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RENEWABLES FOR POWER GENERATION

Status & Prospects

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INTERNATIONAL ENERGY AGENCY

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Status & Prospects

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The International Energy Agency (IEA) is an autonomous body which was established in November 1974 within the framework of the Organisation for Economic Co-operation and Development (OECD) to implement an international energy programme.

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- to maintain and improve systems for coping with oil supply disruptions;
- to promote rational energy policies in a global context through co-operative relations with non-member countries, industry and international organisations;
- to operate a permanent information system on the international oil market;
- to improve the world's energy supply and demand structure by developing alternative energy sources and increasing the efficiency of energy use;
- to assist in the integration of environmental and energy policies.

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- to contribute to sound economic expansion in Member as well as non-member countries in the process of economic development; and
- to contribute to the expansion of world trade on a multilateral, non-discriminatory basis in accordance with international obligations.

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FOREWORD

"New" renewables, e.g. solar, bioenergy, geothermal and wind, stand at a crucial stage in their evolution. Having benefited from several decades of considerable governmental incentive and corporate investment, they are now at a watershed – no longer the pure theoretical possibility in the laboratory, not yet a major market presence. As such, renewables pose unique challenges to energy policy makers to facilitate their pathway into the market while balancing their interest in a purely competitive market.

Renewables for Power Generation 2003: Status and Prospects surveys the current state of solar, bioenergy, geothermal, wind and small hydropower technologies used to produce electricity, and assesses their future prospects. Its findings are a product of the Renewable Energy Market Acceleration Study (REMAC), funded by the European Commission and the Government of Switzerland in cooperation with the International Energy Agency. It provides a comprehensive overview of international technology developments, cost developments and important issues for the future of these six renewable technologies.

This study presents policy makers, managers and the interested public with relevant information on those renewable energy technologies that have entered the electricity market, but are not yet in the mainstream of the energy sector. Policy makers will play a vitally important role in capturing the future potential of these technologies, as government policies will determine their further technological development, cost reduction and competitiveness. This publication suggests that by focussing R&D investments on the intersection of technology development and market experience, and by focussing market supports on those situations where renewables are closest to competitive, policy makers can accelerate the process of bringing renewables into the mainstream, while reducing the costs of doing so.

As governments work to improve energy security and sustainability, renewable energy should emerge as an important part of most countries' portfolios. If supported by appropriate policy frameworks, renewable energy will contribute to a secure, sustainable and economically competitive energy sector.

Claude Mandil
Executive Director, International Energy Agency

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The technical writing of this publication was undertaken by Stefan Nowak, Marcel Gutschner and Giordano Favaro, in close co-operation with Rick Sellers. Within REMAC, the Swiss team was responsible for the technology-related work. During preparation of the manuscript, many organisations and individuals have contributed with their data and comments. The contributions of Ruggero Bertani (ENEL, IGA), Jos Beurskens (ECN), Gregor Czisch (ISET / IPP), Emmanuel Koukios (NTUA) and Arturo Lorenzoni (IEFE) are particularly acknowledged.

IEA Implementing Agreements, national agencies and private companies, as well as industry associations greatly helped with validating and cross-checking the data presented in this publication. The reference sections list these organisations. Valuable input from research, industry and policy stakeholders was received during the two REMAC workshops held at the IEA in Paris (April 2002) and at EURELECTRIC in Brussels (September 2002). This book has also utilised the most recent information about the concept of experience curves and the EXCETP project (Experience Curves for Energy Technology Policy) provided during an IEA workshop (January 2003).

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TABLE OF CONTENTS

LIST OF TABLES

LIST OF FIGURES

EXECUTIVE SUMMARY

Renewables are the second largest contributor to global electricity production. They accounted for 19% of power generation in 2000, after coal (39%), but ahead of nuclear (17%), natural gas (17%) and oil (8%). Most of the electricity generated from renewables comes from hydro plants (92%) followed by combustible renewables and waste (5%) and "new" renewables (3%) including geothermal, solar, wind, tide and others.

Despite the small contribution to global electricity production, "new" renewables made remarkable progress during the past decades growing by an average of 9.3% per annum during the period 1971-2000. These growth rates reflect a 52% p.a. growth in wind energy, 32.5% p.a. growth in solar energy and 8.8% p.a. growth in geothermal energy during this period – albeit from a very low base, according to the IEA's "*Renewables Information 2002.*"

Yet, "new" renewables have not fully entered into the mainstream of the power sector. To accomplish more widespread use, renewables will continue to depend on a supportive policy environment, vigorous investment in R&D, and improved management procedures by utilities for on-grid use.

Renewables for Power Generation 2003: Status and Prospects brings together for the first time the available technical and cost data for the six most dynamic renewable energy technologies for power generation: wind power, geothermal power, biopower, concentrating solar power, solar photovoltaics, and small hydropower. This international comparison allows a realistic assessment of the cost reduction and technological development potential of these technologies and their likely market expansion in the coming years. The publication hopes to assist policy makers by supplying an accurate and comprehensive overview of the most promising renewable energy technologies and their prospects for mainstream use.

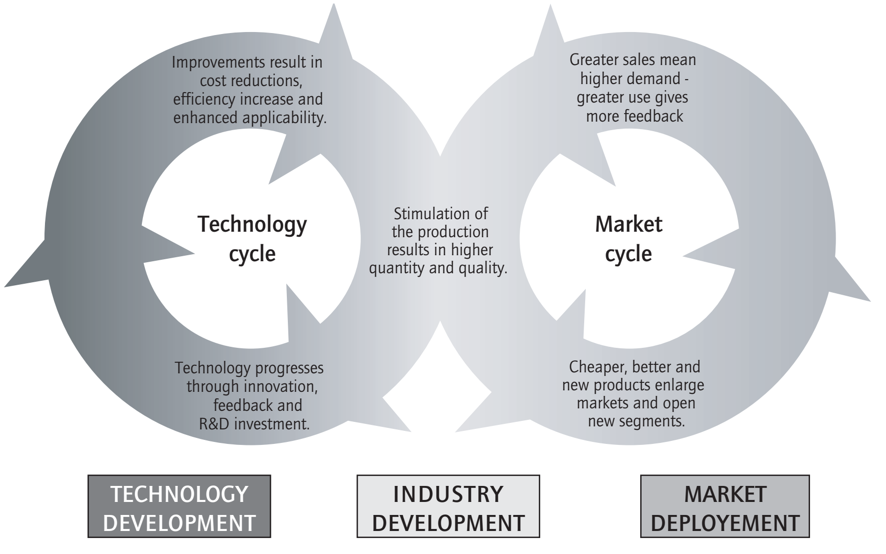
The Dynamics of Technology Progress and Market Growth

To build a policy environment that is effective in furthering renewables' progress toward the mainstream, policy makers should recognise that technology development and market experience are strongly inter-linked and can function as a "virtuous cycle" (see Figure 1). The virtuous cycle takes into account the positive and reinforcing relationships between technology

R&D, improvements in manufacturing, and learning from market experience that can be enhanced by the policy framework. By stimulating both the technology development cycle and the market learning cycle, particularly in those circumstances where renewables costs are attractive, policy support will be most effective.

Figure 1

Virtuous Cycle in a Supportive Policy Environment



Source: NET Ltd. Switzerland based on IEA/OECD (2000).

This virtuous cycle functions in a different manner for each of the renewable technologies, based on the specific maturity of the technology and how far it has progressed in markets. These differences between the six renewable technologies are crucial. Wind energy is not geothermal energy, which in turn is not solar photovoltaic energy, and so on. Each technology has its distinct market role with unique costs and benefits. Thus, while policy makers should recognise the broad similarities of renewables, they must also realise that to affect market growth and competitiveness, they need to address specific technologies in the context of local conditions. By understanding both the virtuous cycle that affects all renewable energy resources, and the unique properties of the individual technologies in comparison to other sustainable energy options, more efficient and effective policy frameworks can be developed.

Technology and Technological Developments

Some renewable electricity technologies have already gained a significant market share and their industry is relatively mature, although they may be far from having fully developed their world-wide potential. For example, small hydropower (SHP) is well-established, as are some segments of the biomass industry. According to the most common definitions, global installed capacity in 2000 was 32 GW and 37 GW, respectively. Geothermal, accounting for 8 GW installed capacity in 2000, has been successfully producing electricity in favoured locations for almost a century and is regaining more attention including in developing countries. Wind energy has been going through vigorous technological and market development and has reached installed capacity of 30 GW in 2002, mostly in Germany (12 GW), US (4.7 GW), Spain (4.1 GW), Denmark (2.9 GW) and India (1.7 GW). The solar photovoltaic market, with 1.1 GW installed capacity in 2000, is still comparatively small, but tripled its volume in the last four years. Concentrating solar power (CSP) technology, despite the technological success of the first commercial experience in the late 1980s, was not able to sustain its market, due to the withdrawal of policy supports. Recent technological development, along with re-kindled government interest, offers the promise of a new start.

Technology development brings major innovative progress in materials, processes, designs and products. In Figure 2, the top illustration shows the increase of rotor diameter size and capacity of wind turbines, graphically demonstrating that technology's progress. The lower illustration shows different solar cell technologies with various technology development improvements including efficiency and costs. Technological developments are key to the prospects for each renewable technology discussed in this study.

• Cost Reduction Opportunities

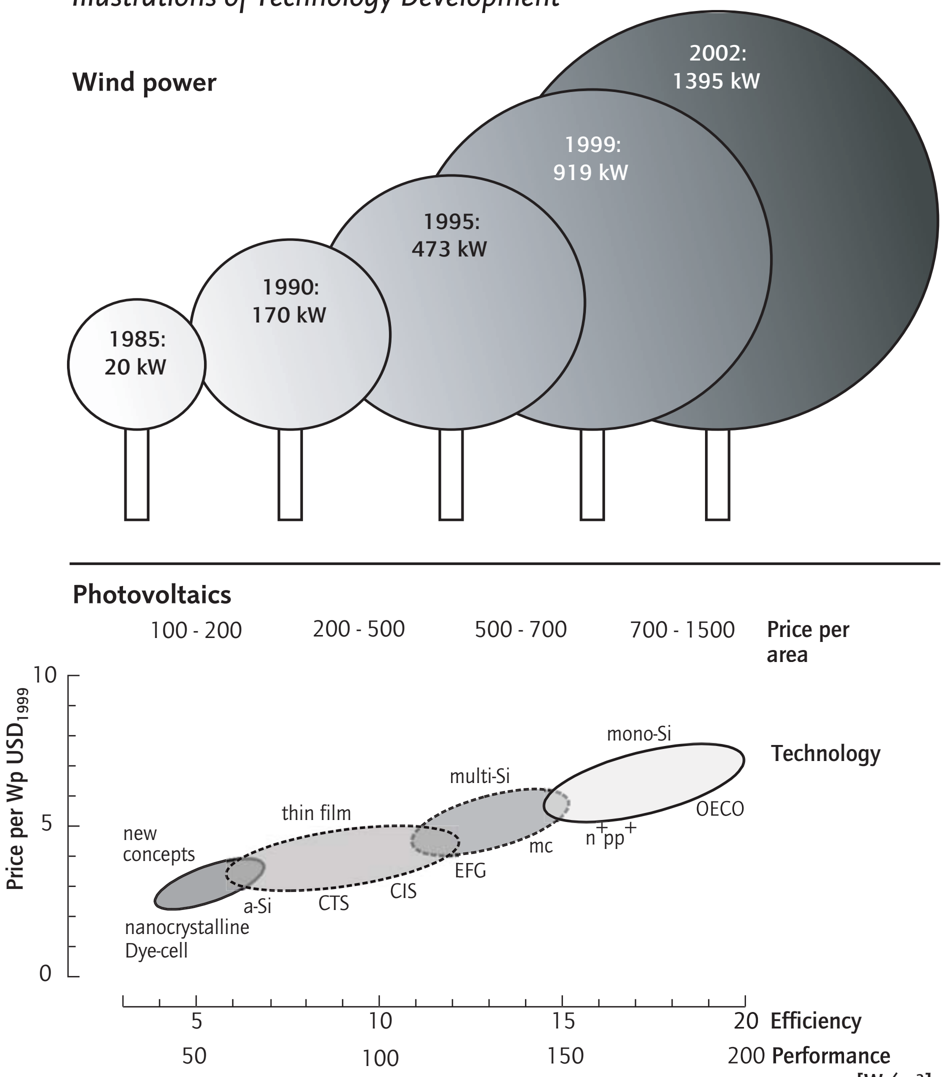
Reducing costs through technology development focuses on the unique situations of each renewable energy technology and application. By specifically targeting areas of cost reduction opportunities (see Table 1) and by keeping the larger "virtuous cycle" in mind, policy makers can keep the costs of facilitating market and technology learning to a minimum.

The technology "learning curves" presented in this book translate the complex relationships among technology, industry and market into a curve of declining costs. However, these curves only interpret the input and output of the learning system; they do not explain the process going on within it.

But, if correctly applied and interpreted, the experience curve helps to identify crucial elements behind and beyond the simple relationships it describes. Furthermore, based on assumptions about market growth, cost reduction can be estimated in specific time-frames. In general, three scales of potential global cost reduction can be identified for renewable electricity technologies.

Figure 2

Illustrations of Technology Development



Sources: NET Ltd. Switzerland, based on raw data from Durstewitz (1999), Systèmes Solaires/EurObserv'ER (2003); and Hoffmann / RWE Schott Solar GmbH.

Table 1

Focal Points for Policy Intervention in Renewable Energy Technologies

Opportunities for improvement of technical and economic performance	Basic research	Applied research	Market introduction	Sustained market
Cost reduction through R&D	Development of new components and system integration allowing for the same service less expensively	Optimisation of components and system integration, providing the same service less expensively		
Performance increase	Development of improved components and system integration allowing for more efficient service	Optimisation of components and system integration providing more efficient service	Implementation of components and system integration	Extension of more efficient service
Economy of scale I (components size)	Development of new designs, processes and materials for increased size of components	Optimisation of new designs, processes and materials for increased size of components	Implementation of new designs, processes and materials for increased size of components	
Economy of scale II (manufacturing volume)	Development of new "scalable" manufacturing processes	Optimisation of new or improved "scalable" manufacturing processes	Building the improved manufacturing platform to increase thru-put	Up-scaling manufacturing platform to increase thru-put
Economy of scale III (plant size)		Optimisation of components relevant for up-scaling power production plants	Implementation of components relevant for up-scaling power production plants	Up-scaling power production plants in order to increase plant efficiencies
Economy from market system	Synergies through exchange of know-how and skills as well as use of common infrastructure	Synergies through exchange of know-how and skills as well as use of common infrastructure	Improvements from pilot demonstrations	Improvements from consumer and supplier feedback

Source: NET Ltd. Switzerland

- The highest potential for cost reduction among the renewable electricity technologies are a) expensive and b) recent in development. They tend to have a steep learning curve with a progress ratio of about 80%, meaning that every doubling of the volume manufactured leads to a cost reduction of about 20%. Globally, solar technologies are expected to reduce their costs by some 30%-50% for each of the next two decades as a result of learning and market growth.
- Medium cost reduction potential can be identified among those technologies that are a) in the low to medium cost range and b) relatively recent in development. They tend to have a learning curve with a progress ratio of around 90%, meaning that every doubling of the volume manufactured leads to a cost reduction of around 10%. Globally, wind is expected to reduce its costs by some 25% for each of the next two decades on this basis, and geothermal by some 10%-25% in the same periods.
- Smaller cost reduction potential is likely among the most mature technologies; the learning curve for these technologies and their components is fairly flat. Globally, technological development for small hydropower and biomass is much slower, likely on the order of about 5%-10% for each of the next two decades. Specifically, conventional components (civil works, turbines) offer low cost reduction potential, likely on the order of about 5%-10% for each of the next two decades.

Cost Structure, Investment and Generation Cost

A particular feature of renewable power is the wide range of investment and generating cost they exhibit. Table 2 presents the ranges of investment and generating cost presented for 2002 and projections for 2010. These ranges reflect the variety of technologies for each renewable power source, the large number of possible applications and the multiplicity of resources. Renewable costs depend on the physical and geographic context, and the system definition as well as the policy environment. Average indicators for renewable power generation costs are thus not well suited to display their competitiveness in either the off-grid or on-grid market in a given country or system.

All the renewable technologies assessed in this book have high up-front investment costs. Capital cost depreciation and interest costs are, thus, the major factor influencing generation costs. There are no fuel costs with the exception of biomass. While operating and maintenance costs (O&M) are generally low compared to conventional power generation, there are marked differences among the technologies in the area of maintenance.

