specific design problems associated with the technology.

Institutional barriers to development were considered in some detail in Watt Committee Report No.15 on small scale hydro,[10] but briefly they hinge upon parliamentary legislation on water abstraction, pollution prevention, land drainage, impoundment and fisheries. In England and Wales this legislation was administered by ten Regional Water Authorities, who interpreted and applied the legislation in their own areas. (It is now administered by the National Rivers Authority.)

#### 6.7.1 Abstraction

In England and Wales the licensing of, and the charges for, the abstraction of water are certainly the most complex part of the water problems for small-scale water-power users. Under Section 23(1) of the Water Resources Act 1963 no-one may abstract water from a source of supply except in pursuance of a licence. The 1963 Act gave powers of enforcement to the river authorities, and the Water Authorities are entitled to levy a charge on the whole of the licensed abstraction in accordance with charging schemes made under Section 31 of the Water Act 1973. Section 16 of the Energy Conservation Act 1981 revises Section 60(2) of the Water Resources Act of 1963 and refers to the need to conserve sources of energy and the desirability of preventing water charges from inhibiting the use of water as a source of energy. All Water Authorities were prepared to give consideration to this by allowing reduced charges in appropriate circumstances, but the discretionary nature of these powers has led to wide differences in intepretation, and a degree of uncertainty for small hydropower developers. Recent court rulings may help to clarify the position somewhat for small users in England and Wales.

### 6.7.2 Pollution prevention

Most small-scale schemes for the discharge of water from a turbine would not be such as to be considered a trade effluent, and therefore a consent to discharge in accordance with the Rivers (Prevention of Pollution) Act 1951 may not be required. It would be necessary to establish this point with the relevant Water Authority.

### 6.7.3 Land drainage

Most hydro-electric schemes that are installed entail the construction of either an under or over water course. If these are constructed on main rivers, consent would be required from the water authority in accordance with the Section 28 of the Land Drainage Act 1976. If, on a non-main river, the proposed construction causes an obstruction to flow, a similar consent is also required in accordance with Section 29 of the 1976 Act.

### 6.7.4 Impoundment

If in a scheme there is to be impoundment of water, it is necessary under Section 36 of the Water Resources Act 1963 to apply for a licence to impound, in addition to any licence to abstract which may otherwise be required. In the event that the impoundment entails storage of more than 25 000m$^3$ of water above local ground level, in accordance with the Reservoirs Act 1975, both the design and periodic inspection of the impounding structure would need to be carried out by qualified engineers as specified under that Act.

### 6.7.5 Fisheries

The Salmon and Freshwater Fisheries Act 1975 requires any scheme which interferes with river discharge by impoundment or by abstraction to have regard for the safety and passage offish. Sections 12 to 15 of the Act refer to sluice-gate operations, gratings for protection of fish intakes, discharge points and consents.

In Scotland the pollution, land drainage and impoundment regulations apply similarly, but the abstraction legislation does not apply, its counterpart being a common law requirement not to alter water use to the prejudice of water users below the development.

The only other barriers to development in the UK which are peculiar to hydro power are its environmental sensitivity (already mentioned under Section 6.6) and the site-specific nature of the design problem. The latter requires that each installation ideally should have individual design attention, which conflicts with the need to keep things simple and hence cheap if mini and micro schemes are to be economically viable.

## 6.8 STRATEGIC CONSIDERATIONS

In the UK context the remaining potential developable hydro resource is small, probably less than 2TWh/year. Nevertheless it has a number of favourable strategic characteristics. These are:

(a) It is renewable, with a fuel source independent of imports or groups of organised labour.
(b) Technological expertise is available within the UK, along with suitable manufacturers of plant and equipment.
(c) The resource is widely dispersed and thus less vulnerable to disruption in the event of war or civil disturbance.

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# Section 7

# Geothermal Energy

## 7.1 INTRODUCTION

Geothermal energy is derived from the earth's natural and continuous heat flow which has been estimated at some $2{\cdot}75\times10^{16}$ cal/h (thermally equivalent to 30 000 million kW). This massive flux can be related to a temperature differential of some 4000–4500°C at the centre of the earth compared with an average of 15°C at the surface of the crust. Considered on this global scale, geothermal energy may be regarded as a renewable source, but for practical purposes the energy available from any individual site will be exhausted within some two to three decades. It is generally accepted that thermal energy is derived primarily from the decay of long-lived radioactive minerals with a smaller, but significant, contribution from a slight cooling of the earth.[1] Before the discovery of radioactivity and the realisation of its significance in the thermal history of the earth, physicists such as Lord Kelvin had calculated that the time required for the earth to cool from an original molten state to its present condition was only some 80 million years. It was subsequently realised that the internal heat source provided by the decay of the long-lived radioactive isotopes reduces the cooling rate sufficiently to accommodate the observed heat flow without the necessity for the full cooling hypothesis. However, Oxburgh and O'Nions[2] have suggested, on the basis of observations on the occurrence and distribution of primordial and radiogenic helium, that the present heat loss from the mantle is grossly out of equilibrium with the helium loss. They deduce that 'Either radiogenic helium is accumulated in the mantle whilst heat escapes, or current concepts for the bulk chemistry of Earth are in error and much of the terrestrial heat loss is non-radiogenic.'

The distribution of heat flow over the surface of the globe can be related in large measure to the concept of 'plate tectonics' illustrated in Fig.7.1. In the zones of active tectonism and volcanism along the 'plate' boundaries, the heat flow peaks at values of 2–3 W/m$^2$ as a result of actively convecting molten rock (magma). Away from such zones, heat is transferred in the crust by conduction through the rocks, and locally, by convection in moving groundwater, to give heat flows on the continents averaging no more than 60 mW/m$^2$. Variations in the vertical thermal gradient are also considerable, being greatest in the vicinity of active plate boundaries and least in the continental shields remote from the boundaries, with average values around 25°C/km. Sub-surface temperatures are related to the gradient, itself a function of the heat flow and the conductivity of the rocks, and locally to the heat production derived from concentrations of radioactive isotopes.

Exploitation of geothermal energy is limited by economic and technical factors. The principal technical problem is the development of practical and economic mechanisms to concentrate and harness the massive but diffuse thermal energy which the heat flow represents. The wide variation in the temperature of accessible geothermal fluids leads to a range of possible applications which are summarised in Table 7.1. Fluids at temperatures below 140°C cannot be directly applied to power generation and must approach 200°C or more to be used with an acceptable level of efficiency. However, for space-heating and some industrial purposes, temperatures in the range 40–60°C are acceptable, as is 20–30°C for some horticultural and piscicultural purposes.

Man has already developed two principal methods of exploiting geothermal resources using naturally occurring fluids as the heat-transfer medium, whilst the technology for a third, in which the transfer medium is injected water, is well advanced. In the vicinity of the active 'plate' boundaries referred to above, natural hydrothermal activity is at its maximum and within such active zones, high temperature and

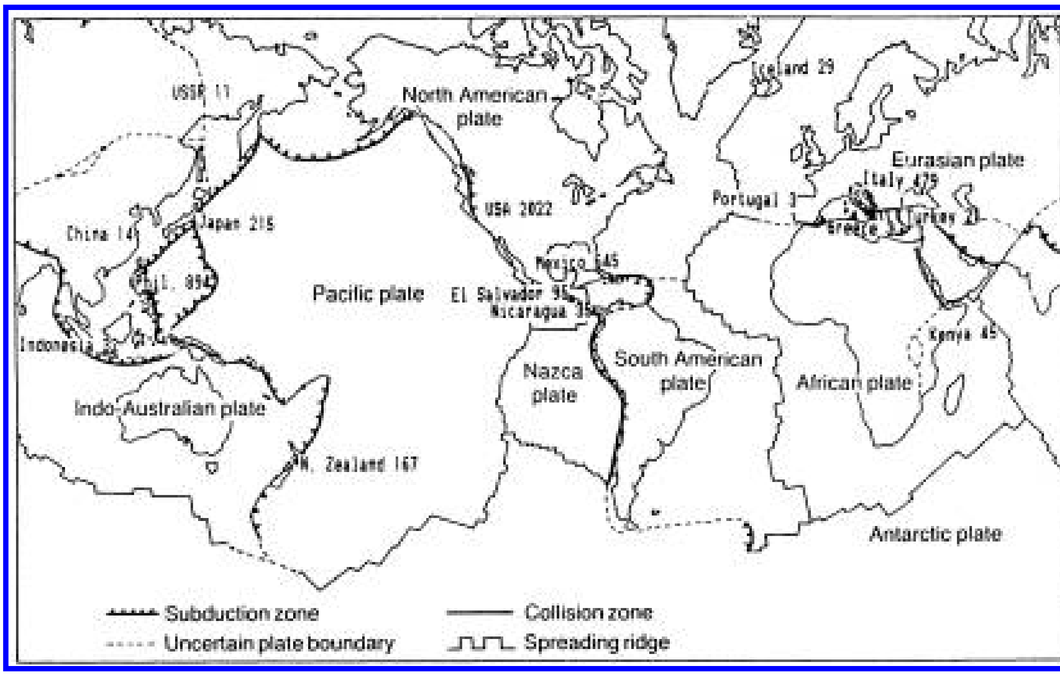


**Fig. 7.1.** A generalised illustration of the distribution of the 'plates' over the earth's surface and the types of boundaries separating them. The electrical generating capacity of countries with geothermal power plants operating in 1987 is indicated in MW (electrical). (Source: Ref. 3.)

high pressure geothermal fluids extracted from boreholes were used to generate some 4·7 GW worldwide in 1985. Power generation began in 1904 in Lardarello in Italy, where installed capacity at the end of 1986 amounted to 430 MW. Since 1904 there have been power generation developments in the USA, Mexico, El Salvador, Nicaragua, New Zealand, Indonesia, the Philippines, Japan, China, the USSR, Turkey, Greece, Kenya and Iceland, as well as in several smaller oceanic islands.[5] Exploration is continuing in many regions.

Away from the active 'plate' boundaries, the second method of development is employed. Permeable strata (aquifers) are tapped by boreholes drilled to depths typically of 1–3 km for the hot waters and brines they contain. These are passed through heat exchangers and their energy extracted for space or process heating before the cooled waters are reinjected into the formation from which they were abstracted. This two-borehole system is termed a 'doublet'. The reinjection has to be undertaken at a sufficient distance to ensure that the cold water does not return to cool the source within the lifetime of the scheme. In many countries where the institutional factors are favourable, such as Iceland, France, Hungary, Canada, USA, China and the USSR, aquifers are actively developed and an estimated 7 GW of energy was produced worldwide in 1985. A potentially important but local variant of this system is the 'geopressured' aquifer which may contain three forms of energy: thermal due to high temperatures, mechanical due to high pressures, and chemical due to a high methane content in the fluids. Such aquifers occur in deep sedimentary basins in which pressures and temperatures are well in excess of those expected at the depth at which the reservoir lies.

The third method of exploitation is still under development and is termed the 'Hot Dry Rock' (HDR) system. Although a variety of sub-surface 'structures' have been considered as mechanisms whereby thermal energy can be extracted from the earth where no natural fluids are found,[6] the most promising is a two-borehole system, or multiples of that design. In this, water is injected via one borehole drilled into a body of hot dry rock to a depth sufficient to provide power generation temperatures. The relevant depth at any site is determined by the local geothermal gradient but in the UK it would lie in the range 6–8 km to give temperatures of, say, 200°C or more. The injected water acts as a heat transfer medium and is circulated through a volume of 'reservoir' rock which is manipulated to form a heat exchanger. As the circulating water is heated, its density falls and the density differential supplements the pumping effort needed to cause it to rise up a second, production borehole. Thence it is passed to a

**Table 7.1 Approximate temperature requirements of geothermal fluids for various applications (after Ref. 4)**

| | °C | | |
|---|---|---|---|
| | 200 | | |
| | 190 | | |
| | 180 | Evaporation of highly concentrated solutions | |
| | | Refrigeration by ammonia absorption | |
| | | Digestion in paper pulp (Kraft) | |
| | 170 | Heavy water via hydrogen sulphide process | Conventional power production |
| Saturated Steam | | Drying of diatomaceous earth | |
| | 160 | Drying of fish meal | |
| | | Drying of timber | |
| | 150 | Alumina via Bayer's process | |
| | 140 | Drying farm products at high rates | |
| | | Canning of food | |
| | 130 | Evaporation in sugar refining | |
| | | Extraction of salts by evaporation and crystallisation | |
| | | Fresh water by distillation | |
| | 120 | Most multi-effect evaporation | |
| | | Concentration of saline solution | |
| | 110 | Drying and curing of light aggregate cement slabs | |
| | 100 | Drying of organic materials, seaweeds, grass, vegetables | |
| | | Washing and drying of wool | |
| | 90 | Drying of stock fish | |
| | | Intense de-icing operations | |
| Hot Water | 80 | Space-heating (buildings and greenhouses) | |
| | 70 | Refrigeration (lower temperature limit) | |
| | 60 | Animal husbandry | |
| | | Greenhouses by combined space and hotbed heating | |
| | 50 | Mushroom growing | |
| | | Balneology | |
| | 40 | Soil warming | |
| | 30 | Swimming pools; biodegradation; fermentations | |
| | | Warm water for year-round mining in cold climates | |
| | | De-icing | |
| | 20 | Hatching of fish; fish farming | |

power generation plant and, where appropriate, a secondary heat exchanger for waste heat recovery before reinjection as the downward limb of the closed circulation loop. Several doublets could be created at a single power generation site by the use of inclined boreholes and recently proposals have been advanced to drill two or more production wells for each injection borehole. In the present state of development, HDR schemes are considered to have the best prospects of success in relatively uniform crystalline rocks such as granite, in which reservoir generation can be undertaken without the problems associated with non-uniform material. Particularly advantageous are radiothermal granites in which radioactive minerals are concentrated and so add additional decay heat to the local heat flow.

The principle of the system has been demonstrated at the Fenton Hill site of the Los Alamos National Laboratory, New Mexico, at power generation temperatures (*c*. 190°C), and also at the Rosemanowes Quarry research site of the Camborne School of Mines, Cornwall, where research has concentrated on the rock mechanics of reservoir creation and management at lower temperatures (70–80°C). Although the results to date are encouraging, some aspects of reservoir control require further development before the system could be regarded as proven technically. Substantial development funding is still required to create a prototype production plant able to demonstrate economic viability. The announcement[7] of continued government funding for a further three-year programme of R & D for the Cornish reservoir manipulation experiments, leading to a major review in 1990, is welcome. Subject to a satisfactory outcome to that review, the development of a prototype demonstration system at operational temperatures and depths—200°C and 6–7 km in the UK—is greatly to be recommended.

## 7.2 EXPLOITABLE RESOURCES IN THE UK

In the mid-1970s the Department of Energy in association with the EEC initiated a programme of research aimed principally at assessing the UK's geothermal resources by the mid-1980s. Estimation of geothermal resources involves calculation of the 'heat-in-place' in the earth down to any given depth in the region of interest. This requires knowledge of the mass of the rocks, their specific heat and their mean temperature.[8] Rock densities are generally in the range 2·60–2·80 Mg/m$^3$ and the average specific heat of rocks is 0·8 J/(g K), increasing to 0·9 at 200°C. It can thus be seen that the principal cause of variation in such estimates is related to the predicted subsurface temperatures in the region. In turn such prediction necessitates knowledge of the geological structure and the regional heat flow.[9]

Computerised maps of the heat flow distribution have been prepared for the United Kingdom by the British Geological Survey (BGS) and have been continuously revised as the data base has grown; an example is shown in Fig. 7.2. These have been employed to predict both temperatures at given depths and depths to given temperatures and hence to produce resource estimates. An example showing the temperature at a depth of 7 km throughout the UK is given in Fig. 7.3. These data must then be related to the occurrence of the relevant rock types and in Fig. 7.4 the distribution is shown of the radiothermal granites and the principal Mesozoic sedimentary basins in the UK. Of the former, those in the Cornubian peninsula and the Weardale granite in north-east England offer the best prospects for HDR, whilst the sediments in the latter contain the main aquifers capable of development for low enthalpy resources.

In assessing the geothermal resources Gale and

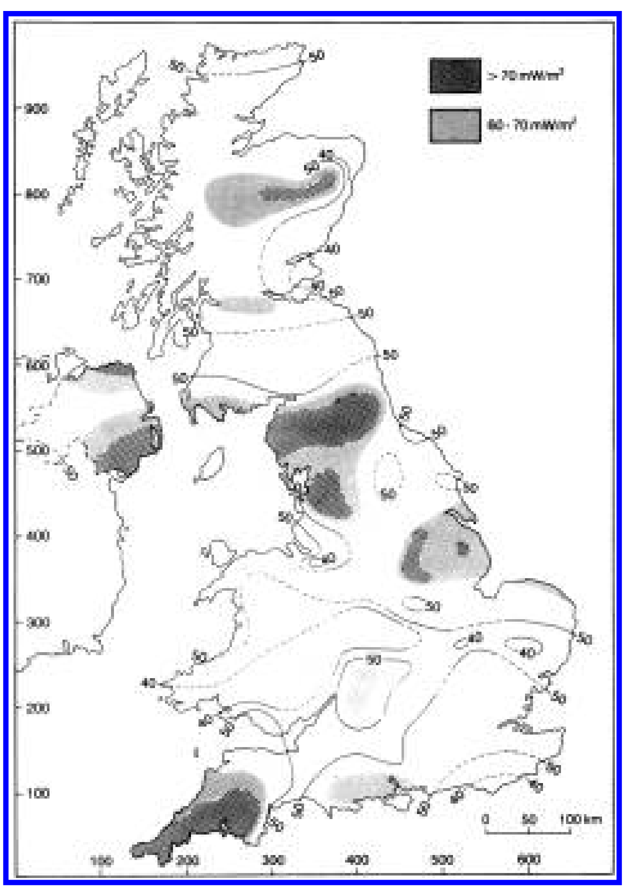

**Fig. 7.2.** Heat flow in the United Kingdom (mW/m$^2$)(Ref. 9; reproduced by permission of the Geological Society).

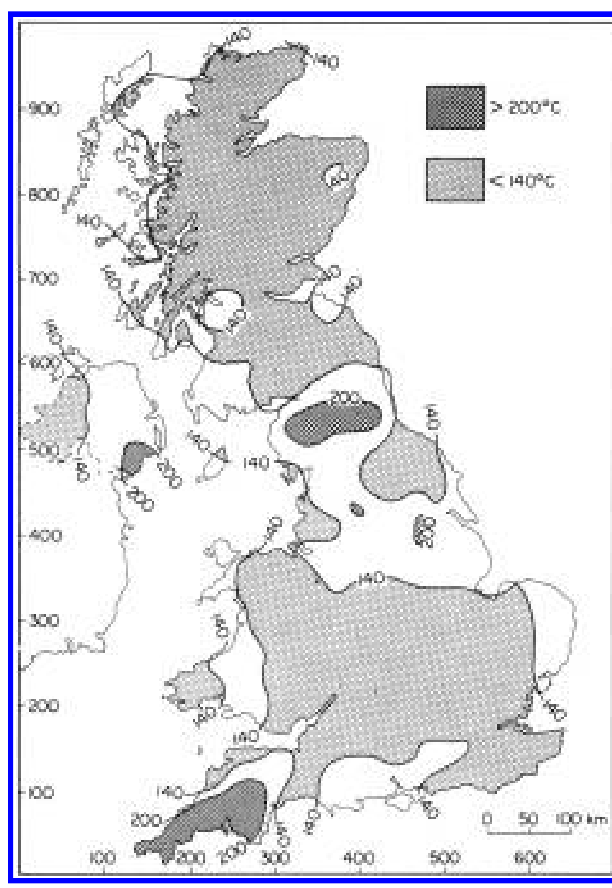

**Fig. 7.3.** Estimated temperatures (°C) at a depth of 7 km in the United Kingdom (Ref. 9; reproduced by permission of the Geological Society).

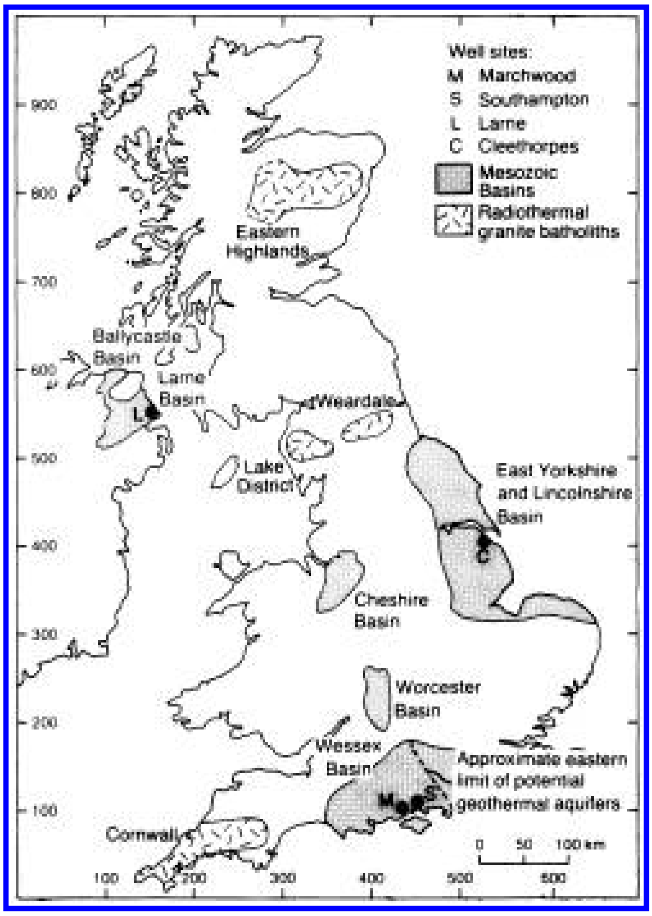


**Fig. 7.4.** Distribution of radiothermal granites and major Mesozoic basins on land in the UK (Ref. 9; reproduced by permission of the Geological Society).

Rollin[8] used the concept of the Accessible Resource Base (ARB) to represent the total heat in place above the limit of economic drilling, taken at that time as 7 km, although a depth of 8 km is now under consideration. The ARB is qualified in various ways in determining the proportion which might be practicably available for exploitation. Such estimates, revised periodically, formed the basis of the calculations by both Newton[11] and Shock[12] in their respective ETSU publications on HDR, and by Garnish *et al.*[13] for the ETSU report on aquifers, as well as for the resource and cost estimates given in ETSU R-30[14] and ETSU R-43.[15] At the present stage of technological development the potential geothermal resources in the offshore regions of the UK have not been determined.

### 7.2.1 Hot Dry Rock (HDR)

The HDR Accessible Resource Base at temperatures of more than 100°C and at depths of less than 7 km has been calculated to be $3{\cdot}6\times10^{10}$ TJ or $130\times10^{4}$ Mtce.[8] Newton[11] estimated that the Technical Potential (the heat energy which could be extracted subject only to technical and efficiency-of-use considerations) of HDR resources is capable of providing 10% of the UK's annual electricity requirement for between 800 and 5000 years: In ETSU R-43 the Achievable Contribution (electrical) is rather more realistically estimated as 2000 TWh, equivalent to 2½% of present electricity generation for up to 200 years, based on the resources estimated to occur in the Cornish and Devonian granites. In his estimation of reserve size, Shock[12] introduced a design base-case for the exploitation of HDR and some rather arbitrary limitations on the accessible areas in which development might take place. Subsequently to the Shock report, BGS suggested as a result of further research that the HDR prospects for the Weardale granite should be upgraded;[10] part of this granite is close to the western edge of the Gateshead urban area. Allowing for this occurrence and for some relaxation of Shock's limitations on accessible areas, it is not unreasonable to speculate that the currently recognisable UK reserves for HDR may amount to some 10 000 MW for boreholes in the depth range 6–7 km and perhaps to 15 000 MW by taking advantage of the higher temperatures at 7–8 km. The costs of constructing a doublet in either depth range are likely to be significantly less than those assumed by Shock due to major reductions in drilling costs as indicated by Batchelor.[16]

### 7.2.2 Aquifers

The areas in which the hot brines found in aquifers might be developed as local energy supplements can be characterised as fields in which the temperature of the brines is greater than 40°C and the transmissivity of the aquifer (the product of the thickness of the aquifer and its permeability) is greater than 10 Darcy metres.[9,17] Their distribution is shown in Fig. 7.5; in all of the fields the rocks of interest are sandstones of Permo-Triassic age which occur in Mesozoic basins. The low enthalpy Geothermal Resource (that part of the Accessible Resource Base that could possibly be extracted economically at some specified time) in the rocks of principal interest at temperatures of more than 40°C is $220\times10^{18}$ J (8000 Mtce). The Identified Resources (the proportion of the Geothermal Resource that is more likely to be available for economic exploitation) within these fields are summarised in Table

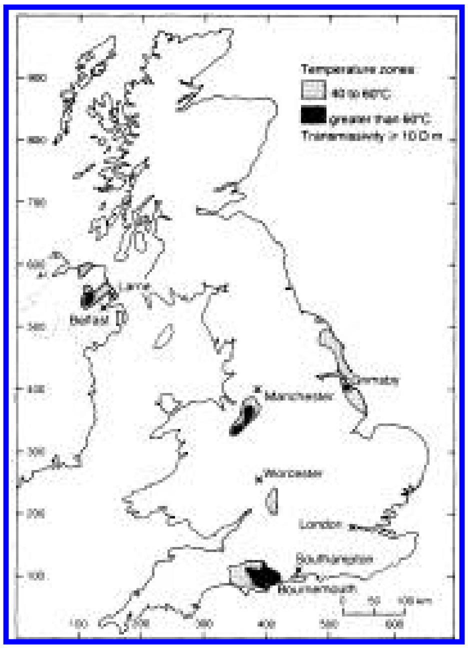


**Fig. 7.5.** Potential low enthalpy fields in the UK, defined by a temperature of more than 40°C and a transmissivity of more than 10 Darcy metres (Ref. 9, reproduced by permission of the Geological Society).

**Table 7.2 Identified Resources of the Permo-Triassic sandstones at temperatures of over 40°C (reproduced by permission of the Geological Society from Ref. 9)**

| | 40–60°C[a] | | 60°C[b] | |
|---|---|---|---|---|
| | $10^{18}$ J | Mtce[c] | $10^{18}$ J | Mtce[c] |
| East Yorkshire and Lincolnshire | 26·2 | 974 | 0·2 | 7 |
| Wessex | 2·8 | 105 | 1·8 | 69 |
| Worcester | 3·0 | 112 | — | — |
| Cheshire | 8·9 | 331 | 1·5 | 56 |
| Northern Ireland | 6·7 | 249 | 1·3 | 48 |
| Totals | 47·6 | 1 771 | 4·8 | 180 |

[a] Use of heat pumps assumed and hence a reject temperature of 10°C.
[b] Assumes heat pumps would not be used and hence rejection at 30°C.
[c] Mtce is million tons of coal equivalent.
Estimates assume development with doublets.
A scale is given to the figures by bearing in mind that the annual use of electrical energy in the UK is about $10^{18}$ J.

7.2 : utilisation of the water between 40 and 60°C implies the use of heat pumps for most purposes. A significant constraint on the development of aquifers for space-heating in the UK is a mismatch between the distribution of the Identified Resource fields and urban heat loads.

## 7.3 ECONOMIC APPRAISAL

### 7.3.1 Electricity generation and CHP

Geothermal resources capable of application to electricity generation and/or CHP can be divided into four systems:

(1) Liquid dominated hydrothermal. In active hydrothermal (volcanic) zones.
(2) Vapour dominated hydrothermal. In active hydrothermal (volcanic) zones.
(3) Geopressured aquifers. In broad, deep sedimentary basins.
(4) Hot Dry Rocks (HDR). Theoretically at any site where drilling permits access to rocks at power generation temperatures, depending upon the generation cycle employed.

The total world potential for geothermal-generated electric power at drilling depths to 3 km using the technology available in 1978 was estimated in the World Energy Survey of the 1978 World Energy Conference as $1{\cdot}2\times10^6$ MW operating for 100 years. However, this is a significant underestimate if drilling to greater depths, generation cycles using lower temperatures and the HDR system are considered.

Within the UK, only HDR need be considered for either power generation alone and/or CHP as the country is remote from active hydrothermal zones and geopressured aquifers do not occur on land. The variety of configurations of turbine and generating cycles which are possible for power and CHP applications, combined in some circumstances with supplementary heating, suggest a wide range of economic appraisals which might be made. The resultant values are greatly influenced by reservoir creation and drilling costs. The latter are related to borehole depths and diameters which, in turn, are determined by the required temperature of the fluids to be made available for heat exchange. The estimated temperatures at relevant depths in the UK (Fig. 7.3) indicate that development and utilisation of efficient binary cycles would result in economic operation.

An outline of the HDR system has been given above and it is clear that to recover the maximum heat the injected water must follow optimum flow paths through the reservoir rocks. These must be of sufficient volume and have sufficient fractured surface area exposed to the fluid to provide the required heat throughout the lifetime of the system, usually taken as 25 years. The process of 'hydro-fracturing' which is employed to create the reservoir is a technique used by the oil industry to increase the permeability of oil reservoirs and so improve the performance of production wells. Its use in granites for HDR reservoir creation is a major extension of the technique in that the 'hydrofrac' produced must result in an anastomosing series of fractures in the volume of the rock separating the injection and production wells and extending well beyond their immediate vicinity. The volume of rock aimed for at Rosemanowes was of the order of $200 \times 10^6$ m$^3$ and the heat-exchange fracture surface some $2 \times 10^6$ m$^2$ to provide an effective system.[12] The injection pressure for the 'hydrofrac' must create permanent flow paths through the rock mass either by opening pre-existing fractures through which flow may at some time have taken place, or by causing flow to occur through incipient fractures through which no flow has previously passed: in either case the aperture of the fracture is of the order of a few tens to hundreds of microns. Such fractures, whether previously open or not, are thought to be the result of the cooling history of the magma from which the granite was derived, and, within a few kilometres of the surface, of the subsequent tectonic history of the region in geological time. Design and control of the 'hydrofrac' ideally requires knowledge of the orientation and magnitude of the in-situ stress of the rocks at the depth at which the reservoir is to be created. Further research to improve present knowledge and understanding of the rock mechanics of reservoir generation is necessary to obtain the best performance from HDR developments. The reservoir creation should be achieved for a capital outlay of some 10% of the drilling costs. Pairs of holes may not necessarily optimise the performance and multiple production wells may prove economic. Lowering the return temperature of the injection water will increase the buoyancy in the production limb and so reduce the pumping power required, but to achieve this, good heat-exchange with the fluid used in the turbine circuit is necessary to optimise the efficiency gains.

Shock[12] explored the economic potential of HDR systems in the UK using various cycles to produce electricity and CHP. He concluded that for electricity alone, use of the Trilateral Wet Vapour Cycle (TWVC) plant is the most promising but that under none of the circumstances examined did CHP compare economically with coal, oil or nuclear energy sources, in contrast to the findings reported the previous year in ETSU R30.[14] CHP finds many applications in other parts of the world but despite its success elsewhere no analysis of large scale schemes in the UK seems to have found favour. The reasons may lie in the institutional framework of energy supply in the UK which may be relevant to the apparently uneconomic application of HDR to CHP. Cost comparisons for a single doublet system using three power generation cycles are shown in Table 7.3 (from Shock[12]). Increasing the number of doublets supplying geothermal fluids to a centralised generation plant reduces the power production costs. For example, with a five-doublet system the TWVC cost drops to a production cost of 4·2 p/ kWh from 5·1 p/kWh at the assumed 6 km reservoir depth.

In an assessment using a slightly different base case to the Shock model and current drilling costs, Batchelor[16] (1987) gives an electricity production cost of 3·5 p/kWh, reflecting a capital cost of £2563/ kW (A.S.Batchelor, personal communication). If a multiple doublet system with centralised generation is considered, the production costs would be expected to decrease to 2–3 p/kWh and the capital costs to approximately £2200/kW, particularly if advantage is taken of higher temperatures in the deeper depth range of 7–8 km. Such costs compare not unfavourably with a typical cost for new hydrothermal plant in active hydrothermal zones of £1680/kW.

It is recognised that such cost analyses are beset with a great number of uncertainties, reflecting the worldwide lack of HDR exploitation. Sensitivity studies were made by Shock[12] to explore the effects of changes of several parameters on the discounted prices of electricity (Fig.7.6). He recognised the volatility of drilling costs in response to the unpredictable requirements of the hydrocarbon industry and world events. The example given above, in which Batchelor[16] employed current drilling costs rather than those assumed by Shock, illustrates the major effect that this factor alone has on the overall costs. Continuing research on HDR reservoir development and management technologies may also lead to cost reductions.

### 7.3.2 Heat supply

#### *7.3.2.1 From HDR*

Economic studies of heating-only schemes for HDR have concentrated to date on district heating for domestic application in the larger urban areas, although application to industrial or horticultural

**Table 7.3 Contributions to Discounted Cost Price of Electricity at mid-1985 prices (Ref. 12, Table 12)(reproduced by permission of the Energy Technical Support Unit)[a]**

| | ORC | | TWVC | | Flash steam cycle | |
|---|---|---|---|---|---|---|
| MW (so) | 4·6 | | 6·6 | | 4·0 (flash temp. 100°C) | |
| Surface plant (£M) | 5·4 | | 7·5 | | 3·7 | |
| (£/kW so) | 1 180 | | 1 121 | | 928 | |
| Drilling and reservoir establishment (£M) | 18·6 | | 18·6 | | 18·6 | |
| (£/kW so) | 4 011 | | 2 780 | | 4 690 | |
| *Capital costs (p/kWh)* | | | | | | |
| Surface plant | 1·40 | | 1·27 | | 1·26 | |
| Drilling and reservoir establishment | 4·00 | | 2·77 | | 4·93 | |
| Connection charge | 0·07 | 5·47 | 0·07 | 4·11 | 0·07 | 6·26 |
| *Running costs (p/kWh)* | | | | | | |
| Water supply | | 0·24 | | 0·17 | | 0·30 |
| Operation and maintenance of wells | | 0·08 | | 0·06 | | 0·10 |
| Operation and maintenance of surface plant | | 0·93 | | 0·76 | | 0·97 |
| Discounted cost of electricity (p/kWh) | | 6·7 | | 5·1 | | 7·6 |

[a] Assumptions: Water flow rate 75 kg/s, Geothermal gradient 35°C/km, Reservoir impedance 0.1 GPa/m[3], Reservoir depth 6 km, Casing i.d. 8½ in (21½ cm).

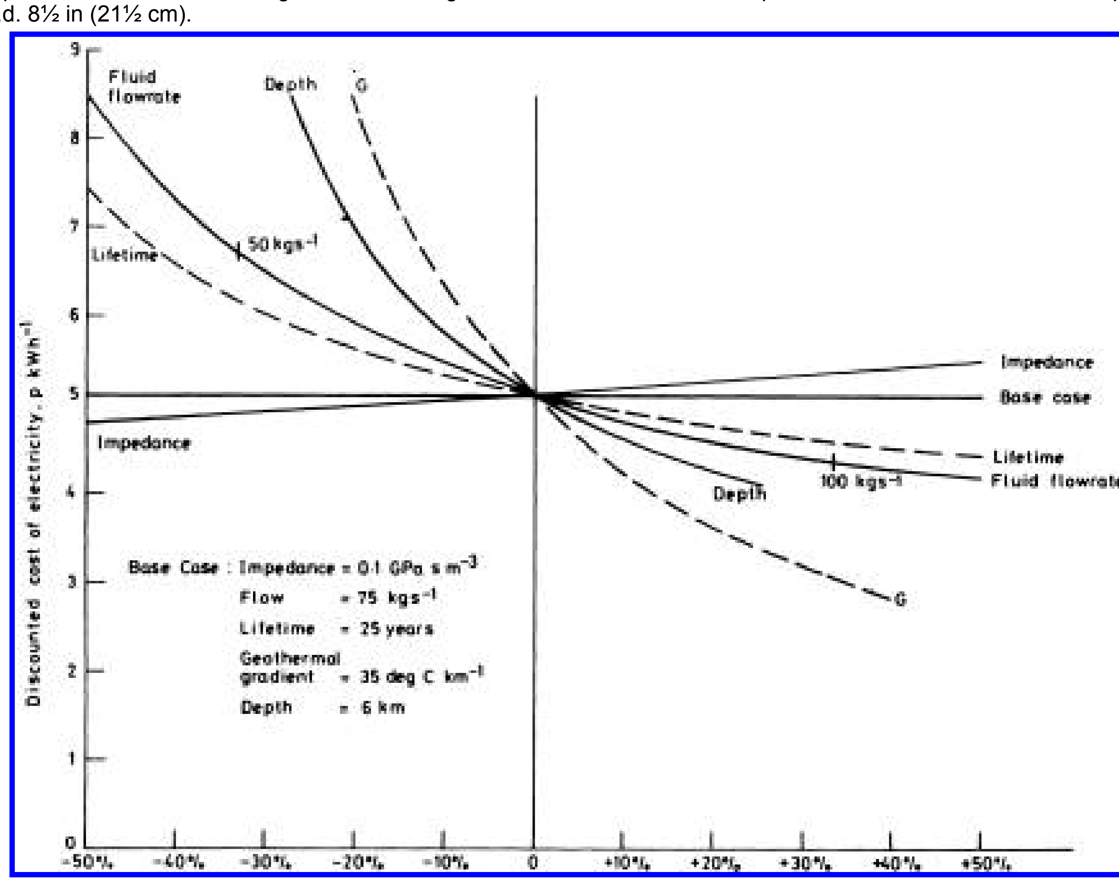


**Fig. 7.6.** Variation in discounted cost of electricity for independent changes in parameters: isolated doublet TWVC case (Ref. 12, Fig. 31a; reproduced by permission of the Energy Technical Support Unit).

process heat should be considered in some circumstances. Moreover, the return temperature of water to the injection well from an HDR district heating scheme would be between 37° and 65°C, offering a source of low grade heat which could be developed on a cascade basis for horticultural and social purposes (see Table 7.1). In some circumstances, the use of a heat storage system could prove economically advantageous.

Large-scale district heating has not been widely practised in the UK, but the scale of development of some 350 small schemes ranging in capacity from 2 to 20 MW was considered too small to justify the HDR drilling costs in the fuel supply scenarios examined by Shock.[12] However, he concluded that at greenfield sites where the geothermal gradient is greater than 25°C, heat-only district heating schemes could be economic with HDR providing the base load, and coal providing the back-up for peak capacity. He estimated the geothermal gradient under 18 urban areas and identified a few as warranting site-specific studies. In the present state of knowledge of HDR systems, however, it would be unwise to assume that an HDR reservoir could be generated in rocks other than relatively uniform crystalline materials such as granite, and such material is not known to underlie the CHP Lead Cities or the nine others selected by Shock. However, the eastern end of the Weardale granite adjoining Gateshead urban area does warrant study.

#### *7.3.2.2 From aquifers*

In an analysis of the aquifer R & D programme undertaken principally by the BGS for the Department of Energy, Garnish *et al.*[13] examined the prospects for exploitation of aquifers in two temperature ranges—above and below 60°C. They concluded that at neither temperature would heat from aquifers be economic in comparison with current gas prices and that the scale of any developments would be essentially local. Although the Department's aquifer programme was discontinued, it had met its objective of assessing the low enthalpy resources available for development, and the published results will be available for consultation when commercial prospects arise. Subsequent to the termination of the programme, Southampton City Council entered into an agreement with the Southampton Geothermal Heating Co. Ltd (a part of the Utilicom Group) to exploit for space-heating the hot brine (76°C) proved in the exploratory well previously drilled by the Department and the EEC at the Western Esplanade in central Southampton.[18, 19]

Extensive technical and financial data on projects using low enthalpy energy from aquifers have been compiled on an international basis by Harrison and Mortimer.[20] Comparison of the economics of schemes in different countries is complicated by the great variety of fiscal infrastructures and technical developments involved. For example, the combined grant/loan scheme introduced in France, specifically to encourage the use of geothermal energy for space heating, compares favourably with the direct commercial loan systems operating elsewhere. Again, the economics of heating schemes differ widely when one may be serviced wholly by geothermal fluid at a temperature of, say, 90°C and another may provide only 65% of the thermal load at 55°C, via a heat pump, with the balance from coal, oil or gas. For these reasons, costs are very site- and country-specific and 'typical' values cannot be given. To illustrate the point, rounded costs of geothermal district heating schemes range from 35 to 100 pence per therm at 1985 prices (R.Harrison, personal communication). The Southampton scheme began operation in January 1988 and is based on 20-year agreements with several consumers within a large commercial development. Each agreement incorporates a two-part tariff—a standing charge of £1.50 per installed kilowatt per month and a commodity charge of £7.25 per MWh of heat consumed; maintenance, connection and metering costs are met by the company (S.B.Thomson, personal communication). However, in this first field trial undertaken within the UK institutional framework, neither the drilling nor the testing costs have been borne by the company and the scheme is partly financed as an EEC Demonstration Project. A small-scale commercial, horticultural application (2.8 ha) has recently also been initiated at Penrhyn, Cornwall, in which warm water (22°C) is derived from an experimental borehole drilled to a depth of 250 m in the Carnmenellis granite.

## 7.4 COMMERCIAL PROSPECTS

### 7.4.1 HDR

Although results are most encouraging, HDR research is insufficiently advanced to state unequivocally that commercially viable systems can be developed. However, assuming that the R, D & D can be taken to an effective conclusion, the commercial prospects for geothermal HDR developments in the UK would seem reasonable, with the present (1987) fuel prices, for both direct heating and electricity generation. The pattern of heat flow in the UK (see Fig. 7.2) led to the development work being carried out in granite at Rosemanowes, Cornwall, run by the Camborne School of Mines,[16] under contract to the Department of Energy and with some financial support from the EEC.

Benefit cost ratios for installation of HDR capacity for electricity generation, CHP and heat supply were analysed by Shock[12] for three scenarios and the results for 1985 are shown in Table 7.4.