Table 2

Ranges of Investment and Generation Costs in 2002 and 2010

	Low investment costs USD/kW		High investment costs USD/kW		Low generation costs USD/kWh		High generation costs USD/kWh	
	2002	2010	2002	2010	2002	2010	2002	2010
Small hydro power	1000	950	5000	4500	2-3	2	9-15	8-13
Solar photovoltaic power	4500	3000	7000	4500	18-20	10-15	25-80	18-40
Concentrating solar power	3000	2000	6000	4000	10-15	6-8	20-25	10-12
Biopower	500	400	4000	3000	2-3	2	10-15	8-12
Geothermal power	1200	1000	5000	3500	2-5	2-3	6-12	5-10
Wind power	850	700	1700	1300	3-5	2-4	10-12	6-9

Note: Discount rate is 6% for all technologies; amortisation period is 15-25 years, and operation & maintenance costs are technology-specific.
Source: NET Ltd. Switzerland.

• Cost Competitiveness

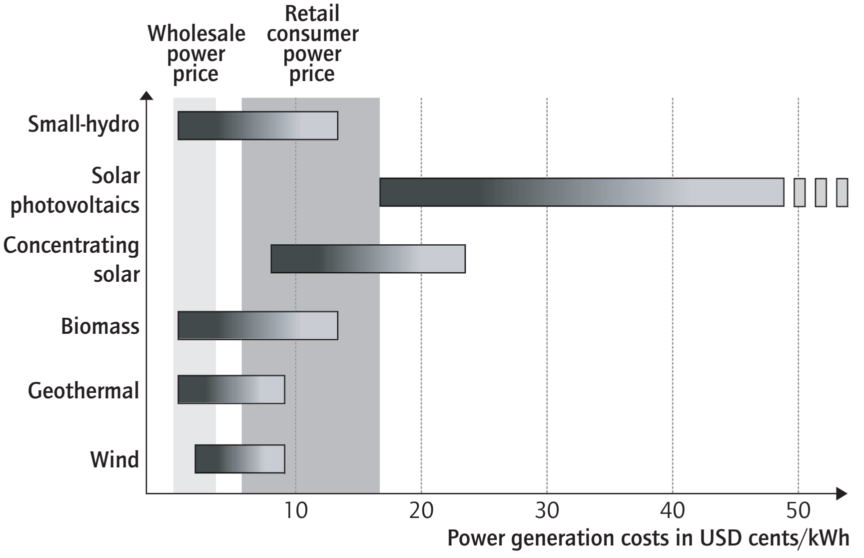
Although the average costs of renewable electricity are not widely competitive with wholesale electricity, renewables can offer electricity and electric services at competitive rates in a wide range of specific on-grid or off-grid situations or applications.

Figure 3 indicates the cost range of renewable power. To identify and exploit real market opportunities, it is necessary to assess the competitiveness of specific applications and services in specific local circumstances. It is only by taking advantage of these unique situations – be it large-scale on-grid applications or niche markets off-grid, or in specific country situations – that renewable electricity can build a vigorous and sustained market.

Many best cases already show that under optimal conditions – *i.e.* optimised system design, siting and resource availability – electricity from biomass, small hydropower, wind and geothermal power plants can be produced at low costs ranging from 2 to 5 USD cents per kWh. Cost competitiveness is then at its best, and renewable power – even without adding environmental or other values that could be attributed to certain kinds of renewable electricity generation – can compete on the wholesale electricity market.

Figure 3

Cost Competitiveness of Selected Renewable Power Technologies.



Note: Cost calculation is based on system investment needed (capital cost is based on discount rate of 6% and amortisation period of 15 - 25 years) and power output. Lowest cost range refers to optimum conditions (proven technology, optimised plant size and design, and high availability of system and resources).
Source: NET Ltd. Switzerland.

Solar technologies are, for the time being, generally not competitive with wholesale electricity, but even they start to compete with retail electricity in certain circumstances where supportive policy frameworks have been established. For instance, photovoltaic solar power is competitive in areas where high solar irradiation coincides with daily (peak) power demand, and high retail electricity costs, in a supportive policy environment. California and other parts of the Southwest United States are examples of such conditions, and such areas have become strong commercial markets.

- **Market Prospects**

Based on current market levels and expected cost reductions, market growth for all six renewable technologies for 2010 is forecast to increase from 95.5 GW to 257 GW, or 10.4% p.a. This forecast assumes continued government support and that no outside factors will significantly alter the competitive environment.

Table 3

Current and Forecast Installed Capacity

	Installed capacity in 2000 in GW	Installed capacity in 2010 in GW (forecast)
Small hydro power	32	45
Solar photovoltaic power	1.1	11
Concentrating solar power	0.4	2
Biopower	37	55
Geothermal power	8	14
Wind power	17	130

Source: NET Ltd. Switzerland.

The forecasted numbers presented here are consistent with the policy changes regarding renewables occurring in some major emerging countries, *e.g.* China, India, parts of South East Asia and South America, but also in some key OECD countries. In the emerging countries, these policies reflect the rapidly growing demand for electricity which can in particular situations increasingly be met by renewable energy on a competitive basis. In OECD countries, the growing penetration of renewable energy is also a consequence of policy changes related to reducing the environmental impact and increasing the diversification of energy supply as well as increasing energy security, and, last but not least, a growing global renewable energy industry. In some OECD countries with favourable market frameworks, vigorous growth of renewable energy technologies is observed. As a consequence, some of today's secondary markets for renewables, *e.g.* off-shore wind, are expected to play a major role over the next decade.

In brief, growth patterns fall into 3 categories:

- Traditional technologies with steady growth: Small hydropower, geothermal power and biopower have been produced for most of the time there has been a utility electricity system. Their annual growth rates are likely to continue at between 1% and 9%. The removal of market barriers and establishment of supportive policies could keep this in the higher end of the range, particularly in developing countries.
- New technologies with vigorous growth: Development of wind power and solar photovoltaics started only a few decades ago. For the past five years or more, they have experienced growth rates between 20% and

40%, a trend which is likely to continue to 2010 if the present policy incentives and R&D investments are maintained.

- New technologies (back) in the starting block: Concentrating solar power (CSP) electricity was launched twenty years ago, but for more than a decade there has not been any new commercial installation. More than two dozen projects are under development worldwide including trough, power tower and parabolic dish technologies. If these projects come about, CSP will increase five-fold by 2010, but is only likely to become a major contributor to power generation in two or three decades.

Intermittency and Reliability

In addition to cost, intermittency and reliability are two of the most important issues facing renewables growth. These issues are intertwined. When renewables provide too much or not enough power, the reliability of the grid is affected. Because renewables cannot economically store energy, they are not as able to dispatch power on demand. Different renewables reflect this issue to different degrees. Several are highly intermittent, such as wind and solar. Several others can be seasonal, including small hydropower and bioenergy. Only geothermal has capacities on the same order as conventional energy systems. Because utilities must supply power in close balance to demand, intermittency can limit the amount of capacity of highly intermittent technologies that can be incorporated in the energy mix.

To a degree, technical solutions and business and regularity practices can extend the penetration of renewables, though these need further development through R&D and innovative management practices. Solutions are different for each renewable and will also be different for on-grid and off-grid markets. For example, wind power and small, bioenergy-based CHP plants are the two renewable technologies where penetration rates on the grid have caused technical problems. In Denmark, Spain, and Northern Germany, wind power penetration rates of over 15% and even up to 50% have been seen. Only in some cases has this resulted in grid problems, while in other cases it was intended to allow for greater production by wind in order to reduce production from coal-based plants. At the same time, wind power may not be available at times. For example, during the European heat wave of 2003, wind production in Northern Germany was only 7% of its rated capacity. Fortunately, this did not cause problems in this instance as there was no coincident peak demand at the time. Short-term strategies to cope with wind intermittency on the grid include improving wind prediction, using variable speed turbines, electricity flow controls, and supplemental generation. Better power quality requires technical improvements to deal with harmonic distortion. Some of the local intermittency of an individual renewable energy system can be compensated by a larger number of these systems in a broader region, or by having alternative generation from other renewable systems. Improving the usefulness of off-grid systems calls for "hybridising" the wind machines with a more dispatchable generator or adding energy storage in a battery.

Although solar energy has not achieved as high a level of penetration as wind, the theoretical limits and solutions are expected to follow a similar pattern. However, PV is expected to enter the utility market through a more distributed model where very small systems on roof tops will be widely spread. As most of the energy will be consumed onsite, the problems for utilities to balance grid energy flows are likely to be manageable until very high levels of penetration are seen.

The other renewables discussed in this book, bioenergy, small hydropower and geothermal, do not display this problem. The reliability issue for bioenergy and small hydropower is resource management by anticipating times of drought, or managing bioresource materials availability.

Reducing the Cost of Policy Support for Renewables

The challenge to governments is to encourage technology progress and market growth while minimising public costs and consumer payments. This can be accomplished by encouraging renewables to develop those markets in which they are most cost-effective. This development must take into account the local, site specific renewable resource conditions and the costs of the conventional alternatives. These should be based on the strongest resource availability and lowest life cycle costs. Below is a general outline of the best competitive paths for the renewable technologies described here, as well as their most competitive niches. While this strategy may appear obvious, it remains a good guide to avoid unnecessary costs by pursuing markets for which the particular renewable is not close to competitiveness or does not match local resource conditions.

- Appropriate areas for **small hydropower (SHP)** development exist around the world (mountainous areas for high head plants, rivers for low head plants and various combinations). It is typically in these areas that small hydropower can contribute power at competitive costs, if there is grid access or local demand. In such optimal conditions, costs can be as low as 3 USD cents per kWh. Once the high up-front capital costs are written off (usually over 15 or 20 years), the plant can provide power at even lower cost levels as such systems commonly run, without major replacement costs, for 50 years or more. SHP plants have a particularly long life time and relatively low operation and maintenance costs, though many plants constructed in the last century can now benefit from refurbishment. Support to exploit SHP should be given to developing countries where it can be a very low cost option.

- **Solar photovoltaic power** is in the early stages of its development, but can still be competitive in isolated off-grid markets and limited areas where high levels of sunshine coincide with daily (peak) power demand. For the latter market, solar PV power costs are in the range of retail utility rates of about 20 USD cents per kWh. In such circumstances, *e.g.*, California, photovoltaics has become competitive with retail electricity, at least as stand-by power and in "building-integrated applications" (BIPV). In the sunnier locations of Europe, the attractiveness of solar PV in the short to medium term continues to depend on incentives. In Japan, a system cost level of USD 3,000 could be reached in the next four to six years, a "docking point" (competitive with retail electricity) to self-sustained markets. Of particular interest in Japan are building-integrated solar systems – installed at the point of electricity consumption with panels that are easy to install. The other key market for solar PV is the off-grid market for rural areas, including industrial and agricultural uses in developed countries, and rural systems in developing countries. The challenge of delivering affordable energy in developing countries is immense. In these circumstances the primary focus should be on "productive uses" for such income-generating activities as water pumping, refrigeration, lighting and other uses that improve the economic welfare of rural communities.

- **Concentrating solar power** is limited in its competitive market potential to arid and semi-arid areas with strong "direct gain" solar radiation. The cost of concentrating solar power generated with up-to-date technology is estimated to be between 10 to 15 USD cents per kWh, with good long-term cost reduction potential. CSP plants can also be "hybridised" in combination with a thermal generator to improve marketability (solar share of power plant) and dispatch-ability (power production on demand).

- Where bio-feedstocks are abundant and their pre-treatment requirements are modest, **biopower** costs can be as low as 3 USD cents per kWh from plants with proven conversion technologies and approaches (*e.g.* co-firing in the US or CHP in Finland). For example, bio-electricity is widely commercial in Finland where feedstocks from large woodland areas and the pulp and paper industry make bioelectricity production competitive and accounted for 17.4% of electricity production in 2001.

- **Geothermal** power can achieve its best cost-competitiveness in areas characterised by high enthalpy (an indicator for the geothermal power potential), low exploration and installation costs; and using proven geothermal technologies. New plants in many areas in the world can produce power at 5 USD cents per kWh or less. Additional revenues from heat or minerals extracted from the subterranean brine can enhance competitiveness.
- **Wind power** generation costs are already below 4 USD cents in many areas with strong, regular winds and good accessibility for plant construction and grid connection. The key to opening new high performance sites, such as in Scotland and the US is installing new transmission lines. As good onshore sites, particularly in Europe, have been saturated, new projects have prompted public challenge due to the concerns of some to having the wind machines in sight (NIMBY). Finding acceptable locations therefore poses an increasing challenge. Offshore wind parks are now being developed, although some of these, too, have prompted NIMBY challenge. The technology to mount and connect offshore wind remains in its infancy. Wind power's mid term success will depend on (a) broadening the number of countries investing in wind power markets beyond Germany, Denmark, Spain and the US, (b) cost reduction of offshore wind and (c) establishing management and technology solutions to intermittency.

It is important to emphasise again the positive impact of market experience on technology development. Often, concepts and prototypes had existed for years (*e.g.*, large wind turbines) but the lack of market experience prevented their successful deployment. Learning investments provided in the context of growing markets helped these early prototypes become competitive products. Identifying and realising those market opportunities where renewables are closest to competitiveness is of paramount importance to trigger learning improvements.

INTRODUCTION

Renewable energy technologies are emerging as strong contenders for more widespread use. Yet despite the remarkable progress made over the past decades through the collaboration of scientists, industrialists, and policy makers, they are not yet fully in the mainstream of the power sector. Some renewable electricity technologies have already gained a significant market share – their industry is relatively mature, although they may be far from having developed their world-wide potential. For example, small hydropower is well-established, as are some segments of the biomass industry. Wind has been going through vigorous technology and market development and has reached considerable market share in a few countries, but still has considerable potential for technological improvement. The solar photovoltaics market is comparatively small, but tripled its volume in the last four years. Geothermal has been successfully producing electricity for almost a century and is currently regaining importance. Concentrating Solar Power was demonstrated in MW sized plants in the 1980s, but its progress subsequently stalled as government supports were withdrawn. New designs and materials suggest a possible renaissance for this technology.

The future of "new" renewables depends on a supportive policy environment. Under conditions where governments support market experience through incentives to manufacturers and consumers, technology development and market deployment are strongly interlinked and function as a "virtuous cycle" (see Figure 1). Technology development results in new, improved and/or less expensive products. These new products can then be sold to serve the needs of more and new customers. Greater sales allow for higher production volumes, and greater use allows for "learning" from experience in the market to further technology development. This symbiosis only operates under a policy framework that equally supports elements of both the technology development and market cycles. Thus, effective policy must take into account that there are positive and reinforcing relationships among technology development, the industry and the market. By stimulating both the technology development cycle and the market cycle, policies can achieve sustained renewables-based electricity market growth. Not only does policy play a central role, but an urgent one as well. Recent scenarios, including the IEA's *World Energy Outlook*, suggest that the market share of renewables in electricity generation thirty years from now will depend largely on policy steps taken in the next several years.

Renewables for Power Generation 2003: *Status and Prospects* hopes to assist decision makers by supplying an accurate and comprehensive overview of the renewable technology sector. This study assesses the current situation and future opportunities for the six main "new" renewable energy technologies that produce electricity. These are:

- small hydropower;
- solar photovoltaics;
- concentrating solar power;
- biopower;
- geothermal power;
- wind power.

The study consists of new analysis on the interaction of technology development and market experience, and a synthesis of insightful studies performed by government agencies and private sector organisations. This publication has consciously excluded other renewable technologies that are at an earlier stage of development, such as ocean energy, as the current focus on them is solely in the realm of research and demonstration. It has also excluded large hydropower, as most IEA governments consider them to be mature and competitive.

The challenge is to consider the entire technology progression from the laboratory, to manufacturing, to market use, as well as from the relationships of these technologies to each other and within the wider energy sector, and do so, both in an inter-sectorial and cross-technological fashion.

An inter-sectorial view is useful because there are important technology-industry-market relationships that affect renewable energy technologies all along the value chain, while providing opportunities for "technology learning". Technology learning is the term for the empirical observation that the cost of an industrially manufactured product decreases by a more or less constant percentage each time the cumulative volume of the product is doubled. Expressed as the "experience curve", technology learning thus reflects the virtuous cycle with both technology development and market deployment issues. The experience (or "learning") curve translates the complex interactions among technology, industry and market into a simplified relationship. However, the experience curve only reflects an empirical relationship between the input and output of a black-box-like learning system and does not explain the processes going on within the learning system. But, if correctly applied and interpreted, the experience curve helps identify crucial elements behind and beyond the simple relationship it represents.

The learning process is not unique to renewables, but is typical for all energy technologies and, indeed, all manufactured goods. The rate of "learning" is different for each technology, and typically slows as technologies progress through the several stages from laboratory to full maturity. This is why renewables costs are declining faster today than those of fossil technologies: renewables are less mature. Knowing the rate of learning, and understanding the workings within the learning system, can give important insights about future technology and market potentials*.

Technology learning in renewable energy (RE) systems provides three key benefits:

- reduction of system cost: the system delivers the service less expensively;
- increase of system performance: the system delivers the service more efficiently;
- enhancement of system applicability: the system can deliver new services.

A *cross-technological* view is useful for understanding how renewable electricity technologies as a whole can best be developed and deployed by understanding how they complement each other, as well as conventional energy technologies in a more diversified portfolio.

Although the electricity produced by renewables does not differ from that of competing sources, the technologies, services and benefits do. Different renewables have specific features and applications which typically cover a different range from those of competing fuel technologies. It is essential to consider these differences in relation to technology, maturity and potential, as well as market segments and growth.

The cross-technological perspective allows the reader to compare commonalities and differences among the six renewable technologies examined in this study. To this end, each chapter is organised along a common structure:

Technology Status

The sections on technology status are descriptive and present the current technical and economic conditions of the technology as follows:

** Technology learning can also be expressed in "progress ratios", which is the learning rate subtracted from 100%.*

- **basic features:** characteristics specific to the technology;
- **costs**: for the main applications as well as for system components and project elements;
- **industry**: an overview of the structure of the industry and its major stakeholders;
- **market:** figures and data concerning important segments and areas;
- **environment:** the environmental challenges and benefits related to the technology.

Prospects

The section on prospects focuses on realised and realisable opportunities to improve the performance of the technology. The section seeks to identify major opportunities in the research and market fields to reduce costs, increase performance and enhance applicability.

- **cost reduction opportunities:** focuses on technology development and potential improvements;
- **market opportunities:** highlights promising market segments and discusses issues favouring market growth.

Issues for Further Progress

Issues that affect the outlook for the technology, as well as strategies to overcome them include:

- **technical issues** that comprise crucial aspects for further development of the technology in order to increase performance and applicability, and to reduce costs;
- **non-technical issues** that affect market potential, including environmental, financial, legal or social issues.

Understanding both the renewable energy technologies and the interactions considered here is a fundamental step to formulating effective policies. The information provided in this study should help policy makers design appropriate frameworks for these renewable technologies at their various stages of progression from laboratory to widespread market use.

SMALL HYDROPOWER

A Brief History of Small Hydropower

Small hydropower (SHP) has been exploited for centuries. First, the energy in falling water was exploited in mechanical form, *e.g.* watermills for milling grain, the simple Norse wheel, and later more sophisticated waterwheels. The invention of the water turbine in France in 1827 led to the development of modern hydropower. In the 1880s, hydropower turbines were first used to generate electricity for large scale use (as opposed to laboratory experiments). In Europe, turbines replaced the waterwheel almost completely by the end of the 19th century. Small turbines were increasingly used throughout Europe and North America, and during this period, today's basic turbine technology evolved. With expansion and increasing access to transmission networks, power generation was concentrated in increasingly larger units benefiting from economies of scale. This resulted in a trend away from small hydropower systems to large hydropower installations between the 1930s and the 1970s.

The oil crisis in 1973 re-kindled interest in the development of small hydropower resources. This led to a revival of the industry, with new turbine manufacturers appearing in the marketplace. Interest in developing hydropower systems again declined through the 1980s and early 1990s due to the low level of fuel prices and the subsequent "dash for gas". More recently, liberalisation of the electricity industry has contributed in some areas to the development of hydropower generating capacity by independent power producers (IPPs).

Technology Status

- **Basic Features**

There is no international consensus on the definition of SHP. The upper limit varies from 2.5 MW to 30 MW, but a ceiling value of 10 MW is becoming more generally accepted. Common definitions for small hydropower electric facilities are:

- small hydropower: Capacity of less than 10 MW;
- mini hydropower: Capacity between 100 kW and 1 MW;
- micro hydropower: Capacity below 100 kW.

The natural factors which affect SHP potential are the quantity of water flow and the height of the head. Flow roughly relates to average annual precipitation and the head depends, basically, on topography. The main requirement for a successful hydropower installation is an elevated head, either natural or artificial, from which water can be diverted through a pipe into a turbine coupled to a generator that converts the kinetic energy of falling water into electricity. The water is then discharged, usually through a tube or diffuser, back into the river at a lower level.

The theoretical power available in a volume of water (Q) is the mass of the water times the height or head (H) the water can fall. In reality, losses due to imperfections in the design of machinery and pipelines have to be considered in every hydropower system. Internal friction in pipelines and channels as water travels towards the turbine causes a loss of potential energy in the system. Hence the head used in calculations is the net head, defined as the potential energy which reaches the turbine system. Similarly, friction and heat losses occur in the turbine, the gearbox and the electric generator. As a rule of thumb, power is equal to seven times the product of the flow (Q) and gross head (H) at the site:

$P\,[kW] = 7QH$ Where: Q = cubic metres per second and
H = net head in metres

Producing one kWh at a site with a 10m head requires ten times the water flow of a site with a 100m head.

SHP can generally be divided into three different categories depending on the type of head and the nature of the plant:

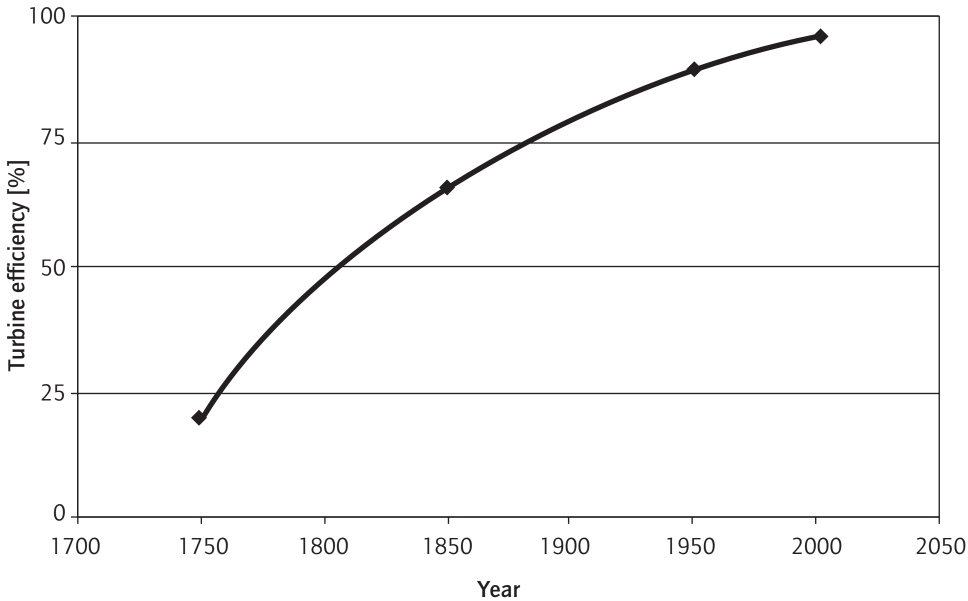
- High-head power plants are the most common and generally include a dam to store water at a higher elevation. These systems are commonly used in mountainous areas.
- Low-head hydroelectric plants generally use heads up to a few metres in elevation or simply function on run-of-river. Low-head systems are typically built along rivers.
- Supplemental hydropower systems are generating facilities where the hydropower is subordinate to other activities like irrigation, industrial processes, drinking water supply or wastewater disposal. Electricity production is thus not the prime objective of the plant but often a useful by-product.

Turbines

During the 20th century, the technology for harnessing water power developed rapidly and turbine efficiencies close to 100% were achieved (see Figure 4). Typically, larger turbines have higher efficiencies. For example, efficiency is usually above 90% for turbines producing several hundred kW or more, whereas the efficiency of a micro-hydropower turbine of 10 KW is likely to be in the order of 60% to 80%.

Figure 4

Turbine Efficiency Over Time



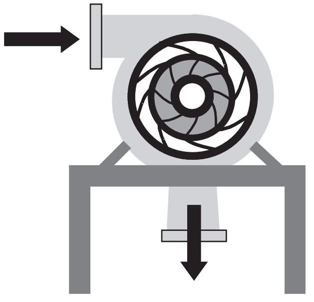
Sources: NET Ltd., Switzerland; World Energy Council (WEC).

Hydraulic turbines transform the water's potential energy into mechanical rotational energy by one or two basically different mechanisms:

- In **reaction turbines** water pressure applies force onto the face of the runner blades, which decreases as it proceeds through the turbine. Reaction turbines run full of water and generate hydrodynamic "lift" forces to propel the runner blades. The most common types of reaction turbines are the Francis and Kaplan turbines. Francis turbines are generally used in a head range of 5 to 250 metres and can be designed with either a vertical or horizontal shaft. Kaplan turbines are axial-flow reaction turbines, generally used for low-heads.

Figure 5

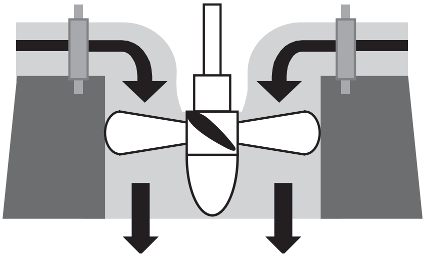
Francis Turbine



Source: NET Ltd., Switzerland.

Figure 6

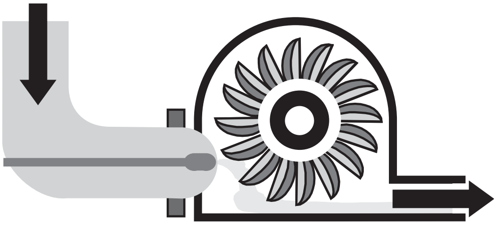
Kaplan Turbine



Source: NET Ltd., Switzerland.

Figure 7

Pelton Turbine



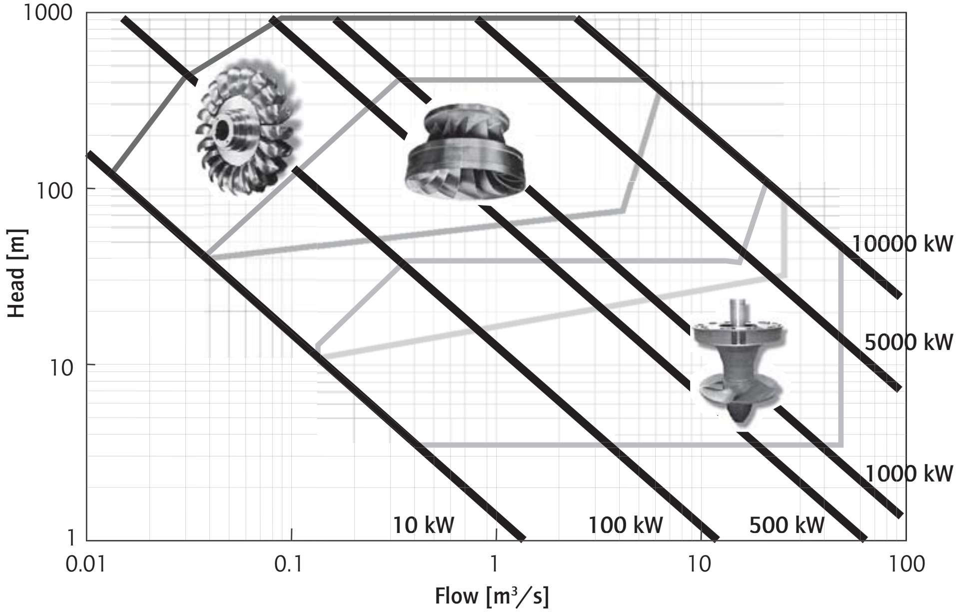
Source: NET Ltd., Switzerland.

- In **impulse turbines** water pressure is converted into kinetic energy in the form of a high-speed jet that strikes buckets mounted on the periphery of the runner. The most common impulse type is the Pelton turbine. It is generally used in installations with a head of 50 to several hundred metres. By adjusting the flow through the nozzle, a Pelton turbine can operate at high efficiency over a wide range of head and flow conditions. Pelton turbines can be designed with either a vertical or horizontal shaft. Another type of impulse turbine is the cross-flow turbine, where water is directed by one or more guide-vanes located upstream. These turbines are relatively cheap and flexible.

Figure 8 indicates the most appropriate turbine according to head and capacity.

Figure 8

Small Hydropower Turbine Selection Chart



Sources: NET Ltd., Switzerland; RETScreen International; MhyLAb. Turbine graphics courtesy of European Small Hydro Association

Generators

Today, generators commonly have efficiency rates of 98-99%. Two main types of generators are used in the small hydropower industry: synchronous and asynchronous generators. Synchronous generators typically have higher efficiency but are more expensive. Control of their rotor excitation also requires a more complex and more expensive regulating device. Both generator types are very well known throughout the industry and have been steadily improved to meet the needs and demands of the hydropower sector.

The efficiency of small hydropower depends mainly on the performance of the turbine, since generator efficiencies are close to 100%. As a general rule, larger and newer plants have higher efficiencies of up to 90%. Average performance is typically in the range of 70% to 85%. Efficiency can be as low as 60% for old and smaller plants.

• Costs

Investment costs for SHP plants vary according to site-specific (*e.g.* topography, hydrology) and local characteristics (*e.g.* planning and administrative issues, social acceptance, finance schemes). The site is an important factor in the technical choice for the SHP system and related costs, whereas other local characteristics influence non-technical costs.

The most important system and cost elements are a) civil engineering, b) equipment, and c) turbine. As a general rule, **civil engineering** costs are higher for high-head plants, mainly because they usually need longer pipelines. On the other hand, turbine costs are higher for low-head plants, which have to pass more water than high-head plants for the same power output and are therefore larger. Low-head power plants also run more slowly and thus cannot be connected directly to the generator. Electrical equipment (which includes the generator, the transformer, the controller, the protection system and the access lines) represent about 25% of the total plant cost for both high and low-head plants.

For supplemental hydropower systems, energy production is only a secondary purpose. Therefore, civil engineering plays a less important role because the most significant construction is already in place. The turbine and the electrical equipment each cost approximately the same as the civil engineering and must be adapted to the principal purpose of the plant.

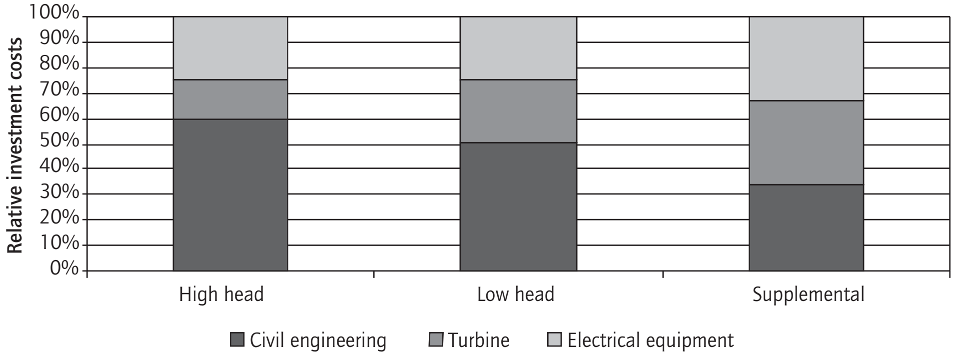
Equipment costs can be highly variable, depending on the country and location, the water source and the quality of equipment. Figure 9 shows an example of SHP elements (turbine, electrical equipment and civil engineering) and relative costs for three different types of SHP plant (high-head, low-head and supplemental hydropower system). This figure helps to identify the key elements where efforts can be made to decrease the overall power plant costs.

Turbines are the most expensive standard component (as opposed to civil engineering, which is highly specific for each site).

High-head plants tend to have lower investment costs; because the higher the head, the less water is required to generate a given amount of power. As a result, these plants can utilise smaller and less costly equipment. However, there are disadvantages often associated with high-head sites. They are generally located in areas with low population density and relatively small local demand for electricity. Long transmission distances to densely populated areas increase final costs. Also, easily- engineered high-head sites are increasingly rare or difficult to develop.

Figure 9

Relative Investment Costs for Three Types of Hydropower Plant



Source: NET Ltd., Switzerland.