Specific sites, such as the Isles of Scilly which are currently served by electricity generated by diesel engine power, at a cost of 8·9 p/kWh, but are located on an outcrop of granite, could economically utilise HDR technology at the present time. However, in the Scillies water supplies for the circulating loop make-up and cooling purposes could produce difficulties unless sea water can be used. Research on this possibility has been started as coastal sites would become attractive if this proves possible.

Probabilistic analysis of sensitivity studies of cost variations of relevant parameters comprising the total costs of electricity generation from HDR sources were made by Shock. He concluded that there is a 70% probability that the cost of electricity by HDR would lie within the range 3·1 to 5·8 p/kWh. As indicated above, the subsequent major fall in drilling costs could reduce these costs to 2–3 p/kWh for higher temperature developments. (This paper was presented in 1987 and since then research undertaken within the Department of Energy's programme, but as yet unpublished, indicates that the costs given in Shock are optimistic (R.J.Taylor, personal communication).)

### 7.4.2 Aquifers

In the UK, exploration boreholes have been drilled to confirm the presence of geothermal aquifers with funds provided by the Department of Energy and the EEC at Larne in Northern Ireland, Marchwood and Western Explanade, Southampton, and most recently at Cleethorpes in Humberside. Although aquifers of adequate temperature were found at these sites, the yields of water and brine were low and the commercial prospects were regarded as uneconomic. However, as previously noted, Southampton City Council in association with a commercial company is exploiting the geothermal well at the Western Esplanade in the centre of the city. The transmissivity of the Sherwood sandstones in the well at Cleethorpes is estimated to be 220 Darcy metres and this would result in a high yield of brine at 50°C: regrettably no commercial use for this supply has been identified.

The lack of indigenous fossil fuels in France has resulted in large-scale development of geothermal aquifers for district heating, and many schemes are now operating in the Paris and Aquitaine basins. Most of these have been developed as geothermal schemes from the beginning but a few have utilised hot waters proved in exploration wells which yielded no hydrocarbons.

**Table 7.4 Benefit/cost ratios for HDR applications (Ref. 12, Table E1)(reproduced by permission of the Energy Technical Support Unit)[a]**

| Scenario | Electricity generation | | CHP electricity | | Heating supply | | |
|---|---|---|---|---|---|---|---|
| | PWR | Coal | PWR | Coal | At well-head | In home[a] (1) | (2) |
| I: Substantial rise in energy prices | 0·6 | 1·5 | 0·4 | 0·6 | 1·3 | 1·1 | 1·2 |
| II: Intermediate rise in energy prices | 0·6 | 1·3 | 0·4 | 0·6 | 1·1 | 1·0 | 1·1 |
| III: Low rise | 0·5 | 1·1 | 0·4 | 0·5 | 0·9 | 0·9 | 0·8 |
| Prices constant at 1985 level | 0·4 | 0·6 | 0·4 | 0·4 | 0·6 | 0·9 | 0·7 |

[a] Assumptions: Electricity Generation: 5-doublet stations, Trilateral Wet Vapour Cycle, installed between 2001 and 2010, geothermal gradient 35°C/km, discount rate 5%. CHP: 1-doublet station, Organic Rankine Cycle, installed between 2001 and 2010, geothermal gradient 25°C/km, discount rate 10%. Heat supply: 50 MW peak capacity mixed HDR and coal, with benefit/cost ratio at optimum mix. Benefits for heat at wellhead compared with coal-fired district heating; for heat in home, benefits for greenfield DH scheme compared with individual coal-fired (1) and gas-fired (2) wet central heating; geothermal gradient 25°C/km, discount rate 10%.

Similarly in the Pannonian basin in Hungary, some 100 of the 1000 low enthalpy geothermal wells now in use were originally drilled during explorations for hydrocarbons. The commercial exploitation of disused oil wells might suggest prospects for future geothermal district heating schemes in the UK when onshore oil reservoirs have been exhausted. However, the geographical mismatch of oil fields and existing heat loads may militate against this.

## 7.5 ENVIRONMENTAL EFFECTS

Whilst geothermal energy might be considered a benign source when compared with fossil fuels or nuclear energy, it is not without some adverse environmental effects. Conventional geothermal power stations in the volcanic zones are similar in bulk to many others and, particularly in early developments, surface pipelines bringing steam from the widely distributed boreholes to central power generation facilities can be unsightly. Most natural discharges from the earth and fluids extracted from boreholes incorporate some gaseous components such as radon, carbon dioxide, hydrogen sulphide and methane. Within the volcanic zones gaseous discharges from associated power stations can cause significant environmental disturbance requiring corrective measures.

Within the UK, however, developments for power generation by HDR schemes are likely to be much less severe so far as gaseous emissions are concerned as the concentrations are much lower. For example, the fluids circulating through granites will bring radon to the surface but the concentration observed to date is no greater than that found in natural streams.[16] If significant sulphide mineralisation were to be encountered in a reservoir zone, however, some additional scaling, corrosion and possibly gaseous emission problems could occur. The high density brines found in UK geothermal aquifers can be more difficult to deal with. The salt concentration is such that, except at estuarine and coastal sites where discharge to the sea can be arranged, untreated disposal to local rivers or public sewers would not be permissible. The cooled brine will have to be reinjected through the second borehole of a 'doublet' to the formation from which it had been extracted; although costly this has some advantages in that the formation pressure is maintained so that the pumping costs are reduced and the risk of subsidence, already slight, is eliminated.

Drilling operations can create a severe noise nuisance, causing problems in some developments, particularly in urban areas. However, recent improvements in noise insulation of rigs and the use of electric motors rather than diesel has largely eliminated that problem. During drilling operations an extensive area, ideally of several hectares, is required for the plant and continuing road access is needed throughout the period of drilling for many heavy goods vehicles. Subsequently the area occupied permanently is determined essentially by the surface engineering plant for the particular development: the only facility required specifically for geothermal purposes is access to the sites of boreholes for a work-over rig, to permit completion of any remedial down-borehole engineering.

The establishment of HDR reservoirs by hydrofracturing and their subsequent operation can generate high stresses leading to the occurrence of small seismic events. For this reason seismic monitoring equipment is installed in all regions in which HDR developments are under consideration well in advance of the first sub-surface experiments. During 1987 a minor 'felt' seismic event attributed to fluid injection at the HDR site at Rosemanowes was recorded at magnitude 2·0 ML on the Richter scale.

The provision of water for both make-up of the circulation fluids and cooling purposes for HDR schemes may create supply problems. At sites adjoining rivers or the coast, cooling for such schemes could be achieved without recourse to cooling towers. Away from such areas, however, cooling towers would be required and, for example, Shock[12] estimated that if 800 MW of generating capacity were to be installed some 25 natural draught towers would be necessary. Thus the incentive to employ low-rise, forced-draught towers to reduce their visual impact, as well as to improve the economy of operation, would be considerable. At present subsurface circulation for heat transfer has only been undertaken with fresh water, although consideration has been given to the use of sea water for this purpose. Over the lifetime of a scheme, large volumes of water would be injected into the thermal reservoir. The current evidence indicates that the water loss from the circulation fluids will be in the range of 10–20% and a source of make-up water will be required. A proportion of the water lost will probably flow away from the immediate vicinity of the reservoir, the amount being related largely to the characteristics of the rocks surrounding that in which the particular reservoir has been created. This mobile water will cause some chemical and/or physical variations in the conditions of the rocks with which it comes in contact.

## 7.6 CLOSURE

The environmental and political factors suggesting future limitations to the availability of fossil fuels has promoted research into alternative and renewable resources of energy, particularly for electricity generation in the UK. Aquifers are not able to provide the high entropy energy required for this purpose but interest has been stimulated in the expectation of high temperature heat from Hot Dry Rocks at depths of 6 km or more in some areas of the UK. Irrespective of which heat extraction technique is employed, the legal position of the ownership of geothermal heat in the UK requires clarification. Internationally the legal position varies considerably, but in some countries legislation has been introduced to control development. An associated legal issue arises in connection with the ownership of minerals which may be extracted in solution in the geothermal fluids.

The occurrence of high heat flows in the radiothermal Cornish granites led to a major research programme being undertaken at sites in the granites by the Camborne School of Mines; much of this research is now ahead of comparable work elsewhere in the world. The prospects for a successful conclusion to this R & D are encouraging. Associated economic analysis indicates that both electrical power generation and CHP systems could be deployed economically in the early part of the 21st century to provide some 2–3% of the UK's present energy demands for some 200 years, although CHP is seen at the present time as a less likely commercial proposition.

Economic analysis also suggests that district heating schemes fed from HDR heat-only schemes may well be economical in given circumstances at the present time and some areas warrant site-specific studies, particularly those where high heat loads are underlain by radio thermal granites. The application of low enthalpy geothermal resources to district heating from aquifers has proved commercially advantageous in many parts of the world and is expected to continue supplementing such energy demands well into the future. In the UK, however, the geographical distribution of the aquifers and the difficulty of forecasting their yields at given sites, coupled with the abundant availability of low-cost fossil fuels and various institutional barriers, have inhibited development of such local energy supplements. The commercially-led applications at Southampton and Penrhyn may lead to a change in this situation.

Given continued financial support at a sufficiently high level to foster the capital-intensive nature of the project and subject to the successful completion of the necessary R & D, a prototype demonstration plant at an operational depth of 6–8 km and a temperature of about 200°C could be in place in Cornwall in the mid-1990s. This would be used to acquire the operational experience at present lacking. Such a demonstration is greatly to be recommended and is likely to attract both commercial investment from British companies and international support over and above that already provided by the EEC.

## ACKNOWLEDGEMENTS

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# Section 8

# Ocean Thermal Energy Conversion (OTEC)

## 8.1 INTRODUCTION

Ocean thermal energy conversion (OTEC) is a base load system. It operates by extracting energy from the temperature difference which exists between the warm surface waters of the oceans over large tropical and sub-tropical areas of the globe, and the deeper waters in those locations, which flow from polar regions. Figure 8.1[1] is a map showing the temperature differences ($\Delta T$), as an annual average, for the oceans.

d'Arsonval first proposed an OTEC system in 1881, using a heat engine working on the Rankine cycle. Fifty years later another Frenchman, Claude, attempted a practical application of the concept in Cuba. France continued with developments intermittently after that, but it was principally practical progress in the offshore oil and gas industries during and since the 1960s which has enabled the OTEC concept to be brought to the stage of realisation, and development programmes now exist in Japan, USA, UK, the Netherlands and India, as well as France.

## 8.2 TECHNOLOGY

A number of variants of OTEC plant are possible, including closed cycle, open cycle; floating, land based, shelf/tower based, or 'grazing'; for generating electricity, for aquaculture, for desalination processes, or for combinations of these. Within the floating variant a number of options are available, including ship-shape hull, semi-submersible, submersible, guyed tower, and possibly others.

'Grazing' OTEC plants, i.e. plants which move either freely with currents, or under their own power, could be used to recover and process deep ocean minerals, produce liquid hydrogen, liquid ammonia and the like for trans-shipment to other areas to be used in industrial processes and power generation, or to process at sea ores and other raw materials which are energy intensive in extraction of the refined product. These grazing applications are likely to develop over a longer timescale, since they will be dependent for their operation, among other things, on a broad agreement to a Law of the Sea Convention.

In all of the different types of OTEC plant listed above, however, major parts involve the use of well-developed materials and equipment, with predictable performance and economy. Much of this material and equipment has also been tried, tested and found satisfactory in the type of marine environment where OTEC plants will operate. The exceptions to this general statement are important, and four specific items—cold water pipe, heat exchangers, moorings, and power transmission to shore—are the subjects of research and development programmes to determine in detail the technical appropriateness and economy of preferred solutions. The last two of those items are of course applicable only to floating OTEC plants.

*Cold water pipe.* The quantities of water involved, and their momentum, are substantial and the velocity in the pipe is unlikely to exceed approximately 4 m/s. Like the rest of the OTEC plant it is designed for a life of 25 years. It must certainly be capable of repair during its working life and, since a number of potential sites for OTEC are in geographical areas subject to hurricanes, should possibly have the ability to be structurally disconnected from the main OTEC hull at fairly short notice in the case of floating designs.

Over the pipe length of 1000 m (or much more for a land based version), sub-surface currents will have

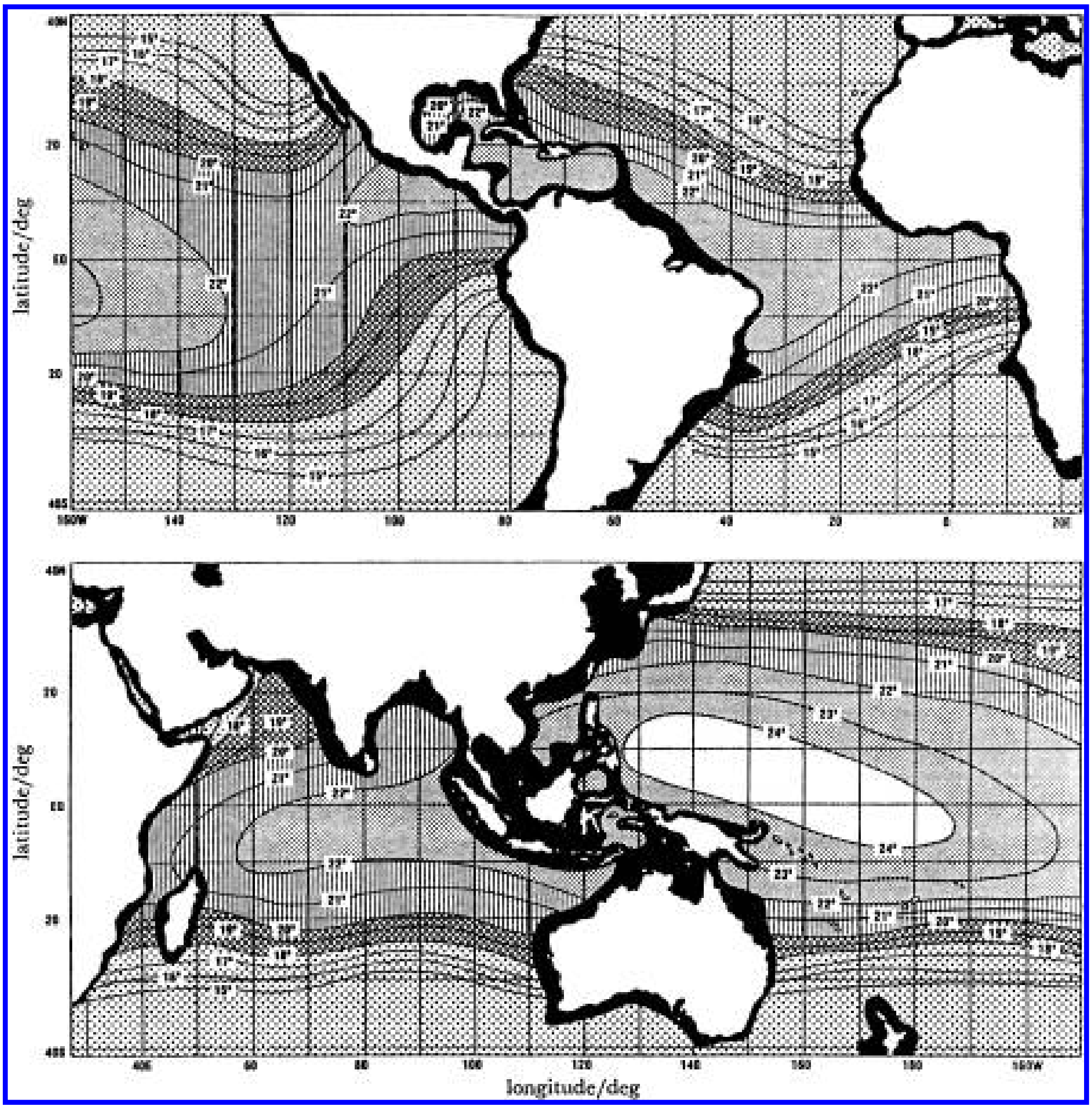


**Fig. 8.1.** The ocean thermal resource: worldwide distribution.

different magnitudes and directions; calculations of loading will therefore be dependent on wind, sea state and current conditions, and extensive analysis is required to determine the critical load conditions. Much work on this has already been done and in Japan and the USA representative practical tests have also been carried out.

Past experience on piles in water, as well as on chimneys in air, confirms that a particular problem with the cold water pipe will involve the nature of vortex formation and shedding, a topic on which the UK is pre-eminent.

The design options available for the cold water pipe include (for materials) concrete, steel, polyethylene, glass-fibre reinforced plastic, fibre/ elastomar matrix, other composites, and sandwiches; (for construction) a single non-articulated pipe, a cluster of these, or articulated versions of either; and (for layouts) lying on the seabed, support by saddles, free hanging, guy-supported, bottom-stabilised, or moor-stabilised.

*Heat exchangers.* Operational efficiency of the heat exchangers—evaporator and condenser—is fundamental to the economic success of the OTEC plant. Achievement of the plant's actual operating efficiency of approximately 2½% is highly dependent on the heat transfer rate in both the evaporator and condenser, and at the low operating temperature difference in these items the maintenance for optimum efficiency is dependent on minimising biofouling and corrosion products on the surface of the heat exchanger materials. The low temperature difference also means that heat exchanger surfaces must be very large to achieve practical power outputs.

These factors result in the heat exchangers being very expensive items. Some United States estimates have placed about 40% of the total cost for early OTEC plants against the heat exchanger system, and British estimates agreed with this when titanium was costed at late 1970s prices. With a titanium/aluminium sandwich present costs are estimated at a lower figure of just over 14%, but this material combination is not yet available. Aluminium, if validated as a heat exchanger material for OTEC plants, should be no more expensive than the 14% figure.

The two main barrier types of heat exchanger are shell and tube, and plate. Other types of heat exchanger, classed as 'barrier-less' or 'direct-contact', have considerable theoretical attraction since the heat transfer process is direct, without an intermediate layer which introduces inefficiency to the heat transfer process. But practical realisation of these direct-contact methods is still a long way off.

Performance can be influenced by variations in the geometric layout, by the addition of fins, and by treatment of the heat exchanger surfaces. Material options include copper-nickel alloys, titanium and alloys, alloy stainless steels, aluminium and alloys, plastics, and sandwich combination materials. France and the USA in particular have undertaken extensive development programmes for OTEC heat exchanger applications.

*Moorings.* The floating variant of an OTEC plant, delivering electrical power to shore, must maintain station by mechanical means (cables, chains) or by dynamic positioning (thrusters), or perhaps even in the future by the use of hydrodynamic forces. In the depths of water which apply—up to 2000 m—mechanical means have not previously been used for extended periods.

Loadings will be site specific and dependent on the OTEC plant size and shape, particularly as far as the ratios of wind/current/wave drift forces are concerned, and there is a large range in the values of each of the forces when calculated from present theories. Further work must be undertaken if sensible design values are to be obtained.

Existing 'deep water' moorings—measured in a few hundreds of metres at most—make use of wire rope or chain, and the historical knowledge of these materials makes them a strong contender for OTEC application except that, for both, their weight becomes excessive. Synthetic fibre ropes have extended their use rapidly in recent years for conventional marine applications, and information on their operational life is building up rapidly.

*Power transmission.* The electrical generating system for an OTEC plant is essentially state-of-the-art, although the particular environmental location and the corresponding conditions do introduce constraints. As far as power transmission for floating plants is concerned, however, developments are necessary, particularly for the riser section from seabed to plant.

The first problem recognised is that existing power cables of MW size have been installed in depths no greater than 600 m, whilst the design requirements specified for a floating OTEC plant could be as much as the 2000 m referred to above. For a substantial number of potential OTEC sites, considerably greater depths will have to be traversed, but these would not be preferred locations for early floating plants. In transmitting electrical power at a high efficiency from source to grid, the distance offshore determines whether transmission is by direct or alternating current. In terms of efficiency alone the alternating current (ac) option is preferred for shorter transmission distances up to approximately 30 km, with losses at about 0.05% of input power/km. For greater distances direct current (dc) is preferred with losses much less at about 0.01 %/km but with the additional inversion and conversion losses of about 2% to be added to this.

For OTEC applications with design depths at 2000 m, cable development itself is not anticipated to present major problems, although long-term resistance to pressure at that depth will require validation; nor is laying of the cable expected to present insuperable difficulties. The problems which will require particular attention are cable junctions at depth, together with maintenance and repair of the cable and the junctions at depth, including the junction with the riser cable.

*Contingency and risk evaluation.* The preceding subsections have concentrated on areas where further work is required, but it is stressed that much of an OTEC plant is routine and established technology—the hull (for a floating plant) or the power hall (of a land based or shelf based unit), the pumps, turbines,

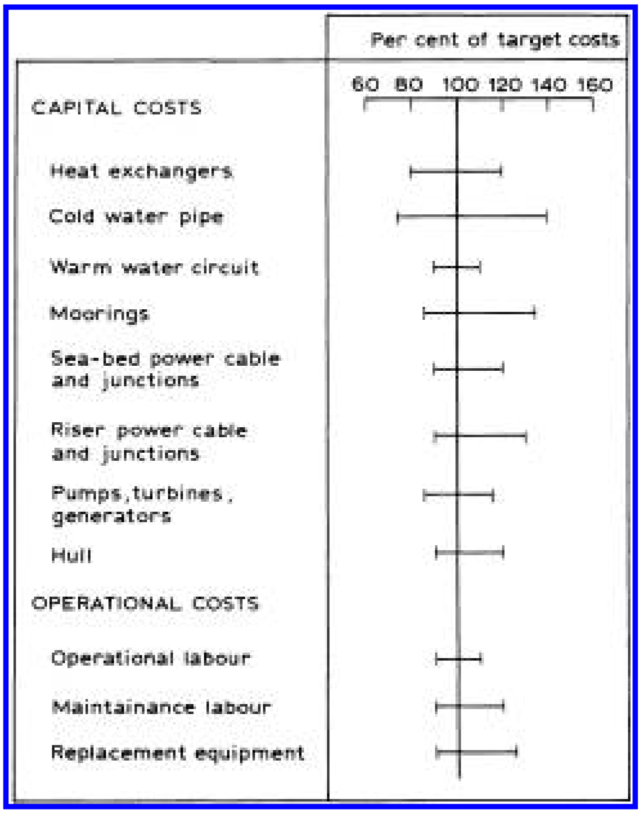


**Fig. 8.2.** Contingency cost estimates for components of floating OTEC plants. (Source; OTECS Ltd.)

generating sets, and in general terms even the heat exchangers. Nevertheless, contingency planning and risk evaluation are an essential part of the OTEC design process, for those established items as well as for the parts where development is still in train, and generous margins are incorporated in current estimates of time and (Fig. 8.2) costs.

## 8.3 ECONOMIC APPRAISAL AND COMMERCIAL PROSPECTS

The case for cost comparability is crucial to the acceptability of OTEC. On the basis of capital costs alone OTEC (and other renewables) show up badly against oil-fired power generation. Oil-fired plant would typically cost a few hundred pounds per installed kilowatt, while OTEC would cost a few thousand pounds per kilowatt. On the basis of capital cost, therefore, the result is a win for oil every time by a very large margin. Maintenance costs for well developed oil-fired plant are low, whereas those of low efficiency OTEC plant will be relatively high. High capital costs of OTEC mean high interest charges to be serviced in relation to the interest charges for the oil-fired plant.

| Cost items | |
|---|---|
| Capital cost (1) | £35·34 × $10^6$ |
| 30% grant (2) | £10·60 × $10^6$ |
| 70% of capital, to be repaid (2) | £24·74 × $10^6$ |
| Annuity factor over 10 yrs (3, 4): 5·8892 | |
| Annual repayment of capital and interest | £ 4·20 × $10^6$ |
| Inspection and maintenance (5), Operational (6) and Insurance (7) | £ 2·47 × $10^6$ |
| Fixed annual charge | £ 6·67 × $10^6$ |
| Fixed annual charge rate | £667/kW |
| Unit generating cost for electricity (8) | 8·46 p/kWh |
| or (9) | 12·68 cents/kWh |

Assumptions:
(1) Uninflated capital cost (1985 values); excluding research, development and test, which are separately funded.
(2) For the demonstration plant only, 30% of the capital cost is obtained as a direct grant
(3) For the demonstration plant, 70% of capital, plus interest, to be repaid in equal annual instalments over only 10 years; zero residual value is also assumed even though design life is 25 years
(4) Interest rate: 11%/annum
(5) Annual cost, 2% of total capital cost
(6) Annual cost, including crew costs, 3% of total capital cost
(7) Annual cost, 2% of total capital cost
(8) Utilization at 90% on the basis of the multiple power pods fitted, i.e. 7884 hr/yr
(9) $1·5 = £1

**Fig. 8.3.** Cost of generating electricity from a 10 MW floating OTEC demonstration plant. (Source; OTECS Ltd.)

| | |
|---|---|
| Site specific data | 1·7 |
| Heat exchangers | 20·2 |
| Cold-water pipe | 6·1 |
| Moorings | 4·9 |
| Electrical transmission (sea bed and riser) | 8·3 |
| Pumps, turbines, generators and control | 12·9 |
| Hull, including warm-water circuit | 18·0 |
| Installation and maintenance | 4·1 |
| Start- up and test | 8·0 |
| Miscellaneous | 1·9 |
| Unknowns | 13·9 |

**Fig. 8.4.** Component percentage costs for 10 MW floating OTEC plant.

A conventional presentation of costing (in this case for a 10 MW demonstration plant), which also includes a derived generating cost, is shown in Fig. 8.3. Merchant bank prepared figures for this same demonstration plant show a real rate of return on total capital employed of 10·3% (nominal 15·8%). A cost breakdown of components for the same plant is indicated in Fig. 8.4.

The calculated generating cost in Fig. 8.3 is interesting and attractive for very many island locations.

An additional presentation, which compares the costs for a conventional with a renewable energy system, is also interesting to consider. Figure 8.5, which in this case is for a 100 MW plant, has its origin in work undertaken by Eurocean, the European group of companies concerned with developments in ocean technology. The actual values incorporated in the figure are the latest ones available from UK calculations, and an oil price of US$40/bbl has been chosen to represent current prices for oil as delivered to a number of island locations. The basis of Fig. 8.5 is that payments for a 100 MW plant, whether OTEC or oil-fired, are arranged to be equal. While the payments for OTEC are capital, operational and maintenance, those for oil are capital, operational, maintenance *and* fuel. Despite the high capital cost of OTEC, after less than 10 years its capital is repaid and further costs are operational and maintenance only. For oil, however, so much of the payment has gone on oil fuel that costs continue to rise as shown, typically to 15 years or beyond. Even when the capital of the oil-fired plant has been defrayed the payments for oil fuel continue. Just how the price of oil will change in the future is open to considerable doubt, but the basic presentation is one which substantial and important parts of the financial community find acceptable. Clearly if oil is at a lower price than shown, the period for payback of OTEC capital will be longer. Once the balance point has been reached, during which generating cost will by definition be the same for OTEC

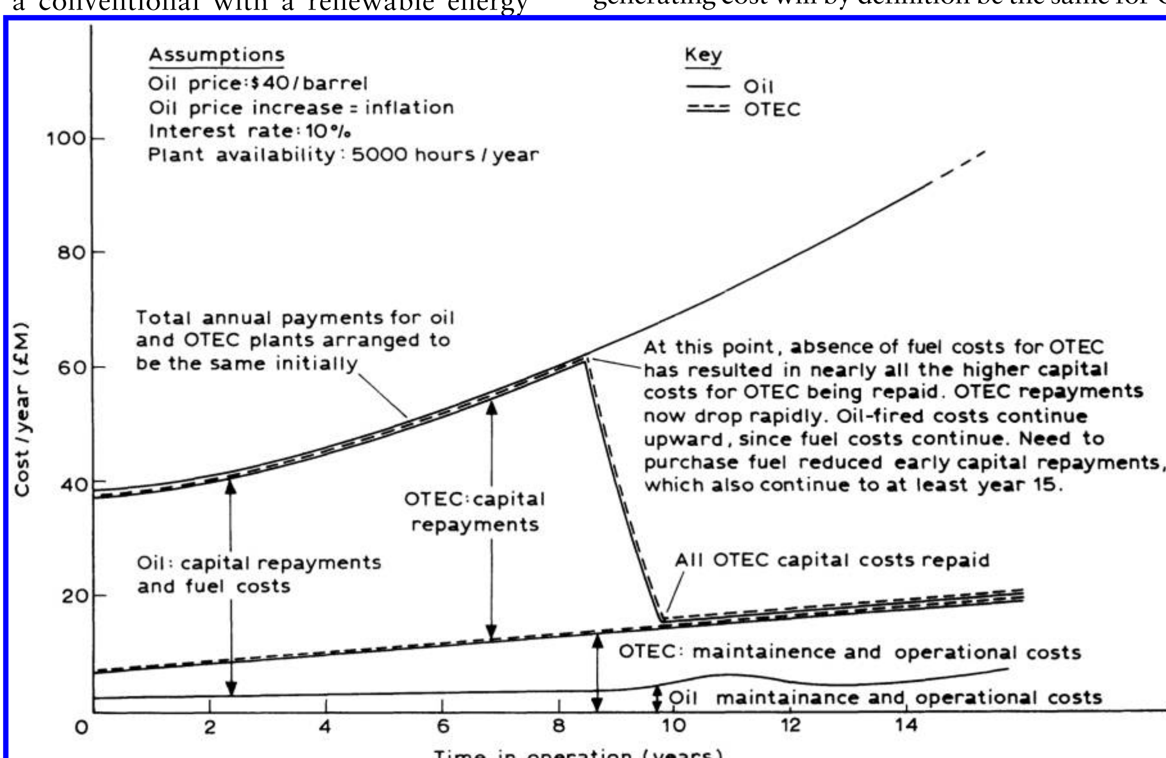


**Fig. 8.5.** Cost comparison for 100 MW OTEC and oil fired generating plants. (Source; OTECS Ltd.)

and oil-fired power, it is seen that OTEC generating costs drop to about 30% of their former value, at which time costs are as low as those of Norwegian hydro power. However, that low price is a bonus to be looked for in the future. At present there is a need to corroborate at demonstration or full size the validity of Fig. 8.5.

Figures 8.4 and 8.5 are specific values for two designs. To discern a general trend, or even to determine if it exists, the values of capital and generating costs for all known OTEC designs have been plotted in Figs 8.6 and 8.7. The survey shows overlap between costs for floating and land based OTEC plants; plants with closed or open working cycles; simple designs using established technology or technologically advanced designs; and so on. These graphical presentations therefore show a range of values for capital costs per kilowatt and for generating costs, against nominal power output. The only amendment to stated values provided in published papers has been to inflate older estimates for capital costs at an assumed rate of 5% per annum to give a standard 1985 base. Confirmation of both the values and the trends shown in Fig. 8.4 and 8.5 has been provided by independent Japanese calculations.

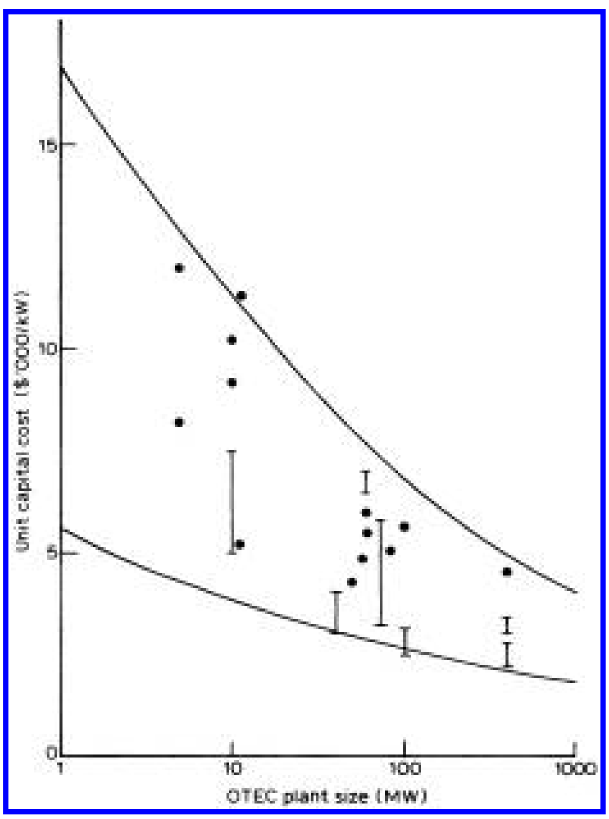


**Fig. 8.6.** Capital cost per kW for all known OTEC schemes (1985 US dollars). (Source; OTECS Ltd.)

Without overstressing the trend, the two figures illustrate a (broad) band of costs for each size, with the expected economy as size increases. Latest calculations for the UK 10 MW design, taking note particularly of improvements in heat exchangers, show a reduction in calculated generating costs from 12·7 c/kWh (as shown in Fig.8.7) to 8·3 c/ kWh. These values are for a $\Delta T$ of 20°C. For each 1°C increase in $\Delta T$ there is an approximate reduction of 10% in generating costs. Thus for areas of the ocean (Fig. 8.1) with $\Delta T$ of 22°C—very large areas containing many island states—generating costs would be approximately 20% below those quoted, or 6·6 c/kWh.

These are values of considerable interest when compared with generating costs by conventional techniques in many of the island nations—in the Seychelles between 10 and 20 c/kWh, in some Caribbean islands at 17 c/kWh, and in the Lakshadweeps in the Indian Ocean at over 25 c/kWh, all using oil fuel costed at 1985 prices.

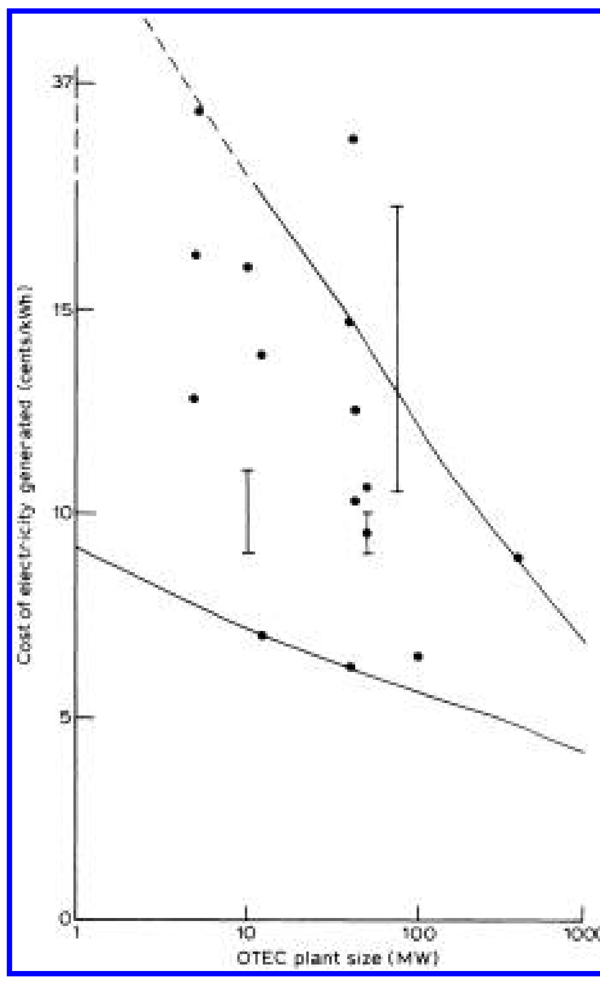


**Fig. 8.7.** Generating cost per kWh for all known OTEC schemes (1985 US dollars). (Source; OTECS Ltd.)

Commercial prospects for OTEC are therefore fundamentally dependent on the claimed economies being achieved and on *simple reliable* solutions being derived for the remaining development items described earlier.

## 8.4 ENVIRONMENTAL ASPECTS

The environmental impact of OTEC systems compares favourably with that of many other energy systems and can be considered under three headings. Firstly, for the closed cycle system, there is a potential, however slight, that the working fluid (ammonia or freon) could escape. The relatively small quantity of this fluid, compared with the surrounding sea volume, would result in dilution to safe levels very quickly. In the case of a land based system, proximity to the shore could result in some difficulty for dilution; or alternatively if fully onshore there is no danger of sea pollution if an impervious bund is constructed around the working circuit.

Secondly, the presently preferred system of cleaning the heat exchangers is by intermittent chlorination. Once again the concentration (0·05 ppm or less) and the frequency (1 h/day or less) is considered by biologists to have minimal impact on the marine life. However, there is no reason why the chlorine should be discharged into the sea at all, being retained and concentrated for subsequent disposal elsewhere.

Thirdly, there is the discharge of (mixed) warm and cold waste water from the heat exchangers. Normal circumstances call for the mixed waste waters to be discharged at a depth where relative buoyancy to the surrounding water would be zero, and trials to date indicate a stable regime which will degrade neither the warm nor the cold resource being used to drive the OTEC plant—indeed, it is in the interests of the designers and the operating utility to prevent such degradation since it will reduce the efficiency of operation. The influence of onshore OTEC plants on the surrounding waters will require longer discharge pipes to ensure this degradation is avoided. If, in the future, 'farms' of OTEC plants running to many hundreds of megawatts are established, the long term influence of discharge waters on warm and cold resource will need to be modelled and tested, but such concentration of OTEC generating equipment is very unlikely to occur before the 21st century.

For the same reason that minimal changes in temperature of warm and cold resource are anticipated due to the existence of OTEC plants, consequential climate variations are also anticipated to be negligible. 'Regeneration' of the cold resource will require further investigation before large OTEC farms can be planned.

Overall, OTEC is seen to be among the most benign of power systems in terms of environmental impact. This comment applies also to visual impact.

## 8.5 INSTITUTIONAL BARRIERS

There have been two potential barriers: funding, and the legal regime.

As Section 8.3 has indicated the simple financing of OTEC plants is satisfactory as a bankable proposition in terms of return on investment; but the fact that such returns do not show in the first three or four years, coupled with the discerned 'developmental phase' of OTEC, makes conventional investors wary. Once a limited number of plants has been built and shown to operate as calculated, the risk will be deemed quantifiable, and there seems little doubt that funds will be forthcoming as for any sound capital project. But at this stage it is not so. When the current difficulty of raising money for the Channel Tunnel—a piece of thoroughly established, traditional, 19th century engineering—is seen, how much more is it likely to be the case for a newer application of technology such as an OTEC plant.

For early plants of megawatt size, therefore, international funding agencies have a key role to play, since such demonstration plants will just not be attractive to the commercial funding sector in isolation. A mixture of grants and loans from national and international funding agencies, together with some commercial finance, is likely to be the way forward. The number of sources of funds, and combinations of one with another, are considerable and specialist financial and techno-economic appraisal of these options is necessary. In a report specifically aimed at the prospects for energy in developing countries, the World Bank reported that it must adopt measures which will allow 'an expansion of investment to develop those indigenous sources of energy that are cheaper than imported oil.' It notes also that '…the investment needed to develop the developing countries' potential energy resources is estimated at US$130 billion a year (in 1982 $) for the next 10 years…' and '…even if international oil prices fall to US$25/bbl (in 1982 $), most of these investments—half of which would be in the power sector—would remain attractive.' The price of oil is now below that level, but recovering; in the meantime the Energy Sector Assessment Programme had been initiated in 1980 by the World Bank and the United Nations Development Programme (UNDP) with the object of examining some 60 developing nations to obtain a diagnosis of their major energy problems and to evaluate the options for solving them. It is noteworthy in the context of the preferred locations for OTEC plants that whilst the smaller island countries (such as the Solomons and St Lucia) do not figure in the statistical assessments undertaken by the World Bank they are included in the Energy Sector Assessment Programme—an indication that the Bank and the UNDP recognise that smallness is no disqualification for energy sector funding from the Bank's resources. Also, since the objective of the Programme is to assist countries to improve their energy situation and their indigenous capability, the isolation provided by an island location enables their energy equation to be looked at in its entirety.

Also, in the context of the countries of the European Communities, the Lome Conventions joining 'the twelve' with 66 Asian/Caribbean/Pacific nations have considerable potential relevance. Together with the Framework Programme of the Communities, there is a double linking of funding opportunities for an OTEC-type programme.

To these two should now be added the EUREKA programme, where there is a unique opportunity to harness the various European OTEC programmes, both within and without the European Communities.

Turning now to the legal regime, Fig. 8.1 indicates how many island countries could theoretically benefit from OTEC power. To the extent that nations are now declaring 200-mile (320-km) Exclusive Economic Zones (EEZs), the legal regime for OTEC plants is becoming simpler. The exception to this would be grazing plants, operating on the high seas outside EEZs, but as noted in Section 8.2 these are not anticipated to be brought into use in the 20th century. The 'constraint' of the legal regime is now therefore rapidly reversing to become a bonus in favour of OTEC plants. National, not supranational, jurisdiction will determine the conditions for their use. Moreover, the resources of the EEZs are potentially greater than the land resources of many island states, not least because the ratio of areas is so great. For example, the ratio is 70 to 1 for Fiji, and 4000 to 1 for Kiribati—both Pacific Island nations with good thermal resources in their EEZs.

On balance, therefore, the single institutional constraint to be overcome is to convince the financing sector that OTEC is a viable technology which will produce satisfactory returns on investment.

## 8.6 MARKET

There is no UK home market for OTEC—the fundamental thermal resource is not available. The same is not true for much of the Commonwealth, which could provide a significant part of any UK OTEC market sector, as noted below.

Whilst a very large number of factors—briefly described later—will together determine market size, the basic necessity is the availability of an adequate $\Delta T$; without that no market can be met. The design value of $\Delta T$ usually used is 20°C and Fig. 8.1 indicates that with only slight exceptions this requires OTEC plants to be located between the latitudes of 25°N and 25°S. When variation of temperature difference through the year is also taken into account, the usable OTEC thermal resource is seen to lie predominantly between the tropics of Cancer and Capricorn. The higher $\Delta T$s are located on or near the equator, with the most attractive location in the Pacific where a large area shows a $\Delta T$ of 24°C.