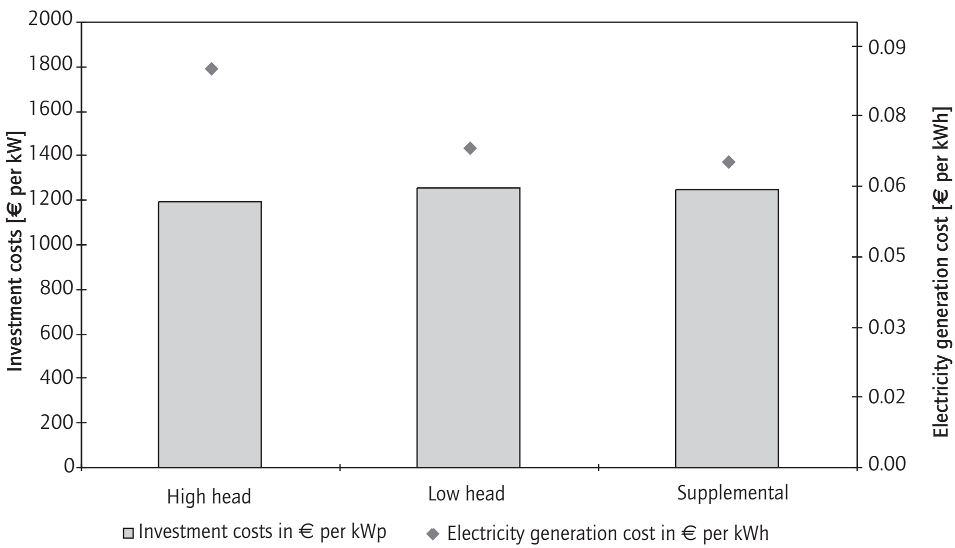
Figure 10

Approximate Power Unit and Electricity Generation Costs in Western Europe for Three Typical Hydropower Plants:

a) high-head with an installed capacity of 1 to 2 MW,

b) low-head with an installed capacity of 1 to 2 MW, and

c) supplemental SHP plant with an installed capacity of a few 100 kW



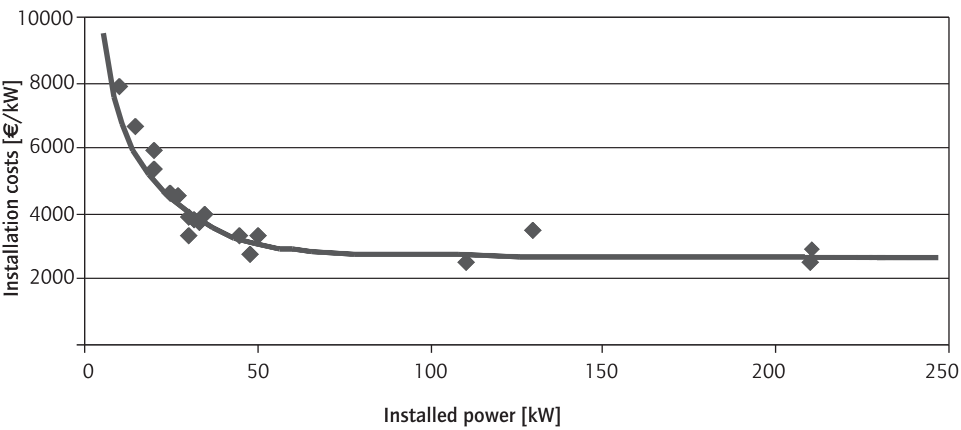
Source: NET Ltd., Switzerland.

Low-head hydropower sites are more common and are frequently found closer to population centres. Investment costs tend to be higher compared to high-head plants, as more water flow is required for a given amount of power, necessitating additional equipment.

Besides geographical characteristics (height of the water drop, site accessibility, hydrology, meteorology) and their impact on the height of head, the size of the plant is an important cost factor. Turbine installation costs grow exponentially as turbine power size decreases (see Figure 11). This inverse relationship between size and cost explains why SHP installation costs grow exponentially inversely to the plant size, as shown in Figure 12. The turbine size depends primarily on the flow of water it has to accommodate.

Figure 11

Specific Installation Costs Related to Capacity Size for Supplemental Plants Combined with Drinking Water Supply Systems in Switzerland.



Source: DIANE 10 Study, Hintermann M. (1994)

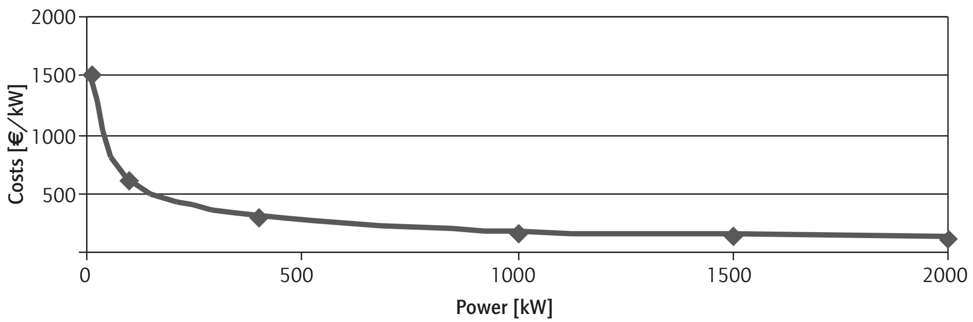
Investment costs differ greatly, even within geographical areas and countries, for technical and non-technical reasons. Figure 13 gives a sampling of some countries in Europe.

Generation Costs

The wide range of investment costs for SHP plants affects electricity generation costs (see Figure 14). Furthermore, electricity unit costs depend greatly on annual production hours (availability), which vary according to local hydrological and meteorological conditions. This explains why electricity costs tend to be lower for low-head and supplemental SHP plants. Although high-head SHP plants tend to produce more expensive electricity, its value can be higher as these plants often have greater storage capacity and can inject power in periods of higher demand, charging higher tariffs.

Figure 12

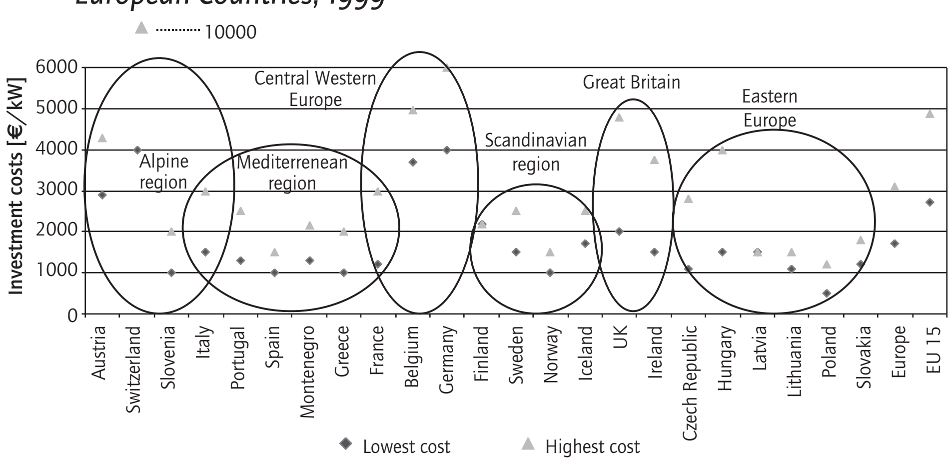
Average SHP Related to Capacity Installed Costs for Turbines from the Most Important European Manufacturers



Source: EurObserv'ER, Hydroelectricity barometer - Energy in rushing water, 1999.

Figure 13

Lowest and Highest Investment Costs for New SHP Plants in Selected European Countries, 1999

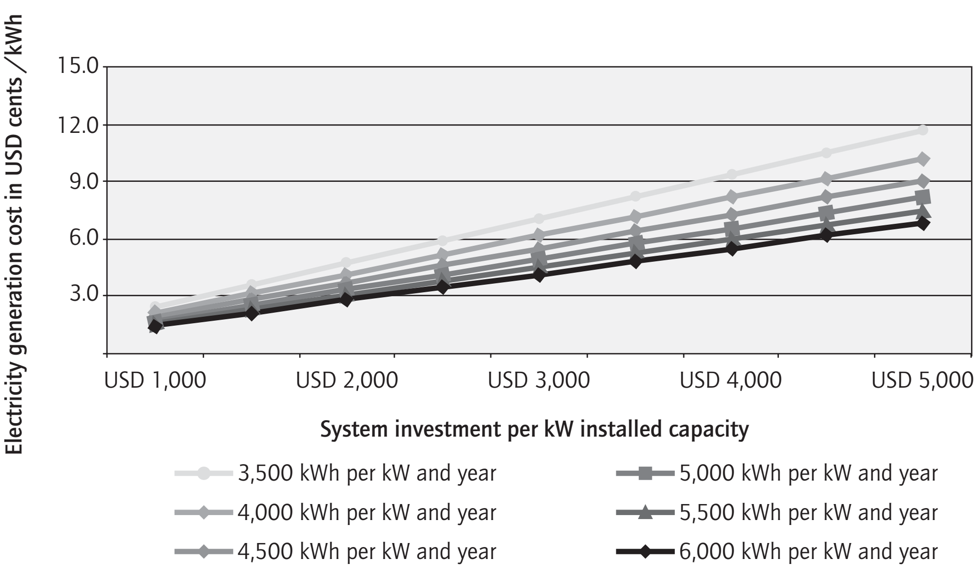


Sources: NET Ltd., Switzerland; raw data from the BlueAGE ESHA study, Lorenzoni et al. (2000).

An example can illustrate the investment-generation-cost pattern: Investment cost per unit of power capacity installed may be USD 2,000 per kW for a high-head SHP plant and USD 3,000 per kW for a low-head SHP plant. Due to higher availability, the low-head SHP plant may produce electricity (6,000 kWh per year per installed kW) at an average cost of USD cents 4 per kWh. The high-head SHP plant may produce 3,500 kWh per year at an average cost of USD cents 4.6 per kWh, as shown in Figure 14. This power can, however, be specifically produced and sold at times of higher demand at higher tariffs.

Figure 14

Approximated Generation Costs for SHP



Note: Based on system investment and annual electrical output. O&M costs are assumed to be 2% of system investment. Amortisation period is 15 years, discount rate 6%.
Source: NET Ltd., Switzerland.

High cost-competitiveness occurs when the plant site has low project and installation costs, adequate water, topography allowing for high flow and/or high head, and consequent high electricity production. Small hydropower costs can then be as low as 3 USD cents per KWh. Appropriate areas for development include mountainous regions for high-head plants, rivers for low-head plants. These are also areas where small hydropower can contribute the most power at competitive costs. SHP plants have a particularly long life span and relatively low O&M costs. Once the high up-front capital costs are written off (usually over 15 to 20 years), the plant can provide power at even lower cost, as such systems commonly last for 50 years or more without major maintenance or operating costs.

- **Industry**

Many parts of the SHP manufacturing industry are connected to other sectors, e.g. manufacturers of generators, gear boxes, electrical control equipment and hydraulic equipment. These manufacturers' products are normally standard and thus, unlike water turbines, can be mass-produced.

The invention of the water turbine in France led to the development of the modern hydropower industry. European manufacturers led the field in the development and manufacturing of water turbines, and exported the technology to other regions. One important reason for European leadership in this area in the past has been the strong domestic market. However, this situation may change, as future growth potential is likely to be stronger outside Europe.

At the end of the 20th century the SHP turbine manufacturing industry is made up of about 175 small water turbine manufacturers worldwide, employing a total of around 25,000 people. Four major multinationals dominate the market for larger turbines. The market for plants generating 0.5-5 MW is more open and includes smaller companies from North America and Asia. In particular, Chinese industry is expected to play a significant role in the future SHP market. Table 4 indicates the number of turbine manufacturers in different regions of the world. Many of these companies also produce equipment for large hydraulic plants.

Table 4

Small-Scale Water Turbine Manufacturers with Export Capability

Region	Number of SHP turbine manufacturers
Europe	70
North America	40
Asia	30
Oceania	20
South America	15

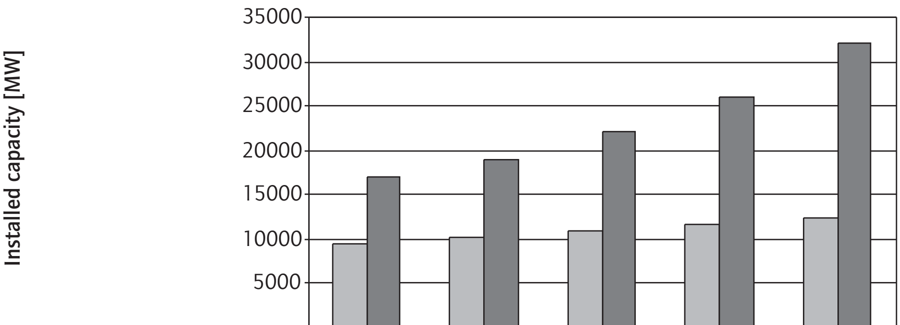
Sources: EurObserv'ER; BlueAGE ESHA study, Lorenzoni et al. (2000).

Market

The global installed SHP capacity was 32 GW in 2000. Most capacity is installed in Europe with 12.5 GW, followed by China with 9.5 GW and North America with slightly more than 5 GW. Higher and different capacity figures (especially for Asia) are reported on the basis of different SHP definitions. Europe added capacity in the range of 30% from 1980 to 2000, tapping a good deal of its developable potential. The rest of the world increased capacity by a factor of 2 in the same period.

Figure 15

SHP Installed Capacity in EU and Worldwide between 1980 and 2000



	1980	1985	1990	1995	2000
Capacity installed in Europe	9,500	10,250	11,000	11,750	12,500
Global capacity installed	17,000	19,000	22,000	26,000	32,000

Sources : NET Ltd. Switzerland, raw data from EUREC Agency, BlueAge ESHA study, Lorenzoni et al. (2000), IASH, Small Hydro Atlas.

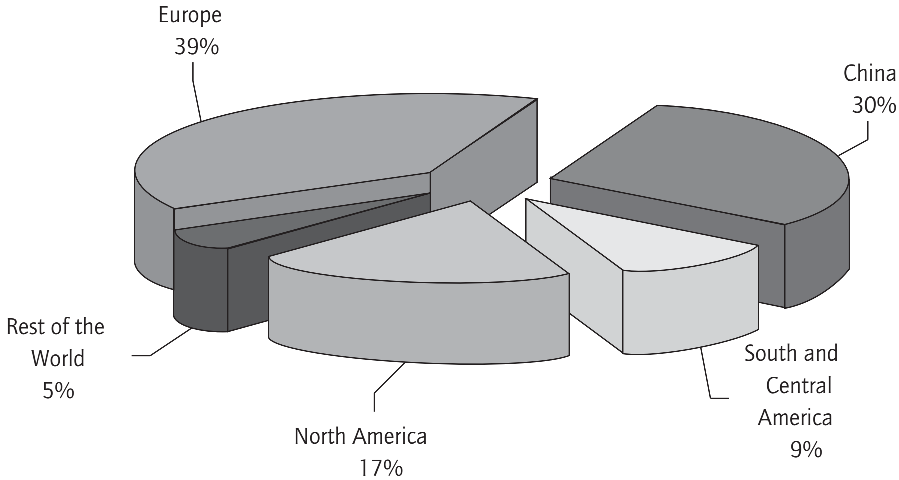
SHP was the leading "new" renewable source of electricity in terms of installed capacity and production worldwide in 2002, but has been overtaken by wind power in 2003. China offers the most dynamic market for SHP technology. In Europe, more than 17,000 SHP plants supply 1.7% of European electricity or 9.7% of total hydropower. The share of SHP in total hydropower installed capacity is 2.5% in Canada, 4% in the USA and 5% in China.

Environment

SHP carries both environmental benefits and costs, and must be managed well to limit local environmental damage. Depending on the type of SHP plant, peak and/or base-load electricity can be produced, although

Figure 16

SHP Installed Capacity Worldwide in 2000



Sources : NET Ltd. Switzerland, raw data from EUREC Agency, BlueAge ESHA study, Lorenzoni et al. (2000), IASH, Small Hydro Atlas.

managing water flow solely to maximise electricity revenues can cause some irregularities of water flow downstream from the plant. Carefully developed, SHP produces very few emissions. In some cases, SHP plants can even help improve water quality, regulate the river flow, enrich the water's oxygen levels and eliminate floating debris or waste. If not handled properly, the possible negative impacts on the environment include:

- damage to the habitat/migration route of fish;
- harm to riverine flora;
- alteration of the character of the river flow;
- impact on ground-water levels;
- garbage accumulation;
- degradation of water quality;
- noise from machinery;
- visual intrusion.

Since most impacts are site-specific, each plant design requires appropriate environmental safeguards. If adequate measures are taken, the environmental benefits of small hydropower systems outweigh its costs.

Nevertheless, hydropower projects are often strongly opposed by local environmental groups and fishery associations. In some countries, these protests have led to national movements against new hydropower projects. In response, the SHP industry has invested significantly in the development of fish protection devices. Two main types of solutions are being used. First, fish moving downstream are prevented from entering the turbine. Second, structures commonly known as "fish ladders" provide passage for fish moving upstream over diversion structures associated with the intake.

Prospects for Small Hydropower

- **Cost Reduction Opportunities**

The potential for cost reduction is different for each category of SHP plant. Only limited increases in efficiency and related cost reductions are expected due to improved turbine-generator design. However, technology development and market deployment can still result in cost reductions, depending on the type of plant and components.