It is apparent that the great majority of opportunities are on (rather small) islands. This is the prime reason that many early OTEC plants will be smaller rather than larger, although with a first plant of megawatt size not yet operational it is difficult, in any case, to reconcile engineering development of a 100 MW plant in a shorter timescale than at least a decade.

Whilst OTEC opportunities are seen to apply particularly to developing countries, then, there are many other factors to be considered before it can be said that a particular country or location is suitable. These include:

(1) Distance from shore of the thermal resource
(2) Depth of ocean bed
(3) Depth of resource
(4) Size of thermal resource within the EEZ
(5) Replenishment capability for both warm and cold water
(6) Currents
(7) Waves

(8) Hurricanes
(9) Sea bed conditions for anchoring
(10) Sea bed conditions for power cable (for floating plants)
(11) Present installed power (and source)
(12) Installed power per head
(13) Annual consumption
(14) Annual consumption per head
(15) Cost per unit, particularly taking note of any subsidy
(16) Local oil or coal production
(17) Scope for other renewables
(18) Anticipated industrial growth
(19) Aquaculture potential
(20) Potable water potential
(21) Scope for 'technology transfer'
(22) Environmental impact

A further important factor in the early days of OTEC development will relate to the possibility of agency loan funding and grants, as noted in Section 8.5.

Regardless of the feasibility of OTEC generated electricity from the point of view of all relevant technical factors, there must of course be a demand for it at a price it can meet, or better. The majority of island countries which do have an adequate demand are found to rely on imported oil for generating power, and further are found to be paying very high prices for this oil: for example, in Tahiti the unit generating cost of electricity as a result of high fuel prices is three times that in mainland France, and other examples have already been cited. In the short term it is islands similar to these which provide the market for OTEC plants, particularly those which have a growing power demand. But the rate of growth of power demand in many independent developing countries is in turn dependent on the price of the power generated. Even present relatively low oil prices inhibit full growth rate because foreign currency (usually in short supply) must be provided for purchase of the oil. Also growth is contained because of the uncertainty of the forward price of oil. This 'energy insecurity' is probably the single most significant factor inhibiting the growth of the developing nations. Also in many cases the percentage of GNP used to purchase oil is well into double figures. The provision of a stable energy price is therefore of the highest priority among economic objectives of such countries. OTEC, like all renewables with no fuel costs, meets this requirement. Unlike most other renewables, OTEC is a base load generating system. Also, despite the world recession energy demand is still growing substantially in many island developing countries. This trend is expected to continue well into the next century, with the share of world consumption for the developing countries rising from about 25% in 1978 to 33% in 2000, and 35–40% by 2020.[2]

Estimates of the contribution by all 'new' energies, of which OTEC is a part, show a substantial growth over the same time periods from virtually zero in 1978 to 3% in 2000 and 6% in 2020, again expressed as percentages of total world demand. Despite the smallness of these percentage figures, they are large in absolute terms and are estimated to be in the range 10 000–11 730 Mtoe (million tons of oil equivalent) in 2000 and 13 760–17 960 Mtoe in 2020.

This growth in demand in developing countries enables OTEC to relate closely to it, because of the conditions already referred to. A UN report[3] lists likely countries.

Estimates of. the world market for OTEC-powered generating plant have been made by the USA, France and Japan, as well as by the UK. For the period 1990–2010 the US study[4] estimates nearly 60 000 MW of OTEC power, using a 10% penetration assumption. A French estimate of 1984[5] suggests that in only the 20 countries with most favourable sites 3500 MW of OTEC power will be installed in the early years, and they have a potential for 30 000 MW over the next 20 years. Estimates by Japan[6] for the Southern Islands of their country indicate over 20 floating plants and at least six land based plants by the year 2000. In addition Japan has also made an estimate for OTEC plants within the whole of its own EEZ and sees opportunities for some 220 plants of about 100MW size in the areas of Okanawa, Kushu, Shikoku, Ogasawara and Kazan Islands by early next century.

Estimates by the UK[7] are more conservative, indicating 1030 OTEC plants worldwide by the year 2010, nearly half being no larger than 10MW capacity, and less than 10% being of 100 MW. On the assumption that the UK captures no more than one-fifth of the conservative UK estimate for a worldwide market, it is in turn estimated that up to 1999 a total of 38 10 MW plants and 32 40 MW plants will be ordered from and supplied through UK organisations—a total of 1660MW.

Note that all of these estimates are dependent on the placing of first orders for the demonstration plants.

It should be noted also, however, that all these figures exclude completely other markets for OTEC power systems—desalination, aquaculture, synthesis of ammonia and hydrogen, refining of ores, and mining of placer deposits. The worldwide total for these applications during the same period has been estimated at some 500 000 MW, but the actual timescale for achievement must be dependent on (for example) the economy of refining ores, and similar factors for the other products. These markets are ignored completely in the above estimates even though the interest in, and economic feasibility of, desalination and aquaculture are growing very rapidly.

## 8.7 OPPORTUNITIES FOR DEVELOPMENT IN THE UK

The lack of a home market is considered by some to be a disadvantage. Set against that are the very strong links which remain directly with many Commonwealth countries for which OTEC is an appropriate energy resource, and only slightly less directly with the many Lome countries associated with the European Communities. Thus as a single-nation manufacturing opportunity, and as an opportunity in conjunction with one or two other member nations of the European Communities, the absence of a home market seems to be a relatively small disadvantage.

The component parts of an OTEC plant (Figs 8.8 and 8.9) are suitable, without exception, for development and manufacture within the UK. Moreover, they require a combination of both traditional and newly established industrial skills. The hull, whether in steel or concrete, can provide much-needed orders for shipyards or platform fabrication yards. The electrical generating equipment, pumps, heat exchangers, turbines and associated piping and ducts will be delivered from established heavy mechanical and electrical engineering contractors. Subsea power cabling, and the moorings and winches, require some development but fit well within the industrial capabilities of the UK offshore industry. The cold water pipe will require development of the fibre-reinforced plastics industrial capability, and the control network will provide opportunities for modern systems engineering skills.

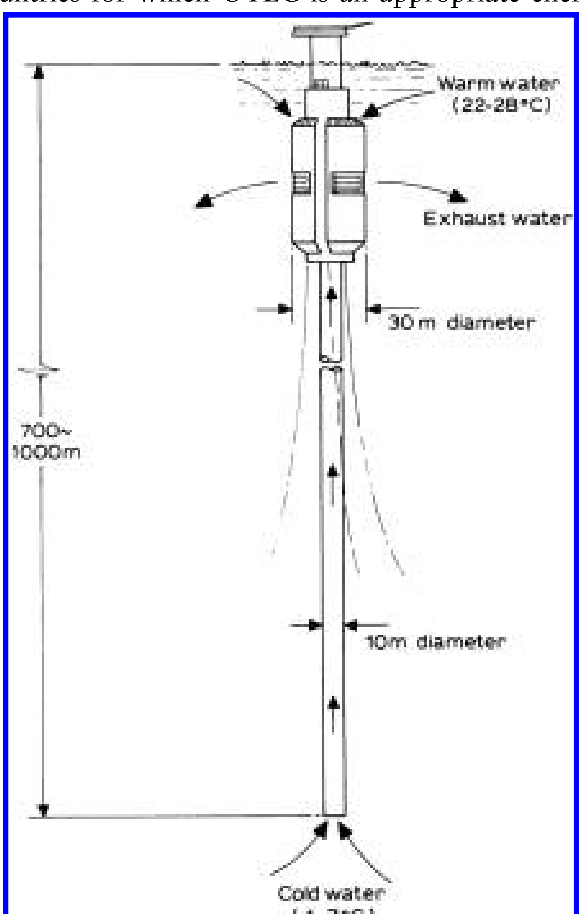


**Fig. 8.8.** Layout for a 10 MW floating OTEC plant. (Source; OTECS Ltd.)

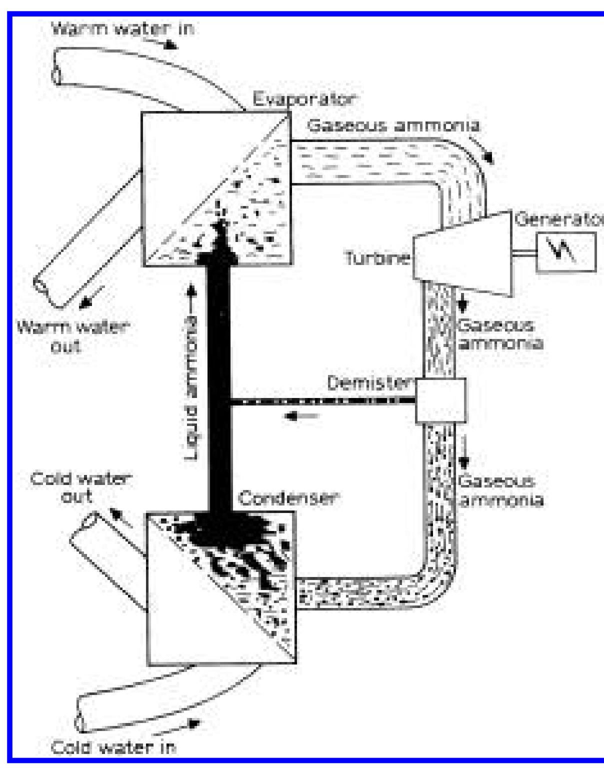


**Fig. 8.9.** Closed cycle OTEC power circuit. (Source; OTECS Ltd.)

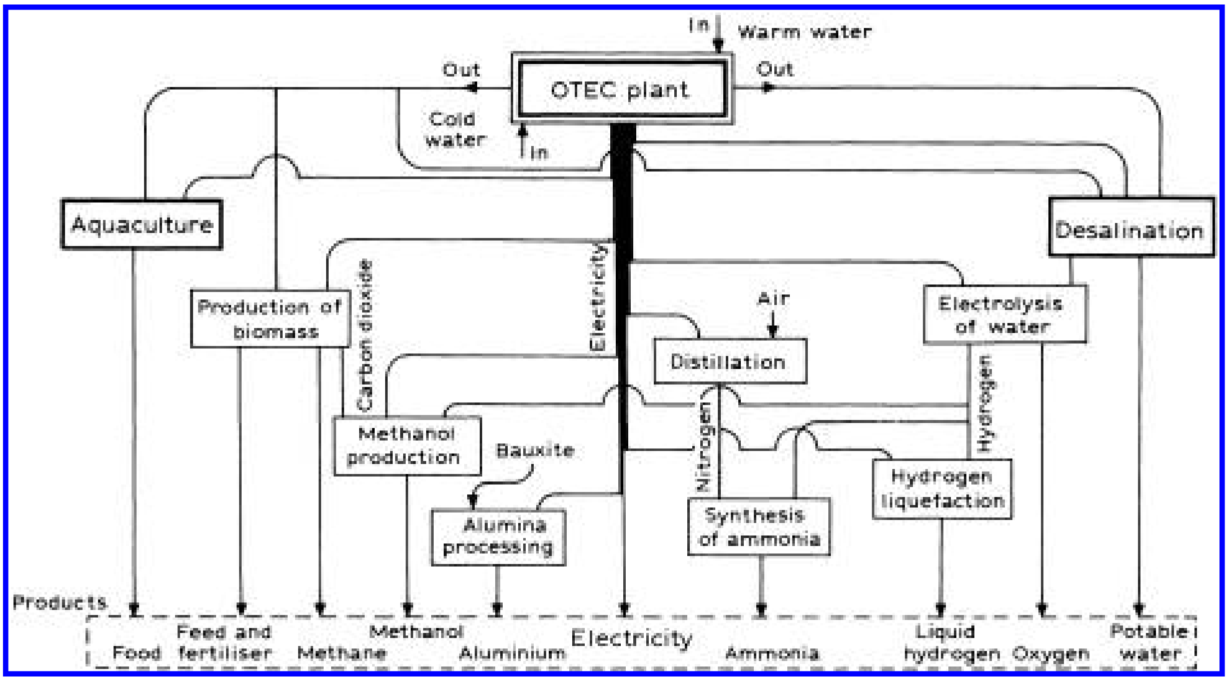


**Fig. 8.10.** Other products which can be associated with an OTEC power generating system. (Source; OTECS Ltd.)

Whilst all these design and fabrication opportunities will benefit the UK economy—the figures quoted earlier for the UK correspond to a turnover of some £650 m per year from the mid-1990s—it must be recognised that the developing countries who will be the predominant customers for OTEC plant will quite rightly be looking for technology transfer on all relevant topics for production equipment. Some would see this as a reduction in the market share for British goods, whilst others would argue that a joint venture with a developing nation in (say) the Pacific would strengthen the opportunity to increase UK national market share in that general area, the latter philosophy appearing certainly to be that of the Norwegian wave energy firms.

## 8.8 CONCLUSIONS

OTEC is a new practical application of much established technology to which has been added a limited number of new items. The characteristic high first cost of this renewable energy, with the absence to date of large (megawatt-sized) demonstration plants, raises difficulties in the funding of plants at present, notwithstanding the attractions of (1) zero fuel cost to the user, and (2) acceptable financial returns to the operator of the plant, and the investor. The absence of practical full-scale proof of these economics, based on operating performance, is the reason for the difficulty in raising funds, for the demonstration plant as well as the production units. But until the demonstration plant is built the economics and performance will be regarded as suspect by financing institutions.

This 'Catch 22' situation can be resolved through the involvement of international funding agencies for the demonstration plant (as described), which appears to be the prime requirement for progressing OTEC further, i.e. to the construction of the demonstration plant.

The market described here is for energy, but the importance of the other potential products—Fig. 8.10 illustrates some—should be stressed, since these can be of substantial benefit to the economy and commercial base of many of the developing countries which would be customers for OTEC plants. These additional products can add substantially to the generating economics of an OTEC plant over and above those described in this section; and the base load characteristic is particularly beneficial for these other activities as well.

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## Section 9

# Solar Thermal Technologies and Photovoltaics

### 9.1 INTRODUCTION

Solar energy has been recognised as a major energy source for many years,[1] but it is only since 19073 that substantial research, development and demonstration projects have been undertaken throughout the world. Two of the main applications are in the provision of heat and electricity. Both applications have some potential in the UK and the opportunities for certain export markets in the supply of equipment and services is considerable.

Solar energy can be easily converted into heat and could provide a significant proportion of the domestic hot water and space heating demand in many countries. The main drawback in high latitude countries such as the UK is that there are many days in the winter months when the total radiation received would be too small to make any useful contribution.

After a brief assessment of the exploitable resources of solar energy in the UK and how this compares with other countries, the two main relevant solar thermal applications for UK conditions are discussed. Active solar systems absorb solar radiation on a collecting surface. This converts the radiation into heat, which is then transferred by a circulating fluid (typically water or air) to the point of use or into a heat store (possibly the hot water tank). Although the technical potential for the contribution of solar heating in the UK is substantial, perhaps up to 15% of total energy demand, the relatively high system cost will inhibit the development of a satisfactory market apart from a few areas such as the heating of swimming pools.

Thermal systems for power generation have a potential in export markets and brief details of the main system are given, although no large-scale demonstrations are planned for the UK.

Passive systems use solar energy naturally by involving conventional building elements for solar radiation collection, storage and distribution. This field has already been identified as ‘Economically Attractive’ by the Department of Energy and there is widespread support for this view. Although passive solar and associated design features involve extra design effort, they do not necessarily involve extra construction costs in new buildings.

Photovoltaic systems are now cost-effective in an increasing number of situations. However, outside the growing consumer product market, applications in the UK are limited to small-scale remote power systems, e.g. marine light beacons. Applications overseas range from small-scale power supplies for rural villages to larger power generation in the megawatt range.

An economic appraisal of these solar applications indicates that in a few cases they can compete with existing conventional systems, but with photovoltaics it is very unlikely that the contribution to total UK energy demand in this century would be other than insignificant. However, very few countries have such an unfavourable solar radiation availability as the UK and the world market potential for both solar thermal and photovoltaic applications is substantial. The opportunities for the UK to be engaged in this rapidly developing new technological field for world trade should not be ignored.

### 9.2 EXPLOITABLE SOURCES IN THE UK

A detailed description of solar radiation and its availability in the UK and elsewhere is beyond the scope of this section but can be found in many of the standard texts, such as Refs 1 and 2.

For the European Communities countries a Solar Radiation Atlas was published in 1984,[3] giving full details of global radiation on horizontal surfaces and both global and diffuse radiation on vertical and inclined surfaces, on a monthly averaged basis.

Direct solar radiation is the solar radiation flux associated with the direct solar beam from the direction of the sun's disc. Diffuse radiation reaches the ground from the rest of the whole sky hemisphere from which it has been scattered in passing through the atmosphere, while global radiation includes all the radiation, direct and diffuse, incident on a horizontal plane. More than half the solar radiation received in the UK is diffuse and this puts a limit on applications which require focusing.

The mean annual daily radiation in $MJ/m^2$ for the UK has been included in a map already published.[4] An extract from data derived by Page[5] from Meteorological Office records shows that there are two main trends—higher levels of global radiation towards the west, where the skies are in general clearer, and lower levels towards the north, which would be expected because of the higher latitude. The data are for the period 1965–1970, with the exception of Aldergrove, which is for 1969 and 1970 only (Table 9.1). The comparatively low radiation levels in the winter period are combined with an increased proportion of diffuse radiation, which greatly reduces the effectiveness of potential solar applications.

Many solar applications require a knowledge of the total radiation on an inclined surface facing in any direction while the only available data are for the total global radiation on a horizontal surface in the same location or within a reasonable distance. Sometimes the only records consist of daily sunshine hours. There are numerous examples in the literature giving various approaches to modelling solar radiation data (see, for example, Muneer and Saluja[6] who cite 63 references). An alternative approach in countries with established radiation networks is to select an 'example year' which most closely represents the statistical average.

## 9.3 SOLAR THERMAL APPLICATIONS

### 9.3.1 Technology

Probably the best known application for the use of solar energy is in the provision of hot water. Solar energy can be easily converted into useful heat and could provide a significant proportion of the domestic hot water demand in the UK and other northern European countries. For low temperature-rise applications the use of simple collectors has already proved to be cost-effective, e.g. for heating swimming pools. However, there are many days in the winter months when the total radiation received will be too small to make a useful contribution, especially in the north of the UK. But these regions often need some heating in the summer and the passive techniques, described below, could be usefully combined with active solar water heating.

### 9.3.2 Active solar systems

The most widely known and best understood method for converting solar energy into heat is by the use of the flat plate collector. These come in a variety of forms, with combinations of flat, grooved and corrugated shapes as the absorbing surface, as well as various methods for transferring the absorbed solar radiation from the surface. Advanced collectors are necessary for temperatures greater than 100°C because most flat plate collectors are unable to function at high temperatures because of their relatively large heat losses. Descriptions of the basic flat plate collector and several advanced collectors are given in Appendix 9.1.

**Table 9.1 Annual variation of the mean daily totals of global solar radiation on a horizontal plane ($MJ/m^2$)**

| | Kew | Aberporth | Aldergrove | Eskdalemuir | Lerwick |
|---|---|---|---|---|---|
| January | 2·13 | 2·39 | 1·67 | 1·54 | 0·82 |
| February | 4·13 | 5·03 | 4·50 | 4·36 | 2·97 |
| March | 8·06 | 9·51 | 7·29 | 7·30 | 6·41 |
| April | 11·62 | 14·25 | 12·22 | 11·47 | 12·21 |
| May | 15·54 | 16·89 | 14·65 | 12·99 | 13·60 |
| June | 18·06 | 20·09 | 19·48 | 16·57 | 16·90 |
| July | 16·03 | 18·13 | 15·35 | 13·64 | 15·42 |
| August | 13·29 | 15·08 | 13·45 | 12·24 | 11·93 |
| September | 9·73 | 10·58 | 8·86 | 7·79 | 6·88 |
| October | 5·79 | 6·16 | 4·39 | 4.52 | 3·54 |
| November | 3·00 | 2·97 | 2·66 | 2·41 | 1·37 |
| December | 1·72 | 1·94 | 1·46 | 1·37 | 0·55 |

The first British work in this field was carried out in 1947 when Hey wood established the characteristics of flat plate collectors. The simplified treatment which he established was used as the basis for some of the later design work in the UK during the 1970s. At the start of that decade there were only two small companies working in the UK. By 1976 the UK section of the International Solar Energy Society had published a report which concluded that the simple payback period for solar water heaters, compared with on-peak electricity, was about 16 years and that solar water heating could be considered financially attractive. However, compared with gas heating it was unlikely to be so in the immediate future. There was no doubt that there was a possible potential market of some 20 million homes, apart from commercial, industrial and government buildings, and the Department of Energy launched a programme on active solar heating in 1977. The final report[8] pointed out that while the technical potential was as much as 45 Mtce (million tonnes of coal equivalent) annually, the high cost of the installations could reduce this to as little as one million tonnes per annum, and even this would require an installation rate substantially above that attained in recent years. Despite the publishing of Codes or Guides to good practice,[9–11] several adverse factors had combined to inhibit the development of a satisfactory market in the UK for active solar water and space heating systems.[12] These included the collapse in oil prices and the relatively small rises in the price of conventional fuels. One small application in the UK has been successful, the heating of swimming pools in the summer season, where the demand for water at about 25°C can be met. One company has also entered the high performance vacuum tube collector market with some success.[13]

Perhaps a better indication of the current maturity of this technology is that the first British Standard BS 5918:1980 was being revised for reissue in 1988 and that two other standards were issued in 1986, British Standard BS 6757:1986, Methods of Test for the Thermal Performance of Solar Collectors, and British Standard BS 6785:1986, Code of Practice for Solar Heating Systems for Swimming Pools. Testing to both National and International Standards is available in the UK at the Solar Energy Unit, Cardiff University, who also publish annually a Directory of UK Suppliers of Equipment in Renewable Energy. This was augmented in 1989 to become a European Directory.

### 9.3.3 Passive solar systems

Most of the collectors described above need some form of pump or fan to circulate the water, air or other heat transfer fluid to the point of storage or use. Passive systems use solar energy naturally, involving the conventional building elements for solar energy collection, storage and distribution. The simplest way to do this is to use the windows as solar collectors. This is known as the 'direct gain' approach. Recent developments include triple or quadruple glazing and heat reflecting films on the internal glass surface. Four other passive systems have been categorised as follows.[14]

(a) The Trombe wall or thermal storage wall in which the heat is stored in a wall which also absorbs the solar energy when it passes through the glazing.
(b) The solar greenhouse, in which the direct gain approach can be combined with the features of the thermal storage wall by building a greenhouse on the south side of a building (in the northern hemisphere).
(c) The roof pond system, in which a shallow pond or tank sits on a flat roof and moveable insulation either covers the top during the day (summer operation) or at night (winter conditions to reduce heat losses).
(d) The natural convective loop using air.

Many projects have been built and monitored over the past five years and almost every solar conference has a section on passive solar heating (and cooling) applications. Mazria[15] was one of the first to describe the main features of passive solar architecture in considerable detail. More recently the Commission of the European Communities[16] has published a European Passive Solar Handbook which covers the basic principles and concepts, and includes case histories, references and suggestions for further reading. These texts could provide a useful introduction to the topic for the professional.

### 9.3.4 The UK government and passive solar design

Passive solar design is now regarded by the Government as one of the most promising renewable energy technologies in the UK.[17] By combining our current energy efficiency measures with passive solar design techniques, energy costs in buildings can be reduced by as much as 40% from today's levels with existing standards.

The Department of Energy's passive solar programme initially concentrated on establishing the worth of the resource in energy terms and it appears that a contribution of up to 14 Mtce annually could be expected.[18]

The first two groups of design studies have now been carried out, one on housing and the other on non-domestic buildings. Design studies were chosen rather than field tests so that comparative tests could be made with a selected thermal simulation model. In the second phase of the programme, several design practices have been invited to prepare building designs incorporating passive solar features. An additional feature of the second phase will be the appointment of a 'solar expert' to each project. His role will be to comment on all the proposals in the design. The client or customer will also be represented at this stage by a person who is already a builder or property developer. These two additions to the design process (the 'expert' and the 'client') will provide extra technical knowledge and an appreciation of real market forces. As a result of the preliminary programme, a passive solar design guide for UK conditions is currently being prepared at the Architectural Association School of Architecture.

The Department of Energy's Passive Solar Programme is closely coordinated with other Government building research and development programmes, e.g. those of the Department of the Environment and the Energy Efficiency Office. The Building Research Establishment also takes an active part in providing advice and participating in the programme.

### 9.3.5 The main technical issues in passive design

A number of issues have been identified in the literature and the UK Government programme will broadly follow the guidelines already laid down elsewhere. These are as follows:

(1) The influence of the local climate on the optimum design.
(2) How the patterns of occupancy affect the various criteria which are being evaluated.
(3) The perceived advantages and disadvantages of the various passive design elements in the selected project, measured against energy use and cost, the feeling of comfort and general well-being, the amenity value and whether or not people are likely to pay for the passive features—the marketability of the design.
(4) The integration of energy use into the overall design process.

### 9.3.6 The energy performance assessments

In addition to the design studies a number of both domestic and non-domestic buildings have been monitored for a year each to determine the energy flows and to evaluate the quality of the environment as perceived by the users. Each study is carried out according to a clear and well-defined methodology. Standard profiles are produced at the end of each assessment and the performance is assessed alongside a similar building design without such passive features.

### 9.3.7 Technology transfer

This has been identified as perhaps the most important and significant part of the whole project. However, until the pattern of designs and assessments begin to emerge, it will not be possible to do more than hold some pilot or trial dissemination studies, based on the present results. Commercial clients, the householder or house purchaser, local and public authorities and institutions, and the decision makers will all need to be informed, as well as the energy professionals, especially those in the design practices not yet involved in this work.

The Department of Energy has recognised this problem and is developing a comprehensive technical transfer programme which will include the testing of a Design Advice Scheme as a way of overcoming this lack of expertise in the professions.

### 9.3.8 Some applications

#### *9.3.8.1 The Bourneville Village Trust Solar Village*

This is the largest single solar housing project in Europe and is funded by the Bourneville Village Trust, the Housing Corporation and the Commission of the European Communities. The Project was started in 1984 following detailed consultations with local residents and various national and government organisations. There are a number of different house types, including direct gain passive houses for single families, two blocks of flats for elderly people and a group of 90 single-family houses for first-time buyers. Special attention has been paid to the orientation of the houses, the majority facing south to maximise solar gain. Monotony of appearance has been avoided through variety in design and by placing some houses slightly off due south. The focus of the solar village is the 'Demonstration House', shown in Fig. 9.1, in which both active and passive features have been combined.

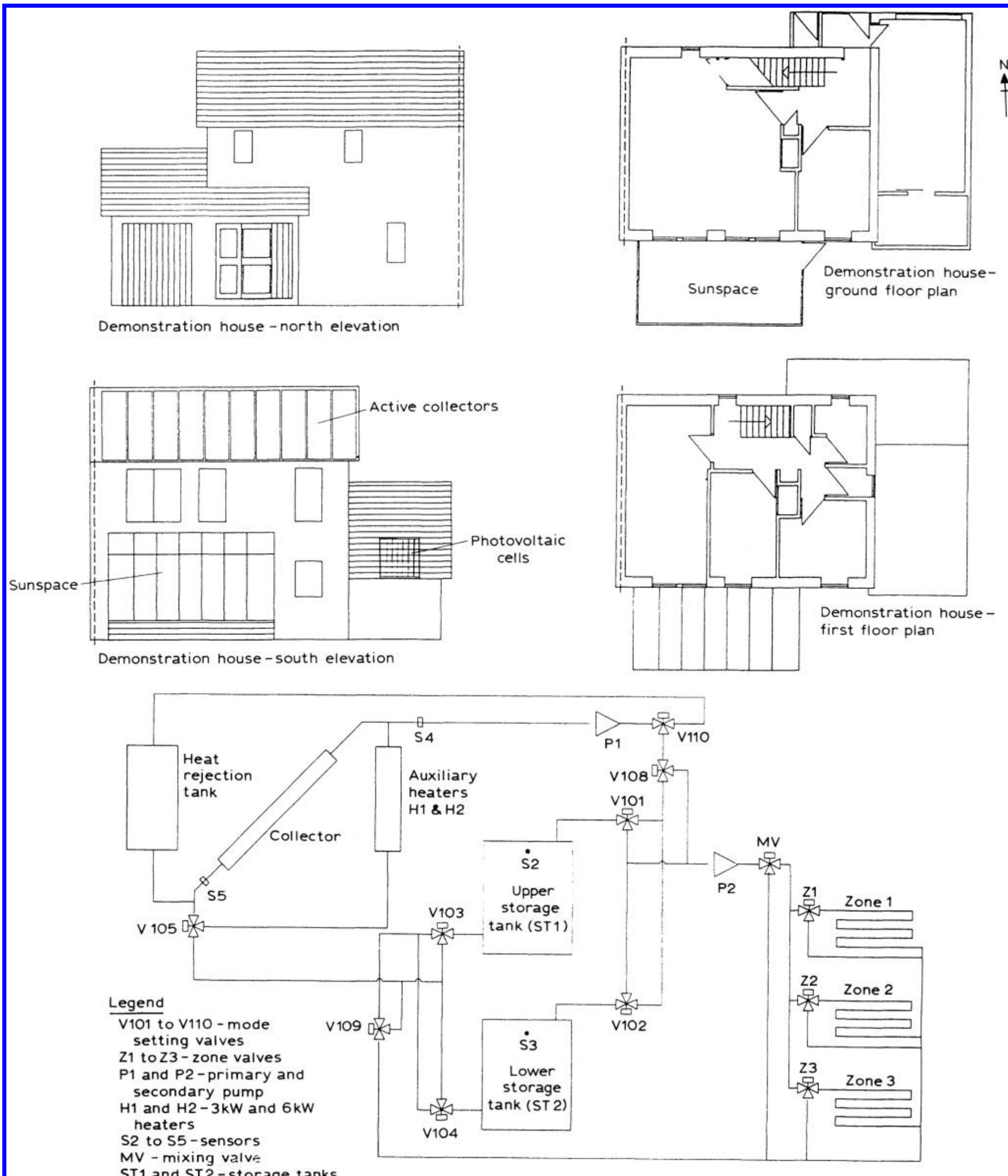


**Fig. 9.1.** The Demonstration House: plans, elevations, and a diagram of the space-heating system.[19] (Reproduced by permission of Franklin Consultants, Birmingham, UK.)

In addition to the heavy insulation and large south-facing direct gain windows of the other adjacent passive houses, there is a large attached greenhouse (or sun space), a variable flow-rate solar water heating system linked to variable volume storage, an active solar space-heating system with phase-change energy storage, a heat recovery system and some photovoltaic power generation. The conventional thermal performance modelling of the houses will be augmented by an assessment of the attitudes and reactions of the occupants.[19]

#### *9.3.8.2 Atria*

Modern interest in the glazed courtyard or atrium has been said to date from 1967, when two innovative buildings were completed in the United States. Since then there have been many developments in North America and Scandinavia, while in the UK the majority of the 500 retail and leisure developments at present under construction also feature atria.[20] Atria provide buffer spaces which protect the occupied parts of the building from the full impact of the external environment. However, in the UK care is needed in the design stage to ensure that the provision of passive solar gains for heating in the heating season do not result in overheating in the summer. Another advantage of atria is that the glazed space has relatively high daylight levels, thus window sizes can be increased as the energy penalties are reduced and daylight can be used more consciously as an alternative to artificial lighting.[21]

One of the best known examples of this design approach is the Wiggins Teape's headquarters at Basingstoke, designed by Arup Associates. This consists of a hollow rectangle built around a fullheight atrium 20 m wide by 40 m long. Half the offices look outward and the rest face into the atrium, which makes daylighting and natural ventilation possible without the associated energy penalties. The economics appear to be very encouraging as the building cost 30% less than its deep plan, artificially lit, air-conditioned predecessor (also designed by Arup Associates) and has been designed to use 25% less energy.[22]

## 9.4 PHOTOVOLTAICS

### 9.4.1 Introduction

The direct conversion of solar energy into electrical energy has been studied since the end of the 19th century. Modern developments date from 1954 when the Bell Telephone Laboratories discovered the silicon solar cell with an efficiency some 10 times greater than the traditional light-sensitive materials used in earlier devices. Photovoltaic cells, modules and systems have developed considerably since then, initially with the space programme of the 1950s and 1960s, and more recently since the 1973 oil crisis led governments to seek alternative means for providing power. Improvements in their costeffectiveness, reliability and lifetime have resulted in photovoltaics becoming the first choice in a wide range of applications on both engineering and economic grounds. For example, the cost of the photovoltaic module, 'the basic building block of the system',[23] has fallen in real terms by a factor of about 10 in the past decade. Unlike many competitive electricity generation systems, the cost of the photovoltaic module is expected to continue to fall.

Photovoltaics is now widely recognised as a mature technology which is poised to move into a new phase in an expanded consumer product market as well as gaining increasing penetration in its present markets which include telecommunications, cathodic protection, remote power and utility demonstration projects.

### 9.4.2 Technology

A solar cell converts light to electricity. A brief description of the basic process is given in Appendix 9.2,[24] which includes a definition of 'peak watts', $W_p$.

There are several photovoltaic module designs which show promise in both performance and cost.[23] These can be broadly classified in three groups as follows: crystalline flat plate, thin film flat plate and concentrator modules. Currently available commercial flat plate modules are based on either crystalline silicon or thin film amorphous silicon cells. There are a number of concentrator installations in different countries and they all use single crystal silicon cells. Crystalline silicon flat plate modules dominate the power market, defined as arrays larger than 50 $W_p$, although amorphous silicon thin film flat plate modules are getting an increasing share. Amorphous silicon cells have had considerable development for the consumer market, which includes all products in which the power supply is built in, such as calculators, watches and clocks. The consumer market continues to expand and at present accounts for over 25% of total world production, mostly in Japan.

For power applications the commonest module type is the flat plate crystalline silicon module, using cells made from single crystal or polycrystalline material. Individual cells are series-strung and then encapsulated behind low iron-content tempered glass. Present module efficiencies are around 11% for single crystal cells and 10% for polycrystalline cells. Recent developments in module design have shown that module efficiencies greater than 15% would be possible using cells with 18% efficiency.

A European Standard exists for the testing of photovoltaic modules. UK suppliers can have equipment tested for electrical characteristics at the Royal Aircraft Establishment, Farnborough, and for mechanical integrity and environmental tests at the Solar Energy Unit at Cardiff University.

It is expected that the design features leading to this improved efficiency will soon be introduced into commercial modules and that module efficiencies of 17–18% could be anticipated with single crystal cells. One of the advantages of the crystalline silicon flat plate module is its excellent reliability. A lifetime of between 5 and 10 years is normally guaranteed at present and operation for periods greater than 20 years is expected.

The present cost of crystalline silicon modules is in the order of $5 per $W_p$. At this level it is becoming increasingly competitive commercially with other electricity supplies, although applications in the UK will become attractive only when costs fall below about £1 per watt, and probably then in hybrid systems with wind or micro-hydro for relatively low (under 100 kW) power applications.

Thin film modules have the promise of low fabrication costs because less of the expensive semiconductor material would be used and large-scale automated fabrication processes are possible. The current costs of amorphous silicon modules are lower than those of crystalline silicon modules even though they have a lower efficiency, typically 6–7%, and within the next year or two will fall below $1 per watt production costs.

Efficiencies of 10–11% have been reported in laboratory tests of amorphous silicon cells and this should soon be available in commercial modules. Other types of thin film modules based on both copper indium diselenide and cadmium telluride will also be commercially available in the near future.

The use of more expensive cells is possible by using optical concentration, and high efficiency cells based on both gallium arsenide and silicon are under development, as are multi-junction cells. This research aims to achieve cells with over 30% efficiency. Already an efficiency of 27% has been reported.[25] When these cells are incorporated in commercial modules, efficiencies greater than 20% are technically feasible.

### 9.4.3 Photovoltaic systems

In space applications the supporting structure and associated electrical conditioning are highly specialised to provide adequate protection from the space environment and to withstand launching and operational conditions.

Typical terrestrial modules produce about 14 V DC and about 3 A under an irradiance of 1 kW/m$^2$. Higher power levels are obtained by series and/or parallel connection. The output from the array depends on the solar irradiance. Matching the load to the array is essential for effective operation. The module must be mechanically supported to withstand wind loads and must be correctly orientated. Higher outputs can be obtained if the array tracks the sun throughout the day. The power output must be delivered in an acceptable form, such as a constant DC voltage or 240 V 50 Hz AC, and this usually needs power conditioning equipment.

Electrical power must be used as efficiently as possible in any stand-alone system to minimise array size and cost for any specific application. Items of equipment other than the photovoltaic modules are known as the Balance of Systems (BOS). Their cost is the BOS cost. Some BOS costs are directly related to array area and can be reduced through increased module efficiency. Area-related BOS costs include the cost of the land, preparation of the site, the array structure and associated wiring and maintenance. Small arrays can often be fitted into otherwise unused land or onto an existing supporting structure, but for arrays above 1 $kW_p$ this may not be possible. However, the area-related BOS costs can show considerable benefits of scale if large numbers of identical sub-arrays can be installed at the same time on the same site.

Power-related BOS costs include the relatively inexpensive (for all except the smallest systems) electronic control equipment. The major costs are for batteries in DC systems and inverters for AC systems. Battery characteristics, e.g. storage density and charging efficiency for low currents, are being continually improved. For most typical applications the battery costs represent about 50% of the module costs.

Inverters have also been developed specifically to match photovoltaic arrays, but the scope for significant cost reduction is limited unless a completely new inverter technology can be discovered. Total BOS costs for large arrays on low-cost easy-access land could be in the order of \$5 per $W_p$, but can often be well above \$10 per $W_p$. With the anticipated improvements discussed above, the lower cost limit might reduce to about \$3 per $W_p$ during the next decade.

### 9.4.4 Applications

In addition to battery charging for many different applications in the leisure and military markets, photovoltaic modules are used in applications beyond the reach of a grid supply. Photovoltaic power systems are already the first choice for some telecommunications applications and for cathodic protection because of their reliability and low maintenance requirements. Photovoltaics are also economically competitive in certain situations in developing countries, e.g. for water pumping, lighting and providing small-scale power. When problems of limited distribution and a maintenance network for modules and systems are removed, these markets could grow rapidly.

Although it is possible to connect photovoltaics into a utility grid, it is not yet economically feasible unless the peak in sunlight intensity coincides with the utility peak load. These favourable conditions occur in the south-west of the United States and photovoltaics can supply electricity competitive with the utility peak load costs, under the present tax and investment schemes. In the southern EEC countries, utilities are examining the possibility of using photovoltaics to supply mountain or island communities, especially those with large summer tourist populations.

## 9.5 EXPORT MARKET POTENTIAL

The markets for terrestrial photovoltaics have been classified into four categories[23] as follows.

(1) Professional. This includes telecommunications, cathodic protection, utility demonstration projects and remote power, including hybrid systems, for a variety of loads, e.g. desalination plants or navigation lights. The purchasers in this market are international agencies, governments and their agencies, and companies. This market will continue to expand as decision makers in these institutions become convinced of the reliability and cost-effectiveness of photovoltaics compared to the alternatives in an increasing number of applications.

(2) Developing countries. The main applications include systems for lighting, refrigeration, radio and TV, water pumping and general village electrification. This is already a well-established market with purchasers from both national and international governmental agencies, non-governmental organisations (NGOs), and sometimes organised groups within the developing countries. The potential demand certainly exceeds the limited funding available from the aid agencies, suggesting that more action is necessary to allow individuals or groups in the developing countries to become the customers.

(3) Consumer power. This is regarded as the least developed of the four categories and includes all applications where the individual is both purchaser and user, e.g. in a remote home or farm, caravans, boats or the leisure industry. Appearance is an important aspect in this market and several manufacturers are now aiming at specific sectors of the market in terms of size, shape, weight, impact resistance and output.

(4) Consumer products. A market dominated by calculators; generally the consumer purchases the product for its own sake. The customer for the photovoltaic cell is the product manufacturer who quite often needs a non-standard product. Many consumer products are expected to operate in room lighting where irradiance levels in the order of 0·1 W/m$^2$ are experienced.

Figure 9.2[23] shows the market readiness of a number of the main applications.

## 9.6 ENVIRONMENTAL CONSIDERATIONS

There appear to be no significant environmental barriers to the widespread adoption of the active solar technologies.[26] The materials used in active solar systems are common in many other industries, e.g. aluminium, copper, steel, nickel and chrome alloys, glass and plastics, insulation and heat transfer fluids. In normal operation there is very little use of additional materials, but if a system with toxic heat transfer fluid is drained and refilled, a safe disposal method is

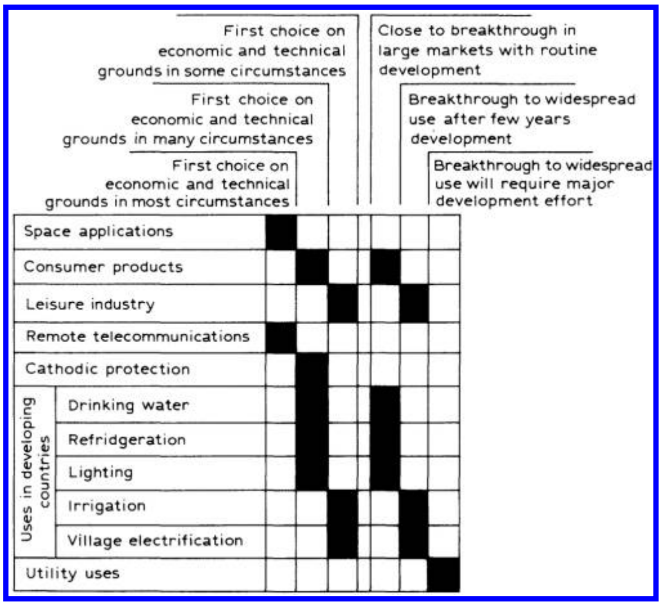


**Fig. 9.2.** Market readiness of photovoltaics.[23]

necessary. Contamination of potable water must be avoided. Some doubts have been expressed about the visual appearance of large arrays of flat plate collectors and in a few applications there could be a land use impact. Safety hazards are normal with any roof-mounted device and these are covered by Building Codes. Very few cases of fire caused by high stagnation temperatures in collectors have ever been reported.[26]

Various studies indicate that there are 'practically no environmental constraints relevant to the development of active solar heating and cooling technology'.[26] Safety and health hazards can be found but are rarely serious or life-threatening and are simply controlled through normal regulatory practices and appropriate guidelines for the design, installation and maintenance of the system.

With passive systems the risks to people and the environment are negligible: The environment is not really changed, it is only used more effectively'.[26] Although concern has been expressed about the possible increase in indoor air pollution, this is not directly a function of the passive solar design, but more due to building energy conservation measures.

High temperature solar thermal systems are similarly considered to be relatively free from environmental impact. Any potential problems would normally be site-specific and easily mitigated. However, the impact on land use, water use or local ecology during the construction and operation of a solar thermal system could be more significant, but less than for most of the conventional power generation technologies.[26] Large areas of land are needed to obtain useful amounts of power and higher latitude countries such as the UK have the additional disadvantage of lower solar radiation levels combined with correspondingly lower energy conversion efficiencies. In the countries where this technology is more likely to find widespread applications, e.g. in countries with hot, sunny deserts, the availability of land would not pose problems.

The production of photovoltaic systems can cause very similar health and safety problems to those found in the semiconductor industry. Under normal conditions, however, the quantities of pollutants generated from photovoltaic production plants are relatively small. During operation there are no gaseous or liquid emissions and there are a number of examples where the photovoltaic array has acted as an environmental heat shield, protecting the building on which it is mounted. Normal precautions for electrical installations must always be taken, and the necessary safeguards from electric shock or fire hazards are written in national systems specifications.

## 9.7 INSTITUTIONAL BARRIERS

There are some barriers to the increasing use of active solar systems in the UK. Although it has been demonstrated that for low-temperature rise applications, such as the heating of swimming pools, solar water heating can compete economically with any other system, there is no recognised route for this experience to be disseminated. The market for medium-temperature applications, typically for pre-heating water for domestic use, has failed to grow because of the relatively high cost and earlier adverse publicity. High-temperature applications for steam production, electricity generation or industrial process heat are not yet at a sufficiently developed stage for market penetration even in those countries where the solar radiation availability is favourable.

However, many successful demonstrations of passive solar energy in housing, in local authority buildings such as schools or hospitals, and in industrial and commercial buildings have shown that significant savings can be made in both heating and lighting costs through the adoption of passive solar techniques. A recent Watt Committee report[27] concluded that The debate, therefore, is no longer whether such climatically interactive buildings can, or in fact should, be built, but is rather concerned with providing the evidence to encourage and reassure clients who wish to request such buildings, designers who wish to design them and tenants/ owners who wish to rent or buy them.' The institutional barriers here are primarily educational in the broadest meaning of this term. Schools and Departments of Architecture, Building and Building Services still need to be convinced that more time should be given to learning these new skills and techniques. There is the major problem of 'training the trainers' in an area where there is very limited UK experience.

The public sector does not normally plan to use solar energy in its own buildings. Most property developers do not show much interest in the energy costs of their buildings. The financial factor does not understand or appreciate the significance of the present use of fossil fuels. For many decision makers there is no energy crisis and there will not be one in the foreseeable future. All these groups should be able to make informed decisions to encourage the wider adoption of passive solar techniques in the UK.

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## APPENDIX 9.1

### The flat plate collector

The flat plate collector can have up to five main components, described by McVeigh[1] as follows:

(a) a transparent cover which can be one or more sheets of glass, plastic film or plastic sheet;

(b) tubes, fins, channels or passages connected to the absorber plate or integral with it, to carry the heat transfer fluid, typically water or air;
(c) an absorber plate, often metallic with a black surface, although a wide variety of other materials may be used;
(d) insulation for the back and sides to reduce heat losses;
(e) a casing or container to enclose the other components and protect them from the weather.

Components (a) and (d) may be omitted in hot climates or where only a small temperature rise, in the order of a few degrees, is required. An approximate expression for the useful heat which can be collected, the Hottel-Whillier-Bliss equation (see, for example, Ref. 28), gives a linear relationship in terms of two operating variables, the incident solar radiation normal to the collector plate and the temperature difference between the mean temperature of the heat transfer fluid in the collector and the surrounding air temperature. The equation includes three design factors which are unique for each collector type: the transmittance-absorptance product relating the transmission characteristics of the cover to the absorber plate surface, the heat loss coefficient, and a further factor describing the effectiveness of heat transfer from the collector plate to the circulating fluid.

### Advanced collectors

For temperatures above 100°C most flat plate collectors are unable to function because of their relatively high heat losses. Two other collector types can overcome this problem. The evacuated tubular collector uses vacuum technology to surround the absorbing collector surface with a double-walled evacuated glass tube. Focusing collectors, tracking or non-tracking, concentrate the incoming solar radiation on the absorbing surface near the base. Tracking focusing systems are usually classified into three sub-groups. Point focusing collectors often have a tracking parabolic reflecting dish in which the direct solar beam is reflected to a central collecting point fixed to the dish. Line focusing collectors have an absorbing pipe placed at the focus. One type uses a linear Fresnel lens system and can achieve a concentration ratio of 40:1. For high temperatures, typically above 400°C, large fields of steered mirrors, or heliostats, reflect the direct solar radiation to a central receiver mounted on a tall tower. European experience with one major project in Almeria, Spain, has been described by Casal.[29]

## APPENDIX 9.2

### Solar cells

A solar cell converts light to electricity. The cells produce both electric current and voltage by the 'photovoltaic effect' and the technology is often given the name 'photo voltaics'. Solar cells are electronic devices and are made from semiconductors such as silicon, usually in the form of thin slices (wafers) about ¼ mm thick. The positive contact is a layer of metal on the back of the wafer, whilst the negative contact on top of the cell must collect the current but also allow as much light as possible to enter the device. The top contact is usually made in the form of a grid, as shown in Fig. A9.1.

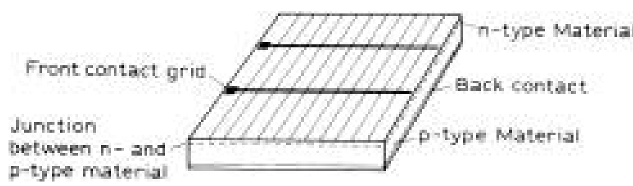


**Fig. A9.1.**

The process by which the absorption of light in a solar cell can produce DC electrical power is represented by Fig. A9.2. Note that a cell must produce both current and voltage to generate power, since power=current×voltage.

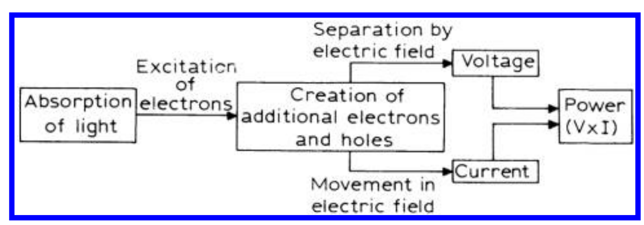


**Fig. A9.2.**

In bright sunlight, a 10 cm-square cell will give an output of about ½ V and 3 A, i.e. about 1½ W of power. Manufacturers quote the output of their cells for a sunlight intensity of 1 kW/m$^2$ (similar to that of the Sahara Desert at noon). This standard output is labelled 'peak watts' or '$W_p$' and is measured at a standard temperature of 25°C· The power output of a solar cell varies with the intensity of light falling on it. The current output will halve if the light intensity is halved, but the voltage will drop by only a few percent. The voltage output also depends on the temperature of the cell and decreases by about ½% for every degree Celsius rise in temperature above 25°C.

# Section 10

# Biofuels

## 10.1 INTRODUCTION

Of the renewable energy resources available to the United Kingdom, biomass is the largest and most economic. However, compared to the situation in other countries, it has been insufficiently considered and funded, with the result that information as to its current usage and future potential is at best sparse and at worst non-existent.

## 10.2 DEFINITIONS

Biomass energy is essentially solar energy captured by green plants in photosynthesis and then stored chemically, usually as carbohydrate, but sometimes as hydrocarbon, molecules. Any fuel subsequently derived from biomass is known as a biofuel, though biomass can be used as a biofuel directly, such as when firewood is burned.

Wood may be considered as a primary biofuel, while ethanol (formed via the microbial fermentation and distillation of crops), biogas (mostly methane produced by the bacterial degradation of biomass) and charcoal (the solid product of pyrolysis of biomass) are examples of secondary biofuels. All biofuels are subjected to, in the widest sense of the term, bioconversion, which is the overall process in which biomass is harvested and either converted to, or used as, a fuel.

The biomass resource consists of natural vegetation, energy crops cultivated specifically for their energy content on terrestrial or aquatic energy farms, biomass residues and biomass wastes. Biomass residues are the plant remains following agricultural or forestry operations. They generally have an alternative use or uses to providing energy, thus incurring a positive cost for their collection, transportation and utilisation as biofuels. This distinguishes residues from actual wastes for which no useful purpose has yet been found. Where pollution controls are enforced, biomass wastes usually incur a cost, in both energy and financial terms, before being returned to the environment. Their utilisation as energy sources, therefore, provides a credit which can be offset against collection, transportation and bioconversion costs. Nevertheless, the distinction between residues and wastes and between useful and not useful vegetation are not clearcut. Ralph Waldo Emerson's 19th century definition of a weed as 'a plant whose virtues have not yet been discovered' certainly has some relevance when discussing potential biomass energy resources today.

## 10.3 THE UK SCENE

Until the latter part of the 17th century man relied almost entirely upon the combustion of wood and charcoal for his energy needs, as he had done for millennia. This situation applied in Britain just as much as it did in the rain forests of Africa, jungles of Asia or outback of Australia. It was the discovery of easily winnable coal that created the Industrial Revolution in England and, soon afterwards, Germany, that marked the beginning of the decline of biomass energy in what was to become the industrialised or developed world. In the 1980s, biomass, chiefly firewood, may account for approximately 1% (there are no accurate statistics available) of UK primary energy consumption,[1] compared to 15% in Finland (the highest figure among the developed countries) and over 90% in many of the world's poorer countries such as Chad, Mali and Tanzania.

A major constraint with respect to the cultivation of energy crops in the UK is the curtailed growing season compared with countries occupying lower latitudes, resulting in reduced annual crop productivities. Thus, while sugar beet yields in the UK are around 23 t/(ha year) on a dry weight basis, in California yields are almost double. Photosynthetic efficiencies are roughly equal at just over 1%, but the greater annual insolation of California (approximately twice that of the UK) allows much greater productivity. At a UK latitude of 53°N, an annual mean insolation on a horizontal surface of 8·9 MJ/($m^2$ day) is obtained, with 18 MJ/($m^2$ day) at midsummer but only 1·7 MJ/($m^2$ day) at midwinter. This midsummer/midwinter ratio of 10.6 compares starkly with those for more favourable biomass productive regions such as central USA (with a ratio of 2·5 at 36°N), southern France (4·8 at 44°N) and Australia (1·8 at 30°S). The respective annual mean values for insolation are 19 MJ/($m^2$ day), 15 MJ/($m^2$ day) and 20 MJ/($m^2$ day).[2] Therefore, most energy crops can be ruled out as potential fuel sources for the UK—the exception being trees for firewood—and any substantial biofuel contribution to the country's energy economy will come from biomass residues and wastes. This prognosis is somewhat complicated by the grain and wine surpluses of the European Community, which could be used for fuel ethanol manufacture, requiring less subsidies to do so than are at present being paid for their production and storage as food. (Including excess beef and dairy products, £$6\times10^9$ worth of food is currently being stored at a cost of £850 million per annum.[3]) On the other hand, the price of grain ethanol in Denmark needed a 40% reduction in order to become economic back in 1984,[4] even before the halving of oil prices early in 1986.

The United Kingdom and Norway are the only two countries in Western Europe which are net oil exporters, and with significant natural gas and oil reserves in place, the UK Government has invested less on alternative, non-fossil energy sources, with the notable exception of nuclear power, than have most of its neighbours and EEC partners. Biofuels have continually received a low level of funding by the Department of Energy, even with respect to other renewable energy options. The Department's expenditure on research and development into biomass energies reached a high of £0·7 million during 1982–83, since when it has fallen to around £0·2–0·3 million per annum in the succeeding years. The annual average expenditure for the 1980s has been approximately £0·35 million. Yet the Department of Energy recognises five biomass technologies as being cost-effective already: solid fuels from dry domestic, industrial and commercial wastes; solid fuels from straw; solid fuels from wood wastes and forest thinnings; gaseous fuels from wet wastes (sewerage and industrial effluent); and gaseous fuels as landfill gas; in addition, energy forestry is considered to show much promise but still requires substantial further development.[5, 6] However, with an energy policy seemingly exclusively controlled by market forces, the nation's biomass energy potential will never be realised unless the Department of Energy more actively promotes biofuels, with more financial and technical backing, in the same way that it does for the nuclear power industry, for example.

## 10.4 BIOMASS TECHNOLOGIES

### 10.4.1 Introduction

The main bioenergy conversion routes are represented in Table 10.1[7] along with the principal products formed and, where applicable, their energy contents. An important criterion in process selection is the water content of the biomass which, if over 70%, may allow only aqueous processing without exorbitant energy expenditure on drying. The constitution and availability of the biomass raw material, together with constraints regarding land, labour and economics, are all vital factors in deciding the conversion path to follow. In the case of energy crops used as the biomass source, inputs as in conventional agriculture or forestry such as tractor power, fertilisers, pesticides and so on, are required, along with incurred harvesting and transportation costs to the bioconversion facility. Collection and transportation costs for biomass residues and wastes must also be accounted, as outlined in Section 10.2.

A further series of possible products are the plant oils such as those of rapeseed, linseed and sunflower. These have higher energy contents than do the more highly oxygenated alcohols (39·5 MJ/kg, 39·4 MJ/kg and 36·9 MJ/kg respectively compared to the 29·7 MJ/kg of ethanol). However, it is difficult to foresee the production of vegetable oil-based fuels in the UK since their value as food grade materials is some two to three times their value as fuels. Of the total world production of 60 Mt per annum, over 85% is used for edible purposes.[8]

### 10.4.2 Direct combustion

The direct combustion of organic matter to produce steam or electricity is the most advanced of these conversion processes and, when carried out under

**Table 10.1 Bioconversion processes and products**[a]

| Process | | Initial product | Final product |
|---|---|---|---|
| Aqueous: | Anaerobic digestion | Biogas (2 parts $CH_4$ to 1 part $CO_2$; 22–28 $MJ/m^3$) | Methane (38 $MJ/m^3$) |
| | Alcohol fermentation | | Ethanol (19 MJ/litre) |
| | Chemical reduction | | Oils (35–40 MJ/kg) |
| Dry thermochemical: | Pyrolysis | | Pyrolytic oils (23–30 MJ/kg)<br>Gas (8–15 $MJ/m^3$)<br>Char (19–31·5 MJ/kg) |
| | Gasification | Low-medium energy gas (7–15 $MJ/m^3$) | Methane (38 $MJ/m^3$)<br>Methanol (16·9 MJ/litre)<br>Ammonia<br>Electricity (3·6 MJ/kWh) |
| | Hydrogasification | | Methane (38 $MJ/m^3$)<br>Ethane (70·5 $MJ/m^3$)<br>Char (19–31·5 MJ/kg) |
| Direct combustion of: | Wood chips (18·6–20·9 MJ per kg dry wt) | High pressure steam | High pressure steam<br>Electricity (3·6 MJ/kWh) |

[a] *MJ/x refers to energy content.*

controlled conditions, is probably the most efficient. Waterwall incineration, whereby water pipes within the walls of the incinerator are heated to produce steam at high efficiencies (the heat being available for district heating schemes), is gaining popularity. Co-combustion of organic matter with coal in more conventional power plants is also a comparatively new approach, while the advancement of fluidised bed systems for wood chip combustion is also now a favoured option.

Dried wood chips, cereal straw and organic refuse, with heat contents of 18·6–20·9 MJ/kg, 16–17 MJ/kg and 10·5 MJ/kg respectively, are all biomass candidates for combustion and can be delivered to the furnace or boiler in a variety of forms. Wood may be combusted as short or long logs, sawdust, bark briquettes or wood chips; straw can be burnt as small or large bales or as pellets (the costs of compression being more than offset by the reduced costs of combustion equipment and better combustion performance);[9] while refuse too can be densified and combusted as refuse derived fuel (RDF). The types of combustion equipment too are many and varied and include simple stoves, boilers with bottom-burning and through-burning systems of various capacity with discontinuous charging, and boilers and furnaces with automatic charging.[10] To improve the quality of combustion and reduce polluting emissions, the biomass fuel should be fed continuously into the reaction zone, the combustion air should be well mixed with the fuel and gas products, and the combustion products should remain in the combustion chamber for a period sufficiently long to allow complete combustion (which for dry wood is 900°C held for 10 min).[11] Boilers can range in thermal output from a few kilowatts to 5 MW or even more. Electricity generation from wood is not considered a feasible option in the UK as yet by government, but should not be ruled out for the future.[12]

### 10.4.3 Pyrolysis and gasification

Pyrolysis entails the distillation of organic matter in the near absence of air or oxygen. Decomposition of wood begins at 300°C and is virtually complete by 450°C. The oil formed in pyrolysis reactions is not suitable for refining and is also corrosive, but it is useful as a fuel oil extender. Char production is particularly relevant to the Third World where it is often used in rural areas to provide a solid fuel with double the energy density of wood (about 33 GJ/t compared to 16·5 GJ/t).

Gasification is carried out in the presence of limited air or oxygen and at higher temperatures (1600–1700°C) and/or pressures than is pyrolysis. Where oxygen only is admitted to the reactor the initial product is a hydrogen/carbon monoxide mixture (synthesis gas), but oxidation using air leads to 42% nitrogen in the mixture (producer gas), thus lowering the heat value from around 14 $MJ/m^3$ to 7 $MJ/m^3$. Synthesis gas can be the intermediary in a number of production routes:

(1) Methanation to SNG (substitute natural gas) gives a product of energy value 38 $MJ/m^3$, the reaction efficiency being increased using fluidised bed reactors and Raney nickel catalysts:

$$CO + 3H_2 \rightarrow CH_4 + H_2O$$

(2) Methanol can be formed by condensation of the gaseous phase followed by distillation to 98% purity:

$$CO + 2H_2 \rightarrow CH_3OH$$

(3) Ammonia is produced by conversion of the carbon monoxide to carbon dioxide, which is then eliminated to leave an almost pure hydrogen stream. Hydrogen is also formed by the reaction

$$CO + H_2O \rightarrow CO_2 + H_2$$

Nitrogen obtained from an air separation facility is added to give an $H_2$:$N_2$ ratio of 3:1 which passes to an ammonia synthesiser, containing an iron oxide catalyst, at 457°C and $30{\cdot}4\times10^6$ Pa.

The overall yield from the reaction

$$N_2 + 3H_2 \rightarrow 2NH_3$$

approaches 90% of theoretical, the unconverted gas being recirculated. An 80 000 t per annum facility recently began operation in Finland based on the gasification of peat,[13] with biomass in the form of fast-growing willow to be used when the peat deposits are exhausted.

Electricity generation within a combined gas turbine-steam cycle is another alternative. Producer gas may become attractive in Third World countries as a source of work energy, particularly where the possibilities for biogas production are poor. Methanol can be converted at 90% efficiency to gasoline directly using a Mobil process employing zeolite catalysts,[14] while the familiar Fischer-Tropsch process produces hydrocarbon fuels, predominantly olefins, from the catalytic (usually using iron oxide) heating of synthesis gas to around 400°C

Biomass can also be converted to methane and ethane by reduction with hydrogen at 540°C and $6{\cdot}9\times10^6$ Pa pressure. However, the need for high temperature and pressure added to the fact that hydrogen itself is a premium fuel limits the usefulness of the process.

Apart from the production of high-value charcoals (e.g. for use in barbecues), pyrolysis of biomass is not commercially practised on a large scale in the UK and other developed countries. Gasification too is now thought to be less important than it was a few years ago[15] when RDF, straw, wood and bracken were all considered potential biomass feedstocks for the process. Gasifiers are still being developed, however, and are classified into updraught, downdraught, fluidised bed and suspended flow types. Downdraught gasifiers were used extensively for running vehicles in the Second World War, though they certainly would not meet today's environmental standards. They would also be uneconomic, and though gasification technology has advanced over the past decade or more, its most likely applications are as small-scale producer gas sources in the developing countries.

### 10.4.4 Chemical reduction/liquefaction

Chemical reduction or direct liquefaction involves the reduction of aqueous biomass by chemical and physical means to yield fuel oils of varying compositions. Carbon monoxide, steam and a slurry of cellulosic material, for example, have been reacted together at 250–400°C and $13{\cdot}8$–$17{\cdot}6\times10^6$ Pa pressure in the presence of an alkaline catalyst to yield an oil of approximate formula $(C_{11}H_{19}O)_n$ and an energy content of 40MJ/kg.[16]

Liquefaction processes generally involve the preparation of the reducing gases by the pyrolysis or oxidative gasification of some of the biomass input. The oil product should be suitable for use as a boiler fuel, though this technology again would seem to have limited scope for application in the UK.

### 10.4.5 Anaerobic digestion

The conversion of biomass to methane is achieved by anaerobic digestion: the bacterial decomposition of organic matter in the absence of oxygen to produce a gaseous mixture (biogas) of methane and carbon dioxide in a roughly 2:1 volumetric ratio. The carbon dioxide can be removed to leave SNG of pipeline quality, while the residual sludge retains its nitrogen to yield a good quality fertiliser. The reaction temperature can be in the mesophilic region of 35–37°C or at 55°C for faster thermophilic rates and the fermentation may be batch, semicontinuous, or continuous. To obtain high methane output the carbon/nitrogen ratio of the input slurry feed must be approximately 30:1. The process is marginally exothermic and the ideal pH for rapid methanogenesis is pH 7–7·2.

The input feed (principally carbohydrate) is hydrolysed and fermented to organic acids (chiefly acetic) and hydrogen in the initial non-methanogenic, acidogenic stage. The acids are then converted by methanogenic bacteria into dissolved methane and carbon dioxide, which themselves finally undergo transition from the liquid to the gaseous phase. About 70% of the methane is derived from acetate. The reaction rates are all slow and the residence time within digesters can be several weeks. This dictates the size (volume) needed to handle a given amount of feed. A faster overall reaction rate would reduce equipment size and capital costs. The methanogenic step is usually considered to be rate-limiting, but this might more properly be the final mass transfer of dissolved methane and carbon dioxide to the gas phase.

The equation for the anaerobic digestion of carbohydrate can be represented as

$$(C_6H_{10}O_5)_n + nH_2O \rightarrow 3nCO_2 + 3nCH_4$$

with 95% of the carbohydrate energy converted to methane energy. The key methanogenic reaction is $CH_3COOH \rightarrow CH_4 + CO_2$.

The optimal conditions for the non-methanogenic, acidogenic reactions and for the methanogenic reactions differ and so the separation of these two main phases facilitates the maximisation of the overall process rate, resulting in significant gains in net energy. In addition, equipment size has been reduced to around 25–35% of the size of conventional systems, lowering the capital cost correspondingly.[17] Other recent developments include digester operation at high loadings of solids; use of immobilised bacteria on solid supports; addition of materials such as activated carbon, fly ash, enzymes, *Lactobacillus* cultures and growth factors to digesters; pretreatment of the influent substrate and/or post-treatment of the residual digested solids to increase biodegradability before recycling or for-ward-cycling; and innovative digester designs such as plug-flow, fixed-film packed bed, fixed-film fluidised bed, upflow sludge blanket, and baffle-flow digesters that provide longer solids retention times over hydraulic retention times.[18]

Ten years ago the most promising substrates for biogas production were considered to be agricultural, but subsequently it has been discovered that a consistently suitable feedstock on most UK farms is not available. Additionally, unless there is an on-site demand for heat plus a pollution control requirement, then farm biogas systems are uneconomic. In fact only 15 farm digesters are now in operation in the UK and around 100 in the USA.[19]

Furthermore, there are less than 10 anaerobic industrial waste treatment plants in the UK, though these are considered to be potentially beneficial. For instance, a 2200 $m^3$ digester in Wales uses anaerobic sludge blanket technology combined with a secondary aerobic stage to treat whey for discharge directly into a river, saving disposal costs of around £30 000 per annum. The biogas is used for production of process heat and generation of electricity, thus saving around £80 000 annually by replacing the previously consumed heavy fuel oil. This is an example of an energy-producing, economic and environment-improving technology somewhat akin to sewage sludge digestion. Over 55% of UK sewage sludge is digested and, where energy recovery occurs for heating and/or generating electricity (as in over 100 sites), then up to £1000 is saved per tonne of sludge processed.[19]

In the EEC countries there were approximately 95 000 $m^3$ total capacity of anaerobic digesters operating in farms in 1983, with a further 174 000 $m^3$ in (mainly) the food and drinks industries[20] from a total of 550 biogas plants altogether. Since 1983 construction of new farm waste plants has been much reduced and less than 50% of existing plants are actually working, though the biomethanation of industrial wastes is now a well-established treatment process.[21]

At present the greatest potential for biogas is from landfill waste disposal sites, with at least 19 energy recovery installations out of a possible 250–300 technically feasible systems operating by the end of 1987. Landfill gas is not processed apart from moisture removal and is mainly used through direct combustion by industries associated with the sites (brick and cement works) or manufacturers nearby. A major limitation to the direct use of landfill gas is the proximity or otherwise of potential customers to the sites themselves. However, no such limitations apply to electricity generation and export to the national grid, courtesy of the 1983 Energy Act. In fact the first 'power station' to be fuelled by landfill gas joined the grid in late 1987. The location is Meriden near Birmingham and the plant will have a power output of 3·5 MW from 2 $m^3$ of gas evolved every minute from the anaerobic digestion of 3500 t of refuse each day.

### 10.4.6 Ethanol fermentation

The fermentation of biomass to alcohols, chiefly ethanol, by the yeast *Saccharomyces cerevisiae* is a well-established technology. Yet its widespread use for the production of power alcohol is limited to the availability of low-cost sugar or starch feeds which need the minimum pretreatment prior to the fermentation stage. The more abundant cellulosic raw materials such as wood and straw require energy-intensive, costly processing before becoming amenable to yeast fermentation.

The equation $C_6H_{12}O_6 \rightarrow 2C_2H_5OH + 2CO_2$; $\Delta G° = -234{\cdot}5$ kJ summarises the process and shows that 180 units by weight of hexose sugar (mainly glucose) are fermented to yield 92 units by weight of ethanol—an overall yield of 51·1 %. But in practice 47% at most of the fermented sugar is actually converted to ethanol. In energy terms, the maximal energy which can be generated by the formation of two gram moles of ethanol and two of carbon dioxide from one gram mole of hexose sugar is 234·5 kJ. The ethanol generated contains approximately 90% of the energy of the products formed.

Ethanol production can be carried out by batch, semi-continuous or continuous fermentations. The batch operation remains the most common, but in a continuous process productivity may be increased by 1–2% and the fermentation time is halved. However, sterilisation procedures must be very thorough since the consequences of contamination are greatly magnified. A typical molasses batch fermentation plant might have a fermentation stage of some 100 000 litres capacity, with prior yeast seed stages sequentially passed through increasing volumes. The concentration of fermentable sugars in the medium is around 12% w/v and these are fermented to ethanol at 6% v/v within 36 h. The temperature is maintained at 30–32°C and the pH at 4–4·5.

Following fermentation and separation, stills with highly efficient rectifying columns are used to obtain satisfactorily pure ethanol. These concentrate the volatile impurities in relatively narrow zones of the column allowing alcohol plus water to distil over into the receiver. Ethanol concentration to around 95% v/v is achieved in a rectification tower, while the fuel oils are collected in a separate vessel. To remove the last traces of water, benzene is normally added, at a later distillation stage, to form an ethanol/water/benzene azeotrope; the water distils off at 64·85°C and the benzene at 68·25°C.

The bacterium *Zymomonas mobilis* is used for fermenting alcoholic beverages in the tropics; it gives higher ethanol yields and lower biomass production than does yeast. A volumetric ethanol production of 120 g/litre each hour has been achieved in a continuous cell recycle fermentation using *Zymomonas*. This is three to four times the rate normally obtainable from a traditional yeast fermentation, making the process both faster and cheaper.[22]

Other innovations aimed at efficiency improvements with respect to ethanol yield, widening the choice of raw material inputs through advances in pretreatment and disintegration, and selecting the most appropriate bioreactor system, are being developed in laboratories all over the world.

Specific examples include the following:

(1) increasing ethanol productivity and decreasing costs compared to batch fermentation by using a continuously stirred tank reactor (CSTR) with cell recycle;
(2) the use of molecular sieves rather than azeotropic distillation as a means of dehydration of the 95% alcohol:water mix produced by distillation;
(3) the alteration of the genes of yeast to improve alcohol tolerance;
(4) the use of immobilised yeast cells;
(5) the genetic engineering of *Saccharomyces cerevisiae* to ferment whey lactose and wood xylose;
(6) cellulose utilisation as a substrate for fermentations, through improvements made in its hydrolysis to glucose (though costs of cellulase enzyme production from *Trichoderma viride* and *Aspergillus niger* need to be reduced drastically, again through genetic manipulation, before the cellulose to ethanol route will be economically attractive);
(7) the use of thermophilic bacteria (mainly clostridia) to ferment cellulose together with improve-ments in alcohol tolerance and the proportion of substrate converted to ethanol;

(8) the use of new substrates, non-fermentable by *Saccharomyces cerevisiae* but fermented by other species such as *Kluyveromyces* sp.

Although research in the UK is continuing on fuel ethanol production from biomass, the Department of Energy does not consider it to be an economic option. While this is the case at present, the fact that ethanol/gasoline mixtures (with ethanol accounting for 5–10% of the volume) have the same octane level as leaded fuels makes gasohol an attractive proposition to countries more environmentally conscious than is the UK (or at least its government). Also, there is a great potential for exporting the technology for ethanol production, as Brazil has been successfully doing, for instance, plus the problems of European food surpluses currently pertaining, as mentioned above.

However, ethanol production costs, depending on the feedstock, are currently about 3–5 times its value as a fuel, and bioethanol manufacture is unlikely to become economically viable without subsidies until crude oil prices reach $55 to $65 per barrel. Additionally, ethanol is arguably technically inferior as an octane booster to certain other oxygenates such as methyl *t*-butyl ether (MTBE) and *t*-amyl methyl ether (TAME), and so must compete in the marketplace with these compounds as well.[23]

It would nevertheless appear that falling oil prices have not deterred those European countries committed to a bioalcohol programme, notably France, though the so-called C quota sugar beet seems to have superseded the Jerusalem artichoke as the favoured energy crop. In the late 1980s the French now seem set on a course for blending bioethanol as an octane booster at the 7% level with gasoline. The annual requirement for a nationwide programme is estimated to be 1500 M1 (1.2 Mt) of ethanol, produced from the fermentation of 150 000 ha of sugar beet plus 350 000 ha of wheat.[24]

By 1988, a further 250 000 t/year ethanol, fermented from 1·25 Mt/year grain, will also be produced in Lower Saxony in the Federal Republic of Germany, requiring over 200 000 ha of land.[25] Sweden, a non-EEC country, has also begun a bioethanol programme which could easily and, it is said, economically[3] blend ethanol with gasoline at the 6% level, necessitating an annual production of 300 Ml (240 000 t) from 50–70% of the country's 1–2 Mt annual wheat surplus grown on 200 000 ha of land.

Fuel alcohol consumption within the EEC as a whole has risen from 400 000 t in 1980 to over 1·5Mt in 1985, but this growth is now slowing down in the face of unfavourable economics.[26] The European Federation of Chemical Industries (CEFIC) maintains adamantly that fermentation ethanol, despite its rising production levels, is not economic; while the European Parliament is strongly opposed to Community subsidies being used for fuel ethanol manufacture from agricultural surpluses, 'though regional outlets do exist and specific projects should be financed where advantageous'.[27]

## 10.5 UK BIOMASS RESOURCES

### 10.5.1 Woody biomass

As indicated previously, the only types of fuel crops likely to be purposefully grown in the UK (at least in the foreseeable future) for their energy content will be in the form of woody biomass to be combusted. Fuelwood can be grown by coppicing (e.g. poplar, willow, alder, etc.) in the more fertile, sheltered lowlands, and via single stem short rotation systems (using Sitka spruce, Scots pine, Douglas fir, etc.) on the less fertile and more exposed lowlands and sheltered uplands. Potentially 1·8–4·6 Mha of land are available for wood production in Great Britain, primarily in the uplands where sheep production would be replaced by modified conventional forestry.[28] Within the last decade over 200 000 woodstoves have been sold in the UK to about 1 % of the housing stock[29] and the present fuelwood market is estimated at 250 000 t/year, though residues from existing forests, at 1·5 Mt/year, could easily meet the demand.[30] Yields from coppicing of 10–15 dry t/(ha year) can be expected on a 4–8 year coppice rotation, and around 12 dry t/(ha year) from single stem species.

The Department of Energy[5,6] rates wood wastes for domestic use as being economically attractive at present, with wood from energy forests and wood wastes for non-residential markets 'promising but uncertain'. However, analysis of single stem short rotation forestry has demonstrated that this type of wood production should be cost-competitive with other fuels even in 20 years' time.[31]

As a result of its programme on renewable energy, the Department of Energy[6] considers that up to 2000 some 19·5 PJ (0·65 Mtce) of fuelwood energy could be obtained annually from existing resources. If wood were also grown specifically as a biofuel, the annual supplies to industry and commerce could reach 30 PJ (1 Mtce) in addition to approximately 84 PJ (2·8 Mtce) to the domestic market. Should energy prices double then the long term projection of the annual supply to industry is around 102 PJ (3·4 Mtce), with a further 300 PJ (10 Mtce) of wood energy consumed in the domestic sector.

### 10.5.2 Natural vegetation

Natural vegetation such as bracken, heather and reeds, has also been investigated as a potential energy source,[32] but it is difficult to envisage such crops making a significant impact other than perhaps in certain limited locations. Harvesting and transportation are major factors in making such 'energy crops' non-viable.

### 10.5.3 Cereal straw

At present the average yearly UK production of straw is 13·5 Mt, of which 50% is burnt in the field or ploughed in since it finds no saleable outlet to use as animal bedding or feed. Annually, 166 000 t, equivalent to 2·7 PJ, are utilised for farmhouse and animal house heating in some 7700 boilers. The maximum potential for on-farm straw combustion is 1·9 Mt/year, but 0·9 Mt/year (14·1 PJ/year) is thought to be more realistic by 2000.[33] In addition, 5·1 Mt/year could be used as a heat source in small industries, particularly the food and drink, cement and brickmaking industries plus light engineering. However, the market forecast is that 386 000 t/year will be used in industry by 2000, with a further 230 000 t/year consumed by the commercial and institutional sectors, giving a total of 9·5 PJ/year. The likely potential for straw heating in the year 2000 in the UK is thus 23·6 PJ (0·79 Mtce).

### 10.5.4 Other agricultural/horticultural residues/wastes

Biddlestone and Gray[34] estimate that, on a fresh weight basis, 1·6 Mt of potato haulms and sugar beet tops, 5 Mt of garden and nursery 'wastes' and 120 Mt of livestock manure are generated each year in the UK. Some of this 'waste' is re-used, for example, as feed for animals, as fertiliser, compost, etc., but most is disposed of, where necessary, by the cheapest route possible to (though not always) take into account environmental considerations. Land-filling or returning to the soil are probably the most favoured routes, but the anaerobic digestion of cattle manure (2·67 Mt/year dry weight production from dairy and l·99 Mt/year from beef cattle), pig manure (0·98 Mt/year) and that from laying hens (0·53 Mt/year),[35] has now lost most of its early promise, as mentioned earlier.

### 10.5.5 Municipal refuse

Approximately 20 Mt of domestic waste are produced annually in the UK, an estimated 90% of which is landfilled and, therefore, potentially available for methane gas recovery. However, while the technical feasibility of gas recovery from landfill can be demonstrated for most sites, feasibility in terms of both net energy output and economic viability remain contentious issues. The Energy Efficiency Office of the Department of Energy has commissioned an, as yet, apparently unpublished survey suggesting that, on a technical basis, 250–300 landfill sites in England and Wales may be capable of producing very significant quantities of landfill gas, equivalent to 35 PJ per annum or just under 0·5% of UK primary energy consumption. Yet in 1985 less than 10 energy from landfill schemes were operational in the UK. Their combined gas output was 1·8 PJ, or only 5% of the potential.[36]

As Table 10.2 shows, around 50% of domestic refuse is organic and, therefore, amenable to energy recovery. New sites recovering gas will mean 14 landfill gas operations on stream for direct firing of kilns and bricks by the end of 1987, with five generating electricity in remote areas. Based on a typical yield of 0·2 GJ per tonne of refuse per annum for 12–13 years, the Department of Energy[6] estimates an annual national potential of 39 PJ (l·3 Mtce) using current practice, rising to a full yearly economic potential of 90 PJ (3 Mtce).

Alternatives to landfilling are the incineration of refuse and the production of RDF (refuse derived fuel). Indeed, the Energy Technology Support Unit (ETSU) at Harwell comments[5] that 'most forms of collected refuse are cost-effective now against national investment criteria; even those at the higher end of the supply cost range could achieve a three-year payback by 1990. The use of collected refuse is now at the deployment stage and the main problems are to demonstrate this cost-effectiveness and to establish commercially reliable routes from supplier to user. The

Table 10.2 Composition profile of domestic refuse in UK (average)

| Composition | % by weight | Average energy content as received (MJ/kg) |
|---|---|---|
| Fine dust | 13 | 9·6 |
| Paper and board | 27 | 14·6 |
| Vegetables and putrescibles | 28 | 6·7 |
| Textiles | 3 | 16·3 |
| Plastics | 5 | 37·0 |
| Glass | 8 | 0 |
| Metals | 8 | 0 |
| Unclassified (wood, shoes, etc.) | 8 | 17·6 |

Allowing for moisture content (typically 20–30% by weight), good quality raw refuse has an average calorific value of 10·5 MJ/kg, compared with 15–16 MJ/kg for air-dried wood and 28 MJ/kg for coal.

resource has the potential to make an important contribution to UK energy supplies—12 to 14 Mt of coal equivalent (Mtce) a year' (360–420 PJ).

A detailed study of the likely potential for RDF indicates that it could satisfy up to 13% of all current heat demand in industry. There are many plants worldwide already making and marketing pelletised RDF (with 60% the calorific value of coal), four of them in Britain—at Eastbourne, Liverpool, Byker (Newcastle-upon-Tyne), and Doncaster. This last plant is based on technology developed at the Government's Warren Spring Laboratory as part of a major resource recovery programme.[37]

There are at present less than 10 Energy Recovery Refuse Disposal Plants in operation in the UK. The potential is probably well over 100. The problem of waste disposal is becoming acute: by the year 2000 landfill sites will be scarcer. West Germany and France are already ahead of the UK in solving this problem, well over half of their refuse being disposed of by energy recovery systems. In the UK only some 15% of household refuse is treated in any way, and less than 5% is used for energy recovery.[38]

### 10.5.6 Other wastes

Around 36 Mt of (mainly) industrial and commercial wastes are produced each year, though the organic fraction suitable for energy recovery will be low. Brewers' grains and food processing wastes could be anaerobically digested, though only 1–2 Mt/year fresh weight are produced in the UK.

Sewage sludge (55% of which is digested) is generated at a level of 35 Mt/year, of which the solids content is l·2 Mt.[34]

## 10.6 ECONOMIC APPRAISAL

As with many other forms of energy provision, biofuel production cost estimates are crucially dependent on various assumptions made by the calculator, such as whether or not to allow for byproduct or waste disposal financial credits, for example. Furthermore, each individual production system will be different in some respect, whether in terms of scale, intensity, resource density and certainly location. Add to this the fact that few biofuel production systems have been commercially tested in practice for any appreciable length of time, making component amortisation and technological reliability determinations little more than 'guesstimates' at this stage.

In the previous sections, the economic viability, or otherwise, of the various biomass technologies operating under UK conditions have been commented upon. Two more detailed case studies from Carruthers and Jones[39] on the combustion of straw and the anaerobic digestion of piggery waste followed by the combustion of the biogas are presented in Tables 10.3 and 10.4. The final costs are given in terms of effective or useful energy as heat. But clearly, the economics pertaining in 1983 were different from those at today's oil price levels, and this has resulted in the shelving of at least one envisaged straw burning system.[40]

In the particular case of wood chip combustion at present oil prices, this is said[41] to 'become economic if one or more of the following factors apply:

(1) the price of the competing fuel exceeds 25 p per therm;
(2) the annual heat load exceeds 50%;
(3) special factors apply, such as urgent need for boiler replacement, or for cleaner flue emission'.