R&D continues to improve efficiency and applicability through the use of composite materials to protect sensitive areas from erosion. Cost reduction potential exists in the areas of civil engineering and O&M, for example, from improved materials and construction methods, and simplified and computerised O&M equipment.

Economies of scale are limited because many components cannot be mass-produced, and the plant and its components must be adapted to the specific site. Some components can and should, however, be standardised.

Following is a brief outline of the cost reduction potential for the most relevant plant components:

Generator: The electrical generator represents less than 5% of the total cost of a power plant and the efficiency of generators for new plants is already close to 100%. Yet standardisation of generator equipment for small hydropower could further reduce installation and maintenance costs.

Turbine: Most water turbines are not mass-produced but individually designed and manufactured in order to optimise the energy that can be extracted from the falling water. This process requires highly competent and skilled personnel. During the 20th century, turbine efficiency of 95-96% was achieved, and thus, only marginal improvements in efficiency may be anticipated in the future. Generally, smaller turbines are less efficient than larger ones. Mid-size turbines could achieve cost reductions of 1.5% and small turbines 3-4%. For low-head and supplemental hydropower plants, the relative importance of the turbine in overall cost is greater than 25%. Thus, greater cost reductions could be achieved by improving turbine efficiency for those types of plant. For supplemental SHP plants supplying drinking or irrigation water, turbine pumps working simultaneously to generate electricity can be a good solution.

Civil Engineering

Since civil engineering represents a large share of SHP plant costs, research is being carried out on improved materials and methods for construction. New techniques to reduce erosion, and new materials to lower costs have been developed.

Operation and Maintenance

O&M costs can be reduced by using standard industrial components, standardised modular equipment and highly automated monitoring devices (remote control, web cams and microphones). Generally speaking, costs are predicted to fall faster for low-head and supplemental plants due to the significant cost share and reduction potential of the electrical equipment in these systems. Costs of high-head plants will decrease less, mainly because in such plants the civil engineering costs – with smaller cost-reduction potential – represent about 60% of the total costs, compared to 50% for low-head plants and 30% for supplemental plants.

• Market Opportunities

Market Potential

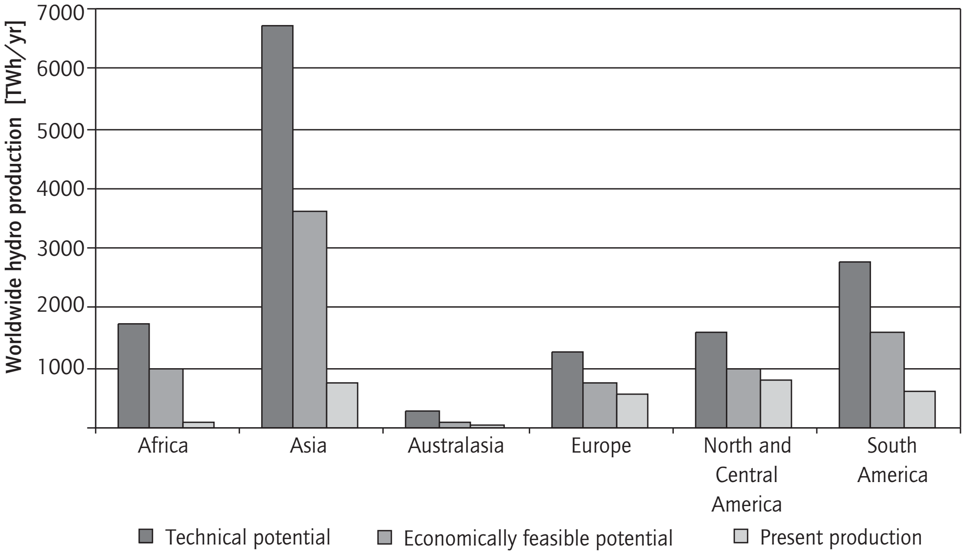
Potential SHP technical capacity worldwide is estimated at 150-200 GW. World hydropower economic potential is estimated at about 7,300 TWh per year, of which 32% has been developed, but only 5% (117 TWh) through small-scale sites.

In Asia, (India, Nepal and China) almost 15% of the potential technical SHP capacity (60-80 GW) has been developed, while in South America only 7% of its potential (40-50 GW) has been realised. In the Pacific and in Africa, less than 5% of the potential (5-10 GW and 40-60 GW, respectively) has been developed. Figure 17 shows the total hydropower technical potential, compared to economically feasible potential and present production.

In North America and Europe, a larger share of the technical potential has already been developed than in developing countries. A recent Canadian study identified 3,600 sites with a technically feasible total potential of about 9,000 MW, but of this, only about 15% would be economically feasible, mostly due to limited access to transmission systems. In the US, some 40 MW are planned for installation in the short to medium term.

Figure 17

Worldwide Technical Hydropower Potential versus Economically Feasible Potential and Present Situation 1998



Source: EUREC Agency.

Technology Factors

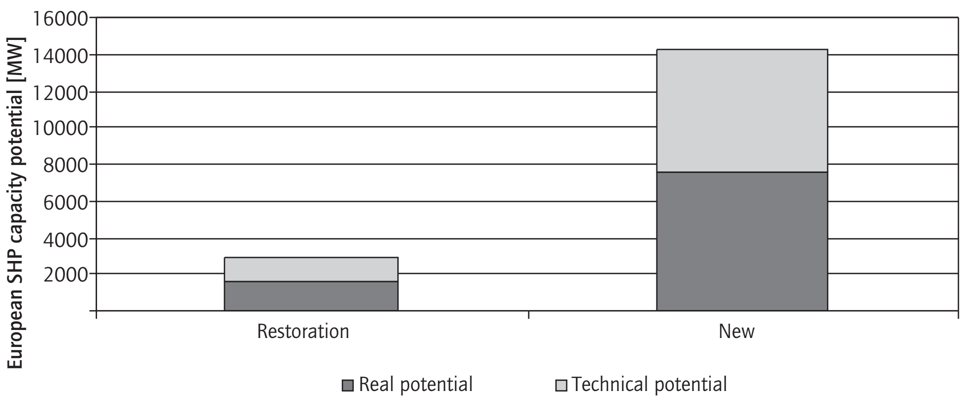
In developed countries there are three key markets for small hydropower with substantial near-term potential: (a) new installations (b) restoration and refurbishing of existing facilities and (c) addition of SHP plants at dams built for flood control, irrigation and drinking water supplies. The greatest potential for SHP exists in *new installations in developing countries*. In rural areas of these countries, energy demand is often moderate and can be met by small or micro hydropower schemes. The plants are frequently operated in isolation or are connected to local grids. The main competitor to SHP today in these circumstances is diesel generation.

Restoration and refurbishment of existing facilities

Refurbishment of old sites means the replacement of old equipment with more efficient turbines and/or generators, which would increase power production and/or reduce maintenance costs. Restoration means a more extensive overhaul of a power plant and can include a change of equipment and/or an improvement of the civil works. The restoration or refurbishment of old sites is one of the most promising and cost-effective ways to increase hydropower generating capacity, as many thousands of old sites developed in the early part of the past century have been abandoned and may readily be restored with modern equipment at competitive cost. Proper restoration, refurbishment and maintenance of these plants would double the European SHP electricity potential (see Figure 18).

Figure 18

Technical and Real European SHP Capacity Potential



Sources: NET Ltd., Switzerland; BlueAGE ESHA study, Lorenzoni et al. (2000). Considers old sites and new plants, taking into account environmental, legal and economic constraints.

Regional Factors

SHP installed capacity is estimated to grow between 1% and 6% per year over the next 20 years. Developing countries are likely to experience higher growth rates than the IEA countries. The largest increase is expected to be in China. Rapid expansion with significant growth rates of 5% or above are expected in other areas of Asia, Latin America, the Middle East, and North and sub-Saharan Africa. Central and Eastern Europe are expected to increase their capacity at a lower growth rate of 2%, mainly through refurbishment and restoration of old sites. The world market for small hydropower technology is worth well over USD 1 billion per year.

Table 5

Key Factors for SHP Potential

Factor	Fact
Capacity installed in 2000 in GW	32 GW**
Potential in 2010 in GW	45 GW
Future potential beyond term year given	medium-high
Rule of thumb for conversion ratio* (installed power to electric output)	1 kW -> 3,500 – 6,000 kWh per year

** Mean value based on European average for the lower rate (30 TWh production and 9 GW capacity in 1995), and the average of selected European countries (12 TWh production and 2 GW capacity in 2000) for the higher rate.*
*** Higher and different capacity figures are communicated based on different SHP definitions.*
Source: NET Ltd., Switzerland.

Table 6

SHP Global Growth Rates and Installed Capacity by 2020

Region	Present	Business-as-usual scenario		Accelerated development scenario	
	[MW]	Growth rate	2020 [MW]	Growth rate	2020 [MW]
China*	9,500	5%	25,000	6%	30,500
Europe	12,500	2%	18,500	4%	27,500
South and Central America	3,000	5%	8,000	6%	9,500
North America	5,500	1%	6,500	4%	12,000
Rest of the World	1,500	5%	4,000	6%	5,000
Total	32,000	3,2%	62,000	5%	84,500

** Higher and different capacity figures (especially for China) are communicated based on different SHP definitions.*
Source: NET Ltd., Switzerland.

Table 7

Cost Reduction Potential for Small Hydropower

	R&D	Economy of scale I (components size)	Economy of scale II (manufacturing volume)	Economy of scale III (plant size)
High-head	2-3%	2-3%	2-3%	2-3%
Low-head	4-5%	4-5%	2-3%	2-3%
Supplemental	4-5%	4-5%	2-3%	4-5%

Note: In % within a decade based on expected technology learning and market growth.
Source: Estimate by NET Ltd., Switzerland.

Table 8

Costs for Small Hydropower in Developed Countries

Current investment costs in USD per kW	Low investment costs: 1,000 High investment costs: 5,000
Expected investment costs in USD per kW in 2010	Low investment costs: 950 High investment costs: 4,500
Current generation costs in USD cents per kWh	Low cost generation: 2-3 High cost generation: 9-15
Expected generation costs in USD cents per kWh in 2010	Low cost generation: 2 High cost generation: 8-13

Source: NET Ltd., Switzerland.

Issues for Further Progress

- **Technical Issues**

Rationalisation, Standardisation and Design

Standardisation of turbine manufacturing has proved difficult. Standard design is best for small hydropower projects where cost rather than efficiency is the most important factor. In most cases, the end-user gains no advantages from standardisation, which is not suited well to the diverse small hydropower market and can result in significant energy losses. Rather than standardisation, the key is to “regularise” design procedures, the general system arrangement, and most of the elements (notably the electromechanical equipment, control systems and grid-connection arrangements), but the size and primary hydro components individually calculated and manufactured.

Computerised tools are being developed to assist in turbine design, as well as in the design of supply canals, inlet gates, grids and draft tubes for small hydropower projects.

The development of SHP plants requires specialised skills. A common complaint among technical experts is that SHP developers and project managers lack necessary knowledge or experience in plant construction. A systematically optimised design should be possible for small hydropower turbines, but this is not the case at present. Many manufacturers lack the technical expertise or facilities to design and test turbines.

Materials

Low-cost materials like steel and ceramics resistant to sand erosion and machine components made of plastic, glass fibre, etc. need to be developed for SHP.

Civil Engineering

Civil engineering represents a major portion of the total cost of a small hydropower plant, often more than 50% (including penstock in the case of high heads). Although few advances in civil engineering for SHP can be expected, some progress has been made in the use of geotextiles. These materials can be used in the construction of weirs, storage lagoons and drainage under the power canals to prevent landslides. Research into reducing the cost of the penstock (which can account for almost 50% of the total civil engineering cost) could result in improving the cost-effectiveness of SHP plants. For example, it appears that the use of fibreglass in the penstock can be cost-effective for a plant of up to about 2 MW. Powerhouses should also be studied to ensure that they are integrated into the local environment and soundproofed at moderate cost.

Electromechanical Engineering

- **Generators:** Since present generator efficiency is close to 100%, appreciable cost reductions from more R&D are uncertain. The use of higher-performance materials (for example, high-performance magnets for synchronous machines) may improve efficiency, but would also increase costs. Improving some materials, such as less expensive cooling fluids, may also reduce costs, but efficiencies might decrease. The benefits of developing suitable, inexpensive, multi-pole generators to eliminate gear-boxes in low-head applications need to be studied.
- **Variable speed:** The adjustment of turbine speed allows maximum turbine efficiency regardless of operating conditions. However, as electrical power has to be supplied at constant voltage and frequency, an electronic frequency converter must be used. This requires additional investment and results in a certain loss of efficiency. The economic balance, the application range, and the resultant benefits of such a solution have to be carefully studied in terms of the turbine characteristics and hydraulic variability. Interestingly, technology transfer from wind applications may be viable.
- **Controlling and monitoring:** In recent years, most small hydropower projects have used personal computers for system control and monitoring. Specific software can be used for data collection and remote control of the plant. Intelligent electronic devices (IED) for operation, closed loop control,

protection and monitoring offer cost-effective solutions. A wired or unwired telecommunication link to a regional control centre for remote control and monitoring can lower maintenance costs.

- **Non-technical Issues**

Institutional and regulatory rules can cause delays for approval of SHP projects, but could be streamlined without loss of oversight responsibilities. Procedures for gaining permission to use river water can be simplified and, in order to enhance environmental support, a standard method to determine acceptable minimum river flow could be established.

Although many sites have the potential for hydropower production, development can lead to significant ecological impacts. Past hydropower projects have disrupted fish runs, flooded large areas and converted rapids into placid lakes. With some foresight and precautions, small hydropower sites can be adapted to meet local environmental concerns and comply with the latest environmental policies. Various techniques can help minimise ecological impacts: e.g. fish ladders, careful operation of reservoirs, integration of powerhouses into the landscape and noise reduction. Other more complex techniques include guidance systems to deflect fish from small hydropower intakes and outfalls without energy. Environmental issues and their solutions need further exploration in order to produce definitive and broadly acceptable guidelines for SHP designers and planners.

Proper assessment of sites and selection of equipment can have an important impact on costs. Digital ortho-photography, digital terrain models and computer software programmes offer new techniques and solutions. Remote sensing techniques can also be used to assess isolated sites.

Green markets represent an important opportunity for further deployment of SHP. Thus it is important to develop a labelling programme to encourage SHP to be better accepted by the wider public. SHP needs to be marketed through literature, trade events and missions. Dissemination activities should be undertaken to encourage “market pull” from the potential growth areas.

SOLAR PHOTOVOLTAIC POWER

A Brief History of Photovoltaics

The direct relation between light and electricity was demonstrated by Becquerel in 1839, but it was not until the development of diodes in 1938 and transistors in 1948 that the creation of a solar cell became possible. Bell Labs patented the first solar cell based on silicon in 1955. This was the starting point for higher cell efficiencies, leading to the commercialisation of photovoltaics.

Photovoltaic (PV) technology has been used in space and terrestrial applications from small appliances like calculators to large-scale, multi-megawatt power stations.

Technology Status

PV technology and applications are characterised by their modularity – PV can be implemented on virtually any scale and size. The overall efficiency of systems available on the market varies between 6% and 15%, depending on the type of cell technology and application. The expected life span of PV systems is between 20 and 30 years. The solar modules are the most durable part of the system, with failure rates of only one in 10,000 per year. Some components, *e.g.* the inverter and battery, have to be replaced more regularly.

Experts expect crystalline silicon (market share 85% in 2002) to remain dominant in the coming years and thin-film solar cells to be considerably less expensive in the medium to long term. Different cell technologies can exist side by side. Some applications require high efficiency in a small space (crystalline silicon), while others need less expensive material covering a larger area (thin-film cell technologies).

Individual PV cells are interconnected and encapsulated between a transparent front, usually glass, and a backing material to form a solar PV module. PV modules for energy applications are normally rated between 50 and 200 W. The PV module is the principal building block of a PV system and any number of panels can be interconnected in series or in parallel to provide the desired electrical output.

The balance of system (BOS) components (everything except the PV module) complete the PV system to make it useful for different applications. Inverters, for instance, allow connection to the AC grid. Other structural elements can be used to integrate a PV system into a building. Batteries can store the solar electricity produced during the daytime. The two main types of PV systems are stand-alone and grid-connected.

Table 9

Examples of PV Applications According to Size

Size class	Applications
up to 10 W	Pocket calculators, radios, remote wireless sensors, small chargers, electric fences
10 W-100 W	Small illumination systems, call boxes, traffic signals, parking meters, navigation lights, small communication systems, weather stations, solar home systems, medical refrigeration, cathodic protection, small stand-alone systems for isolated dwellings
0.1 kW-1 kW	Medium-sized pumping systems and irrigation systems, desalination plants, propulsion of smaller recreation boats, stand-alone systems for isolated buildings, small rooftop systems, small hybrid systems
1 kW-10 kW	Medium-sized, grid-connected building and infrastructure-integrated systems; large stand-alone systems for isolated buildings; medium-sized hybrid systems
10 kW-100 kW	Large grid-connected systems either building and infrastructure integrated or ground-based
0.1 MW to 1 MW and above	Very large grid-connected systems - either building-integrated or ground-based

Source: NET Ltd., Switzerland.

Stand-alone or off-grid PV systems are used in areas that are not easily accessible, that have no access to electricity mains, or where grid connection is uneconomic or unnecessary. A typical stand-alone system consists of a PV module or modules, a battery and a charge controller. An inverter may also be included to convert the direct current (DC) generated by the PV modules to the alternating current (AC) required by many appliances. Stand-alone systems can be subdivided into industrial applications (telecommunications, water pumping, street illumination, etc.) and rural domestic applications (isolated housing).

PV systems can also be connected to the local electricity network. The electricity generated by the PV system can be used immediately (e.g. in homes or on commercial buildings) and/or can be sold to an electricity supply company. Power can be bought back from the network when the solar system is unable to provide the electricity required (e.g. at night). This way, the grid acts as a kind of "energy storage system" for the PV system owner, eliminating the need for battery storage. Grid-connected systems can be subdivided into building-integrated applications and grid-support power.

Costs

Costs for entire systems vary widely and depend on system size, location, customer type, grid connection and technical specifications. Less expensive grid-connected systems cost about USD 4.5 - 6 per W. Stand-alone systems cost more but are frequently competitive with other autonomous small-scale electricity supply systems.

Investment Costs for On-grid Systems

Average installation costs are around USD 5-9 per W for building-integrated, grid-connected PV systems. The lowest costs are around USD 4.5-5 per W, for example in the Danish Sol-300 programme, in the American Sacramento District Pioneer programme, in the second phase of the Dutch City of the Sun project, in the German 1.5-MW large-scale installation in Relzow and in household systems in Japan. Examples of the cost structure for flat-roof, sloped-roof and façade-integrated PV systems in Western Europe are shown in Table 10. Costs vary according to the maturity of the local market and specific conditions. For example, installation costs are now relatively low in Germany due to the experience gained in the 100,000 Roofs Programme. Furthermore, system costs vary significantly depending whether the system is part of a retrofit or is integrated into a new building.

In many cases, the added cost to the building of the PV is less than the figures shown here, as in modern systems the PV often replaces other building materials, and thus those costs are saved. For example, PV can be competitive in some markets where cladding materials are expensive. Table 11 compares different cladding materials on the basis of cost per square metre.

Table 10

Typical Costs (in USD) of Small (1-5 kW) Building-Integrated Photovoltaic Systems in Urban Areas of Switzerland, 2002

Cost category	Flat roof		Sloped roof		Façade	
USD/kW	min	max	min	max	min	max
Project development, engineering and other costs	400	1,800	400	1,800	500	1,800
Modules	3,300	4,500	3,300	5,500	3,300	6,000
Inverters	500	800	500	800	500	800
Cabling	250	350	300	500	400	600
Module support structure	350	450	400	600	600	1200
Mounting and installation	1,200	1,600	1,400	2,000	2,000	2,500
Total investment	6,000	9,500	6,300	11,200	7,300	12,900

Source: NET Ltd., Switzerland.

Table 11

Costs of Cladding Material (USD_{2000} /m²)

Polished stone	2.400–2.800
PV	500–1.500
Stone	800+
Glass wall systems	560-800
Stainless steel	280-400

Source: IEA-PVPS/Eiffert P. et al, 2001.

Costs of on-grid systems can be lower for land-based installations; however, such installations also need adequate sub-structure, which limits cost reduction potential.

Investment Costs for Off-grid Systems

For off-grid systems, investment costs depend on the type of application and the climate. System prices in the off-grid sector up to 1 kW vary considerably from USD 10 to 18 per W. Off-grid systems greater than 1 kW show slightly less variation and lower costs. This wide range is probably due to country and project-specific factors, especially the required storage capacity. For example, in the US Southwest, DC systems with four to five days of storage capacity can be installed. A local retailer can profitably install a simple system with PV arrays, mounting hardware, charge controller and a lead-acid, deep-cycle battery bank for USD 10-13 per W. In a moderate climate, an AC system with ten days of storage capacity, a stand-alone inverter and ground-mounted hardware can be installed for USD 13-17 per W. High-reliability systems for industrial uses in moderate climates with 20 days of storage, all-weather mounts, battery enclosures and system controllers cost at least USD 20 per W.

Generation Costs

Investment costs are one of most important factors determining the cost of the electricity generated from PV installations. Operation and maintenance costs are relatively low, typically between 1% and 3% of investment costs, and the lifetime of PV modules is 20 to 30 years. However, inverters and batteries have to be replaced every five to ten years, more frequently in hot climates.

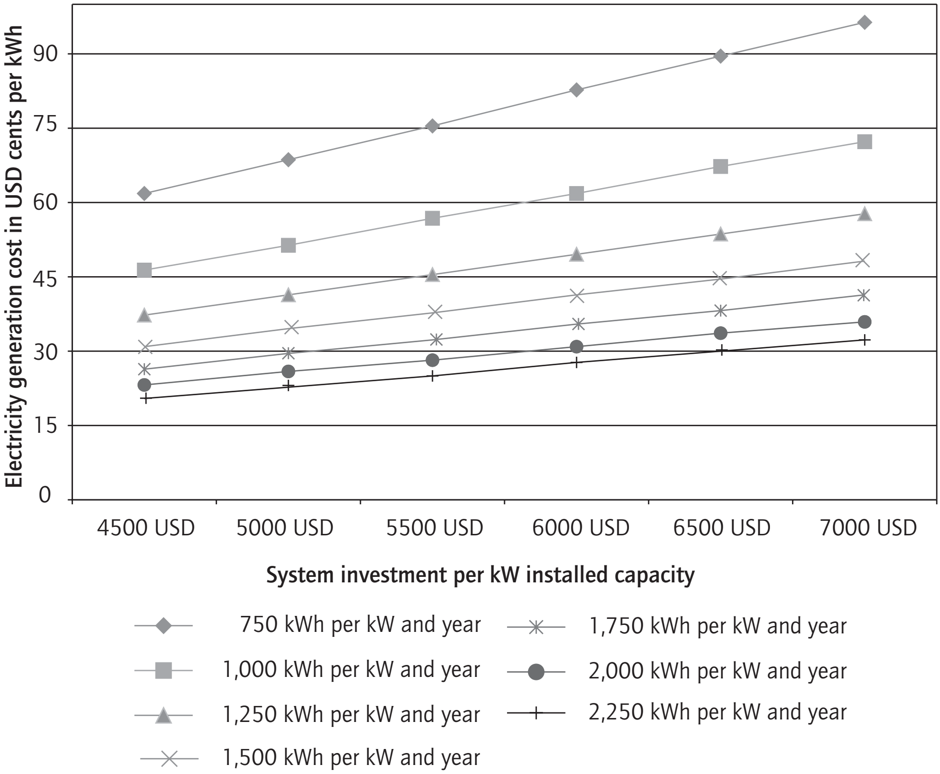
While "harmonised" investment costs (same components and systems in different areas) are relatively similar, kWh costs depend greatly on the solar irradiation level. Electrical output is roughly proportional to the incident light reaching the active area. Hence, an efficient PV system receiving 1,100 kWh of solar irradiation per year and per square meter may produce 110 kWh of electricity per year and per square meter in most areas of Germany. The same system receiving 1,900 kWh of solar irradiation per year and per square meter may produce 190 kWh of electricity per year and per square meter in some areas of California. The electricity costs 40% less in the second case, where irradiation is about 70% greater. Electricity output also depends on other factors like operating temperature, reflectivity and share of diffuse light.

Based on system investment and annual electrical output (but ignoring other factors such as risk and the environment), generation costs can be estimated for a range of applications (see Figure 19). Today's lowest generation costs (20 to 30 USD cents per kWh) occur with installations having low investment costs (around USD 4,500) and high energy output (over 1,500 kWh per kW per year). In the best locations, these costs can fall below 20 USD cents per kWh over the lifetime of the system.

Cost-competitiveness is greatest where high solar irradiation coincides with daily (peak) power demand. In Japan, a system cost level of USD 3,000 is projected to be reached in four to six years.

Figure 19

Approximated Generation Costs for Solar Photovoltaics



Note: Based on system investment and annual electrical output, O&M costs are assumed to be 2% of system investment. Amortisation period is 15 years, and discount rate is 6%.
Source: NET Ltd., Switzerland.

Industry

The PV industry is relatively young and vibrant. Today's silicon solar industry is comprised of:

- 7 electronic-grade silicon producers;
- 15 wafer producers;
- 25 cell producers;
- 100 module producers.

The industry is growing rapidly and achieving "dynamic competitiveness". It not only uses waste silicon from the computer industry, but is about to create its own supply. Large energy companies like BP and Shell, and electronics companies like Sharp, Kyocera and Sanyo are the main PV producers. Ten companies accounted for almost 90% of the world's cell/module production in 2002 (see Table 13).

Table 12

World PV Production in MW, 1994-2002

	1994	1995	1996	1997	1998	1999	2000	2001	2002
Europe	21.7	20.1	18.8	30.4	33.5	40.0	60.7	86.4	112.8
USA	25.6	34.8	38.9	51.0	53.7	60.8	75.0	100.3	100.6
Japan	16.5	16.4	21.2	35.0	49.0	80.0	128.6	171.2	251.1
ROW*	5.6	6.3	9.8	9.4	18.7	20.5	23.4	32.6	47.8
Total	69.4	77.6	88.7	125.8	154.9	201.3	287.7	390.5	512.3

** ROW – Rest of the World*

Source: PVNews, March 2003.

Table 13

Main PV Producers, 1999-2002

Company	1999 MW	2000 MW	2001 MW	2002 MW
Sharp	30.0	50.4	75.0	123.1
BP Solar	32.5	41.9	54.2	66.8
Kyocera	30.3	42.0	54.0	60.0
Shell Solar	22.2	28.0	39.0	47.5
Sanyo	13.0	17.0	19.0	35.0
Astropower	12.0	18.0	26.0	29.7
RWE (ASE)	10.0	14.0	23.0	29.5
Isofoton	6.1	9.5	18.0	27.4
Mitsubishi	n.a.	12.0	14.0	24.0
Photowatt	10.0	14.0	14.0	15.0
Total	166.1	246.8	336.2	458.0
World total	201.3	287.7	390.5	512.3

Source: PVNews, March 2003.

PV manufacturers have developed diverse strategies for competing in global markets. Some of these methods include:

- **Locating near end-use markets:** Manufacturers benefit from feedback by end-users on product design. Distance from end-use markets can be partly compensated by making technically trained marketing representatives available.
- **Starting local and small:** Reduced transportation costs and more direct feedback. Small plants can be expanded as demand increases.
- **Starting big:** Large plants achieve economies of volume and scale that reduce production costs. This technique has also led to financial problems when companies try to expand too quickly, particularly into new technology manufacturing.
- **Separating cell and module production:** PV cell manufacturing requires expertise and infrastructure. Because assembly of cells into modules does not require the same level of expertise, manufacturers often ship cells for assembly to countries with end-use markets.
- **Establishing in-country corporate presence:** Manufacturers located in-country obtain preferential treatment, such as exemptions from certain taxes. Additionally, some countries, such as Germany, provide investment incentives for building plants.

The manufacturers can be subdivided into two broad categories: those that purchase ready-made cells and assemble them into modules, and vertically-integrated manufacturers who manufacture their own cells and modules. Amorphous silicon manufacturers normally have vertically-integrated production lines, as the cell and module are usually assembled in the same process.

The manufacture of balance of system components such as inverters, batteries and battery charge controllers, and array support structures constitutes a large industry. In the absence of an international standard for grid connection, inverters are largely selected on the basis of compliance with connection requirements in a particular country.

A number of countries with little or no module manufacturing capacity are active in other areas of the industry. For example, Isovolta/Werndorf of Austria produces and exports approximately 50% of world demand for tedlar used in PV modules. Crystalox of the UK and ScanWafer of Norway are major exporters of multi-crystalline silicon ingots and wafers. Automation Tooling Systems of Canada has developed and marketed automated PV cells and sells customised module manufacturing lines. Two Swiss companies, Meyer & Burger and HCT Shaping systems, have a large share of the market for wire saws used for cell production.

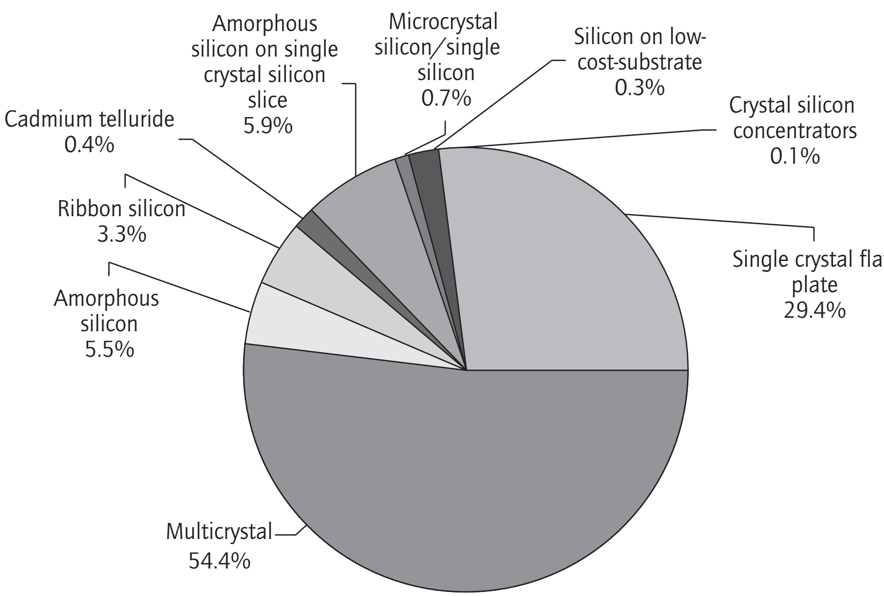
The US industry is export-oriented: more than 80% of the approximately 150,000 charge controllers manufactured by US suppliers are sold abroad. The Japanese PV industry primarily supplies its domestic market. The European PV industry currently imports about as many modules as it exports.

Market

The annual production of PV modules has been growing at an average rate of more than 30% in recent years. PV module production capacity is now over 500 MW per year. The latest data on global cell/module production by cell technology in MW are given in Figure 20.

Figure 20

World Production by Cell Technology in 2002



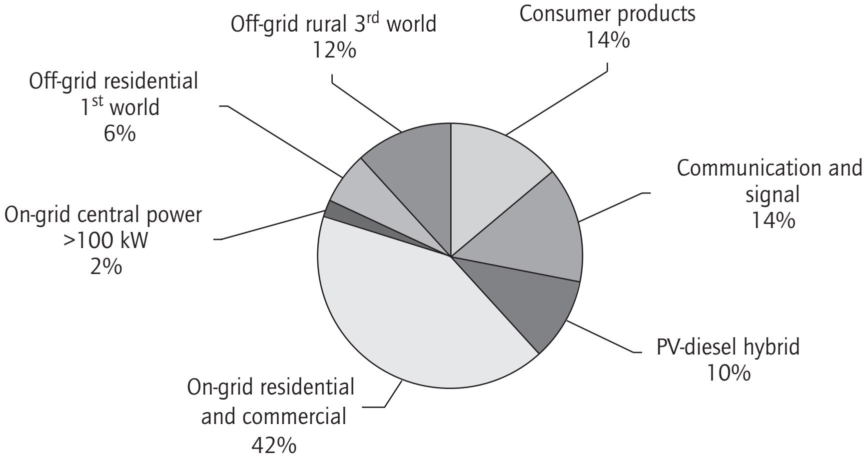
Source: PVNEWS, March 2003.

In 1990, PV was used mainly in stand-alone systems, for rural electrification and small-scale applications. Since then, the number of grid-connected systems has greatly increased. Europe and Japan have the largest number of distributed grid-connected PV systems, mostly building-integrated (BiPV).

The market share of distributed grid-connected PV installations has been growing steadily and reached 63% of cumulative capacity installed in IEA PVPS countries by the end of 2001*. Figure 21 provides an overview of the seven major segments of the PV market.

Figure 21

Relative Share of PV Market in 2000



Source: Sarasin Bank.