**Table 10.3 Economic breakdown of heat production via the combustion of straw (1983 data)**

| | | | |
|---|---|---|---|
| **Feedstock production** | | | |
| *Output* | | | |
| 2·5 t straw (89% DM) per hectare per year | | £/ha | £/t |
| *Costs* | | | |
| Variable costs: | tractor fuel[a] | 1·60 | |
| | baler twine | 3·30 | |
| Machinery depreciation and repairs: | | | |
| | baler[b] | 5·67 | |
| | bale accumulator[b] | 0·68 | |
| | trailer[c] | 3·30 | |
| | tractor[d] | 9·36 | |
| Labour[e] | | 13·39 | |
| **Total** | | **37·30** | **14·92** |
| **Combustion** | | | |
| *Output* | | | |
| 475 GJ per year[f] | | | |
| | | £/year | £/GJ |
| *Costs* | | | |
| Boiler depreciation and interest[g] | | 500·0 | |
| Labour[h] | | 226·38 | |
| Total | | 726·38 | |
| Straw production costs (49 t) | | 731·08 | |
| **Total** | | 1 457·46 | 3·07 |

[a] *10 litres/ha at £0·16/litre.*
[b] *100 h/year at 0·9 h/ha.*
[c] *200 h/year at 3·15 h/ha.*
[d] *1000 h/year at 4·05 h/ha.*
[e] *5·8 h/ha at £2·31/ha.*
[f] *60% combustion efficiency.*
[g] *60kW boiler—£2700 (including chimney) depreciated over 12 years at 15% interest.*
[h] *2h/t at £2·31/h.*

Comparative costs of conventional fuels in the UK at this time (1983) in terms of effective energy were (£/GJ): fuel oil, 4·83–5·80; coal, 4·00–6·31; natural gas, 3·20–6·99; electricity, 7·61–15·44; propane, 6·25–6·88. Thus the effective energy for straw at £3·07/GJ and piggery waste at £4·65/GJ compares well economically, provided that there is a local on-farm demand for the heat produced. Different assumptions regarding depreciation of equipment, interest rates and so forth will provide different costs and so one-off calculations must be seen in their true perspective. Cost ranges are more likely to be meaningful than is an individual cost of a biofuel for a particular location and set of circumstances.

United States estimates for a number of conversion routes are given in Table 10.5.[42] The processes are graded as to their comparative cost per unit of energy produced, with pyrolysis of wood to char set as unity. Some indication is given of the wide variations in costs perceived from essentially the same process operating in different situations. It must also be remembered when making comparisons, however, that a joule of ethanol or electricity is more valuable practically than, for instance, a joule of charcoal. Not surprisingly, the cost per unit of energy output tends to increase with increasing process complexity. Where waste products are not used as the biomass feedstock the process is less likely to be economically favourable in temperate climes.

Finally, it has been argued that the cheapest way to generate electricity from any of the renewable energy resources is to use refuse as the feedstock. Urban Waste and Power Ltd of the UK are about to build a power station utilising finely ground Liverpool refuse which could supply 24 MW to the national grid by 1990.[43]

## 10.7 ENVIRONMENTAL ACCEPTABILITY

Biomass fuel technologies may be either environmentally beneficial or otherwise—much

**Table 10.4 Economic breakdown of heat production via the evolution and combustion of biogas from piggery waste (4000 pigs)(1983 data)**

| | | |
|---|---|---|
| **Gas production** | | |
| *Output* | | |
| 1·82 TJ biogas per year[a] | £/year | £/GJ |
| *Costs* | | |
| Long-life digester equipment[b] | 4 500 | |
| Short-life digester equipment[c] | 2 245 | |
| Maintenance | 750 | |
| **Total** | **7 495** | **4·11** |
| Effective cost (gas production only)[d] | | 4·90 |
| **Gas combustion** | | |
| | £/year | £/GJ |
| *Costs* | | |
| Boiler depreciation and interest[e] | 568 | |
| Maintenance | 400 | |
| Total | 968 | |
| Gas production cost | 7 495 | |
| **Total** | **8 463** | **4·65** |

[a] 320 $m^3$/day gross, less 35% for digester function and losses=208 $m^3$/day net×350 days/year=72 800 $m^3$/year at 25 MJ/ $m^3$.
[b] £22 500 depreciated over 10 years at 15% interest.
[c] £7500 depreciated over 5 years at 15% interest.
[d] Assuming 84% combustion efficiency.
[e] 64 kW boiler at £48/kW depreciated over 12 years at 15% interest.

**Table 10.5 Comparative costs for various biomass conversions per unit of energy output (1979 data)**

| Process | Comparative cost rating |
|---|---|
| Wood to char and oil for direct combustion | 1–1·3 |
| Steam production from wood via direct combustion | 1·1–1·2 |
| Medium-energy gas production from cattle manure via anaerobic digestion | 1·5–3·3 |
| Wood to oil via catalytic liquefaction | 2·0 |
| Substitute natural gas production from cattle manure via anaerobic digestion | 2·2–5·3 |
| Substitute natural gas production from wood gasification (oxygen blown reactor) | 2·4–2·9 |
| Wood to methanol via gasification (oxygen blown reactor) | 2·9–3·7 |
| Ammonia from wood via gasification (oxygen blown reactor) | 3·3–7·0 |
| Wheat straw to medium-energy gas via anaerobic digestion | 4·9–8·8 |
| Electricity generation from wood via direct combustion | 6·1–6·9 |
| Algae to ethanol via acid hydrolysis and fermentation | 7·0–9·9 |
| Corn straw to ethanol via enzymatic hydrolysis and fermentation | 7·4–16·2 |
| Kelp to substitute natural gas via anaerobic digestion | 7·7–8·3 |
| Sugarcane to ethanol via fermentation | 11·9 |
| Wheat straw to ethanol via enzymatic hydrolysis and fermentation | 19·5 |

depends on the attitudes and legal requirements of their exponents. Plants are a diffuse energy source and require much human labour in their collection, thus increasing the possibility of occupational accidents in both forestry and agricultural operations. Direct combustion of biomass, particularly in domestic stoves, releases large quantities of particulates and polycyclic hydrocarbons but produces much less sulphur dioxide than other solid fuels. Animal slurry may be polluted with heavy metals and bracken appears to have carcinogenic properties if ingested in quantity, and it is by no means certain that such chemicals are rendered inactive by anaerobic digestion.[32] The situation is thus a complicated one, though it can be said unequivocally that biomass combustion is less polluting than fossil fuel combustion, notably in the case of coal.

The Organisation for Economic Co-operation and Development[44] has summarised the environmental, or potential environmental, effects of biofuel production systems very succinctly and recognises the complex ecological analysis required should such systems greatly expand. The pollution resulting from oil-based fuels would tend to be reduced. Such pollution (including acid rain) stems from CO, $CO_2$, NO, $SO_2$ and lead emissions. Tests carried out with engines and vehicles running on alcohol or vegetable oils show that the levels of such emissions are reduced, and even totally eliminated in the case of lead.

However, biofuels produce aldehydes or formaldehydes in greater quantities than does gasoline. Their toxicity under the operating conditions envisaged has not been established, but research is continuing in this area. The use of an alcohol blend has gained ground as a result of the regulations to reduce the lead content of petrol now gradually being introduced in the various countries of the OECD.

Pollution caused by animal wastes is a matter of increasing concern and the regulations tend to lay down specific requirements for storage, treatment and spreading. Biogas production accordingly (but arguably) seems an economic means of treating effluents. The anaerobic fermentation process in fact cuts down pollution by effluents, primarily by appreciably reducing odours and the number of pathogenic organisms which are present or may later migrate into the water table. It also improves the sedimentation rate so that solids can be obtained which are easily used as fertilisers, a particular advantage when the farm does not have large enough areas for liquid spreading (feed-lots). Analyses have shown that the fertilising value of these residues does not differ significantly from that of the effluents (the nitrogen in particular is retained). Furthermore, landfill technology is primarily a waste disposal operation in which methane recovery can be considered a bonus where it is economic to do so.

The energy use of biomass may on the other hand have negative effects at the agricultural level or in the conversion stage, some of them (brought about if there were a substantial growth of bioenergy) being difficult to foresee. There may be some risk of excessive use of wastes, such as straw, preventing certain substances required by the soil, in particular for its physical structure, being returned to it. There is also reason to fear that over-exploitation of certain marginal land would not allow the necessary minimum fertility of the soil to be maintained and would in some cases expose it to the risk of erosion by destroying the necessary minimum cover. It is certain that additional pressure will be put on fragile, hitherto little-used land and this risk cannot be ignored. Moreover, direct combustion of wastes and residues can give rise to problems, notably air pollution. In this connection, straw-fired boilers have recently made considerable progress (the burning of straw in the field being, in any case, a far worse source of pollution).

However, the risks of pollution are considerable in certain conversion plants. This is particularly true in the case of those treating sugar beet and cane. Thus, each tonne of cane treated to produce alcohol leaves on average 910 litres of residual liquors (430 $m^3$ per hectare planted) which are highly polluting, in particular having a BOD (biological oxygen demand) of $5–10\times10^3$ ppm and a high metal content (in particular potassium: from 1 to 4·6 kg $K_2O$ per $m^3$). In terms of BOD, 2 litres of residual liquors are equivalent to one person a day. In Brazil the production of $10{\cdot}7\times10^9$ litres of alcohol in 1985 would imply the production of 140 million $m^3$ of liquors. Some of this can be used to produce biogas, but this solution is only of interest in the case of beet (the effluent from methanisation remains a pollutant to some extent, moreover, owing to its high potassium content). Where sugar cane is concerned, the distilleries always have an excess of bagasse (about 30%) and do not need biogas energy. The liquors can also be used as a substrate for the production of monocellular proteins or the preparation of animal feed additives. The simplest technique probably remains lagooning—its impact on alcohol production costs is very limited, but it is not completely effective (there is a risk of groundwater pollution). However, a new process, the Biostil process, has just been developed in Sweden whereby the liquors produced can be reduced from 10–15 litres per litre of alcohol to less than one litre per litre of alcohol.[44]

Finally, we come to a controversial environmental issue—the so-called 'greenhouse effect'. This phenomenon results from the fact that carbon dioxide allows short-wave sunlight to pass through our atmosphere but effectively blocks the return of the Earth's long-wave or infra-red radiation back into space. Therefore as more and more carbon dioxide is emitted as a result of increased fossil fuel combustion, its build-up in the atmosphere causes the Earth's temperature to rise. Warmer Earth temperatures would greatly alter the world's agricultural regions, weather patterns, coastlines, and even wealth distribution. It has been variously estimated that, with greater and greater fossil fuel burning, the atmospheric concentration of carbon dioxide will have risen by 300–700% by the year 2200. This compares with a smaller but significant rise of 25% over the last 100 years. The best way to deal with the greenhouse effect threat (though some scientists maintain that the threat does not exist) would be to drastically cut down on fossil fuel use as our main energy supply and insist on alternatives which do not produce carbon dioxide. This may well happen anyway, but the planting of more and more trees which, of course, utilise carbon dioxide in photosynthesis, will aid in carbon dioxide mopping-up operations and at the same time provide a fuel source which, when combusted, releases only the amount of carbon dioxide which it fixed from the atmosphere originally.[45]

## 10.8 COMMERCIAL PROSPECTS AND EXPORT POTENTIAL

It must be stated that the UK is significantly behind most other developed countries in the development and commercialisation of biomass technology equipment, and this applies virtually in every case, whether biomass-fired boilers, digesters, gasifiers, and so forth. There are only a few farm-scale biogas plant manufacturers in the country and around 20 boiler manufacturers, most of whose products are aimed at refuse-firing, though an increasing number can handle wood chips and even straw. However, there are several dozen wood-fired boiler companies on the European mainland, many of which have British subsidiaries. Countries such as France, Sweden, the USA and Brazil now lead the world in bioethanol fermentations, and so commercial prospects in the whole area of biomass technology for UK companies, both in the domestic and overseas markets, are poor, at least for the present and immediate future.

## 10.9 INSTITUTIONAL BARRIERS

Apart from the Department of Energy's low funding of biofuels R & D compared to other countries and other energy sources (a point already made), the most significant institutional barriers or constraints to a substantially expanded UK biomass programme are connected with the change in land use such a strategy would inevitably bring. This, according to Carruthers and Jones,[39] especially applies to the development of forestry fuel crops on presently unafforested land. Constraints on land transfer may result from direct ownership of the land, tenancy, or legal rights of others. Also, some exotic plant species are banned under the Wildlife and Countryside Act, 1982.

Conservation areas such as National Parks, Sites of Special Scientific Interest, Nature Reserves, and so on, are all unlikely to be used for biofuel production, even if it could be shown to be profitable. Additionally, Water Authorities have expressed concern at the impact of land use changes in water catchment areas. However, new initiatives, in both the UK and the EEC as a whole, should favour increased production of biomass for energy as a result of changes in land use policy.

## 10.10 CONCLUSIONS

Biofuel production in the UK is small, perhaps 1 % of primary energy consumption, even by Western standards, yet could be significantly greater. The Department of Energy, not particularly generous in its funding of biomass development as an energy source, still considers five technologies as being cost-effective in 1988: solid fuels from dry domestic, industrial and commercial wastes; solid fuels from straw; solid fuels from wood wastes and forest thinnings; gaseous fuels from wet wastes (sewerage and industrial effluent); and gaseous fuels as landfill gas; energy forestry is considered to show much promise but still requires further development. When summed, 264 PJ (8·8 Mtce) of heat energy are economic now from UK biofuels according to the Department of Energy, with perhaps 588 PJ (19·6 Mtce) by 2025. These figures respectively represent just over 3% and 7% of current energy demand in the country, but are conservative in the opinion of many scientists working in the field (Hall,[12] for example, quotes a potential figure of 10%).

Fuel ethanol fermentations are not included in this overall biofuel assessment, but with arable land becoming available for other uses as it is taken out of food production, the cultivation of fuel crops such as sugar beet, fodder beet, the Jerusalem artichoke and cereal crops might become economically attractive, especially as North Sea oil reserves diminish. At present the UK is very rich in fossil fuel reserves, but this situation, particularly with respect to oil and natural gas, will not last far into the next century, and it is hoped that government recognises this fact and is prepared to invest in our energy future, when liquid fuels will be at a premium. The energy economy of the country in 2025 will be significantly different from that in 1988, and the great versatility and diversity which biomass technologies have in their ability to produce a whole range of solid, liquid and gaseous fuels, heat and electricity will only be neglected to the detriment of our future available national energy supply sources.

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# Part 3

# SYSTEM CONSIDERATIONS

# Section 11

# Environment

## 11.1 INTRODUCTION

Before consideration can be given to the environment, it is essential to define exactly what is meant by the term 'environmental pollution'. In practice, it can take many forms, usually specific to a particular source. In general, however, it is the effect of any human activity on our world which is considered to be detrimental.

In the last few decades, coal- and oil-burning power stations have come under increasing attack for causing environmental pollution such as acid rain and the 'greenhouse effect'. Nuclear power stations had been accused before, but particularly after, the Chernobyl disaster of causing generally increased radiation levels and outbreaks of leukaemia in their vicinities. Inevitably, attention has focused on alternatives to these energy sources for producing electricity in the hope of reducing environmental pollution. The renewable energy sources, in particular, have received increasing attention because, as they do not have a fuel cycle, they are regarded as environmentally more benign.

It is the purpose of this Section to summarise the environmental effects of each form of renewable energy source currently being used, or under review, for electricity generation. In this way, comparisons can then be made between renewable energy sources and conventional sources. It must be pointed out, however, that the environmental effects of the mining and processing of materials for the construction of the actual energy extracting devices have not been included as these are common to all energy conversion systems. Similarly, the energy content of the conversion systems has not been considered. The only other major factor to be neglected is that of human displacement.

## 11.2 PRESENTATION OF INFORMATION

Descriptions of the actual technologies used by the renewable energy sources will be found in other Sections of this Report. To prevent duplication, and to present the information in an easily assimilable form, a tabular format has been used here (Table 11.1).

Basically, the 15 different technologies presented in this Report head each column of the table. The major environmental effects considered, the rows of the table, are those effects these technologies have on Land, Water, and Air, together with Wastes, Working Fluids and Gases, General Effects, and Catastrophes. Each major effect is then subdivided.

To present the information in a comparative way, each box on the table is occupied by an L (large effect), M (medium effect), S (small effect) or 0 (not applicable). Footnotes are used for qualification and further explanation.

Although this comparison is qualitative, it is important to prevent it being too subjective. This can most easily be achieved by comparing the renewable technologies with conventional fossil-fuelled or nuclear power stations of comparable output. Thus, the final (16th) column of the table refers to conventional power stations. Some of the categories, for example navigational hazards, do not apply to these stations and thus a '0' is appropriate. For the others, either S, M or L has been chosen and inserted so that it is not necessary to further sub-divide the entries, i.e. L+, L++, etc. Only one extra row is required, under catastrophes, to cater for incidents such as Chernobyl.

**Table 11.1 Large (L), medium (M), small (S) or no (0) environmental effects of renewable energy sources**

| Environmental effects | Wind | | Tidal | Hydro | | Wave | | Geothermal | | OTEC | | Solar | | | Bio-mass | Oil, Coal, Nucl.[a] |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | Land based | Off shore | | Large scale | Small scale | On shore | Off shore | Hot dry rocks | Aqui-fers | On shore | Off shore | Solar pass-ive | Therm-al act-ive | Photo volt-aic | | |
| *Land* | | | | | | | | | | | | | | | | |
| Land use/sterilisation | S[b] | 0 | 0[c] | M | S | S | 0 | L[d] | S | S | 0 | S[e] | S[e] | S[e] | S | M |
| Land erosion: | | | | | | | | | | | | | | | | |
| construction | S | 0 | S | S/M | 0 | S | 0 | S | S | S | 0 | 0 | 0 | 0 | 0 | M |
| maintenance | S | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | M |
| Seismicity/subsidence | 0 | 0 | 0 | S[f] | 0 | 0 | 0 | S | S | 0 | 0 | 0 | 0 | 0 | 0 | M[g] |
| *Water* | | | | | | | | | | | | | | | | |
| Wave alteration/ coastal erosion | 0 | 0/S | L | 0 | 0 | S | M | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Navigational hazards | 0 | S[h] | S | 0 | 0 | 0 | M/L | 0 | 0 | S | S | 0 | 0 | 0 | 0 | S[i] |
| Water levels/flow patterns/velocity/ sediments | 0 | 0 | L | L | S | 0 | S | S | S | 0 | 0 | 0 | 0 | 0 | 0 | M |
| Drainage | 0 | 0 | M | L | 0 | 0 | 0 | S | S | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Salinity changes | 0 | 0 | M[j] | 0 | 0 | 0 | 0 | S | S[k] | S | S | 0 | 0 | 0 | 0 | 0 |
| Fish & marine biota, biofouling | 0 | S | M[j] | S | 0 | S | S | 0 | 0 | S | S | 0 | 0 | 0 | 0 | 0/S |
| *Air* | | | | | | | | | | | | | | | | |
| Bird hazards | S | S | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | S |
| Aesthetics[l] | L | S | S | S | S | S | 0 | M[d] | S | S | 0 | S | S | S | 0/S | L |
| Acoustic noise | S | 0 | 0/S | S | 0 | S | 0 | S | S | S | 0 | 0 | 0 | 0 | 0[m] | M |
| $CO_2$ enrichment, $O_2$ depletion | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | S | S | 0 | 0 | 0 | 0[n] | L |
| *Wastes working fluids and gases* | | | | | | | | | | | | | | | | |
| Solid | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0[p] | L[a] |
| Liquid | 0 | 0 | 0 | 0 | 0 | 0 | 0 | M[q] | L[q] | S | S | 0 | 0 | 0 | S[m] | L[a] |
| Gaseous | 0 | 0 | 0 | 0 | 0 | 0 | 0 | S | S | 0 | 0 | 0 | 0 | 0 | S[m] | L[a] |
| Industrial | 0 | 0 | 0[r] | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | S[m] | L[a] |
| Sewage | 0 | 0 | 0[r] | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0[p] | 0 |
| *General* | | | | | | | | | | | | | | | | |
| Endangered species | S | S | S | S | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | M |
| Intensive culture | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | S[s] | 0 |
| Physical presence | L | 0 | L | L | S | S | 0 | S/M | S | S | 0 | 0 | 0 | 0 | 0 | L |
| e–m interference | S | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | S | 0 | S |
| Failures of rotating equipment | S | S | S | S | 0 | 0 | 0 | S | S | 0 | 0 | 0 | 0 | 0 | 0 | L |
| Fire | S[t] | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | S | S | S | S | L |
| *Catastrophes* | | | | | | | | | | | | | | | | |
| Dam burst | 0 | 0 | S | L | S | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Sea device breakage | 0 | S | 0 | 0 | 0 | S | M | 0 | 0 | S | S | 0 | 0 | 0 | 0 | 0 |
| Tracking system failure | S | S | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | S[u] | 0 | 0 |
| Other | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | L[v] |

[a] These have been included purely for illustrative purposes. No attempt has been made to differentiate between them.
[b] If public access or farming is permitted up to base of windmills, otherwise L.
[c] No 'land' is occupied by the barrage itself but mud-flats, etc., could be permanently covered by water instead of periodically uncovered.
[d] Mainly due to number of cooling towers needed because of low thermal efficiency, but no fuel storage areas are required.
[e] Frequently attached to existing buildings, otherwise M/L.
[f] But could be large in areas of high geological activity.
[g] Only by fuel extraction.
[h] These would probably be located in shallow sea where they would not form a hazard.
[i] Possibly during the importation of coal/oil.
[j] Still under investigation; this is a generally accepted view.
[k] However, salinity changes are eliminated where reinjection is practised.
[l] This category is extremely subjective and dependent on individual point of view.
[m] Dependent on the technology.
[n] Provided there is no net depletion of resource.
[p] Since much of the biomass source is itself solid waste, the waste after conversion must be less.
[q] Working fluid (water) generally contains a high concentration of dissolved salts, but no waste water arises if reinjection of the fluid to the aquifer is arranged.
[r] Tidal plant may disturb existing arrangements but is not itself a pollutant.
[s] Dependent on whether energy crops are grown.
[t] Lightning.

[u] L if satellite-borne device as has been proposed for the 21st century.
[v] Radiation escape as at Chernobyl.

## 11.3 CONCLUSIONS

From the table it can be seen that for no technology do the entries (each column) match those of the conventional plant. This tends to confirm the belief expressed earlier that the renewable energy sources are environmentally more benign. There is only one category (each row) where the renewable technologies are comparable with, or worse than, the conventional and that is Land Use/Sterilisation. In view of the low energy density of most of the renewables that is not unexpected.

It must be asked, therefore, why there has not been a greater exploitation of the renewable energy sources. It can be argued that the overall environmental attractiveness of the renewable energy sources is not adequately treated by the traditional market pricing mechanism and thus they have failed to achieve adequate market penetration. This review of the environmental effects of renewable energy sources is, indeed, purely qualitative. However, Hohmeyer has shown that some, at least, of the external effects of energy systems can be adequately quantified or monetarised. He identified three principal areas where these external effects should be considered: environmental effects, including effects on human health; general economic effects, such as changes in employment; and public subsidies, direct or indirect. He concluded that the external benefits of wind and photovoltaic energy systems were of the same order of magnitude as the market price of conventionally generated electricity, and similar to the external cost of conventional power stations.

Thus, the net effect of not taking these social costs/ benefits into account (and several major factors, such as the environmental effects of all stages of the fuel cycles, were neglected in Hohmeyer's study as they have been here) was shown to discriminate against the renewable energy sources and favour conventionally generated electricity. For example, on the Severn tidal power scheme, the positive benefits such as flood prevention, increase in long-term employment and increase in land values can be very substantial indeed, though not necessarily to the benefit of the promoter or operator involved.

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# Section 12

# Integration of Renewable Energy Sources in Electrical Power Systems

TAYLOR, R.H., *Alternative Energy Sources—for the centralised generation of electricity,* Adam Hilger, 1983.

## 12.1 INTRODUCTION

Power systems using so-called conventional sources of electricity—coal, oil, and nuclear, for example—have evolved in such a way that the demands of consumers can be met with very high levels of reliability.

Conventional generating plant is potentially capable of continuous operation and at the same time is highly concentrated in nature. Generating systems have evolved so that they are frequently large, with total installed capacities of many tens of gigawatts (GW), although there are many systems, often found in islands, which are much smaller.

The special characteristics of the renewable sources are concerned with their often greater variability; for example, the wind does not blow all the time. The greater diffuseness and geographical location of these sources need also be taken into account. These characteristics will create new problems for system planning and operation if significant capacities are installed. The nature of the problems, however, vary greatly according to system size.

In many respects, the problems are greatest for small systems. A substantial part of the maximum demand may then be supplied by just one or a few units—for example, a small cluster of wind turbines—on a system with just one or two diesel generators. Complex control strategies may be required in such circumstances if the renewable sources are to give substantial savings.

Generally, the operational problems are less severe for larger systems. This is partly because there are more thermal generators on the system. This means that individual units have to be cycled less frequently, and more tend to be online at any one time, so that there is more system inertia and more regulating capacity making it easier to maintain system frequency and voltage. Also, larger systems may have greater diversity in the renewable source; short-term fluctuations at different sites will be smoothed out, larger-scale variations will be less rapid, and the frequency with which the renewable source is producing extremes of power may be greatly reduced. Larger systems are also more likely to have some hydro or storage capacity.

Offset against this is the fact that on larger systems, the consumers may expect a much higher quality of supply, so that control needs to be finer, and the fact that the renewable source is competing against much cheaper energy, provided by large and efficient thermal generators.

A further complication arises from the possibility of interconnecting power systems. There is usually some benefit from this, either because one system has access to cheaper power than another, or simply to pool peaking capacity to meet the risk of shortage on either system. These advantages may well be increased if large capacities of renewable energy are installed. Effectively, interconnection increases the diversity of all the resources; spread over Europe, for example, wind energy would be a very reliable power source. It is evident that the optimum use of such resources in any European sense could involve increased levels of electricity trade, and a relaxing of current agreements stipulating that countries should not rely on neighbouring systems for reserve capacity.

Since the choice of an energy source is made ultimately on economic grounds, the integration of energy sources into a system is not purely a technical matter, and all relevant cost variables must be taken into account, otherwise the wrong conclusions may be drawn.

The supply of heat as well as electricity may be part of the business of the utility, and so it may be necessary to take this into consideration when planning the system.

This section considers how these characteristics affect the integration of new and renewable energy sources into electricity generating systems. The interdependence of economic and technical factors is stressed.

## 12.2 POWER SYSTEM OPERATION

### 12.2.1 Introduction

Once an electricity generator has been connected to the system, it is normally operated in a 'merit order' in which the cheaper the plant is to run, the more it is required to operate. Renewable sources such as wind power are usually very cheap to run, so their output will be used whenever available. Therefore they act as a 'negative load', reducing the net demand upon thermal sources and so saving fuel.

The output from many renewable sources varies over time, and it may not be very predictable—but the same is true of electricity demand. Load on the CEGB system varies by a factor of up to 2 in its daily cycle, and so small amounts of an intermittent renewable source will not greatly change the situation. The CEGB estimates that the proportion of intermittent and continuous renewable sources could rise to 20% of the total electricity supplied without causing serious problems.

### 12.2.2 The merit order and load-duration curve

The generating plants on a system are ranked in a merit order of operating costs, in which generally plant with more expensive operating costs (fuel and other costs) are only called upon to run if all available cheaper units are already generating.

This is expressed very clearly by the load-duration curve (LDC). This defines the total duration for which load on the system lies above a given level within a given time period. An example LDC, for CEGB demand in the year 1984/85 is shown in Fig. 12.1. It shows, for example, that demand was never below 17 GW, that the maximum demand was around 50 GW, and that average demand was about 28 GW.

The figure also illustrates how plants can be notionally 'loaded under the LDC' in merit order, with plant grouped into tranches of similar unit types. Nuclear power, which has high capital cost but low running costs, is loaded to serve the baseload demand. At the opposite end of the merit order, gas turbines, which are cheap to build but expensive to run, serve only the peak demand.

Since the LDC is a plot of power against duration of supplying that power, the area under the curve represents energy supplied. The total area under the LDC is the total system demand for the period covered. The LDC is very useful for electricity supply analysis, and many aspects of renewable sources can be understood by looking at their impact on the 'net LDC'—the duration curve of demand minus renewable input.

The LDC, however, gives no indication of power system development over time, system reliability, the impact of plant unreliability on operating costs, or the dynamic aspects of system operation.

### 12.2.3 Thermal plant startup, ramp rates and part loading

Generating plant normally operates most efficiently and cheaply at full and constant load, that is, base load. Starting up, shutting down and load changes all incur additional costs, which are greater the more intermittent sources there are on the system, and the more variations in consumer demand. The way in which typical startup costs vary with plant type, and with the length of time offline, are shown in Fig. 12.2. As an indication of their importance, startup losses account for something over £100m/ year on the current CEGB system—maybe 3% of total operating costs.

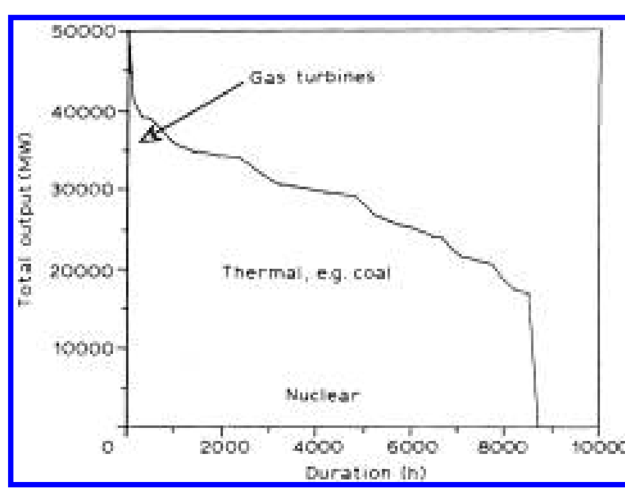


**Fig. 12.1.** 1984/85 load-duration curve (LDC) for CEGB system.

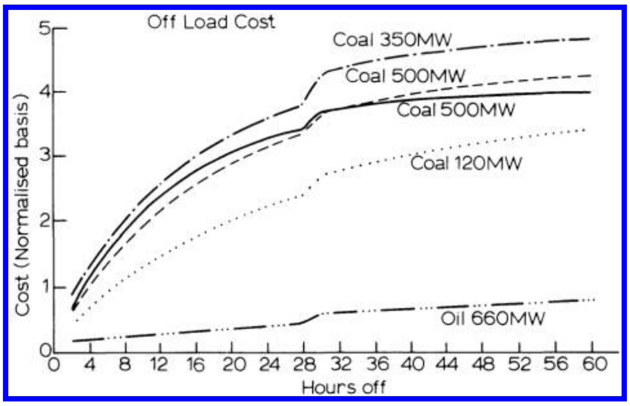


**Fig. 12.2.** Thermal unit start-up costs as a function of off-line time, for a range of thermal units. (Source: CEGB.)

For a more detailed discussion of such dynamic aspects of system operation and constraints on plant operation see, for example, Sterling (1978)[1] and Fenton (1982).[2]

Conventional thermal capacity cannot respond quickly to changes in demand. By comparison, gas turbines, even very large ones, are distinguished by their very rapid response, and can start up from cold in as little as 5 min. The response of hydro plant can be even quicker; the turbines at the 1800MW Dinorwig pumped storage scheme in Wales can be brought to full power within just 10 s from a state of spinning in air, and they can be powered from standstill within 1 min.[3] The penalties involved in repeated starts are relatively small.

Such considerations also set limits on how rapidly the output from thermal units can change—the maximum 'ramp rate'. Again this can vary a great deal between units, but typical figures for modern plant indicate that output can change by 3–5% per minute at most, some baseload units being restricted to under 2%.

The limits on ramp rates can be a significant constraint during the sharp morning pick-up in demand, and gas turbines sometimes have to be started up for short periods to maintain system frequency.

Part-load operation imposes different penalties. Typical fuel use as a function of plant output is shown in Fig. 12.3, the loss in efficiency being approximately linear over much of the operating range.

Thermal plants cannot generally be run stably at very low outputs for long. Technical limits for most large units lie in the range 30–50%. Lower levels could be achieved, but this would require substantial modifications. A discussion of part-loading capabilities is given in Fenton (1982).[2]

### 12.2.4 Power system control and operating reserve

All these factors set limits on the flexibility of power systems, and there must be operating reserves of various kinds to ensure that the system can meet all likely conditions.

The issues surrounding power system reserve are widely misunderstood, particularly with respect to the impact of renewable sources. This is largely because there are many different sources of reserve, with different characteristics and timescales, and several different reasons for holding reserve, which again point to different requirements and timescales. Table 12.1 is a summary of the various sources of variation and reserve.

The kinetic energy stored in the rotating masses of the generators is sufficient to meet variations on periods of less than about 10 s, but for periods from 10 s to a few minutes the main reserve is the stored steam in the boilers on thermal units.

The steam reserve in boilers does not last for more than a few minutes. Within this time, more power must be fed into the boilers if the higher output is to be maintained. If this capability is required, then some units must be run part-loaded, giving what is known as 'spinning reserve'. Extra power is then available rapidly, constrained only by the ramp rate; most of the spare is available within about 10 min.

Gas turbines provide the next source of power system reserve, one which overlaps with spinning reserve. As noted, most can be made available within 5–15 min.

Additional energy is not available until extra steam turbines on the system have been started up, either from hot standby in about an hour or so, or if they are cold it may take 8–10 h.

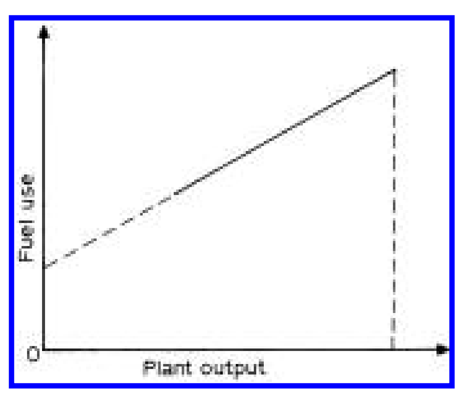


**Fig. 12.3.** Fuel use as a function of plant output for a typical British coal unit.

Table 12.1 Sources of variation and operating reserve on power systems

| | Timescale | Sources of variation | Sources of reserve |
|---|---|---|---|
| Class 1 | 10 s<br>2–3 min | Thermal plant failures<br>Transmission failures<br>Random demand variation | Inherent inertia<br>(rotor inertia + boiler pressure in steam turbines)<br>Some hydro/storage units |
| Class 2 | 2–3 min to 10–15 min | As class 1 + some demand uncertainty | As class 1 + ramping of thermal spinning reserve<br>Remaining hydro/storage<br>Gas turbines |
| Class 3 | 10–15 min to 1–1·5 h | Demand + plant variations | Any remaining spinning reserve and gas turbines |
| Class 4 | 1–1·5 h to 10 h | Demand + plant variations | Thermal steam plant startup (from various standby levels) |

Hydro plant can cover the whole range of reserve requirements, pumped storage playing an important role in substantially reducing the need for spinning reserve, limited in practice by the amount of storage capacity available.

Finally, a further source of reserve is in the ability of most generating units to run above the normal declared maximum capacity, although in general this reduces efficiency and in the long run may reduce lifetime and increase maintenance requirements.

If all sources of reserve have been exhausted, excess load can be shed by a reduction in system voltage and frequency.

Power systems cannot, of course, supply demand above available capacity for any significant time, nor survive major disruptions to the transmission network, which may cut out large capacities from part of a network at a stroke—the cause of the most famous blackouts in developed grid systems. But with the various sources of reserve outlined, generation on well-developed power systems is more robust and flexible than is often assumed.

Beyond the short to medium time horizons, utilities may have other measures which can be called upon, such as 'standing reserve' which is available at a few days' notice, or which could in emergency be made ready over a period of weeks to months. In addition, there may be transmission links with neighbouring systems, such as those between Scotland and England.

### 12.2.5 The potential role of load management and tariff incentives

For larger penetrations of intermittent renewables, the system integration costs could be reduced by the use of modern electricity load management. Techniques which have been in use for a number of years such as offpeak, maximum demand and interruptible tariffs have had substantial effects on the daily load curve which is now much flatter and less peaky. Over 2 GW of demand on the CEGB is regularly removed from peak times by arrangement with large consumers, resulting in the need for less generating capacity, and the substantial increase in offpeak usage has raised the system load factor considerably, with consequent large savings, which can be shared with the customer.

The arrangements for load management which have been established for a number of years are by their nature somewhat inflexible and are not suitable for dealing with the rapid fluctuations which would occur with intermittent renewable sources. Pumped storage offers a highly effective method for dealing with such variations but its potential is limited by the number of sites which are economically available. However, the latest developments in load management can offer precise and rapid response to short term variations in the capacity available by automatic switching of, for example, space and water heating and refrigeration loads. These measures include the Radioteleswitch, now commercially available, and load management systems using power or telephone lines for communication. In the ultimate, advanced metering techniques could allow a 'spot price' to be transmitted to consumers, and regularly updated in line with system conditions, using meters which display the current price.

Such measures, coupled with improved appliance design and control measures used by the customer, could significantly alter the economics of renewable energy sources at larger penetrations.

## 12.3 POWER SYSTEM PLANNING

### 12.3.1 Interaction between system integration and economics

In correct modelling of the effects of system integration, it is necessary to ensure that all significant variables are included. A convenient checklist can be derived from consideration of all the costs and savings which will result from the introduction of new generating capacity. These costs and savings, summarised from Jenkin (1982)[4] are as follows:

*Costs*

- Capital cost of the new capacity, including interest during construction
- Direct and indirect transmission and distribution costs
- Fixed other works costs which do not vary with plant running and which may be expressed as an annual fixed charge per kW
- Variable other works costs which are dependent on plant operation and which may be expressed as a cost per kWh generated
- Fuel costs, if any
- Overheads
- Increases in fuel, fixed, variable and overhead costs of other plant

*Savings*

- Capital savings resulting from the capacity credit which may be attributable to the new generation source
- Fuel savings resulting from the reduction of load factor on other existing plant and the displacement of new plant
- Savings in fixed, variable and overhead costs of other plant

The difference between savings and costs is the net benefit which allows economic measures such as benefit/cost ratio, internal rate of return or payback period to be determined. The CEGB's term for net benefit is net effective cost, which is negative for a saving.

### 12.3.2 Capacity displacement and remix at higher penetrations

The marginal capacity value of intermittent sources inevitably falls as more is added, because the output from successive plants is correlated, in contrast to most conventional sources. The way in which it does so depends upon the whole distribution of output from the source. As the capacity rises, the probability of there being little or no output increasingly dominates the capacity credit and eventually determines the limiting thermal plant displacement.

For the CEGB system this figure may, however, be several gigawatts even for intermittent sources which have a significant chance of generating nothing. This is because the system requires a substantial planning margin of thermal plant over maximum expected system demand—the 24% currently used implies a margin of about 12 GW, due in roughly equal measure to load growth uncertainties and the effects of conventional plant unavailabilities. This figure can be reduced by several gigawatts if enough wind energy is introduced, for example, as there is still a good chance of meeting demand even on the rare occasions when peak load coincides with no wind energy.

The decline of capacity credit at higher system penetrations does not mean that the total capacity value also declines towards zero. This is because there is a capacity remix value, due to the change in optimal thermal plant structure as a result of having intermittent sources on the system.

The primary reason why the optimal plant mix changes is a simple load duration effect: with intermittent sources generating for some of the time, thermal units have to supply less energy than would otherwise be the case. Plants which have higher fuel costs but which are cheap to build therefore become more attractive relative to high capital-cost units. Consequently, there is less capital-intensive plant built, giving a net capital saving.

This effect may be amplified by operational factors; high capital cost plants are designed for baseload operation and often incur substantial start-up or part loading costs. The variability of wind power thus tends to reinforce the load duration effect of capacity remix.

In detail, the magnitude and value of capacity remix depends greatly on the characteristics and costs of the system, even for a simple 'target year' analysis in which the plant mix is fully optimised. It is complicated by the fact that, of course, changing the planned plant capacity also changes the system operating costs, so capital and fuel savings cannot be considered independently. A discussion for wind energy is given by Grubb (1987)[5, 6] where it is concluded that overall such effects are not likely to be very important except for high penetrations on systems with a large nuclear component.

Such conclusions are preliminary. The effects cannot be examined properly without a full generation-expansion analysis of system development over time which includes intermittent sources.

Finally, the fact that sources such as wind turbines can be constructed relatively rapidly also has important capital consequences. The major component in the uncertainties which determine the planning margin on the CEGB system is the error in load prediction. If wind turbines can provide an element of firm power within 2–3 years—perhaps with the aid of some peaking backup, if there is already significant wind on the system—this should in theory allow the planning margin to be reduced.

It should be noted that capacity issues are rarely as important as fuel savings. There may already be substantial capacities of old, inefficient plants, displaced by new investments. Even if the system does need extra new plants just to maintain system reliability, it may be cheapes t to build 'peaking' plants—typically gas turbines. Saving this at small penetrations is a useful addition, but hardly the critical factor in wind economics. Wind energy is valuable primarily because of its fuel savings and, like all other plants for meeting baseload demand, cannot be justified primarily in terms of capacity needs.

The most important point is that for any given system developing over future years, there is an optimum mix of all types of capacity which will give minimum total lifetime costs and so produce the cheapest electricity.

## 12.4 CHARACTERISTICS OF DIFFERENT RENEWABLES

### 12.4.1 General characteristics of electricity producing sources

The costs which need to be considered consist basically of capital, variable and fixed operating costs, and overheads. The savings result from fuel saved and the reduction in capital and other expenditure on other plant. These factors are outlined above in Section 12.3.1. In determining true costs and savings, consideration needs to be given to the following characteristics of electricity generators:

- Availability at times of high system demand
- Overall output distribution and average availability
- Existence of energy constraints (e.g. lack of water for hydro plant)
- Startup characteristics and controllability
- Degree of forced fluctuations
- Predictability of output
- Correlations in output/outages between different units
- Correlation between source availability and electricity demand
- Resource inhomogeneity and location
- Unit size and construction times

Each power source, whether conventional or renewable, is distinguished by different combinations of these characteristics. From the system planning or operational point of view, differences between different types of generating plant, including renewables, are of degree, not kind. Each characteristic is discussed below.

### 12.4.2 Particular factors

#### *12.4.2.1 Availability at times of high system demand*

This affects primarily the contribution which the plant makes towards system reliability. No plant is 100% reliable, so there is always a finite risk of failure. All plants will reduce the probability of system failure to some degree. Therefore all plants have a 'capacity value'.

#### *12.4.2.2 Output distribution*

The distribution of output from a power source affects its value in two ways. It will save other types of fuel, which may be nuclear, coal or oil. If wind power becomes available at the time of maximum demand it will save expensive distillate fuel for gas turbines; at other times when coal and nuclear plant are running, coal will be saved.

The variability of a generating source also affects the optimal investment in future plants. If a lowvariability renewable source has been added, a small amount of further thermal power will be able to generate at full load whenever it is available. If the highly variable source has been added, the new thermal source may sometimes have to be partloaded, or energy from the renewable source discarded. This may affect the choice of thermal investment.

#### *12.4.2.3 Energy constraints*

Energy constraints mean that a source cannot be used to full available power at all times because the total energy generation in a given period is limited. This applies primarily to intermittent sources such as wind or hydro plant; it may also apply to thermal plants if there is interruption of fuel supply.

*12.4.2.4 Startup characteristics and controllability*

Renewable sources on a large system will normally be operated to full available capacity. Occasionally, however, it may be necessary to run renewable sources at less than available capacity, when they would be able to contribute to reserves. This would have a value to the system.

*12.4.2.5 Forced fluctuations*

The variability of individual sources can be usefully expressed as a coefficient.[7] If variability is defined in the dynamic sense as the annual average hourly rate of change of power divided by the average power generated per day, where only positive increases are considered, then typical values are given in Table 12.2.

Two-way generation would not greatly decrease the total tidal variability, there being two bursts of power in every tidal cycle up to about half the power of an ebb-generation scheme. However, combining out-of-phase schemes could greatly reduce the variability. Wave energy varies less rapidly than wind energy. The figure here is particularly small due to the relatively low power rating of the designs considered for large-scale wave generation.

*12.4.2.6 Source predictability and operating reserve*

The requirement for operating reserve on power systems has been discussed in Section 12.2.4. Clearly, if an individual source adds to reserve requirements on the system because its output cannot be well predicted, its value may be reduced.

Enough rapid reserve must be available to protect the system against the possibly sudden failure of a conventional plant. Because sudden failure is a rare event, however, the probability of two units failing simultaneously is negligible and the reserve capacity required is equal to the largest single infeed to the system.

Several of the renewable sources come in relatively small units. Short term fluctuations at different sites would occur independently and tend to cancel each other out, so they would not add to the existing requirement for very rapid reserve even if deployed in large numbers (see Appendix). But on longer timescales the output of individual units is correlated and so the unpredictable variation may be significant over longer periods, perhaps enough to swamp the small errors involved in forecasting load a few minutes to hours ahead.

Significant storage on the system reduces or eliminates the need for thermal spinning reserve and so reduces the reserve costs incurred.

The predictability of the intermittent sources is not yet well enough known for reserve requirements to be determined with accuracy for larger penetrations. An upper limit to reserve penalties can be set by choosing a simple rule-of-thumb forecast, such as 'persistence' forecasting in which it is assumed that the current output will persist indefinitely. For wind energy widely dispersed in England and Wales, this would produce a penalty rising from zero at very small capacities (when the wind variations would be drowned in those of the load) up to about 10% of expected fuel savings if the wind capacity were large enough for wind prediction errors to drown those of the load. This total is split roughly equally between the intermediate (15 min to 1 h) and longer term reserve requirements.

Although the penalties identified are small taken individually, their combined effect could become quite significant if large capacities of intermittent sources were ever considered. In such circumstances an additional and major source of loss would be the need to start discarding energy from the intermittent source when the power output was large and demand low, in order to maintain sufficient thermal power generation for system reserve and control purposes.

In practice for the large integrated power systems in Britain it is unlikely that such levels of intermittent plant—

**Table 12.2 Typical coefficients of variation for electricity demand and some intermittent renewable sources (annual average)**

| | Average MW/h increase / Daily MW mean power |
|---|---|
| Electricity demand | 0·5 |
| Wind energy (in one major region) | 1·8 |
| Wind energy (dispersed over England and Wales) | 1·3 |
| Tidal energy (standard single ebb-generation scheme) | 6·3 |
| Wave energy (1 site data—south Uist) | 0·8 |

tens of thousands of megawatts—will be reached in the foreseeable future. However, this is not the case for small isolated systems such as on some islands, and it may also apply to isolated parts of the distribution network connected to the rest of the system by weak links.

#### *12.4.2.7 Correlations in power output*

In conventional plant, unit failures may usually be considered independent of each other and of system demand. In contrast, the output from many renewable sources will be closely correlated between sites. Then, additions of capacity cannot be considered in isolation; the impact on grid reliability, net power fluctuations and uncertainty will all be dependent on the amount and distribution of other units already in place.

#### *12.4.2.8 Correlation with electricity demand*

Correlations with electricity demand may affect the economic value of a source. A distinction may be drawn between 'seasonal' correlations and short term correlations.

Most conventional thermal units show some seasonal correlation with demand by virtue of maintenance scheduling, which is arranged as far as possible for the low demand summer months. Renewable sources, notably wind and wave power, also have a substantial positive seasonal correlation. Other sources, such as solar, would have a negative correlation in Britain. In addition for some renewable sources there may also be short term source-demand correlations due to common causes such as weather or diurnal cycles.

The impact of positive source-demand correlation is to increase the value of fuel savings from a source and increases its contribution to system reliability. Short term positive correlation in particular could give a source a very high capacity value.

#### *12.4.2.9 Resource inhomogeneity and location*

To a good approximation, conventional electricity sources can be assessed at a fixed cost per unit capacity. In contrast, the economics of most renewable sources depend on the density of a natural energy flow, which may differ greatly between sites. In exploiting such a resource, the cheaper sites will tend to be used first. To analyse the economics of large scale use, some attempt must be made to investigate the profile of resource density. This and other factors will also affect the location of a source.

#### *12.4.2.10 Unit size and construction time*

In addition, the planning margin of installed capacity over expected demand is partly determined by the uncertainty in demand growth over the period required for ordering and completing new plants. Renewable sources vary between the very large and very small; the latter could be mostly constructed in factory and installed within months. Clearly, the ability to deploy an energy source at short notice will be beneficial and may enable the planning margin to be reduced.

### 12.4.3 The nature of the interface

The nature of the interface between a renewable energy source and the system into which it is connected is determined by the characteristics both of the source and of the system. In a large system with strong connection points, the effects on the system will be global rather than local. In a small system, or one which is an isolated part of a larger system, the transient electrical effects must be considered. The general issues of connection of new sources of generation into a system were summarised by Walker (1984)[8] as including the following:

- Voltage limits
- Voltage disturbances
- Frequency limits
- Harmonic limits
- Power factor
- Recovery after clearance of faults
- Phase unbalance
- Firmness of new capacity
- Safety of personnel

All except the last of these is concerned with the quality of the supply. Recently Gardner (1987)[9] discussed in detail the question of the supply interface and showed how the above technical factors affect it. Although the discussion was concerned specifically with wind power, much of it applies to other renewables also.

**Table 12.3 Connection voltages for given power levels**

| Voltage (kV) | Typical range | |
|---|---|---|
| | Fault level (MVA) | Power level (MW) |
| 132 | 1 000–3 000 | 100–700 |
| 33 | 200–700 | 10–50 |
| 11 | 20–200 | 0·5–20 |
| 0·415 | 5–15 | 0·3–1·0 |

The voltage of the distribution system into which the renewable is connected is determined by the fault level of the installation which in turn limits the maximum size of the generating capacity: see Table 12.3.

## 12.5 IMPLICATIONS FOR DIFFERENT RENEWABLES

### 12.5.1 Biomass

The prevailing UK view until recently, summarised by Bevan and Long (1987),[10] is by implication that biomass fuelled plant will on the whole provide heat only rather than combined heat and power, although this picture is now changing. Such installations will have the same characteristics as other continuous sources. Small plants located far from major generating centres may have the advantage of reducing the need for transmission reinforcement which would otherwise be required.

Biomass, unlike other renewable energy sources, has a fuel cost which must be taken into account when assessing its overall economics. For this reason it will take its place in the merit order and may not be suitable for base load generation.

### 12.5.2 Hot dry rock geothermal energy

Geothermal plant would also provide a continuous supply of electricity, but since there is no fuel cost will therefore be used for base load supply. There may be advantages in that the need for transmission system reinforcement will be reduced if the Cornish geothermal resource is developed.

### 12.5.3 Large scale hydro

The annual load factor of a hydro system is variable and depends on the rainfall in the year. The only significant potential for new capacity is in Scotland. There are no short term problems and consequent costs of large penetration of hydro capacity, although sufficient spare capacity of other types of generation must be provided to cover years of low rainfall. The capacity credit of hydro plant is therefore between that of continuous and random renewables. Large scale in UK terms is relative only, the resource being comparatively small by comparison with that available in some other countries. These characteristics make the economic assessment of hydro plant complex.

Because of the location and nature of hydro power, transmission connections and environmental issues may pose major problems.

### 12.5.4 Small scale hydro

The annual load factor of small hydro, of output a few megawatts or less, is likely to be more dependent on rainfall since run-of-river plant will probably be predominant. This is because the normal river flow is the main source of water, and there will be smaller reserves of water than in installations with large reservoirs supplied directly from catchment areas. The capacity credit of small hydro is therefore likely to be less than that of larger scale plant.

### 12.5.5 Tidal power

This is a predictably intermittent source for which capacity credit can be relatively easily determined. However, because of the way the tidal cycle varies with time, the capacity credit of a tidal scheme is less than that of a random source of the same output. For example, the firm power output of the Severn Barrage has been determined as 1·1 GW for a maximum installed capacity of 7·2 GW, or 15%. This compares with an annual load factor which is estimated as 21% for a yearly output of 13 GWh. This apparent conflict with Swift-Hook's conclusion (2) is explained by the need to determine the firmness at the time of national peak, and not over the whole year.[11] The integration of small barrage schemes such as the Mersey is relatively easy, but a large scheme like the Severn (7·2 GW) would require substantial transmission provision and reinforcement at 400 kV.

The specific variability of tidal power could result in significant cost penalties: it has been estimated that around 8% of the ideal fuel savings from the Severn Barrage would be lost if there were no control over its output. However, some degree of control is possible, and this would substantially reduce the figure.

A mix of different tidal schemes, for example the Solway Firth and Morecambe Bay which are about 5–6 h out of phase with the Severn, would clearly together have higher capacity credits than a single scheme and therefore would have a beneficial effect on the economics.

### 12.5.6 Wave power

The only large wave power resource is likely to be off the west coast of Scotland. Its randomness is closely comparable to that of wind power and so the effects of large penetrations on the system would be similar. However, the location of a large wave power station in Scotland would require extensive transmission works at 400 kV which would add significantly to the cost of wave power. Small units (<1 MW) offer prospects for island supplies, particularly those which are shore mounted, or close inshore are likely to have lower civil and transmission costs.

Geographical separation will be an important consideration as it is for wind power.

### 12.5.7 Wind power

The effects of large penetrations of random sources such as wind power have already been discussed. These effects will be dependent on the characteristics of the rest of the system in which the wind capacity is installed. The effects on the CEGB will be quite different from those on the NSHEB system, and different for small isolated or quasi-isolated systems. There would be no significant transmission difficulties in integrating large dispersed wind capacity on land, but any large offshore wind power development would require its own transmission system offshore, onshore connection points and transmission reinforcement.

Capacity credit for wind power will be about equal to its winter load factor, which could be 30–40% depending on the machine rating. However, it is important to take into account long term climatic variations in assessing the firmness of wind power. Palutikof and Watkins (1987)[12] have shown, using a time series of wind speeds for 1898 to 1954, that energy output for a wind turbine on a poor year would have been less than half that of a good year. Clearly, estimates of the economic viability of wind power must take into account such variability.

### 12.5.8 Photovoltaic

Solar power from photovoltaic cells is predictably intermittent in climates which have a high incidence of direct sunlight, but is more random in temperate climates such as that of the UK because of the vagaries of the weather. Because photovoltaic generation is unlikely to form a significant proportion of UK capacity, its effects on the system need not be considered further.

The solar resource is not small in total, the intensity in Britain being about half that in the Sahara and concentrated in summer. However, there must be a dramatic fall in module costs if the technology is to be attractive in Britain.

### 12.5.9 OTEC

Ocean Thermal Energy Conversion would be a firm source of electricity and so would present no more difficulties in its system integration than any base load source. However, by its nature it will make no contribution to our electricity supply and so it need not be considered in a UK context

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## APPENDIX 12.1

### A case example: the integration of wind energy

Many of the issues considered in previous sections can be usefully illustrated with reference to wind energy. It is variable, unreliable, and only partially predictable. How does this affect its value?

At sufficiently low penetrations, we can see from Section 12.4 that the wind fluctuations are drowned out in load variations, so there is negligible extra cycling of the thermal plant, and the system reserve requirements are also unaffected. Wind energy also then has a capacity credit equal to the mean power available in winter (studies suggest that any relationship between wind availability and peak demand in winter is very weak indeed, so that treating them as independent is as good an assumption as any).

Wind energy at small penetrations is therefore as valuable as thermal plants to within a per cent or two. (In principle the favourable seasonal variations of wind energy may make it worth more than thermal plant, but this needs to be set against the ability schedule maintenance on thermal plant. This also gives a favourable seasonal variation in plant availability.)

But how much is 'small' in this context? As the capacity of wind power rises its value declines for many reasons. The rate at which it does so depends heavily on the diversity of the wind energy.

Figure A12.1 shows the approximate capacity savings which would come from wind energy on the CEGB system as the capacity rises, for a range of diversities. The first few thousand megawatts would save an equivalent capacity (in terms of mean winter power) of conventional sources, but the contribution falls off thereafter. Ten gigawatts of wind power capacity, if dispersed in England and Wales, would save around 3 GW of thermal plant; but the total saved could not rise about 5·5 GW (about 10% of the total thermal capacity). This compares with the current 'planning margin' of 24%, and means that there would be an excess of thermal plant over peak demand of perhaps 7 GW (this analysis is based on real hourly wind and load data in the period 1971–79) as discussed by Grubb (1987).[5,6]

What about fuel savings, and the various operating penalties associated with wind energy? For intermediate penetrations, these can be estimated if we know the variability of the wind energy (as measured by the 'mean power variation') and its predictability.

For dispersed wind energy in England and Wales, the mean power variation has been estimated at around 0·016 GW/h per GW of wind capacity, compared with mean load variation of 0·6 GW/h.

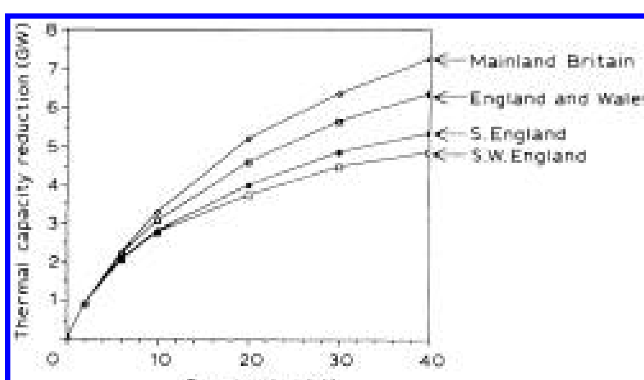


**Fig. A12.1.** Baseload capacity displacement with increasing wind penetration: variation with wind diversity.

Clearly, large wind capacities would have to be installed before these fluctuations became very significant. The costs of plant startup on the current CEGB system account for 3–4% of operating costs. Applying these figures suggests that even if wind energy supplied 20–30% of demand, the additional startup losses would amount to only about 5% of the ideal fuel savings (Grubb, 1987).[5,6]

As outlined in Section 12.4, we can also compare the unpredictability of wind energy with that of load, though the approximations are cruder. So are the data, as we have little idea how predictable wind energy would be in practice. The costs of reserve are generally not very high, however (they account for barely 1% on the current CEGB system). Even when the wind capacity is high enough for wind prediction errors to dominate the reserve requirements, the additional requirements for spinning reserve and/or storage use are unlikely to penalise wind energy by more than 5%, if many sites are combined to avoid the wilder short-term variations.

To this, the effects of uncertainties on longer timescales, say more than 2 h ahead (which affects the scheduling and standby of thermal units), need to be added. Analysis suggests that this could be just as significant as the need for shorter term reserve.

Although none of these penalties taken individually is large, their combined effect could become substantial. However, if high penetrations of wind energy were ever considered, these various penalties would soon be overshadowed by the need to start discarding wind energy at times of fairly low demand, because it would be essential to keep some thermal plant connected (and nuclear plants could not be taken offline anyway). Furthermore the value of the fuel saved by wind energy progressively declines as wind energy penetrates higher up the merit order, especially once wind and nuclear power begin to compete for supply.

The practical importance of these various effects can be encapsulated by considering the marginal value of fuel savings from wind energy as the penetration into the system increases. Figure A12.2 shows such a study, using a computer model of a possible future CEGB system which has a moderate nuclear capacity (supplying abut 20% of demand) and wind energy spread widely in England and Wales, but assuming no power exchange with Scotland or Europe and no more electricity storage than is already on the system (the average prediction errors for wind energy at all

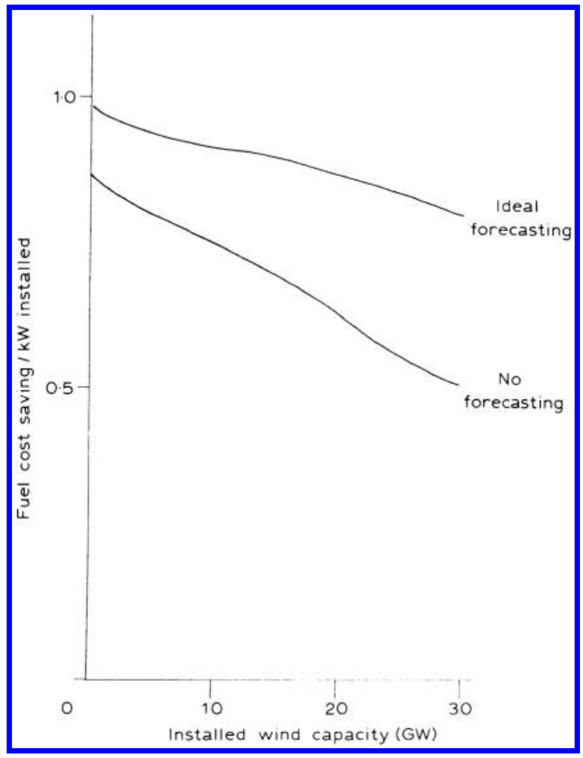


**Fig. A12.2.** Normalised marginal fuel savings from wind energy.

timescales are assumed to be half those obtained if the wind is completely unpredictable).

The message of such studies is that wind energy could supply maybe 10% of demand (implying 8–10 GW of installed capacity for current demand levels) before the penalties start to become significant—up to this level, the marginal fuel savings are only reduced by a few per cent from the initial value (though as noted above the capacity credit value would start to decline somewhat earlier).

Its value then starts to decline steadily but not very rapidly: the system could absorb 30% to 50% of its energy from dispersed windpower without real difficulty. However, even if enough sites could be found in total, which seems highly unlikely, all the better sites would be used up long before this. Given the reduced value of wind energy at such penetrations, it is implausible that wind energy could be generated cheaply enough from low windspeed sites to make such capacities economically attractive.

Although the question 'how much can the system absorb?' is often asked, it is this steady decline in value combined with rising costs which really matters, and the same applies to most other renewable sources.

# Section 13

# Economics of Renewable Energy Sources

## 13.1 INTRODUCTION AND ECONOMIC COMPLEXITIES

### 13.1.1 Possible methods of evaluation

This Section sets out to compare the economics of the renewable energy sources—a difficult and complex task. A complete analysis would probably need to cover the energy policy of the entire country and that, needless to say, is beyond the scope of a single section. It will be necessary to restrict the comparisons to the renewables themselves rather than include all existing methods of generation.

It is also difficult to make meaningful comparisons between sources of energy in different forms such as heat, mechanical energy or electricity. This section will be mainly concerned with methods that generate electricity or high grade energy (zero entropy). With lower grades of energy, quality as well as quantity must be considered (via some additional measure such as entropy, or temperature) and that is much more difficult to place a value on. One method of doing so is to consider how much energy could be produced from the lower grade source in terms of the amount of electricity it could have produced. That procedure is not wholly satisfactory and each such case really needs to be costed and valued quite separately on its merits according to the application for which it is suited. However, the generation of electricity is a widespread application of considerable national importance for which most of the renewables are well suited and for which they can be directly compared. A comparison concentrating mainly on electricity generation will be very worth while.

Many different methods of evaluating ways of generating electricity have their advocates. For example, plant manufacturers will prefer to quote the initial capital cost based on rated performance since that is a knowable quantity that can be guaranteed and tested prior to commissioning and is not dependent on future factors that may vary, such as operating costs, breakdowns, life, available energy, etc.

The operator and the consumer are concerned not only with the initial cost but also the rate at which they have to repay it. Unfortunately a short payback period is no guarantee of a profitable investment in power plant; a system that lasts just long enough to repay the investment and one which repays it many times over may have exactly the same payback period (which may be quite short) but they clearly differ in their total profitability. The rate of return on investment suffers from the same difficulty, whether it is the monetary rate of return (i.e. including inflation) or the real rate of return (i.e. net of inflation): a high rate of return is only attractive if it is sustained for a long enough period.

Energy accounting analysis checks that plant produces more energy throughout its life than is consumed in its manufacture, and again that is probably worth checking. Plant that consumes nearly as much or more energy to make as it can ever generate will be suspect. Nevertheless, it is only the cost or quality of that energy that really matters. The energy put into the plant during manufacture matters no more than energy put in during its operation, e.g. as fuel which will certainly exceed the energy output. Both should be kept reasonably low but neither has to be kept to any particular level as long as the overall system is economic.

When faced with the purchase of plant, it is natural for any company to think in terms of borrowing the money to pay for it on a mortgage to be repaid over some period. That period should not continue after the plant has ceased generating or there will be no income to pay the mortgage. The period may be shorter than the life of the plant for tax or other reasons and then the cost of units will be increased to start with, while the capital is paid off, and then reduced to the level needed to cover only the operating costs thereafter. If a plant is regarded as producing units at different times, the cost of energy can be quoted by averaging over all the units produced and suitably discounting costs to the present. That amounts to levelling the cost between the units and gives the same result as amortising by means of a level mortgage over the whole life of the plant. So to quote an average lifetime cost of energy, the amortisation must be taken as part of a level mortgage, which also includes interest, over the life of the plant. Any other calculation is more complicated but only leads eventually to the same result.

It is evident that quoting costs of energy can be grossly misleading unless accompanied by statements concerning the underlying financial conditions assumed, e.g. discount rates and capital recovery periods.

Having considered the repayment of capital and interest, it is only necessary to add the running costs (including fuel costs if applicable) required to generate energy (e.g. units of electricity) in order to arrive at a lifetime generating cost of units, usually expressed in £/kWh (or equivalent units).

A method that is currently favoured by the electricity supply industry is to compare with the best existing alternative option and to quote the net effective cost. A negative net effective cost indicates that a saving can be made. This naturally requires as detailed a knowledge of the baseline system as of the system under study and is not so convenient for comparing different systems directly with each other.

When evaluating projects, the use of a cost/benefit ratio is often advocated. It would be feasible to use such an approach for energy production but the result is probably equivalent to several of the other methods. Indeed, it should be noted that many of these methods are equivalent and must represent the same answer in different terms. Different methods may, of course, be sensitive to different parameters and require different data to evaluate them and so the choice will often depend upon what information is available and the use to which the results will be put.

### 13.1.2 Factors affecting break-even costs

Having found a measure of the cost of energy, the next step is to say whether that cost is favourable or not as far as any particular system is concerned. The break-even cost will differ from one power system to another depending on the mixture of plant and the power system characteristics at any point in time.

Then, too, many factors will change with time and those changes must be taken into consideration. Future fuel cost escalations (in real terms) dominate the consideration of fossil fired plant and considerable uncertainties are involved. Oil prices have fluctuated wildly in the last 15 years and predictions of steady coal price escalations to the end of the century have not materialised.

Just as future fuel costs affect the picture, so do future planting policies, plant mixes and demand growth. To optimise the utilisation of existing and future energy technologies is clearly a task of considerable difficulty that is fraught with uncertainties. In this section these uncertainties and complexities will be avoided by calculating only the cost and not the value of energy.

Within the nationalised electricity supply industry that existed up until 1989 the Electricity Boards that sold electricity in the United Kingdom could not avoid these difficulties. They were required by law to publish tariffs at which they would purchase electricity and those tariffs were required to reflect fairly their avoided costs and not to treat any class of consumer or supplier unfairly with respect to any other. In simple terms, they had to say what the true break-even price for electricity was and they were required, with the force of law, to get it right!

Common tariffs were published by the 12 Area Electricity Boards in England and Wales and could be picked up at any electricity showroom. The price at which it was economic for them to purchase electricity varied with the time of day, week and year but averaged out to £0·025/kWh (1987). This price was the appropriate break-even cost to take for a source of power that is steady (such as geothermal) or whose periodic or random variations are not correlated with the time of day or week or year. For sources with marked diurnal or seasonal variations, a higher or lower figure would apply. For example the wind blows harder at the time of greatest load demand in winter. Wave power is similar, but for solar power the break-even figure would be reduced because there is less sun at times of peak demand, in winter after dark.

The average figure paid to the Central Electricity Generating Board for the electricity which they generated was easily established by dividing the total amount of electricity sold (232 611 GWh in 1986/87) by the annual revenue (£8 156 000 000) excluding sales of steam, etc.[1] The average CEGB price in 87 was around £0·035/kWh.

The difference between the price the Electricity Boards were prepared to pay to the CEGB (£0·035/kWh) and to a private supplier (£0·025/kWh) was attributed to fixed charges and overheads which the CEGB had to bear but which a private supplier did not. One obvious major item was the cost of the transmission network but that could only account for part of the difference. It may be that some of the overheads included by the CEGB, e.g. for research, should also have been allowed to a private supplier. Such arguments will become very pointed when the CEGB is split into private suppliers and presumably the two figures will come together in due course. In the meantime, any source that can generate at below the lower figure of £0·025/kWh can be regarded as clearly economic and worth pursuing while any source with generating costs lying in the interesting region between the two figures (£0·025/kWh to £0·035/kWh) is marginal and worth further serious consideration.

The break-even price is also evidently dependent upon the power system into which the electricity is fed. The North of Scotland Hydro Electricity Board (NSHEB) with a substantial proportion of hydro generated at around £0·026/kWh over most of its region (but nearer £0·06/kWh for its islands and isolated areas which include some diesel). The South of Scotland Electricity board had a high proportion of nuclear and also had significantly lower generating costs than the CEGB, around £0·021/kWh. The published purchase prices of the two Scottish boards were lower than for the 12 Electricity Boards in England and Wales, around £0·018/kWh.

The Electricity Boards were probably in a better position to know the true costs than anyone else and at least their figures provided a widely publicised yardstick against which generating costs could be judged. Any private electricity producer had to compete with these prices to stay in business.

### 13.1.3 System integration, environmental and institutional factors

Although it will be beyond the scope of this Section to evaluate total system costs, present or future, it will be necessary to include many of the straightforward costs of system integration. The cost of site services and connection to the transmission system are included in all the estimates for electrical power generation. A number of the other considerations for power system integration have been covered in Section 12.

Many of the factors that will influence the decision for or against various renewables are not economic at all, but environmental or institutional. For example, it has been accepted for some time that on really good windy sites wind turbines would already be economic, but many of these sites are beauty spots and the deployment of hundreds of large machines would be environmentally unacceptable, so wind power may not be pursued as actively as its straightforward cost advantage would indicate.

Institutional factors, too, are important and can affect the economics in many situations. For example, local rates or taxes paid by Electricity Boards were typically 2% of their total costs per annum. For private generation, the costs are effectively based upon the cost of the power plant and were around 2% of that cost per annum, a figure which sounded quite reasonable until it was appreciated that this amounts to 25% or more of total costs. Water extraction charges have been payable in many parts of the country simply for passing water through a water wheel or hydro-electric plant and again this added a very substantial amount to the cost of energy production. Water extraction charges were being reviewed but representations made to the Department of the Environment, not least by the Secretary of State for Energy, regarding rates, e.g. for wind turbines, have produced no changes to date, although rationalisation is promised in 1990. Until these local taxes on energy production are changed, private ownership of renewable (and probably other) power plant cannot be competitive. The costs presented in this section are those for renewables installed by the Electricity Boards under existing legislation and taxation conditions.

Section 11 deals with these environmental and institutional factors.

### 13.1.4 Chosen method of costing: advantages and limitations

In the face of all these complexities, some method of evaluation must be chosen. Since the renewables require no fuel (with the exception of biomass) most of the expenditure on them is for the initial capital which will be a known quantity and it will be appropriate to make estimates relative to that. By the same token, the renewables will be at the top of the merit order, i.e. the lowest running cost for any power system, and so their contribution can be calculated without the need to consider the complexities of the rest of the system or of other power plant. The economic comparison need take no account of interaction with the operation of other stations on the system, and can be set out to sufficient accuracy using estimates of the direct generation costs at each station (Ref. 2, para. 2.21). The uncertainties of future fuel price escalations can be avoided by working solely in real terms financially, i.e. in today's money, inflation can be considered separately with its future uncertainties eliminated from consideration.

The cost of electrical energy supplied seems to be the most appropriate indication to choose when comparing the renewables, as noted previously. If the cost of electricity is to be levelled over all the electricity generated then it is necessary to repay capital by means of a level mortgage from the time the plant starts generating to either the end of its useful life (lifetime costs) or a shorter period determined by the period allowed for capital recovery. All prices will be expressed in today's money, e.g. in £/kWh net of inflation, and so it will be necessary to use real costs and real rates of return.

This lifetime costing will be used as the basis for calculation arising from a questionnaire, discussed later, with variations on these reference values for different 'lifetimes' related to capital recovery periods also presented.

## 13.2 CAPITAL COSTS

### 13.2.1 Initial capital

Capital costs are often regarded as one of the most well defined parameters in any costing exercise because they are determined once and for all at the start of a project. There are points to watch, however, particularly when a new technology is involved. Enthusiasts tend to quote prices that are too low while commercial organisations, wanting to recover their development and launching costs as rapidly as possible, often quote prices that are too high.

Capital costs are always strongly dependent upon the scale of production and the scale of activity must be taken into account when making cost estimates. For the Severn barrage, only one scheme is possible (although there are options over what that scheme will be and many of the units would be replicated). For many of the other renewables, with small unit sizes, costs will fall dramatically with the scale of operation, as has been convincingly demonstrated for wind power in the last few years. The cost of individual prototype wind turbines gives very little guide to the cost of a complete wind farm and reductions in cost of two or three times are quite usual.

When a type of power plant has not been built before, or at least not for some time, there is inevitably uncertainty about both labour and materials costs. For example, there is considerable uncertainty about the true cost of building a nuclear power station in the United Kingdom due to the infrequent and irregular ordering of such stations in the past. If specialist expertise is required, the new development may create a shortage of skills that pushes wage rates up. On the other hand, if the labour market has spare capacity, it may be able to meet the additional demand at marginal costs well below the average level.

There is a tendency to regard the capital cost estimates of purchasers or independent observers as wholly unrealistic compared with those of the plant manufacturers. In narrow context, e.g. for the next plant order, this is clearly correct because a supplier can be held to his quotation even if it was too low—and will still charge the same price if it was not, keeping the profit for the company. Taking a broader view, in the longer term there is plenty of evidence that manufacturers get their estimates just as wrong as everyone else, sometimes becoming insolvent in the process. There is no substitute for careful and detailed analysis.

The best position is where recent major purchases have been made and are operating successfully. Failing that, cost estimates must be made of individual components and parts of the system with realistic costs for engineering the system as a whole.

Advances in technology have produced significant improvements in the efficiency of many of the renewables. It is obvious that improved efficiency cuts fuel consumption in any conventional or nuclear generating system, but there are no fuel costs for the renewables—that is their whole point!—and so it is often felt that efficiency is not important. If the energy is free, how can the efficiency matter?

In most systems, the cost is dominated not by the plant to handle the electricity output but by the plant to capture the energy input. The higher the efficiency, the smaller the input energy for a given amount of electricity and hence the smaller the cost of the plant to capture it. Thus efficiency has a direct effect on the capital cost of plant to capture renewable energy, even though the source of energy costs nothing.

### 13.2.2 Interest during construction

One source of additional cost is the interest incurred on the capital during construction (idc) before the plant starts producing electricity and earning revenue. It is appropriate to treat interest during construction as capital because it is money that must be paid before the plant can become operational.

It is a fairly simple matter in principle to add this interest, year by year, to the capital cost. The calculation can become a little lengthy, with as many terms as there are years of construction, as shown in Section 13.4.3, and capital expenditures need to be estimated for each of those years. By working in real terms, the fraction of total capital expended each year simply reflects the fraction of the work done. With inflation, the actual money spent for a given amount of work changes year by year and the total amount to be paid during a lengthy construction period can be escalated by 50% or 100% due to idc, but in real terms only 10% or 20% of initial capital will be normally involved unless there are substantial delays during construction.

Overruns on construction timetables are unfortunately very common and represent a major source of uncertainty in cost for projects with long construction periods. For plant with long construction times such as tidal power, significant delays would add significantly to the total cost and that is a danger that must be carefully avoided. For plant with small unit sizes, such as wind, wave, biomass or solar, construction periods can be less than a year; for example, complete wind farms have been built in six or nine months. No interest during construction then normally arises; any that is required is included by the constructor in his cost estimates. Even if there are significant delays or changes in the construction schedule, there should be no corresponding cost increases that are significant. Last year's solar cells or wind turbines will be earning revenue, even if this year's installations are delayed; but last year's civil works on a major project will be losing money on idc if this year's mechanical or electrical works are delayed.

### 13.2.3 Refurbishing and replanting during life

With many types of plant, some parts have longer lives than others. The civil engineering component will often be built to last for 50 or 100 years in order to cope with extreme weather conditions. Electrical installations can still be found working after 40 or 50 years but mechanical plant often does not achieve such lifetimes. It may therefore be economical to carry out substantial replanting during the life of the generating station. This is common practice with conventional fossil-fuelled generating plant. The boiler, which can represent a quarter or a third of the cost of the plant, may be retubed every 10 or 15 years, and the turbines may occasionally be rebladed while the generators and transformers usually continue working quite reliably for long periods.

In the past, improved technology has become available over such time scales and it has been worth scrapping the old plant and replacing it with completely new, high efficiency plant, the cost being justified by improvements in performance. As technology matures, performance limitations may be reached which are fixed by the laws of physics, as with the Carnot or Rankine cycles. New plant cannot then produce significant savings by improved performance and it may be more economical to extend the life of plant by replacing major components. This is a major area of research in the power industry today.

The same thinking is applicable to the renewables for long-lived plant such as a tidal barrage and for shorter-lived plant such as wind turbines whose rotors can suffer exceptionally severe fatigue conditions and may need to be replaced half-way through life.

As far as costing is concerned, such delayed expenditure is favourable. A small business would welcome the opportunity to pay for such future expenditures out of revenue, but it would actually be reducing its capital borrowing requirements thereby, and so it is appropriate to include such future expenditures in the capital estimates. This appears to introduce a slight anomaly since capital is usually regarded as being spent before commissioning; for consistency the money would have to be spent at commissioning by putting it aside to earn interest until it is needed to pay for the replanting. Obviously a smaller sum can be set aside, an amount that is sufficient to grow to the required figure by the time the replanting has to be carried out. This gives us the cost calculation that we need for Section 13.4.3. The capital equivalent of the cost of replanting is just the present-day-worth of the future expenditure.

### 13.2.4 Decommissioning costs

Decommissioning costs can be treated in just the same way as costs of replanting. The expenditure comes at the end of the productive life of the plant rather than at some other point in time but the calculation is the same: the extra capital cost equivalent is just the present-day-worth of the future decommissioning cost according to the formula for *R* in Section 13.4.3. Swift-Hook[3] has dealt with decommissioning costs in relation to wind turbines but many of the points which he considers are relevant to all of the renewables.

The costs of dismantling most of the renewables will be small. The estimates given by Swift-Hook[3] to raze wind turbines to the ground are in the range 1% to 5% of capital cost, although total removal and reinstatement might cost more. Scrap values are likely to be in the same region so they will offset the dismantling charges and the net costs of decommissioning are likely to be around zero. Plant with a larger civil engineering component may cost proportionally more to decommission when the time comes, but because it lasts much longer the expenditure is much deferred and its present-day-worth is negligible. The procedure of ignoring decommissioning costs entirely is therefore probably quite accurate for all renewable systems.

### 13.2.5 Operation and maintenance

For conventional plant, the biggest item under operating costs is usually fuel. The renewables have no fuel costs and so attention is not usually focused upon their costs of operation. These costs are important, however, because they can in themselves represent a significant part of the total cost of energy—perhaps as much as a quarter or a third. The amount spent on operation and maintenance will also have a direct effect upon plant availability which can account for a further substantial part of the total cost. It is therefore vital that operation and maintenance should be carefully planned to achieve adequate reliability—and by the same token, that renewable generating plant should be designed for ease of maintenance.

Operation and maintenance costs must represent a forward projection in any new technology and such projections are remarkably difficult. For technologies where multiple units of small unit-sizes will be involved (such as wind, wave or solar), the cost of operating and maintaining a single prototype unit will give very little guide to the cost for a substantial installation where it will be economic to have a permanent maintenance team on site. With site maintenance staff immediately available, outage times will be much less than if engineers must be called out from the factory to attend the failure of individual units. Direct cost-scaling will not apply and careful estimates are therefore needed to derive realistic figures for operation on a significant scale.

Where O&M costs are available for a practical installation, it is important to relate the costs to the scale of operation if they are to be considered in relation to other installations or used for economic comparisons. Three common ways to quote O&M costs are:

(a) per unit of energy (suitably averaged and levelled);
(b) as a fraction of the cost of energy; and
(c) as an annual fraction of initial capital costs.

The first way has the merit of being directly understandable in money and energy terms. The second has the advantage of escalating O&M costs automatically with inflation as energy costs rise. The third is related to the plant itself and not to the amount of energy it produces, so it may be more appropriate when considering a given type of plant in a variety of different energy regimes; this method, (c), is the one that has been chosen for Section 13.4.3.

## 13.3 GENERATION

### 13.3.1 Resource availability

Much effort has gone into establishing the geographical distribution of the various renewable energies. Maps are available on a worldwide basis for tidal ranges, insolation, wave heights, wind speeds and geothermal gradients. In many instances, detailed local topography has a profound influence upon the intensity of the resurce, e.g. in a tidal basin or over a windy hilltop. The intensity in turn has a profound effect upon the economics. It is not therefore sufficient to quote the total resource available. The resource must be quoted in relation to a given intensity level or cost band, and ideally it should be expressed as a series of bands or a continuous cost function.

Wind energy provides an obvious example. There are a few very windy areas in Britain with annual average wind speeds of 9 m/s or more where generation costs would be very low indeed. Such areas would probably be sufficient to generate a few hundred megawatts of electricity. More moderate wind speeds, below 8 m/s, are available over much larger areas but the economics are then not so favourable. Clearly the cheapest sites should be used first but the position is then complicated by questions of scale production.

After the first few hundred megawatts of any new technology have been installed, significant cost reductions are to be expected by the use of quantity production techniques without considering the improvements in technology that seem almost inevitable.

For example, wind power plant costs are expected to fall progressively as larger quantities are manufactured and installed. The low generation costs initially available at very windy sites will then become available on a more widespread basis at many more sites with more moderate wind speeds (Ref. 4, p. 20). Proponents of photovoltaics, too, claim that cell costs will fall as increasing quantities are manufactured.

### 13.3.2 Plant availability

The availability of generating plant throughout its life has a direct effect upon the number of kilowatthours of electricity generated and hence upon the cost of energy. Availability at times of peak demand determines the firm power contribution or capacity credit. Power plant availability is therefore an important parameter. It can vary a great deal between types of power plant; 88% is good target to aim at for conventional power plant; that is the average achieved by the CEGB for the various items of plant on their system. Large modern coal-fired units can achieve slightly higher figures, around 92%, while nuclear plant with its more stringent maintenance requirements and longer repair times can achieve little more than 80%. Sizewell B PWR expects to achieve no more than 55% availability in the first year or so after commissioning and British AGRs have averaged much lower availabilities throughout their lives to date.

High temperature corrosion, erosion and fatigue seem to present particularly difficult materials problems as far as very long plant lifetimes are concerned. Hydroelectric power plant, which has no high temperature or highly radioactive parts, and which does not involve massive heat exchangers, has availabilities nearer 100% and it is to be expected that well designed renewable power plant will be able to achieve similar figures in many cases. Tidal power, with its low head water turbines, for example, has a good deal in common with hydro power technology. Wind power plant, too, does not have to cope with the problems of heat exchange, although it does need to cope with severe storm conditions from time to time. Wave power also avoids high temperature problems but has to cope with a hostile marine environment. Geothermal power does involve major heat exchange, although the temperatures are much lower than for thermal power plant; the problems of corrosion therefore tend to be less severe but the size of the heat exchangers, which can represent a substantial part of the total cost, are correspondingly greater. Ocean Thermal Energy Conversion (OTEC) has even smaller temperature differences to cope with in a relatively hostile marine environment.

By such comparisons it should be possible to predict the availabilities to be expected of well designed plant. Practical demonstrations of plant availabilities for the renewables are not very widespread as yet. Successful demonstrations of *good* availabilities are even rarer but it is upon those demonstrations that interest inevitably focuses for planning purposes; nobody would plan to install types of power plant that have proven to be unreliable if reliable examples can be obtained.

As with the costs of operation and maintenance, it is difficult to forecast with the availability to be expected under service conditions from the experience of a prototype installation. One-off repairs by factory-based teams will inevitably take longer than those carried out on a routine basis by experienced teams available on site. Experience with wind farms in California provides very clear demonstrations of this point.