Environment

Replacing fossil fuel-based electricity generation with PV can yield significant environmental benefits. However, two issues bear noting. First, PV consumes a large amount of electricity in its production. While PV's energy payback is on the order of 2–5 years, the energy used is almost always from the grid, so some consider that renewables "inherits" the emissions of the supply. Second, PV arrays are quite large and require space for their deployment. Where these arrays can be integrated into roofs, or where marginal or rural lands can be used, this is not a problem, and can even generate savings. However, the future concept of large arrays near urban load centers carries a possible conflict for land use. Other issues include:

- **Manufacturing and substances of concern:** PV's manufacturing process uses toxic and flammable/explosive gases like silane, phosphine or

* *PVPS refers to the IEA PhotoVoltaic Power System Implementing Agreement, a technology collaboration project that brings together researchers for R&D. PVPS countries include: Australia, Austria, Canada, Denmark, Finland, France, Germany, Israel, Italy, Japan, Republic of Korea, Mexico, the Netherlands, Norway, Portugal, Spain, Sweden, Switzerland, United Kingdom and the United States of America.*

germane, and toxic metals like cadmium. However, current control technologies appear sufficient to manage wastes and emissions in today's production facilities. Recycling technologies are being developed for cell materials. The development of thinner layers and better deposition processes can make the use of these materials more efficient. The use of cadmium and other "black list" metals in PV components is controversial, though there are no indications of immediate risks.

- **Energy payback times:** As mentioned above, the effective energy payback time of PV systems depends on the technology used and the type of application and energy yield in different climates. Although it varies by type of technology, the payback time is much shorter than the 20-30 year expected lifetime of a PV system. For crystalline silicon modules, most of the energy is needed for silicon production, while for thin-film modules the encapsulation materials (e.g. glass) and processing represent the largest energy requirements. There remains a large potential for reducing energy use in production, which will also reduce the inherited emissions.

- **Operation and emissions:** PV systems operate virtually without any harmful emissions. They work silently and do not emit any gases. Electromagnetic interference may cause technical problems, but it is not harmful to humans.

- **Land use:** Large-scale, ground-based PV arrays may become a future issue where land is scarce. However, small scale PV systems can be easily integrated into buildings, an advantage in comparison to other power plants.

Prospects for Solar Photovoltaics

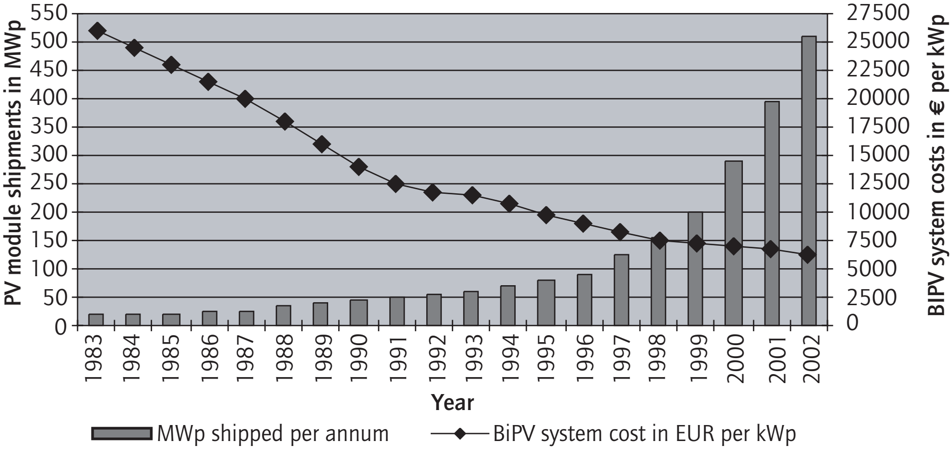
- ### Cost Reduction Opportunities

Cost reduction has been a key issue for PV, as costs are still relatively high compared to other types of grid-connected electric technologies. But cost reductions of BIPV systems have been considerable and average costs have been reduced by a factor of 2 in each of the last two decades, as depicted in Figure 22. This trend is likely to continue in the future.

Cost-reduction opportunities for cells and modules are important because these items are expensive key components of PV systems. Improvements in cell technology efficiency through R&D are depicted in Figure 23.

Figure 22

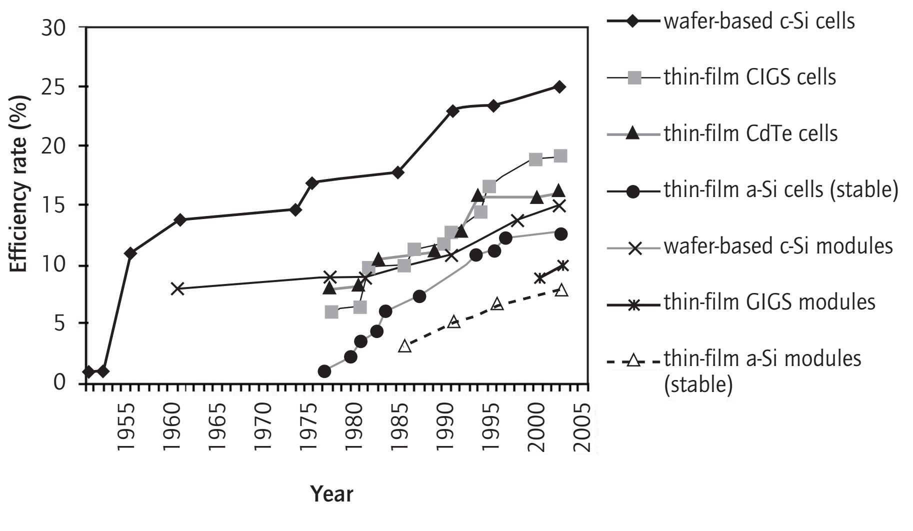
Annual World PV Module Production (columns) and Building-integrated PV System Costs (dots), 1983-2002



Sources: NET Ltd., Switzerland; PV News, February 2002.

Figure 23

Evolution of Cell Efficiency

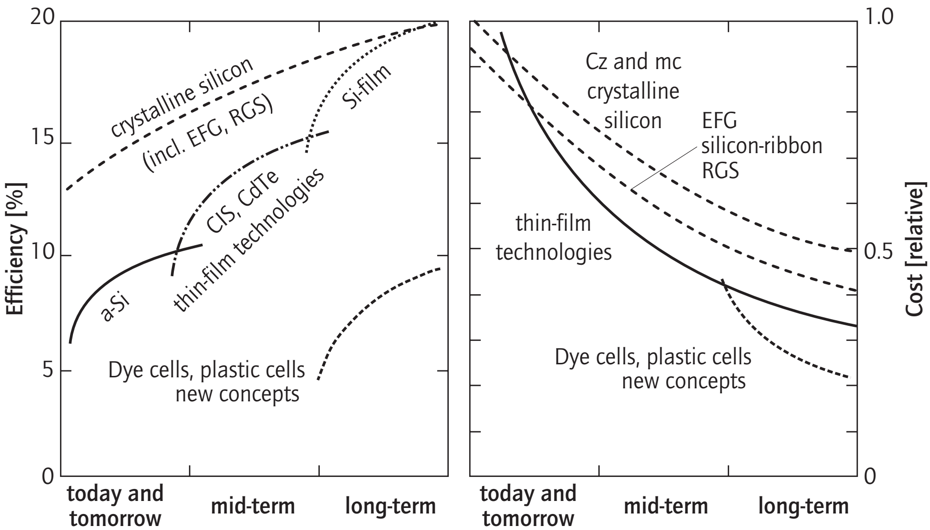


Sources: IEA-PVPS Task 7 (2003), "Education and Training Material for Architects", Utrecht.

R&D is especially important for new cell technologies to enter the manufacturing sector and markets. There are a number of PV cell technologies, each of which offers unique characteristics. New cell technologies evolve through R&D but also require manufacturing experience to become commercial. Because PV cell manufacturing requires large investments, market and manufacturing volume is very important.

Figure 24

A Conceptual Road Map for Photovoltaic Cell Technology



Source: Hoffmann W., RWE Schott Solar GmbH.

The MUSIC FM project concluded that up-scaling the manufacturing plant to 500 MW would result in module costs below € 1_{1995} per W for multi-crystalline silicon. In theory, manufacturing costs for different thin-film technologies would be around € 0.7_{1995} per W at a scale of 60 MW. A recent study by Arthur D. Little indicated that cost reductions close to 50% are possible for most technologies in the period from 2000 to 2010, bringing manufacturing costs down to USD 0.95 to 1.40 per W. Major contributions come from:

- up-scaling from 10 MW to 100 MW, allowing cost reductions due to volume purchase, balanced line, larger equipment and higher throughput;

- increased cell efficiency (a 2% to 4% cell efficiency increase translates into an efficiency gain of 20% for established crystalline silicon technologies and up to 40% for thin-film technologies);
- improved manufacturing and handling processes (fewer broken and out-of-spec products, improved material utilisation).

The cost reduction potential is around 25% for a tenfold up-scaling and another 25% for increased cell efficiency and enhanced processes.

Key findings from various studies indicate:

- cost reduction potential in semiconductor processing must be exploited to lower manufacturing costs;
- feedstock issues become more important for crystalline silicon once manufacturing costs have substantially decreased. Thus, availability of low-cost material must be assured;
- costs for other materials (substrates, encapsulants, pottants, mounts, electrical connections) dominate when semiconductor costs are optimised;
- overhead costs decrease in relative terms when manufacturing volumes increase.

Projected costs vary considerably for individual PV cell and module technologies but have common aspects: R&D and increased volume can contribute to overall cost reductions of almost 50% within a decade in the areas of feedstock, device and cell efficiency, and manufacturing processing.

Although modules represent about 60% of grid-connected system costs, reducing the cost of components BOS is also important for bringing down total system costs. For instance, the efficiency rate of common inverters in the range of 1.5-3.3 kW was between 85.5% and 90% in the years 1988 to 1990. Today their efficiency is above 90%, even for smaller units (100-200 W), and is often close to 95% for the most common models. Technical improvements are expected to increase efficiency and extend their lifetime to 15 - 20 years. Costs for inverters in particular could be reduced through higher manufacturing volumes.

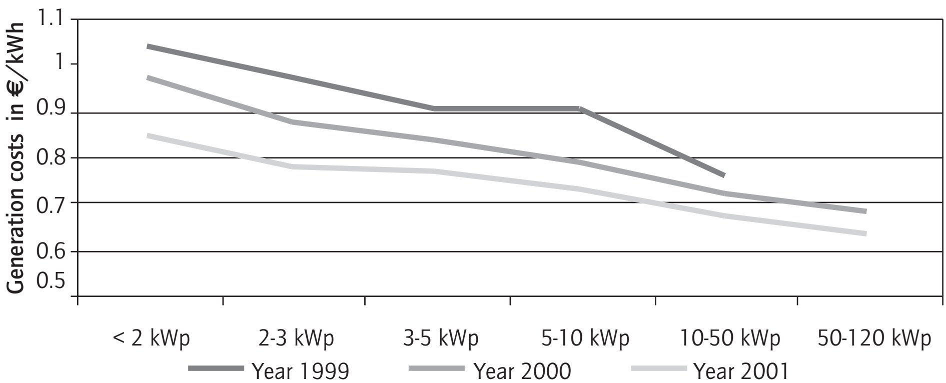
Cost reductions have been more substantial for BOS (inverter, mounting structure, installation labour and planning) than for modules in recent years, especially in markets that have reached a critical mass in volume sales, such as residential systems in Japan and Germany. For example, installation costs are lowest for 2 kW PV installations in Germany thanks to enhanced standardisation of planning and mounting procedures and materials, as well as installation experience that has resulted in the need for less on-site labour. In Japan, PV is becoming a common building material. Many houses are either prefabricated or constructed of standardised building components. These building trends favour the integration of solar modules. This advantage has been recognised by solar manufacturers and they have either bought housing or construction companies, or concluded strategic alliances with such companies.

For stand-alone systems, storage is a key issue. Battery system components have been adapted for the charge/discharge behaviour of PV in order to increase battery life span. Special software is used to design systems for specific locations and circumstances.

Economies of scale with respect to the size of the generation plant contribute to reduce system and installation costs. Data from the Swiss PV subsidy programme from 1997 to 2001 show economies of scale averaging 14% for medium to large-scale (> 50 kW) plants compared to small-scale (2-4 kW) plants. Cost data do not distinguish between different types of installations but only between different size classes. Note that generation costs came down by around 20% from 1999-2001 for small-scale installations (up to 10 kW) and by around 10% for larger installations. This underpins the fact that volume (experience and standardised procedures for small-scale applications) induces considerable cost reductions and that economies of scale, due to PV generator size, are less significant compared to other technologies because of the modular structure of PV.

Figure 25

Average Generation Costs for Different PV System Size Classes in Germany, 1999-2001



Source: Data from German Federal Ministry of Economics and Labour.

Economy of scale can be relevant for some component sizes. For instance, inverters cost substantially less on a per kW basis in large sizes than in small ones. The same is true for modules and batteries although the difference in cost between large and small components is not as great as with inverters.

PV technology needs market stimulation to improve products and increase volume. Opening up markets stimulates private-sector R&D and initiates the learning process. R&D progress and associated cost reductions will be crucial to the future of PV.

Market Opportunities

Market Potential

Theoretically, the potential for photovoltaic applications is tremendous as sunlight is ubiquitous and areas available for development and applications abound. Building stock in industrialised countries offers enough suitable surfaces for PV to generate between 15% and 50% of current electricity consumption.

Electricity output and costs of PV applications depend primarily on the amount of sunshine in a given area. Roughly speaking, the ratio of solar irradiation to electrical output is directly proportional, although other factors like operating temperature, dirt, reflexivity and share of diffuse light influence this relationship.

Technology Factors

On the basis of traditional cost-evaluation PV is not competitive, by a factor of 10 or more, with conventional base load power from the grid. However, solar electricity is being successfully deployed on the grid. This is both in areas of expensive conventional peak power and high solar irradiation (*e.g.*, California) through subsidy support. As a result, the market for grid-connected PV (*e.g.*, Germany and Japan) rooftop systems is the fastest-growing of all PV applications.

Building-integrated/decentralised, grid-connected photovoltaic systems are becoming more common, especially in Europe, Japan and the US. In these regions, the biggest potential application is rooftop systems on houses and commercial buildings connected to the local electricity network. PV for use in building-integrated systems is already manufactured as a construction material, making the building's outer surface multifunctional.

This is seen most often in Japan, although it is now entering the US and European markets. Significant programmes to encourage BiPV include the 100,000 Roofs Programme and favourable feed-in tariff rates in Germany; the 70,000 Roofs Programme in Japan; and the One Million Solar Roofs Initiative in the US. One of the most successful policy supports has been the establishment of “net metering” rules in the US, where PV on rooftops can feed into, or draw out of, the utility distribution network for the same cost. Thus cost competitiveness of PV can be measured on the basis of the retail cost of electricity, instead of the wholesale cost of electricity.

The advantages of BiPV are: a) the built environment can be used in a multifunctional way, b) distribution losses are reduced because the system is installed at the point of use, c) no extra land is required for the PV system, d) installation costs can be reduced if the system is incorporated within the structure, e) energy storage is not required and f) BiPV building materials can already compete with costly façade materials like marble.

Stand-alone PV systems (mainly industrial) are also becoming more versatile. They can supply energy competitively for a great variety of remote applications as well as for modern infrastructure-related applications, such as telecommunications. Developing countries also offer many opportunities for PV in rural areas – for example, applications for water pumping, communications, solar home systems and micro-grids.

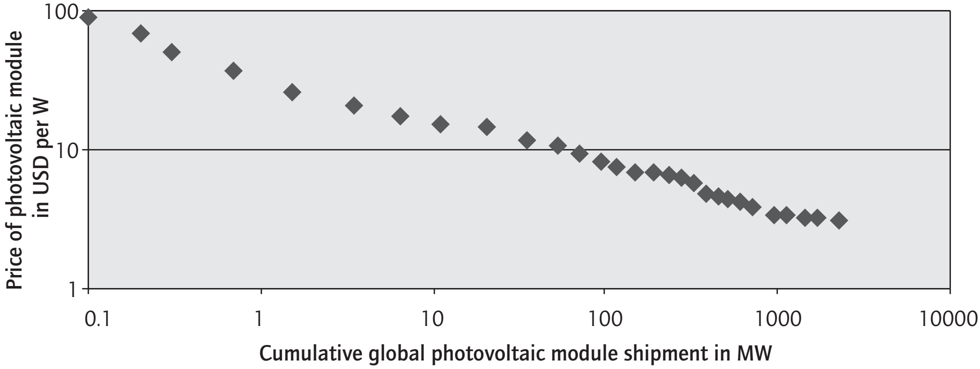
Consumer applications from calculators to mobile telephones can be solar-powered, as PV for this use remains the practical and low-cost option. A profitable market for the industry already exists.