Wind farms also demonstrate another general feature of availability. Small units operating in parallel allow high availabilities to be achieved. Not only does the failure of a single component (such as a nut or bolt) affect a more limited amount of power but the repair or replacement of a unit can be much more rapid so that outage times are much less. Wind turbines generating 250 kW are erected in less than a day in California and so even major failures can be replaced or repaired very rapidly. Design for ease of repair and maintenance is an important aspect of such plant. Major wind farms in California have for some time been achieving availabilities in excess of 95%.[5,6] Solar power will share these advantages of small unit sizes; so also will wave power, although access difficulties may reduce device availabilities. Tidal power with as many as 216 turbo-generators in the Severn Barrage will share the same advantages as far as failures of mechanical and electrical plant are concerned and it is to be hoped that the probability of a failure in the civil engineering is remote.

### 13.3.3 Other losses

In evaluating and comparing different types of power plant, it seems wise to include a parameter to cover other factors that have not so far been mentioned or that tend to be omitted from published data. An example might be transmission, transformer or inverter losses if they have not already been included in the overall plant efficiency. Additional costs (or savings) may arise if the renewable source is connected into the power system in some untypical manner: distributed solar panels or wind turbines feeding into local area networks at low voltage levels could involve short lines and thereby save on transmission. Interactions between units may degrade performance as in the case of groups of wind turbines in a wind farm; such losses must be taken account of separately as predictions are made on the basis of individual machines.

### 13.3.4 Life and amortisation

Design for a specified life is a standard feature of good engineering practice. Although this feature is often sacrificed in the early stages of any new development when there is a struggle to achieve technical performance or economic competitiveness, it is a central aspect of production engineering. Individual prototypes and early designs of renewable plant have exhibited short lifetimes in many instances, but there seems to be no inherent reason why any of the renewables cannot be designed for suitable lifetimes. Thirty years is a typical figure which is found in most mechanical and electrical engineering design codes and most of the renewables seem to aim for around that figure; many of the schemes listed later in Tables 13.2 and 13.3 have taken 25 years to be on the safe side. Tidal barrages and mini-hydro dams involve a major proportion of civil engineering construction which tends to last much longer and so they have taken longer lifetimes with major replacement of mechanical and/or electrical plant during life.

Amortisation is the repayment of capital and can take place over any period, irrespective of the life of the plant or equipment. For many planning/costing purposes and for economic comparisons, it is unsatisfactory if there is still value left in the plant and it continues to generate when all the capital has been repaid; however such situations arise because capital recovery periods are inevitably less than technical lifetimes. Paid-off plant then provides extremely cheap energy (O & M costs only) for the remainder of its technical life.

## 13.4 COSTINGS

### 13.4.1 Real rates of return

In making economic assessments the approach is straightforward: as well as repaying its cost over the life of the plant, a charge must be made for the use of the resources involved, the 'opportunity cost of capital'. To apply the terminology 'capital' against which one assesses 'interest' does not imply that one is either a capitalist or a usurer. The resources used to build power plant could alternatively have been used for other purposes, and some measure must be applied in order to be able to balance the cost of the alternatives.

This principle applies irrespective of one's political or religious beliefs: regimes which find the concepts of 'capital' or 'interest' offensive—as do some major countries in the world—make just the same sort of calculations. It is simply necessary to compare projects according to the resources they consume as well as the benefits they produce and to balance the requirement for a large initial expenditure against costs and benefits that are spread over a period.

It needs to be re-emphasised that the rates of amortisation and of interest used for project comparison are not necessarily those actually paid throughout the project. It may, for example, be that the capital does not need to be refunded at all or that larger repayments are made to suit tax legislation; or a different rate of interest from that used in the assessment may be paid to a particular source of funds. Whatever financial arrangements are made to generate a given value of energy, it is obviously best to choose projects which require both less initial expenditure and less running costs. Where a choice must be made between the two and lower initial costs must be balanced against lower running costs, a trade-off is necessary and the discount rate used for project comparison represents that tradeoff.

If all costs are to be quoted in real terms, i.e. in today's money net of inflation, the discount rate must also be quoted in real terms, i.e. net of inflation. This is, on the face of it, at variance with normal banking practice which does not call for interest or capital repayment in real terms. However, the differences are only in the terminology as the following concrete example shows.

If a bank lends £100 this year and charges 9% interest on its money, it expects to be repaid £109 next year in next year's money; it describes that repayment as £100 of capital and £9 interest. If inflation is running at 4%, say, the repayment next year is worth 4% less in this year's money, i.e. only £105, so in today's money the repayment is £96 capital and just under £9 interest. It becomes clear that there is a certain artificiality about the transaction when it is viewed in this way and that the bank is using the interest it charges partly to compensate it for not being repaid the full value of the amount it lent, i.e. to cover the effects of inflation. A more realistic view is that the bank does expect to be repaid the full value of what it lent (£100 on today's money, £104 in next year's money) but really charges a lower interest rate (5%) that is less than the money interest rate which it quotes (9%) by the amount of inflation (4%).

Interest rates are normally determined at the start of a transaction when the future rates of inflation are uncertain. All such investment decisions on industrial development therefore involve an implicit gamble on, or hedge against, future inflation. Private industrial companies are frequently involved in such currency speculation, wittingly or unwittingly, when undertaking engineering projects, particularly when international currencies are involved. Such risks can be avoided almost entirely by buying money forward but, as with many other forms of insurance, this is frequently not done.

**Table 13.1 National discount rates, 1987 in major OECD countries**

| | |
|---|---|
| Netherlands | 4% |
| FRG | 4%–4·5% |
| Canada, Ontario Hydro | 4·5% |
| USA | 5% |
| UK[a] | 5% |
| Italy | 5% |
| Turkey | 5% |
| Finland | 5% |
| Spain | 5%–8% |
| Switzerland | 6% |
| Canada, New Brunswick | 6·6% |
| Norway | 7% |
| Belgium | 8·6% |
| Portugal | 9%–14% |

[a] *In 1989 the UK government increased the required rate of return for public sector investments to 8%.*

For the present assessment purposes, choices between projects should be based upon their true engineering costs. Particularly when the decisions involved are on a sufficient scale to affect the national interest, it is more important not to confuse real engineering economics with those of financial or other speculation. If there are to be gambles on inflation, those costs should be identified separately. This is certainly the view taken by governments generally around the world. Interest rates in many countries are notoriously volatile, but Table 13.1 (reproduced from Ref. 7) shows that most OECD governments, including that of the UK, have required a real rate of return on capital of around 5% per annum for major long-term investments such as power plant, so 5% p.a. is a convenient rate to take in this study as a reference value.

### 13.4.2 Private versus public capital

In common with all other national organisations, in the decade prior to 1989 the CEGB planned and costed the future development of their power system on the basis of a 5% required real rate return. Although they can reasonably be regarded as one of the more successful nationalised industries, their actual rate of return in real terms (on a current cost accountancy basis, net of inflation) has been nearer to half that figure. Private industry, on the other hand, usually expects to produce a better real rate of return that this, perhaps twice as much or more, i.e. 10%, because if a project is to attract investment, it must do significantly better than simply putting money in the bank. Real rates of return can therefore cover a considerable range, according to which part of the public or private sector is involved.

The only costs of electricity that are widely recognised and accepted as a basis for comparison have been those published by the Electricity Boards and by the Government, which up to 1989 have been based upon the statutory 5% and any meaningful comparisons have therefore had to use that figure. It was a corollary, however, that major investment in electricity generation would almost inevitably be restricted to the public sector while these differences in real rates of return existed. This point has been brought out particularly strongly by studies of the River Severn Tidal Barrage.

The position will not necessarily change dramatically when the Electricity Boards in Great Britain are privatised. Return on an investment tends to be the difference between two rather large quantities, total income and total costs, and so electricity charges would not need to double in order to produce double the return on capital. The break-even cost can be expected to rise faster than inflation after privatisation or, if foreign coal is imported in large enough quantities to reduce overall costs significantly, the UK balance of payments will suffer. Some form of shadow pricing which will minimise the changes would be needed to offset this effect.

### 13.4.3 Generation cost calculations

The appropriate formula enshrining the various principles and involving the different parameters set out previously is:

$$G=C[R+(I+J)+M]/hLA(1-a)$$

where $G$ = generating cost of electricity,
$C$ = initial capital cost per kilowatt,
$R$ = annual charge rate on capital,
$I$ = interest during construction factor,
$J$ = refurbishment and replanting factor,
$M$ = annual operation and maintenance cost ($I$, $J$ and $M$ are expressed as fractions of the original capital),
$h$ = hours in a year=8760,
$L$ = nominal annual load factor for energy source, e.g. wind,
$A$ = plant availability, and
$a$ = a loss factor to include all other losses.

The annual charge rate, levelling amortisation and interest over the life of the plant and allowing for decommissioning costs and scrap values at the end of life, is

$$R=r[1-(s-d)/(1+r)^n]/[1-1/(1+r)^n]$$

where $r$ = required real rate of return,
$n$ = plant life (and capital amortisation period) in years,
$s$ = scrap value as fraction of initial capital, and
$d$ = decommissioning costs as fraction of initial capital.

The factors $I$ and $J$ cover the costs of interest during construction and major refurbishment or replanting during the useful life of the plant; assuming that interest is charged yearly from the end of each year in which expenditure is incurred, they are given by:

$$I = c^1+\ldots+c^i(1+\mathrm{r})^{i-1} \qquad \text{(idc)}$$

$$J = c^j/(1+r)^j+\ldots \qquad \text{(replanting)}$$

where $c^i$ = fraction of initial capital spent in ith year before commissioning, and
$c^j$ = amount spent on replanting in eachyth year after commissioning as a fraction of initial capital.

By inserting values of the cost and performance parameters into these formulae, corresponding generating costs of energy can be found. It is an important feature of this study that the renewables have all been costed on the same basis in this way.

Clearly the generation costs arrived at are wholly dependent upon the input data parameters provided and a major part of the study centred upon the collection of valid data. The Watt Committee Working Party identified one or more national experts for each of the renewables and held detailed discussions with them on the status of the various technologies and on the common basis on which they should all be costed. Each group of experts was then required to write a narrative account of each field (which is published elsewhere in this volume) and to complete a detailed questionnaire.

The questionnaire is set out in Appendix 13.1. It involves 56 questions altogether and requires upper and lower limits to be stated in all cases where numerical estimates are given. Evidence required to support all of the estimates is by way of reports or published references in which the figures given are justified in detail. All of the detailed performance and cost figures need to be self-consistent together with a number of additional questions in the questionnaire, the latter to allow cross-checks to be made on internal consistency, notably with regard to the nominal load factor.

In order to assess the cost levels that each of the alternatives can actually achieve at its present stage of development, 'best guess' estimates were called for of 'present-day' costs. All costs were to be in mid-1987 money, even maintenance or replanting costs which would probably not be incurred for a considerable time and would then be at inflated prices. It was accepted that costs would be projected to the next major installation and not restricted to demonstration or prototype units which cannot give typical costs, as was pointed out in Section 13.3.2. The key parameters and calculated generation costs are presented in Table 13.2.

Table 13.3 presents these and other estimates of generating costs for comparison for this best significant tranche of each of the renewable technologies. This tranche represents the first few hundred megawatt-hours per year of delivered electrical energy, i.e. approximately 100 MW of conventional equivalent capacity installed.

There are of course, some uncertainties in the cost level quoted for the best gigawatt or so of each renewable and these are dealt with in Section 13.6.1. Various aspects of the data collected and in particular the sources from which they are derived are discussed in Section 13.5. There are many caveats to be noted when any technology is reduced to a single figure and a number of these are indicated in Section 13.6.5. However, the generation costs given in Table 13.3 are the best, central estimates that can be made from the data available. The caveats entered in Section 13.6.5 and elsewhere could increase or decrease these generation costs.

Subsequent installations after the first tranche would not have the advantage of the best sites and with poorer resources (e.g. lower wind speeds or temperature gradients), generation costs will be higher if the same plant costs are assumed. Figure 13.19 later in this section shows an estimate of the amounts of energy available at various cost levels (corresponding to available resource intensities) based upon mid-1987 plant costs for each of the renewables. The exploitable resources at various cost levels are discussed further in Section 13.6.3. There are greater uncertainties in these estimates of subsequent installations, not only because their locations have not been so well considered, but also because the cost reductions to be expected from quantity production have not yet been taken into account.

## 13.5 BASIC COST AND PERFORMANCE DATA AND DATA SOURCES

### 13.5.1 Biomass

Biomass is a term used here to cover a variety of energy sources and technologies including forestry wood and forestry waste, landfill gas production, general industrial and commercial wastes (paper, wood, cardboard and plastics), specialised industrial wastes (scrap tyres, hospital wastes, poultry litter, etc.) and municipal solid wastes. With such a heterogeneous contribution to energy supply it is not possible to quote one meaningful cost of electricity production. For this reason biomass is excluded from the survey results given in Table 13.2. Instead Table 13.4 presents some results of an analysis conducted by the UK Energy Technology Support Unit (ETSU) and NORWEB in the north-west region of Great Britain in 1988.[8] This table shows the range of contributions to energy supply at the initial marginal costs encountered in this mixed industrial and rural area comprising a population of some 4·755 million and containing approximately 8·6% of the nation's customers for electricity. By extrapolation of these results there would appear to be a national resource arising from waste products alone capable of generating electrical energy of some 39 TWh at a cost of 7 p/kWh or less (1988 money).

### 13.5.2 Mini hydro

The economics of mini hydro were dealt with in Watt Committee Report No. 15.[9] The technology is well established but new developments are taking place. Generating costs are dependent upon available flow rate (cub metres per second) and gross head (in metres), but the effects of storage complicate the issue so that there is no simple relationship; installations are very site-specific and the lowest costs are achievable when use can be made of existing work or natural features. Frictional losses in the pipework are accounted for in the quoted device characteristics along with mechanical and electrical losses. Transmission losses are taken as a nominal 1%. Hydroelectric power plant has an availability, including preventative maintenance, of about 95%; given adequate storage and reasonable maintenance schedules, no other energy need be lost.

**Table 13.2 UK electricity generating costs using renewable resources (mid-1987 and using a 5% discount rate)**

| Generation cost factor | | Wind | Mini-hydro | OTEC | Geothermal-HDR | Tidal | Geothermal–doublet | Offshore wave-clam |
|---|---|---|---|---|---|---|---|---|
| Basic capital cost | £/kW | 600·00 | 978·00 | 4 400·00 | 2 563·00 | 845·00 | 1 718·00 | 840·00 |
| Capital cost with IDC | % | 100·00 | 101·91 | 113·95 | 104·84 | 116·00 | 105·48 | 101·25 |
| Replanting costs | % | 8·15 | 10·41 | 31·02 | 24·63 | 4·70 | 23·45 | 12·89 |
| Proportion replanted | % | 15·00 | 45·00 | 45·00 | 50·00 | 58·00 | 50·00 | 23·00 |
| Design life | years | 25·00 | 60·00 | 25·00 | 25·00 | 120·00 | 26·00 | 25·00 |
| Real annual rate of return | % | 5·00 | 5·00 | 5·00 | 5·00 | 5·00 | 5·00 | 5·00 |
| Annual amortisation charge | % | 7·10 | 5·28 | 7·10 | 7·10 | 5·01 | 6·96 | 7·10 |
| Operation & maintenance | % | 0·86 | 0·55 | 5·00 | 2·50 | 0·75 | 3·50 | 3·00 |
| Total annual charge rate | % | 8·53 | 6·48 | 15·29 | 11·69 | 6·80 | 12·47 | 11·10 |
| Nominal load factor: | | | | | | | | |
| – from performance | % | 6·10 | 35·88 | 97·38 | 100·00 | 0·00 | 100·00 | 33·50 |
| – from load curve | % | 43·75 | 57·38 | 99·38 | 100·00 | 34·00 | 100·00 | 38·63 |
| – claimed | % | 32·41 | 57·00 | 99·00 | 100·00 | 22·00 | 100·00 | 25·00 |
| Availability | % | 96·00 | 95·00 | 90·00 | 90·00 | 95·00 | 90·00 | 85·00 |
| Other losses | % | 10·00 | 1·00 | 7·00 | 10·00 | 3·00 | 10·00 | 0·00 |
| Overall load factor | % | 28·00 | 53·61 | 82·86 | 81·00 | 20·27 | 81·00 | 21·25 |
| Generation costs | p/kWh | 2·08[a] | 1·35 | 9·25 | 4·22 | 3·23 | 3·01 | 5·00 |

**Table 13.3 Estimated UK electricity generating costs (p/kWh)**

| Energy source | 1987 costs at 5% discount rate over technical lifetime[a] | Mid-1989 costs at 10% discount rate for various capital recovery periods[b] | | | CEGB estimates, 1988[c] | Other | Dept. of Energy 1988[d] |
|---|---|---|---|---|---|---|---|
| | | 10 years | 15 years | 20 years | | | |
| Mini-hydro | 1·4 | 4·8 | 3·9 | 3·5 | 1–5 | 1·5–2·9[e] | — |
| Wind—onshore | 2·1 | 5·4 | 4·4 | 3·9 | 2–3 | 2–4[e] | 2·7–3·4 |
| —offshore | — | — | — | — | 3·5–8 | — | 4·2–7·4 |
| Geothermal | | | | | | | |
| —multiplet | 3·0 | 7·7 | 6·2 | 5·5 | 3·2–6·4 | 10–17[e] | 3–6 |
| —doublet | 4·2 | 10·7 | 8·7 | 7·7 | | | |
| Wave—shore-based | 3·2 | 10·6 | 8·6 | 7·6 | 3–4 | | 4–5·5 |
| —offshore | 5·0 | 12·8 | 10·3 | 9·2 | 9·8–17·2[f] | | >10 |
| Tidal—Severn | 3·2 | 11·6 | 9·4 | 8·4 | 3·5–4 | 3·5[g]–5·9[h] | <3·5 |
| —Mersey | 2·95 | 10·7 | 8·7 | 7·7 | 3·5 | 4·8–6·9[i] | |
| Biomass | — | 0·34 | 0·28 | 0·24 | — | 1·8–2·1[j]<br>0–7[k] | — |
| OTEC | 9·3 | 23·8 | 19·3 | 17·1 | | | — |
| Solar—photovoltaics | 62 | 140 | 113 | 101 | | | — |

[a] Estimated from questionnaire from mid-1987.
[b] Estimates from questionnaire updated by inflation, mid-1987 to mid-1989.
[c] CEGB evidence to House of Lords, February 1988, HL paper 88, 'Alternative energy sources'; 5% discount rate; design life expectancy.
[d] 'Renewable energy in the UK: the way forward', Energy Paper 55, Department of Energy, June 1988, HMSO, London; 5% discount rates; design life expectancy.
[e] Reference 8; 10% discount rate; design life expectancy.
[f] Department of Energy estimate, 1985.
[g] 5% discount rate
[h] 8% discount rate
$\left.\right\}$ Severn Tidal Power Group Evidence to Hinkley Point 'C' Public Enquiry, January 1989.
[i] Reference 8; 10% discount rate; Barnik Point, Askam Point, Wyre; design life expectancy.
[j] Reference 8; landfill gas; 10% discount rate; design life expectancy.
[k] Reference 8; 10% discount rate; general industrial and municipal waste; design life expectancy.

*Table 13.2* — contd.

| Generation costs factor | | Inshore wave | Offshore wave-duck | Solar—active | Solar—process heat | Solar—passive | Solar—photovoltaic | Geothermal—aquifer |
|---|---|---|---|---|---|---|---|---|
| Basic capital cost | £/kW | 830·00 | 1800·00 | 500·00 | 500·00 | 200·00 | 6000·00 | 1500·00 |
| Capital cost with DC | % | 100·00 | 100·00 | 100·00 | 100·00 | 100·00 | 100·00 | 100·00 |
| Replanting costs | % | 24·98 | 0·00 | 0·00 | 0·00 | 0·00 | 0·00 | 1·09 |
| Proportion replanted | % | 75·00 | 0·00 | 0·00 | 0·00 | 0·00 | 0·00 | 2·00 |
| Design life | years | 50·00 | 25·00 | 20·00 | 25·00 | 60·00 | 20·00 | 20·00 |
| Real annual rate of return | % | 5·00 | 5·00 | 5·00 | 5·00 | 5·00 | 5·00 | 5·00 |
| Annual amortisation charge | % | 5·48 | 7·10 | 8·02 | 7·10 | 5·28 | 8·02 | 8·02 |
| Operation & maintenance | % | 3·00 | 2·00 | 5·00 | 5·00 | 3·00 | 2·00 | 1·00 |
| Total annual charge rate | % | 9·85 | 9·10 | 13·02 | 12·10 | 8·28 | 10·02 | 9·11 |
| Nominal load factor: | | | | | | | | |
| — from performance | % | 26·48 | 0·00 | 16·25 | 0·00 | 0·00 | 0·00 | 0·00 |
| — from load curve | % | 32·59 | 12·50 | 13·75 | 12·50 | 12·50 | 12·50 | 12·50 |
| — claimed | % | 30·00 | 40·40 | 11·50 | 11·50 | 11·50 | 11·50 | 100·00 |
| Availability | % | 98·00 | 90·00 | 95·00 | 96·00 | 99·00 | 99·00 | 90·00 |
| Other losses | % | 0·00 | 0·00 | 5·00 | 5·00 | 0·00 | 3·00 | 5·00 |
| Overall load factor | % | 29·40 | 36·36 | 10·38 | 10·49 | 11·39 | 11·04 | 85·50 |
| Generation costs | p/kWh | 3·17 | 5·13 | 7·15 | 6·57 | 1·66 | 62·09 | 1·82 |

[a] For average wind speeds at the best sites of about 9m/s.

**Table 13.4 Biomass in the northwestern (NORWEB) area of Great Britain**

| Energy source | Plant rating (MW(e)) | Annual output (GWh/year) | Load factor (%) | Capital cost (£/kW) | Build time (years) | Life time (years) | Energy cost (p/kWh)[a] |
|---|---|---|---|---|---|---|---|
| Forestry waste | 1 | 7 | 80 | 600–1 000 | 1–2 | 15 | 3–7 |
| Landfill gas | 0·4–5 | 299 | 35–85 | 500–660 | 1–2 | 15–25 | 1·8–2·1 |
| General industrial waste | 0·4–5·6 | 63 | 90 | 600 | 1–1·5 | 20 | 0–1 |
| Special industrial waste: | | | | | | | |
| —Tyres | 5 | 40 | 90 | 600 | 1–1·5 | 20 | 0–1[b] |
| —Hospital waste | 0·43–1·8 | 17·8 | 90 | 720–1 400 | 0·5–1 | 20 | 0[c] |
| Municipal solid waste | 62–271 | 433–1 902 | 80 | 2 287 | 2–3 | 20 | 4–7 |

[a] All costs based on a 10% discount rate and 1988 money with payback over respective lifetimes.
[b] Assuming a disposal saving of £10/t.
[c] Assuming a disposal saving of £30/t.

### 13.5.3 Wind

Factors affecting wind energy economics were dealt with in detail by the BWEA Position paper 'Wind energy for the UK' published in January 1987.[4] Those performance figures and costs are now outdated and the latest performance, cost and availability figures for a 5 MW wind farm of 20 wind turbines built in California in 1986 are presented in this volume and elsewhere;[6] for recent construction costs in Britain see Section 5 of Ref. 10. The capital cost figure of £600/kW (1987), or approximately £800/kW (1989), is still a target cost rather than an actual cost depending for its realisation upon mass production economics. System connection and site costs might add a further £100–£150/kW to this figure. Wind resources are from Ref. 11 and the key parameter is annual average wind speed. Losses due to interference between machines sited close together in large wind farms must be taken account of and are dealt with in Ref. 12. The electrical output rating for a wind turbine of a given rotor size has a relatively small effect upon the overall economics (a more highly rated generator will operate at a lower load factor) and it is the annual energy capture or the average power output which determines the total amount of electricity that is generated and hence the economic value of a wind farm: this is very site-dependent and tidal power (and wave power) are similar in this respect. There will be cost differences of two or three to one between the best and worst areas of the country.

Offshore wind energy has been the subject of many national and international studies which were reviewed recently by Swift-Hook.[13] There is a very substantial resource, more than present electricity supplies.[14] There are difficulties in obtaining detailed up-to-date cost estimates: by the time detailed offshore studies have been completed, based presumably upon the latest land-based design, that design has been superseded by a much cheaper one. An approach based upon offshore/onshore cost ratios is recommended.[13]

### 13.5.4 OTEC

Costs and technology for projected demonstration projects were presented at the IEE 1987 Energy Options Conference[15] (see also Ref. 16), based upon a fuller and more detailed assessment for the 1986 World Energy Conference.[17] Ocean temperature difference between the surface and 1000m is the dominant factor. Designs of plant and consequent economic estimates are based upon minimum values which occur in winter.

### 13.5.5 Geothermal

Geothermal power was reviewed by Shock.[18] Generation costs for recent technologies and developments on hot dry rock are set out by Batchelor.[19] Economics are dominated by drilling costs while thermal gradients (or water temperature available at depth) and water flow rates (or impedances) through the fractured rock and reservoir management (active or passive) can also affect costs. A single doublet of boreholes (cold down, hot up) is regarded as the basic technology. Multiple boreholes, with several producers for each injector, offer the improved economics listed but they are regarded as more developmental. There are institutional and legal difficulties that have been dealt with briefly in Section 7.

### 13.5.6 Tidal

The costs of tidal power have probably been the subject of more extensive paper studies than any of the other renewables. The Bondi Committee reported on the Severn Barrage in 1981 and since then several major studies have been and are being funded. The figures given in this analysis are based upon the Proceedings of the ICE Symposium on Tidal Power held in October 1986 (Duffett and Ward; Carr). Operational performance data which provide a sound and practical basis for these estimates are available from the Rance Barrage although that technology is now more than 20 years old. Modern low head hydroelectric installations have a good deal in common with a tidal barrage and give some guide to costs for both dam construction and water turbines, but the continuous variations in water level make a tidal scheme more complex. The choice of generator rating has relatively little effect upon the economics of the electrical energy that can be extracted from a given barrage; more highly rated turbines will operate at lower load factors, just as for wind energy. Details of the Mersey Barrage proposals were contained in a report by Rendel Parkman and Marinetech NW published in 1985.[20]

### 13.5.7 Wave

A wide variety of different wave energy devices have been studied but little work has been funded in the last three or four years. The original Salter Duck[21] is one of the best known, and detailed cost and performance estimates on the most recent developments by the Edinburgh group were given by Salter himself at the IUTAM Symposium on the Hydrodynamics of ocean wave-energy utilisation in July 1985; his figures have been used, suitably escalated for inflation to mid-1987 prices.

The Lanchester/Coventry Polytechnic Group have studied the circular SEA-Clam, and their cost and performance figures are derived from the March 1986 Report on ETSU Contract E/5A/ CON/1676/1381. Details were presented at the IEE Energy Options Conference at Reading in 1987.[22]

Inshore wave power systems are claimed to be the most economic. Such systems are necessarily sited in specific locations where limited amounts of water are available; hence the designation ‘inshore’. Because of the relatively small number of such sites available, the inshore wave resource is seen as quite small and therefore has not until recently been actively pursued by the UK Department of Energy in their wave energy programme. The Norwegians have pursued two such systems very actively and practical performance data are now available for tapered channel coast. Details of the oscillating water column system were presented at the IEE Energy Options Conference in Reading in 1987.[23]

### 13.5.8 Solar

Present costs for photovoltaics are firmly based upon megawatt-scale installations in California, Europe and elsewhere. Photovoltaics have probably been the subject of more forward cost projections than most of the other renewables. One or two orders of magnitude reduction in costs are required to compete with those of bulk electricity generation although many special applications for small power supplies are already economic. Such large extrapolations are frequently criticised as unrealistic, but the field of semiconductor technology happens to be one where just such cost reductions have been achieved as a result of quantity production in recent years. Forward projections of that sort have not been attempted in this paper, however, and the costs presented are for existing technology which makes no claim to being economic, as yet, for bulk electricity production.

## 13.6 DISCUSSION

### 13.6.1 Risks, uncertainties, sensitivity analyses, spider diagrams

Where possible, data on each of the technologies have been derived from working installations, but these are rather scarce for the renewables and those available do not usually represent the latest technology. In many cases, cost and performance estimates for a full renewable power plant have been established on the basis of the known costs for separate individual units or sub-systems which could be assembled to provide a complete system. This is the approach adopted for other power plant. For example, the Sizewell B design of PWR has never been built before with all the safety features called for as a result of the Public Enquiry and by the Nuclear Installations Inspectorate, but it is assembled from units most of which have been built or which use existing technology; thus the whole installation can therefore be costed with some confidence.

In making best estimates of the cost of renewable sources of power, it is not sufficient to err on the 'safe side'. (There are, after all, many who would regard the renewables as safer than other systems since they do not produce ionising radiations, acid rain or other atmospheric pollution; they would no doubt claim that 'the safe side' is in favour of the renewables!) Where there is uncertainty, it needs to be faced and not side-stepped. It is common practice to handle uncertainty in the outcome of a project by requiring it to make a higher rate of return. While this reduces the risk of making a loss it also reduces the chance of making a gain, which was presumably the reason for considering the project in the first place; it does nothing to reduce the uncertainty—indeed, it increases it in absolute terms. That is why the government's Treasury Rules specify that uncertainty should be dealt with separately and they no longer recommend an increased rate of return. Where there is uncertainty, it should be reduced as far as possible and quantified.

There may be costs associated with this process; for example, research can be a means of reducing uncertainty, as well as of reducing costs. The renewables no doubt differ in the amount of research and development they each require—certainly options on that subject seem to differ considerably and frequently to conflict. Proponents of a technology often see no inconsistency in claiming both that it is already proven to be worth commercial exploitation because it is economic and at the same time that it requires government funding for further research. Such lack of logic is perhaps excusable when renewables need to compete with the massive research and development and other subsidies given to nuclear plant and to fossil fuel generation which are not included in the costs of energy.

In general, small unit sizes will require low development costs but even for major projects such as a tidal barrage, development costs will represent only a small part of the total cost of a single installation. By contrast the amount spent on nuclear power research every year represents a substantial fraction of the cost of a single nuclear power station, and, by convention, such costs are not included in the generation costs that are quoted. It would not therefore be unreasonable to attempt to include such estimates for the renewables.

When faced with uncertainty, there is considerable merit in taking central estimates or average figures.

Not only is this a commonsense approach but it is also mathematically correct. It provides best estimates of minimum error, maximum likelihood and various other statistical parameters of interest, at least for normal distributions. When faced with a choice of known options, however, the situation is very different: when one *can* choose, one should always choose the best! Faced with machines of good, bad and indifferent performance, it makes no sense at all to pick an indifferent design just because it is average. Similarly with good, bad and indifferent sites to choose from, one should clearly choose the best ones available in the first instance. It must be recognised that the numbers of such sites will be limited but by the time they have been filled, the scale of production may well have produced significant cost reductions which should allow similar generation costs to be achieved at less favourable sites that are more widely available.

Costings are therefore presented for the best technologies available for each of the renewables. Uncertainties in each of the various parameters which influence costs have been considered individually. Where costs are directly (or inversely) proportional, the corresponding uncertainties are straightforward; for example, 10% uncertainty in capital cost gives 10% uncertainty in the cost of energy (if all other parameters are unaffected); it will be recalled that annual O&M costs have been expressed as a fraction of capital, as explained in Section 13.2.5.

'Spider diagrams' are a convenient and condensed way of illustrating such variations in cost.[24,4] Figures 13.1 to 13.16 show the sensitivities of the costs of energy from various renewable sources of power to the key performance and cost parameters.

In quoting the best costs, it is necessary to bear in mind that the costs of many sources such as tidal, wind and mini-hydro are very site-dependent and the best costs will relate only to limited resources. It is therefore necessary to quote the resource that is available at any stated cost level. This has been done in Table 13.4 and Figure 13.19 below.

### 13.6.2 Effects of changing interest rate

There are few surprises in the cost sensitivities described in Section 13.6.1. The exception concerns the cost variations for various discount rates. It was explained in Section 13.4.1 that wide ranges of real rates of return need to be considered. Figure 13.18a shows how the costs of energy from different renewable power sources vary according to the required real rate of return. It can be seen that all of the renewables vary in the same way with the sole exception of tidal power.

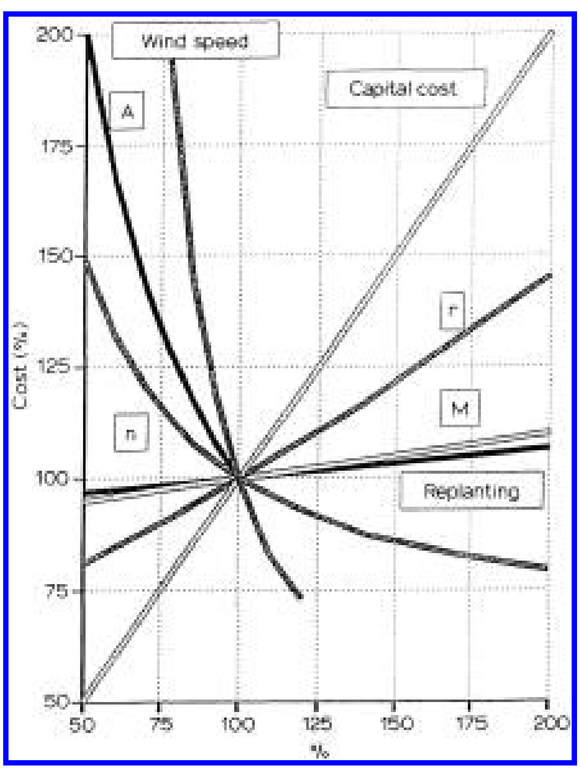


**Fig. 13.1.** Generating cost sensitivity analysis for wind energy: A=availability; n=life; r=intereest rate; M=operation and maintenance.

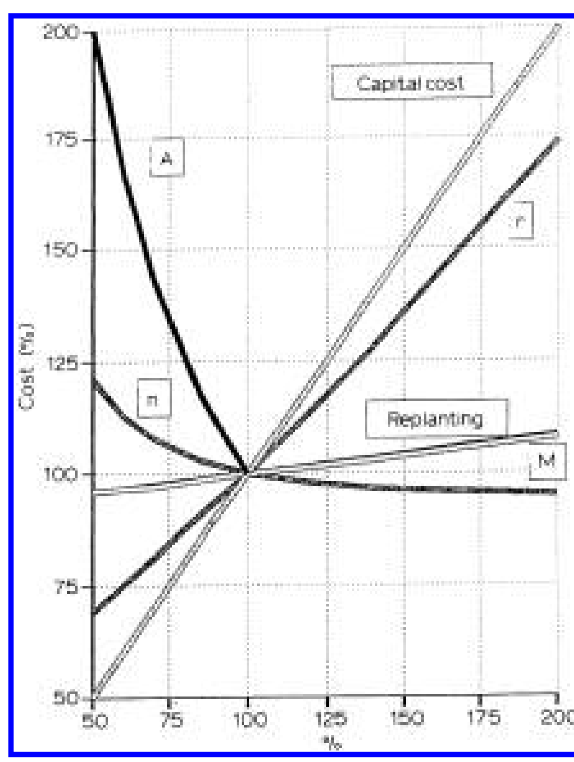


**Fig. 13.2.** Generating cost sensitivity analysis for mini-hydro; A, n, r and M as in Fig. 13.1.

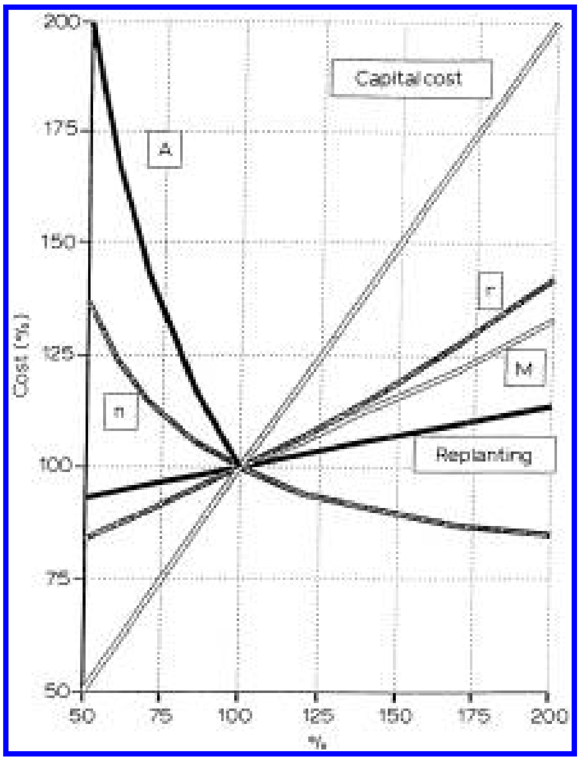


**Fig. 13.3.** Generating cost sensitivity analysis for OTEC; A, n, r and M as in Fig. 13.1.

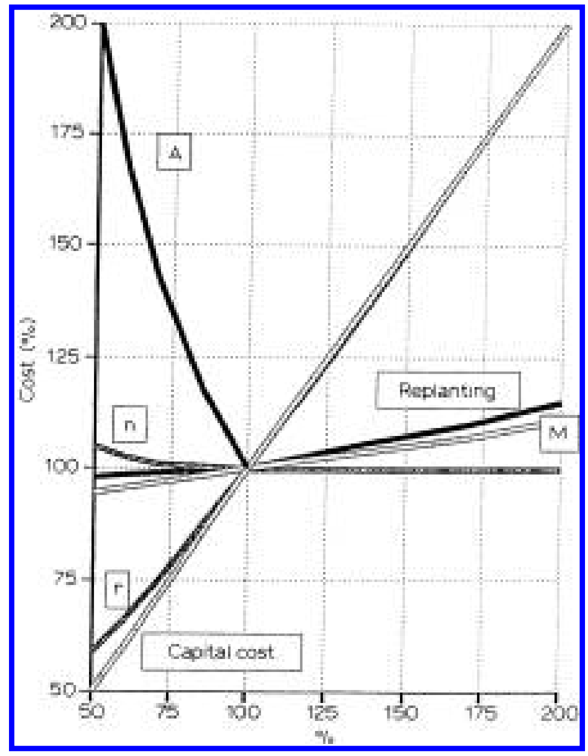


**Fig. 13.5.** Generating cost sensitivity analysis for tidal energy (Severn Barrage); A, n, r and M as in Fig. 13.1.

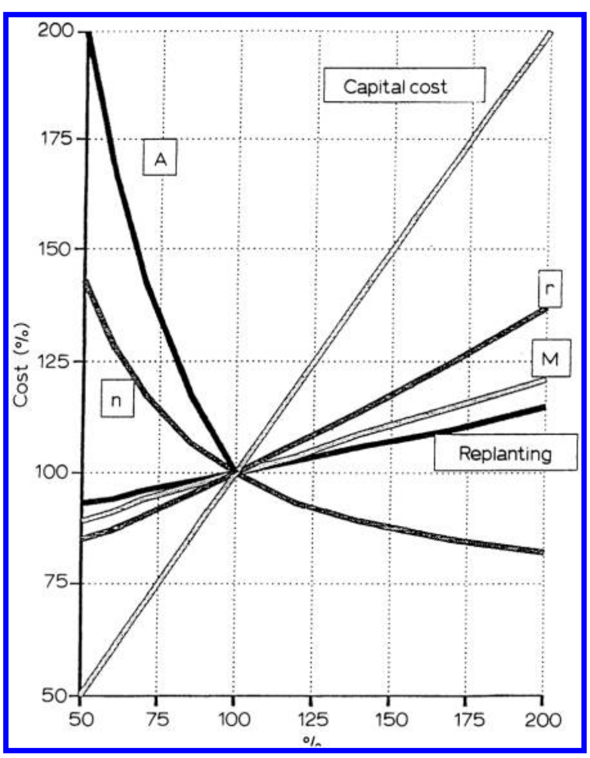


**Fig. 13.4.** Generating cost sensitivity analysis for geothermal energy (hot dry rock); A, n, r and M as in Fig. 13.1.

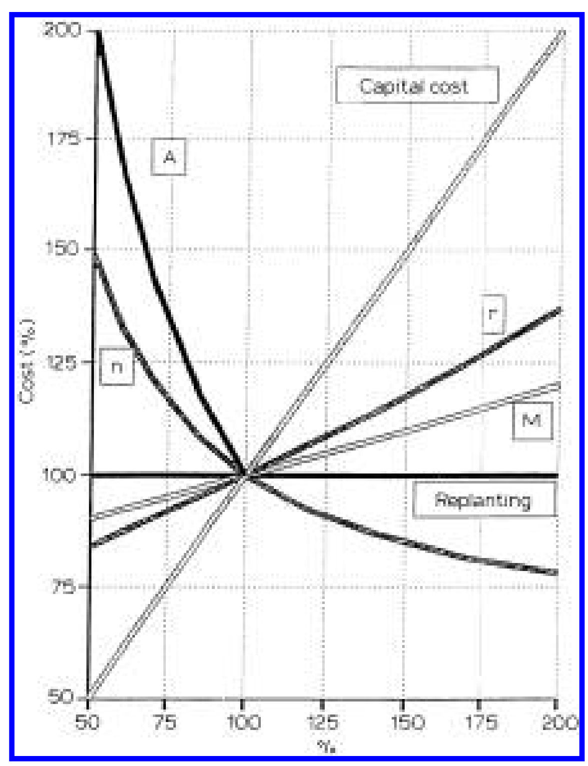


**Fig. 13.6.** Generating cost sensitivity analysis for biomass energy; A, n, r and M as in Fig. 13.1.

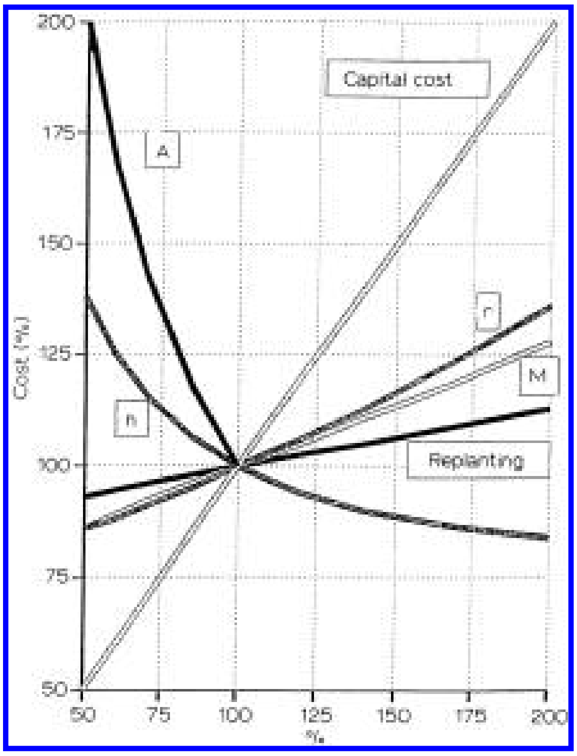


**Fig. 13.7.** Generating cost sensitivity analysis for geothermal energy (multiple doublets); A, n, r and M as in Fig. 13.1.

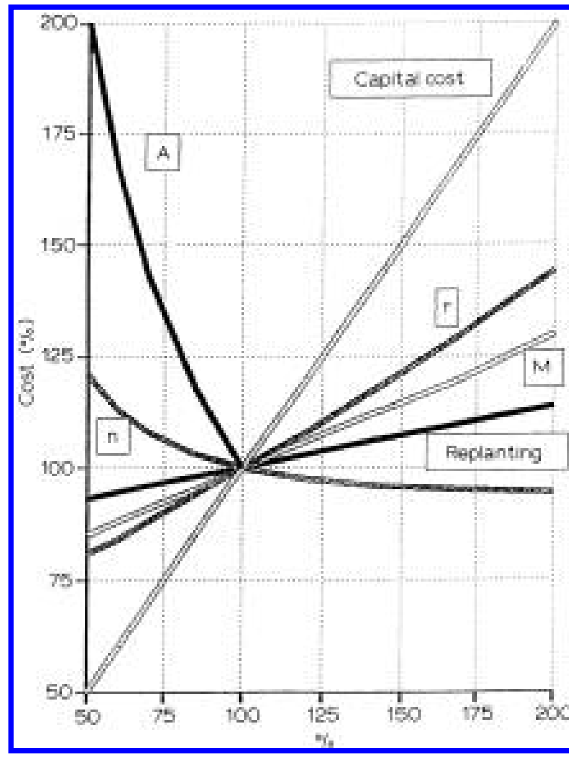


**Fig. 13.9.** Generating cost sensitivity analysis for wave power (shore-based OWC); A, n, r and M as in Fig. 13.1.

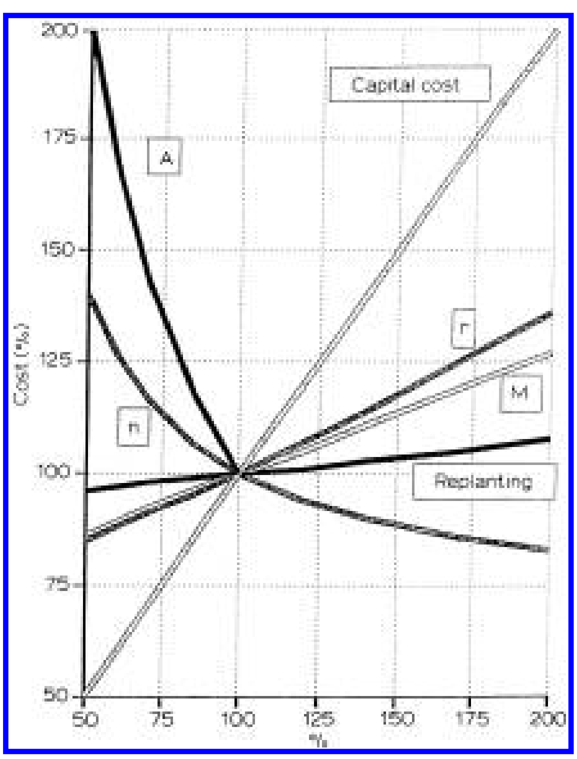


**Fig. 13.8.** Generating cost sensitivity analysis for wave power (Clam); A, n, r and M as in Fig. 13.1.

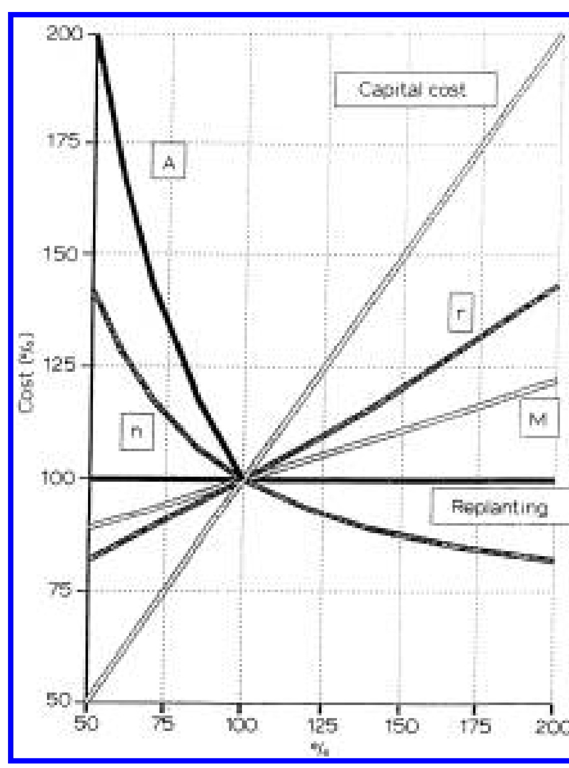


**Fig. 13.10.** Generating cost sensitivity analysis for wave power (Salter Duck); A, n, r and M as in Fig. 13.1.

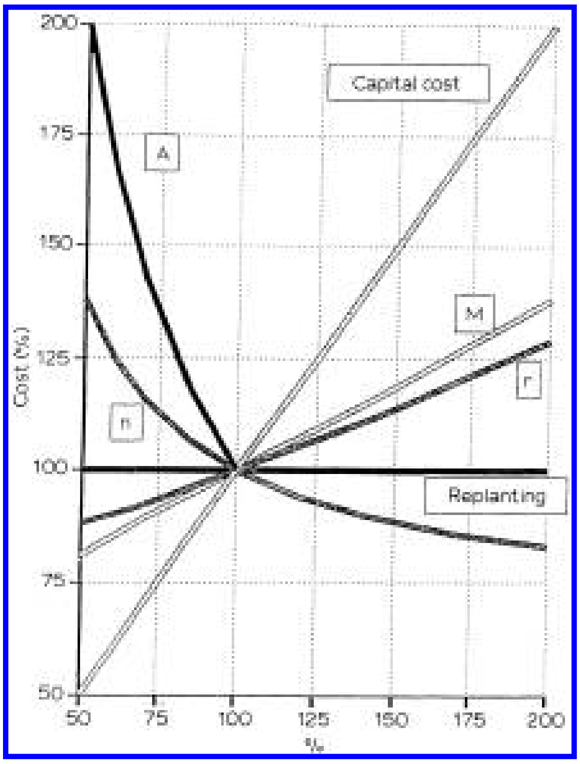


**Fig. 13.11.** Generating cost sensitivity analysis for active solar power; A, n, r and M as in Fig. 13.1.

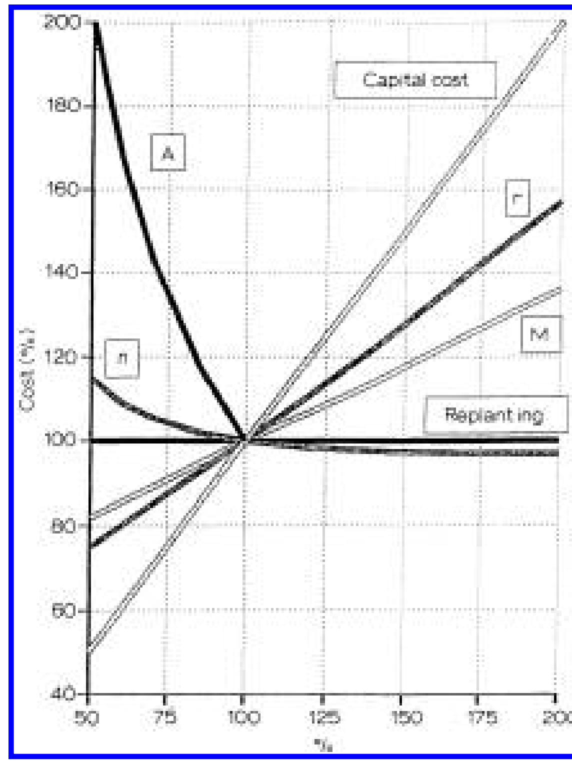


**Fig. 13.13.** Generating cost sensitivity analysis for passive solar heating; A, n, r and M as in Fig. 13.1.

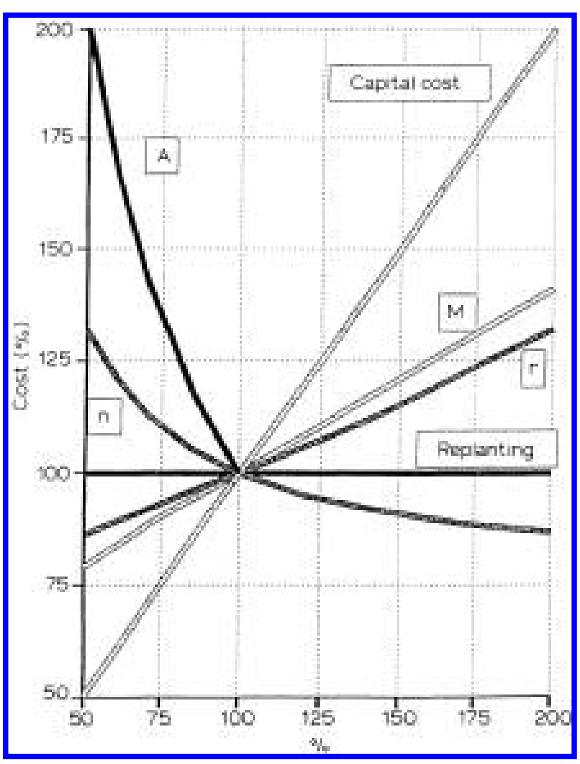


**Fig. 13.12.** Generating cost sensitivity analysis for solar process heat; A, n, r and M as in Fig. 13.1.

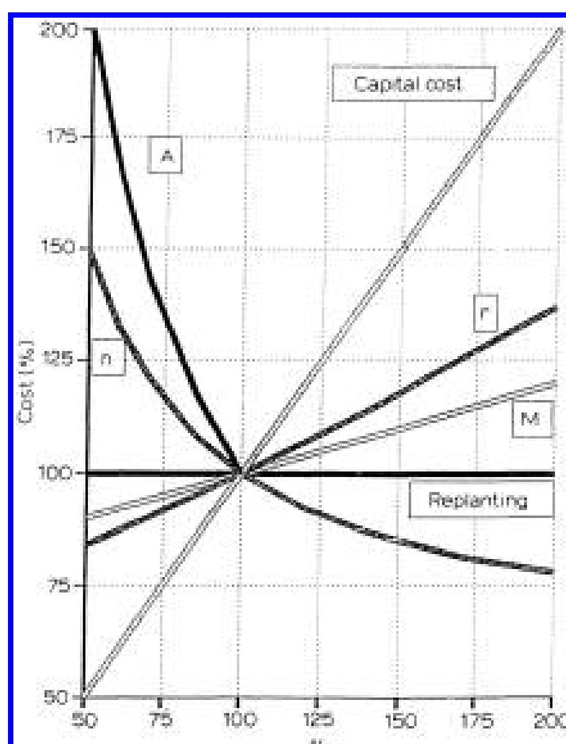


**Fig. 13.14.** Generating cost sensitivity analysis for solar photovoltaic energy; A, n, r and M as in Fig. 13.1.

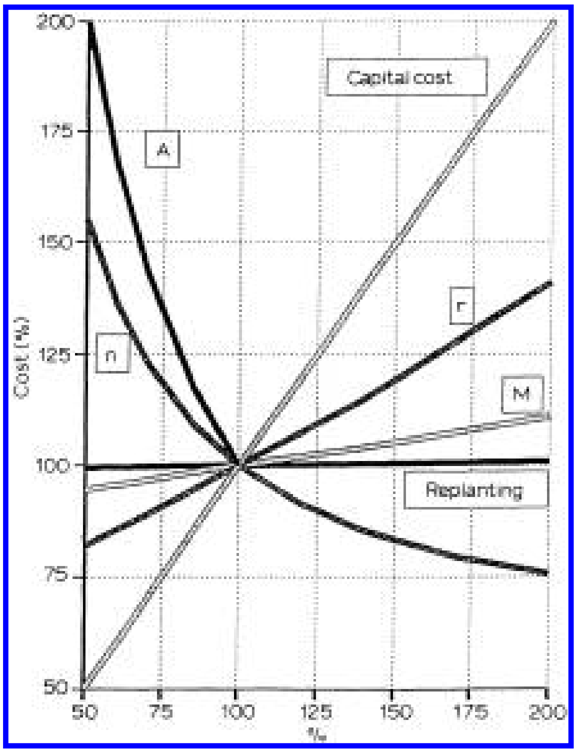


Fig. 13.15. Generating cost sensitivity analysis for geothermal energy (aquifers); A, n, r and M as in Fig. 13.1.

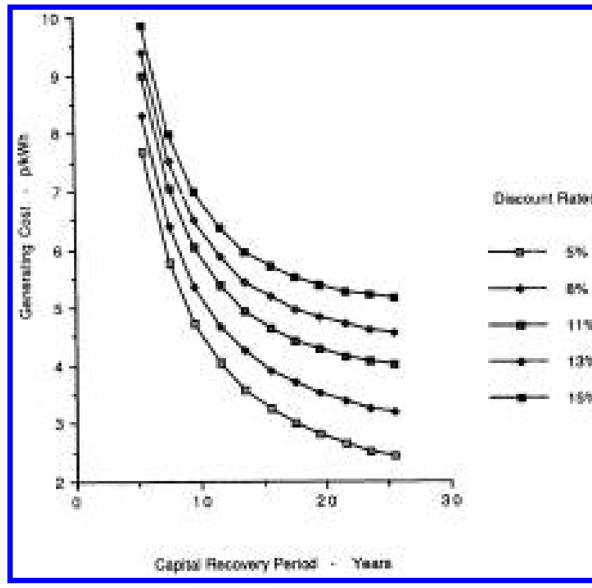


Fig. 13.17. Wind power generating costs.

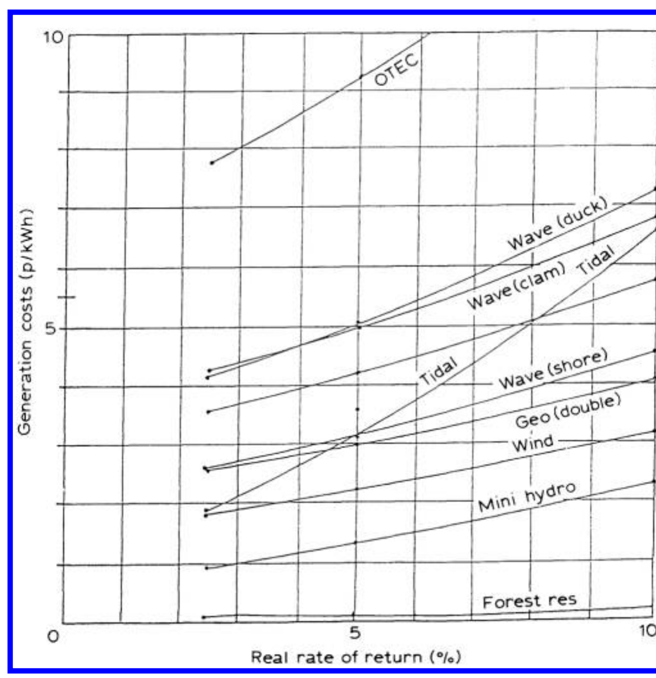


Fig. 13.18a. Generating cost escalation with discount rate.

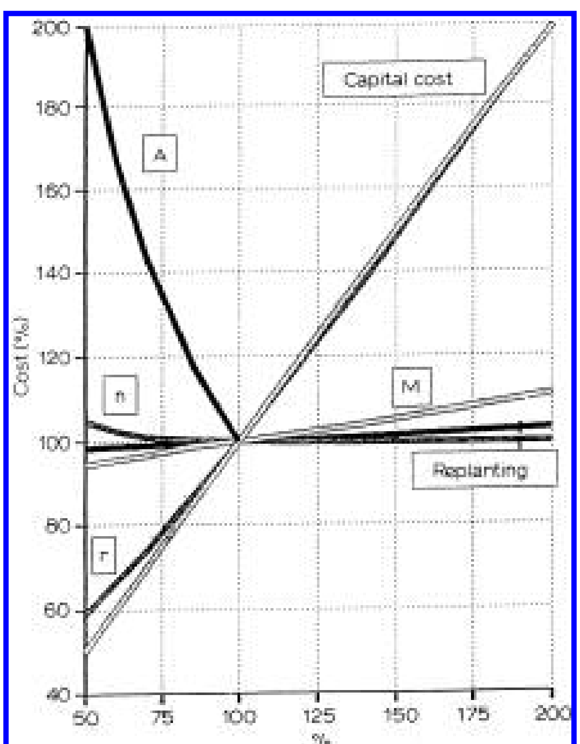


Fig. 13.16. Generating cost sensitivity analysis for tidal energy (Mersey Barrage); A, n, r and M as in Fig. 13.1.

This means that the relative economic position of each renewable with respect to the others is unaffected by the changes in interest rate discussed in Section 13.4.1, again with the exception of tidal power. Required rates of return are already being increased throughout the electricity supply industry and it seems likely that they may rise still further when privatisation is introduced. It is interesting to see that the relative economics and the best buys amongst the renewables will be unaffected by such changes.

This observation is in sharp contrast with other sources of power. The economic balance shifts markedly towards coal as interest rates rise and away from nuclear which is capital intensive.

Tidal power provides a notable and unfortunate exception amongst the renewables. From Fig. 13.18a, the economics of tidal power are seen to be middle-of-the-road for 5% real rate of return. At the lower rates of return actually earned by the CEGB in the past, tidal power would have looked extremely favourable compared with all other renewables. However, at the higher rates of interest that are expected by private industry, tidal power looks distinctly uncompetitive compared with most of the other renewables. Further analysis showing the relationship between unit cost of electricity and discount rate at 1986 prices for various barrage schemes is presented in Fig.13.18b. It is fortunate for larger scale hydroelectricity that its available resources have already been almost fully exploited in the UK during a period of cheap public capital; with its high capital cost and long life, it too would have been uneconomic with private (or public) finance if higher rates of return had been required.

In the real world, a large established utility will be able to raise capital from the government or major national or international banks at preferential rates of interest. A small private company or utility may have to pay one and a quarter times as much for its money (perhaps an extra two percentage points or more). Such differences will produce real variations in cost: if the large organisation can get cheaper money, it should be able to generate more cheaply. This institutional advantage is in principle no different from any other saving of scale available to a large organisation, such as in longer production runs. It does, however, mean that until such institutional barriers are removed, smaller companies will find it difficult to compete with the large utilities, whether or not they are privatised. If they are able to do so, it may well be that they will find different types of power plant economic, e.g. plants which have shorter lifetimes or which are less capital intensive.

### 13.6.3 Exploitable resources at various cost levels

The amount of energy that can be exploited at the costs set out in Tables 13.2, 13.3 and 13.4 may be limited by a variety of factors. The most evident will be the resource availability discussed in Section 13.3.1. Figure 13.19 shows estimates of the resources available at various cost levels with present plant prices. In many cases these costs are likely to fall as the scale of production increases and the technology advances.

Mini-hydro is the cheapest of all the renewable sources of power that can be installed but unit sizes are small and the number of sites available is fairly limited. Obviously this resource should be exploited as far as possible, and that may involve hundreds of installations, but the total amount of energy available

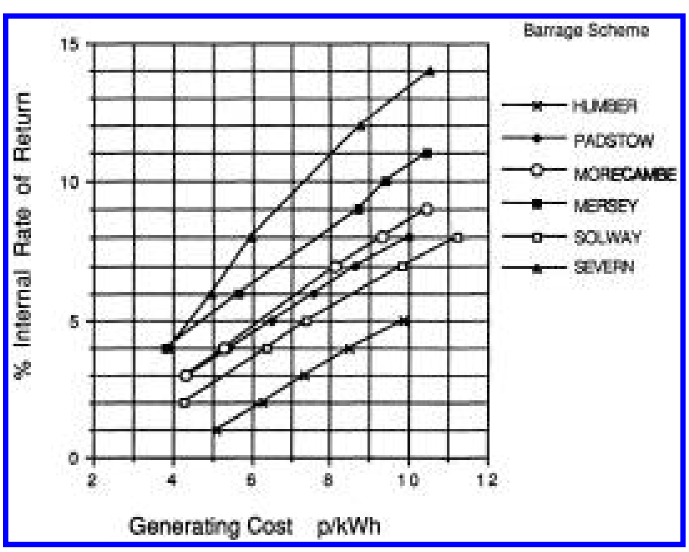


**Fig. 13.18b.** Generating costs for various barrage schemes for different internal rates of return.

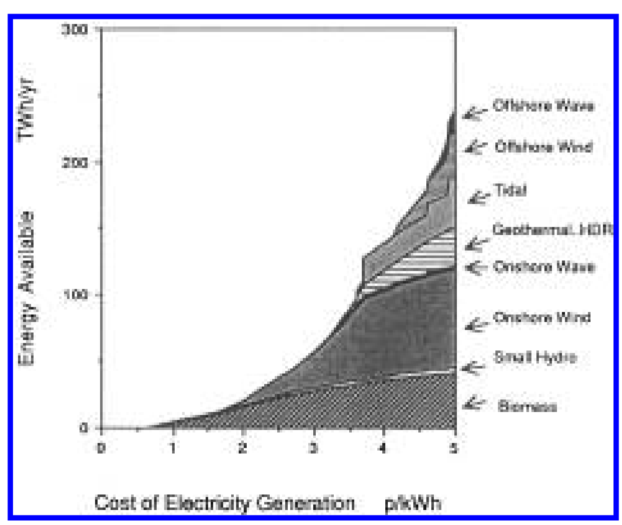


**Fig. 13.19.** Estimated resource-cost curves for the renewable energy sources at 5% discount rate (1987 costs).

at very low cost sites will be very modest in terms of national requirements.

Wind has a much greater total resource and the best sites have competitive generating costs. The total wind energy resource over the whole of Great Britain would be 1000 GW if the entire countryside could be wind-farmed, but it is usually estimated that environmental and other constraints would limit the resource to 20 GW or 30 GW at most.[2] The CEGB[2] believe that there is 1 GW of wind power at £0·022/kWh or cheaper. Certainly there are about 16 000 $km^2$ in the country as a whole where the synoptic wind speeds are adequate for that and only 1% or 2% of those windy areas would need to be covered with wind farms to provide 1 GW of installed capacity.

Synoptic wind speeds over the entire country are all within 20% of the wind speeds that are economic today and so all possible wind farm sites anywhere in the land would become economic if 50% cost reductions could be achieved after the first gigawatt (the first 10 000 to 40 000 machines, depending on optimum size) as a result of quantity production. Cost reductions of this order have already been achieved over the last few years in wind energy and sizeable reductions are projected for other technologies (such as PWR), so such further developments seem well within the bounds of feasibility. In California, 1 GW of wind power was recently installed within a period of three years and that shows what can already be done when there are adequate economic incentives. The economic incentives in California were provided by tax credits and subsidies but the technology has now reached the stage where it can be economic in the UK in its own right (viewed as a public sector development with capital recovery over the whole lifetime).

Resources available at various cost levels were included in the questionnaire for all the technologies and so the 'league table' is able to include an estimate of the resource of each renewable, expressed as a percentage of national electricity requirements, available at the stated cost level. Costs are given in Tables 13.3 and 13.4 for the best technology at present available on the best sites which are sufficient to provide a significant resource. Additional resources are available in most instances on less economic sites, as shown in Fig.13.19; they may become viable later on, as explained in Section 13.3.1.

Against this, the environmental and institutional factors mentioned in Section 13.1.3 and dealt with in detail in previous Sections of this volume may limit the permitted level of exploitation despite any economic advantages. That has certainly happened to nuclear power in a number of countries and could happen to the renewables in the UK.

### 13.6.4 Commercial prospects

The generating costs calculated for the data in Table 13.2 and listed in Tables 13.3 and 13.4 can be scaled to mid-1989 values from the mid-1987 values (the date of the survey) by allowing for price inflation (11·7%).

With privatisation in 1990 other changes are necessary. The historic discount rate of 5% is no longer appropriate so a higher rate of, say, 8% in real terms is adopted. A final modification is to calculate the costs on the basis of various capital recovery periods of 10, 15 and 20 years respectively. Using the results of the 1987 questionnaire the generating costs can then be found as shown in Fig. 13.17 and 13.3 where for purpose of comparison, estimated generation costs from other studies are also included.

The commercial prospects for the renewables within these constraints depend in turn upon the electricity market prices of the receiving system. As noted in Section 13.1.2 the average price paid to the CEGB for electricity sold to the Area Boards was 3·5 p/kWh whilst the average price at which it was economic for the Area Boards to purchase electricity from private generators was 2·5 p/kWh. In the future, privatised industry with higher discount rates and shorter capital recovery periods, electricity costs/prices should be considerably higher. Such possibilities are illustrated in Fig.13.17 for wind power which indicates that a private wind power generator expecting to recover capital in, say, 10 years at a real rate of return of 8% would be bidding for contracts at about 5–5·5 p/kWh supplied in 1989 money.

### 13.6.5 Caveats

It is important to recognise that, although the data used in this analysis are probably the best at present available, inevitably they are of variable quality. Greater confidence can obviously be placed in the practical costs and performances of commercial installations (such as operating wind farms) than in estimates based solely upon paper studies and laboratory-scale investigations. Results from full-scale prototypes or demonstration units (such as the

Rance tidal scheme) will carry greater credibility than extrapolations from small-scale models. On the other hand, rapid developments are taking place and so results based upon technology and installations which are up-to-date cannot be well proven and vice versa.

It is only fair to point out that the Questionnaire turned out to be over-ambitious: the complete information called for, including high and low bounds on every parameter, could not actually be produced for every single aspect of any of the renewables and inevitably some responses were less detailed than others. Nevertheless, the detailed nature of the questioning did achieve the primary purpose, which was to elicit very full information, with detailed estimates that could be well supported, for all of the relevant factors that directly affect costs. It was possible to ensure that estimates of quantities such as mechanical availability, operation and maintenance, and losses were realistic for each of the renewables and that exceptionally high or low values could be justified. These quantities are often omitted from published data and reliable figures are not necessarily available even from prototype installations (as pointed out in Section 13.3).

The final results in Table 13.3 follow directly from the figures provided by the experts in Table 13.2. Any single figure must be taken in conjunction with the sensitivity analysis represented by the relevant spider diagram. Also, although those figures were the best available when they were collected, experience has shown that they need to be updated almost continuously.

Although all of the figures provided from the Questionnaires have been subjected to the same analysis, it is not always easy to ensure that they are uniformly optimistic or pessimistic. Central estimates were called for and it was hoped to avoid both optimism and pessimism, but the feeling emerged from detailed discussions that this aim had not always been achieved. For example, serious and detailed assessments, which have a view to direct commercial exploitation, can normally expect to include quite explicitly a substantial contingency allowance where no comparable demonstration project is available upon which current detailed costs can be based; this was as much as £0·005/kWh in the case of the Severn Barrage studies.

Again, it was felt prudent to leave conservative generating costs that can be substantiated in great detail for tidal power in Tables 13.2 and 13.3 and elsewhere, but the need to update estimates as soon as new results can be fully justified must be reemphasised.

So, where technological progress and/or detailed design studies and optimisations are taking place, there may well be substantial reductions on the generating cost estimates given in this Section. Nevertheless, problems can also appear. For example, the wind industry went through a period of serious fatigue failures of wind turbine blades a few years ago. The solutions to such problems may well result in cost increases. This does not seem to have happened in the case of wind energy but examples from the aerospace and nuclear industries show that costly failures can affect the economics of a whole technology.

The information on which the estimates in this Section are based comes from experts in the field who are familiar with the latest technology and data. However, all data must be treated with due scepticism. It would be difficult to support the case that data from non-experts should be preferred to data from experts; but experts can be enthusiasts and enthusiasts tend to take optimistic views of the likely costs and performances of their favoured technology.

To counteract this tendency, information on all aspects of the various systems have been quantified as far as possible and sufficient detail called for to ensure that vital factors which are often skated over (such as reliability and operating costs) have not been hidden and ignored. All sources of data have been clearly referenced as far as possible so that readers can check them for themselves and can form their own judgments of how reliable they are. Most importantly of all, each of the renewables has been costed on exactly the same basis.

## 13.7 SUMMARY AND CONCLUSIONS

A convenient way of comparing the economics of the various renewable sources of power is to estimate the levelled cost of the energy they produce. This is particularly suited to sources of energy which have no fuel costs. On the other hand market costs must be related to appropriate discount rates and desired capital recovery periods.

The unknown financial effects of future inflation are avoided by expressing all costs in present-day money or in 'real terms'. Future costs are 'present-day-worthed' by discounting them at a suitable rate of interest; future interest payments must be similarly discounted and the rate of interest in real terms is less than the money rate of interest by an amount due to inflation.

The important technical factors which affect the economics of renewable sources of energy include the resource availability and the rated output of the plant together with its life and availability (taking account of mechanical outages and other losses). The important economic factors are the costs of plant construction, operation, maintenance and refurbishment and the real rate of interest.

Data on costs of plant, of maintenance, of refurbishment, of operations, etc., were obtained on a comparable basis for each of the renewables from experts by means of a standard questionnaire which also called for detailed performance and resource estimates and for the sources of the data. The sources of the data and other notes are presented in Section 13.5. The data were evaluated on a standard basis using the formulae given in Section 13.4.3.

Detailed results are listed in Table 13.2. The sensitivities of the generation costs for each of the renewables considered are also shown in the form of spider diagrams, Figs 13.1 to 13.6. The generating costs for the best few hundred megawatts or so for each of the renewables are summarised in Table 13.3, and the resources available at various cost levels are shown in Fig.13.19. These resource/cost curves are provided by way of example, of course, rather than by way of accurate estimates. Figure 13.19 shows that changes in the required rate of return on capital, i.e. interest or discount rate, will not affect the relative economics except for tidal power.

All forward-looking estimates need to be treated with caution. However, renewable technologies have been developing rapidly and further cost reductions are predicted in a number of areas. There is a clear need to keep such assessments under review.

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# Appendix 13.1

# Data Collection Questionnaire

**RENEWABLE ENERGY COST AND PERFORMANCE FIGURES**

1 Name of renewable energy source ____________________

| | | | hi | lo |
|---|---|---|---|---|
| CAPITAL COSTS | | | | |
| 2 Total capital cost per installed kilowatt* | ________ | *£/kW | ______ | ______ |
| 3 which includes grid connection costs of | ________ | £/kW | ______ | ______ |
| COSTS DURING CONSTRUCTION | | | | |
| 4 Construction period | ________ | years | ______ | ______ |
| 5 Costs in year before commissioning * | ________ | *% of capital | ______ | ______ |
| 6 Costs in year 2 before commissioning * | ________ | *% of capital | ______ | ______ |
| 7 Costs in year 3 before commissioning * | ________ | *% of capital | ______ | ______ |
| 8 Costs in year 4 before commissioning * | ________ | *% of capital | ______ | ______ |
| 9 Costs in year 5 before commissioning * | ________ | *% of capital | ______ | ______ |
| 10 Costs in year 6 before commissioning * | ________ | *% of capital | ______ | ______ |
| 11 Costs to year 7 before commissioning * | ________ | *% of capital | ______ | ______ |
| LIFE-TIME COSTS | | | | |
| 12 Design life-time of installation (and amortization period) * | ________ | * years | ______ | ______ |
| 13 Annual operation and maintenance costs will amount to * | ________ | *% of capital | ______ | ______ |
| 14 Re-planting costs will be * | ________ | *% of capital | ______ | ______ |
| (for major re-furbishments | | | | |
| 15 within the life of the after * | ________ | * years; | ______ | ______ |
| plant that are too large | | | | |
| 16 to be averaged out as and then * | ________ | *% of capital | ______ | ______ |
| annual maintenance) | | | | |
| 17 after * | ________ | * years; | ______ | ______ |
| 18 and then * | ________ | * % of capital; | ______ | ______ |
| 19 after* | ________ | * years; | ______ | ______ |

RATED PERFORMANCE

A description of the (typical) renewable energy system on which these performance figures are based is given in the following reference:

20 author ____________________

21 year ____________________

22 publication ____________________

23 volume ____________________

25 other information

24 page ______________________________________________

The intensity of this renewable
source of energy is measured in
26 terms of the following quantity: ______________________
(eg annual mean wind speed for wind energy)

27 for which the (SI) units are: ______________________
(eg m/s for wind)

| | | hi | lo |
|---|---|---|---|
| The rated value for this quantity, ie the value for which the system | | | |
| 28 produces its maximum or rated output is | * ______________ * | ________ | ________ |
| (eg rated wind speed for a wind turbine) | | | |

TIME-VARIATIONS OF THE RENEWABLE SOURCE OF ENERGY

Throughout the year the source of energy
varies in the following way:

| | | | |
|---|---|---|---|
| | for ___100___ % | | |
| of the time it is 0% of its rated value or better; | | | |
| 30 | for * ________ * % | ________ | ________ |
| of the time it is 25% of its rated value or better; | | | |
| 31 | for * ________ * % | ________ | ________ |
| of the time it is 50% of its rated value or better; | | | |
| 32 | for * ________ * % | ________ | ________ |
| of the time it is 75% of its rated value or better; | | | |
| 33 | for * ________ * % | ________ | ________ |
| of the time it is 100% of its rated value or better. | | | |

RENEWABLE ENERGY SYSTEM PERFORMANCE CHARACTERISTICS

The performance characteristics of this
energy system can be described as follows:

| | | hi | lo |
|---|---|---|---|
| | it produces ______0___ % | | |
| of maximum (rated) output when the source is 0% of its rated value; | | | |
| 34 | it produces * ________ * % | ________ | ________ |
| of maximum (rated) output when the source is 25% of its rated value; | | | |
| 35 | it produces * ________ * % | ________ | ________ |
| of maximum rated) output when the source is 50% of its rated value; | | | |
| 36 | it produces * ________ * % | ________ | ________ |
| of maximum (rated) output when the source is 75% of its rated value; | | | |
| | it produces ____100___ % | | |
| of maximum (rated) output when the source is 100% of its rated value. | | | |

NOMINAL LOAD FACTOR

The variation of system output throughout the year can therefore
be summarised in the following way:

for ____100___ %

of the time the output is at least 0% of maximum;

37 for * ________ * % ________ ________
of the time the output is at least 25% of maximum;
38 for * ________ * % ________ ________
of the time the output is at least 50% of maximum;
39 for * ________ * % ________ ________
of the time the output is at least 75% of maximum;
40 for * ________ * % ________ ________
of the time the output is at least 100% of maximum.

The (time) average of this performance characteristic is called the nominal load factor. It expresses the average output that is available due to the variability of the source of energy as a fraction of maximum (or rated)
41 output. Its value is * ________ * % ________ ________

LOST ENERGY

Because of mechanical and other outages, the renewable energy system will not be available for 100% of the time for which
42 the source is available, but only for * ________ * % ________ ________
of that time.
43 Other losses of energy may arise from ________________________

44 and/or from ________________________
45 and/or from ________________________
46 and/or from ________________________

Together, these other losses can be
47 represented by a loss factor of * ________ * % ________ ________

TOTAL RESOURCE

48 The total resource has been estimated as ________ TWh/a ________ ________
This is made up as follows:
49 ________ TWh/a ________ ________
from the best sites for which the source
50 intensity is better than ________ ________
51 ________ TWh/a ________ ________
from good sites for which the source
52 intensity is better than ________ ________
53 ________ TWh/a ________ ________
from average sites for which the source
54 intensity is better than ________ ________

(If possible, please provide a complete curve of the resource against source intensity)

55 Author ________________________
56 Date ________________________

# THE WATT COMMITTEE ON ENERGY

## Objectives, Historical Background and Current Programme

1. The objectives of the Watt Committee on Energy are:

   (a) to promote and assist research and development and other scientific or technological work concerning all aspects of energy;
   (b) to disseminate knowledge generally concerning energy;
   (c) to promote the formation of informed opinion on matters concerned with energy;
   (d) to encourage constructive analysis of questions concerning energy as an aid to strategic planning for the benefit of the public at large.

2. The concept of the Watt Committee as a channel for discussion of questions concerning energy in the professional institutions was suggested by Sir William Hawthorne in response to the energy price 'shocks' of 1973/74. The Watt Committee's first meeting was held in 1976, it became a company limited by guarantee in 1978 and a registered charity in 1980. The name 'Watt Committee' commemorates James Watt (1736–1819), the great pioneer of the steam engine and of the conversion of heat to power.
3. The members of the Watt Committee are 60 British professional institutions. It is run by an Executive on which all member institutions are represented on a rota basis. It is an independent voluntary body, and through its member institutions it represents some 500 000 professionally qualified people in a wide range of disciplines.
4. The following are the main aims of the Watt Committee:

   (a) to make practical use of the skills and knowledge available in the member institutions for the improvement of the human condition by means of the rational use of energy;
   (b) to study the winning, conversion, transmission and utilisation of energy, concentrating on the United Kingdom but recognising overseas implications;
   (c) to contribute to the formulation of national energy policies;
   (d) to identify particular topics for study and to appoint qualified persons to conduct such studies;
   (e) to organise conferences and meetings for discussion of matters concerning energy as a means of encouraging discussion by the member institutions and the public at large;
   (f) to publish reports on matters concerning energy;
   (g) to state the considered views of the Watt Committee on aspects of energy from time to time for promulgation to the member institutions, central and local government, commerce, industry and the general public as contributions to public debate;
   (h) to collaborate with member institutions and other bodies for the foregoing purposes both to avoid overlapping and to maximise cooperation.

5. Reports have been published on a number of topics of public interest. Notable among these are *The Rational Use of Energy* (an expression which the Watt Committee has always preferred to 'energy conservation' or 'energy efficiency'), *Nuclear Energy, Passive Solar Energy, Air Pollution, Acid Rain and the Environment, The Chernobyl Accident and its Implications for the United Kingdom, Gasification,* and *The Membrane Alternative.* Others are in preparation.
6. Those who serve on the Executive, working groups and sub-committees or who contribute in any way to the Watt Committee's activities do so in their independent personal capacities without remuneration to assist with these objectives.

7. The Watt Committee's activities are coordinated by a small permanent secretariat. Its income is generated by its activities and supplemented by grants by public, charitable, industrial and commercial sponsors.
8. The latest Annual Report and a copy of the Memorandum and Articles of Association of the Watt Committee on Energy may be obtained on application to the Secretary.

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Telephone: 071–379 6875

# Member Institutions of the Watt Committee on Energy

British Association for the Advancement of Science
*British Nuclear Energy Society
British Wind Energy Association
Chartered Institute of Building
Chartered Institute of Management Accountants
*Chartered Institute of Transport
Chartered Institution of Building Services Engineers
Combustion Institute (British Section)
Geological Society of London
Hotel Catering and Institutional Management Association
Institute of Biology
Institute of British Foundrymen
Institute of Ceramics
Institute of Chartered Foresters
*Institute of Energy
Institute of Home Economics
Institute of Hospital Engineering
Institute of Internal Auditors (United Kingdom Chapter)
Institute of Management Services
Institute of Marine Engineers
Institute of Mathematics and its Applications
Institute of Metals
*Institute of Petroleum
Institute of Physics
Institute of Purchasing and Supply
Institute of Refrigeration
Institute of Wastes Management
Institution of Agricultural Engineers
*Insitution of Chemical Engineers
*Institution of Civil Engineers
*Institution of Electrical Engineers
Institution of Electronics and Electrical Incorporated Engineers
Institution of Engineering Designers
Institution of Environmental Sciences
*Institution of Gas Engineers
Institution of Geologists
*Institution of Mechanical Engineers
Institution of Mining and Metallurgy
Institution of Mining Engineers
Institution of Nuclear Engineers
*Institution of Plant Engineers
Institution of Production Engineers
Institution of Structural Engineers
International Solar Energy Society—UK Section
Operational Research Society
Plastics and Rubber Institute
Royal Aeronautical Society
Royal Geographical Society
*Royal Institute of British Architects
Royal Institution
Royal Institution of Chartered Surveyors
Royal Institution of Naval Architects
Royal Meteorological Society
*Royal Society of Chemistry
Royal Society of Health
Royal Town Planning Institute
Society for Radiological Protection
*Society of Business Economists
Society of Chemical Industry
Society of Dyers and Colourists
Textile Institute

*Denotes permanent members of The Watt Comittee Executive

# Watt Committee Reports

2. Deployment of National Resources in the Provision of Energy in the UK
3. The Rational Use of Energy
4. Energy Development and Land in the United Kingdom
5. Energy from the Biomass
6. Evaluation of Energy Use
7. Towards an Energy Policy for Transport
9. Assessment of Energy Resources
10. Factors Determining Energy Costs and an Introduction to the Influence of Electronics
11. The European Energy Scene
13. Nuclear Energy: a Professional Assessment
14. Acid Rain
15. Small-Scale Hydro-Power
17. Passive Solar Energy in Buildings
18. Air Pollution, Acid Rain and the Environment
19. The Chernobyl Accident and its Implications for the United Kingdom
20. Gasification: Its Role in the Future Technological and Economic Development of the United Kingdom
21. The Membrane Alternative: Energy Implications for Industry