Most experience curves for PV tend to have progress ratios around 80 - 82%, which translates to a learning rate of 18 - 20% for each doubling of volume. It can be anticipated that PV continues to show a relatively high learning rate thanks to its technological potential with respect to further enhancing materials, system design and manufacturing processes. As with other industries, this rate may decrease in the future as volumes increase and technologies mature.

Experience curve analysis shows that a large cost reduction opportunity, in relative terms, exists. Compared to wholesale electricity, however, PV power will remain comparatively expensive over the next two decades except where the solar resource is particularly strong.

Figure 26

Experience Curve for PV Modules, 1968-2002



Source: IIASA/Harmon.

Regional Factors

PV is unlikely to be a significant contributor to the energy balance in the short to medium term. Current market growth of 30% per year is the result of government incentives. The resulting cost reductions are impressive, as every doubling of the volume produced has brought about a cost decrease of some 20%.

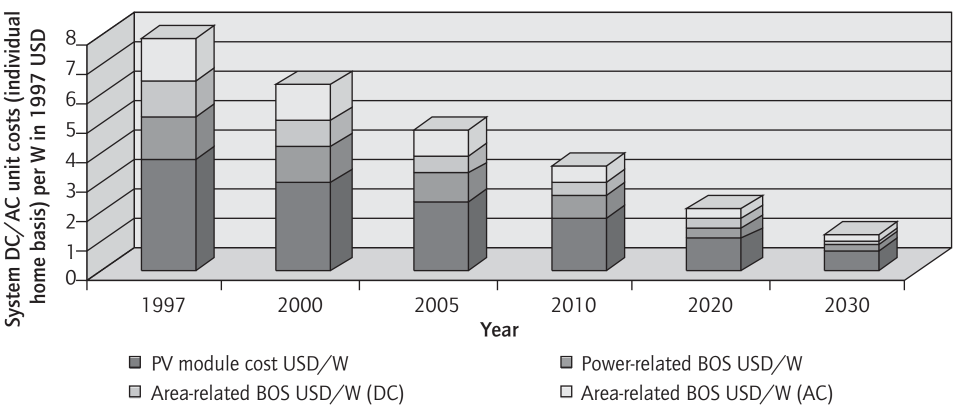
Many countries adopted specific policy and industry goals for PV over the past decade. Japan's official growth goal is 4.82 GW by 2010, and the US industry's target is 2.14 GW. The European Commission's target is 3 GW of installed PV power by 2010. The European PV Industry Association (EPIA) has about the same target. Another 1.2 GW of installed capacity is forecast for the rest of the world. In order to achieve these goals, according to EPIA, annual cell and module production would need to grow to around 870 MW for Europe, 1,360 MW for Japan and 450 MW for the US, with additional production outside these areas. To reach these ambitious goals of more than 11 GW of installed PV power worldwide by 2010, the global growth rate would have to be close to 30%, resulting in a yearly global shipment of PV cell and module production of around 2.9 GW in 2010.

Since these goals were fixed, PV has experienced vigorous growth. Based on a more conservative interpretation of potential market expansion, annual volume may grow from 0.5 GW in 2002 to around 2 GW in 2010. Cumulative global capacity might increase from 2 GW in 2002 to around 11 GW in 2010. As a result of cost improvements from a market of this scale, system costs would then be around USD 3 to 3.5 per W and could drop by another 40 to 50% by

2020. These cost figures fit quite well with forecasts given by the World Energy Council with projected installed system capital cost of around USD 1,500 per kW for PV solar technology in 2020 and by EPRI/DOE for building-integrated PV systems costing around USD 2,000 per kW (see Figure 27).

Figure 27

Cost Development and Indicators for Photovoltaic Systems



Note: Based on crystalline silicon residential systems.
Sources: EPRI, US DOE.

Table 14

Cost Reduction Opportunities for Solar Photovoltaics (%)

	R&D	Economy of scale I (components size)	Economy of scale II (manufacturing volume)	Economy of scale III (plant size)
Solar photovoltaics	Up to 20 - 25	Up to 5	Up to 15	Up to 5

Note: In % within a decade based on expected technology learning and market growth.
Source: NET Ltd., Switzerland.

In sum, about half of the future cost decreases for PV will be the result of R&D into improving materials, processes, conversion efficiency and design. Substantial cost reductions can also be gained through increased manufacturing volume and economies of scale. Increasing the size of components and plants will also reduce costs.

Table 15

Costs for Solar Photovoltaics

Current investment costs in USD per kW	• Low investment costs: 4,500 • High investment costs: 7,000
Expected investment costs in USD per kW in 2010	• Low investment costs: 3,000 • High investment costs: 4,500
Current generation costs in USD cents per kWh	• Low cost generation: 18-20 • High cost generation: 25-80
Expected generation costs in USD cents per kWh in 2010	• Low cost generation: 10-15 • High cost generation: 18-40

Source: NET Ltd., Switzerland.

Table 16

Key Factors for Solar Photovoltaics

Factor	Fact
Variable influencing energy output	• Global irradiation
Limiting factors	• Grid (load) capacity
Capacity installed in 2002 in GW	• 2 GW
Potential in 2010 in GW	• 11 GW
Future potential beyond term year given	• Very high
Rule of thumb for conversion ratio* (installed power to electric output)	• 1 kW –> 1,200 - 1,800 kWh per year

** Assumptions: solar irradiation 1,200-1,800 kWh / m² and year, system efficiency 10%.*
Source: NET Ltd., Switzerland.

Issues for Further Progress

• Technical Issues

Feedstock

There are no short-term supply limitations, but demand from the PV industry versus world market supply of crystalline silicon may become a short-term issue as production levels increase. Should a bottleneck develop, new production of feedstocks could be brought on line.

Solar Cell Technology

Manufacturing approaches have diversified recently. A few technologies have entered the industrial stage while many others are still in the pilot manufacturing or even laboratory phase. It is likely that different technologies will continue to co-exist for different applications for some time. Many varieties of materials are being researched, but they are far from the manufacturing stage. An early assessment of production processes, industrial compatibility and costs should be undertaken.

Balance of System

Both grid-connected and stand-alone applications need better BOS components. A variety of reliable components are available; nevertheless, the efficiency, lifetime and operation of some components can be further improved, especially inverters and batteries. Standardisation and quality assurance are crucial for components as well as for the entire system. Ultimately, BiPV systems should be treated like almost any other building construction component.

The Japanese technology development programme has been particularly successful. Some key elements of this programme are given in Table 17.

Long-term R&D

While cost reduction potential through learning in PV technology, as in other technologies, should lead to major cost reductions over time, they are unlikely to lead to cost competitiveness for on-grid power generation. Long-term R&D needs to focus, therefore, on how to improve solar technologies with new and more cost effective technologies. The time horizon of this R&D effort extends well beyond the 2010 limit of this work's focus.

R&D focused on the long-term is, therefore, of high importance for PV, in particular for the solar cell. Furthermore, to bring new concept cells and modules to production, new manufacturing techniques and large investment is needed. Such developments typically require 5 to 10 years to move from laboratory research to industrial production. Over the next decade, thin film technologies are expected to display their potential for cost reduction and improved performance, and grow to significant shares of the shipped volume.

Novel concepts for PV can be found in some of today's most promising scientific fields, including nanotechnology, organic thin films and molecular

Table 17

Diffusion Scenarios for Photovoltaic Power Generation in Japan

		2000	2010	2030
R & D	Reduced manufacturing costs	Development of technology for manufacturing thin-film solar cells	Mass-production technology for thin-film solar cells Development of solar cell components	Development of super low price cells such as wet solar cells
	Improved conversion rate	Increased efficiency of thin-film solar cells	Further increase in efficiency of thin-film solar cells	Super efficient solar cells (40% conversion)
	Increased applications Improved performance	Development of unified solar cell modules with building materials Development of flexible boards for amorphous cells	Technology for combined systems of solar cells Multifunctional module for storage cell	
Promotion	Home-use field	Increased interest because of independent market Strengthening of efforts by power companies	Actual spread of unified modular unit with building materials	
	Public facilities	Improved reliability of new technologies	Actual spread of unified modular unit with building materials	
	Factories, etc.		Widespread voluntarily introduction in industry Introduced as power source by power companies because new storage technology ensures supply stability	

Source: Japanese Advisory Committee for Energy, 1996.

chemistry. Such developments – ultimately aimed at imitating photosynthesis artificially – are likely to be characterized by ever closer relationships among different scientific disciplines (e.g. physics, chemistry, etc.). The challenge will be to develop such devices with high conversion efficiencies and long-term stability in order to match the expected life-time of 25 years and more.

- **Non-technical Issues**

A number of non-technical issues can greatly affect the potential cost reduction and market growth of PV. For example, through partnerships and networking, synergies could be developed to bring different skills together for R&D, manufacturing and marketing. Mainstream industries such as glass, display manufacturing, and the building and electronics sectors have complementary skills from which PV can benefit. These synergies would become more important as market volume increases.

PV offers many environmental benefits, but some consider that PV inherits emissions from its consumption of grid electricity generated by fossil-fuels. This drawback can be reduced by using less energy in the manufacturing process. A key future goal should be to decrease the energy payback time, in order to reduce the pollution from fossil plants providing the electricity for cell and module production.

Standards and codes help create confidence and better handling of PV products. Quality assurance is important and continued market observations as well as professional education are needed. Planning and connection restrictions should be avoided and regulations should favour the integration of PV in the built environment.

There is still a lack of information and understanding of PV technology in electric utilities, the building industry and finance sector. Best practices should be communicated, appropriate applications should be promoted and sector-specific marketing strategies developed. PV should be an integral part of the energy portfolio and building and urban planning. Dissemination activities should convey the added values of PV and the specific issues to be addressed.

As with any other relatively new technology, and particularly for applications that require sizeable early investment, appropriate financing solutions need to be developed. Confidence-building in the finance sector is crucial to increase investment volumes.

CONCENTRATING SOLAR POWER

A Brief History of Concentrating Solar Power

The idea for solar-powered steam engines originated in France in the 1860s, and in the following two decades, solar-powered engines were constructed and used for several applications. In the early 1900s, the first commercial solar motor and a 45-kW sun-tracking parabolic trough plant were built in Meadi, Egypt. These early designs were the basis for R&D in the late 1970s and early 1980s, when solar-thermal plant projects were undertaken in a number of industrialised nations, including the US, the former Soviet Union, Japan, Spain and Italy. These plants, covering the whole spectrum of available technology, failed to reach the desired performance levels, though R&D continued improving technology and increasing system scale. However, it was not until the development of power towers in the 1980s that the first large-scale solar-thermal electric generators were built. Meanwhile, a series of nine solar-electric generating stations were built in California's Mojave Desert.

Technology Status

Applications of concentrating solar power are now feasible from a few kilowatts to hundreds of megawatts. Solar-thermal plants can function in dispatchable, grid-connected markets or in distributed, stand-alone applications. They are suitable for fossil-hybrid operation or can include cost-effective thermal storage to meet dispatchability requirements. Moreover, they can operate worldwide in regions having high direct normal insolation*, including large areas of Africa, Australia, China, India, the Mediterranean region, the Middle East, the South-western United States, and Central and South America. "High direct normal insolation" means strong sunlight where the atmosphere contains little water vapour, which tends to diffuse the light. At present, Concentrating Solar Power (CSP) technology can be exploited through three different systems: parabolic trough, parabolic dish and power tower. All the CSP technologies rely on four basic elements: concentrator, receiver, transport-storage and power conversion. The concentrator captures and concentrates direct solar radiation, which is then

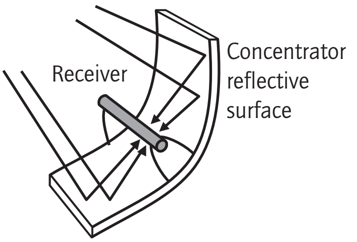
* *The term "insolation" is a measurement reference to the degree of incoming solar radiation.*

delivered to the receiver. The receiver absorbs the concentrated sunlight, transferring its heat energy to the power-conversion system. In some CSP plants, a portion of the thermal energy is stored for later use.

The parabolic trough system, commonly known as the "solar farm", uses linear parabolic mirrors to reflect sunlight. The parabolic dish system, generally known as a "dish/engine" system, collects sunlight through a round parabolic solar collector. The "power tower" system employs heliostats (large sun-tracking, reflecting mirrors) to concentrate sunlight onto a central tower-mounted receiver.

Figure 28

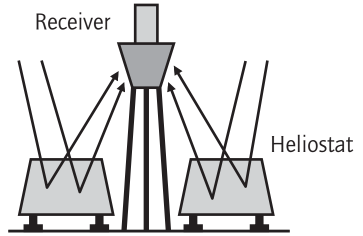
Trough System



Source: NET Ltd., Switzerland.

Figure 29

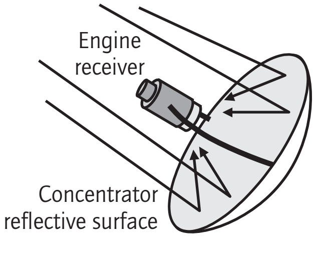
Power Tower System



Source: NET Ltd., Switzerland.

Figure 30

Dish/Engine System



Source: NET Ltd., Switzerland.

Although parabolic trough plants are currently the most mature CSP technology they still have considerable potential for improvement. Power towers, with potentially low-cost and more efficient thermal-storage, could offer dispatchable power from solar-only plants with a high annual capacity factor in the medium term. The planned projects in southern Spain (Solar Tres and PS10) will be very important in demonstrating this potential.

Dish/engine systems will be used in smaller, high-value applications. In theory, power towers and parabolic dishes can achieve higher solar-to-electric efficiencies and lower costs than parabolic trough plants. Parabolic dish systems are the most efficient of all solar technologies, with currently about 25% solar-to-electricity efficiency. The 4-95 Stirling Power Conversion Unit (PCU) now holds the world's efficiency record for converting solar energy into grid-quality electricity, with almost 30% efficiency at 1,000 watts per square metre.

Table 18

Peak Efficiency and Annual Capacity Factors for the Three CSP Technologies, 2000

	Parabolic trough	Power tower	Dish/engine system
Peak efficiency	21%	23%	29%
Annual capacity factor (without and with thermal-storage)	24%	25%-60%	25%
Net annual efficiency	13%	13%	15%

Sources: DOE; SolarPACES.

- **Hybridisation**

Because of their thermal nature, each of the CSP system technologies can be "hybridised", or operated in combination with conventional fossil fuels. Hybridisation has the potential to dramatically augment the usefulness of CSP technology by increasing its dispatchability, improving its performance by making more effective use of power generation equipment, and reducing technological risk by using conventional fuel when needed.

Hybridisation efforts are currently focussed mainly on the parabolic trough, but the learning from these studies may be transferred to the other types of systems. The Integrated Solar Combined-Cycle System (ISCCS) design offers a number of potential advantages to both the solar plant and the combined-cycle plant. For power tower systems, hybridisations are possible with natural gas combined-cycle and coal-fired or oil-fired Rankine plants. Initial commercial-scale power towers will likely be hybridised with conventional fossil-fired plants. Because dish/engine systems use heat engines, they have an inherent ability to operate on fossil fuels. However, hybridisation for dish/engine systems is still a technological challenge.

Thermal Storage

Like hybridisation, thermal storage improves the dispatchability and marketability of solar-thermal power plants, allowing them to deliver electricity on demand, independent of the solar cycle. Storage not only allows high-value dispatch of power, but can decrease costs by permitting the use of smaller turbines.

The most advanced thermal storage techniques have been applied to power tower technology. The lessons learned from Solar Two (a 10 MW solar power demonstration project in the Mojave Desert, California) are being applied to the first commercial molten-salt power plant, Solar Tres (SIII), a 15 MW demonstration project in Spain. Other advanced thermal storage technologies will be explored in future demonstration plants.

There is no thermal storage option for current trough technology. SEGS plants meet dispatchability needs with natural gas-fired boilers. A molten-salt plant similar to the one used in Solar Two, but for lower temperatures, deserves evaluation. Dish/engine system technology does not offer thermal storage capacity. Other options, such as battery storage, are possible but expensive. Dish/engine systems are ideal for grid-connected applications, and may be more useful for stand-alone applications with the addition of storage.

Costs

Investment and electricity generation costs depend on a multitude of factors related to technology (e.g. system performance, component size, power cycle, dispatchability), local logistics (e.g. plant size, location, irradiation, land cost, water availability) and market circumstances (e.g. manufacturing volume, project financing, taxation).

Investment Costs

Table 19 gives an overview of emerging CSP technology costs at high radiation levels (>1,700 kWh/m^2). Only the parabolic trough costs have been proven through commercialisation. The costs for power tower technology and dish/engine systems are based upon pilot or demonstration plants and thus need confirmation. Costs are listed for the next systems to be deployed and do not represent future costs which are expected to be much lower.

Differences in the investment and generation costs for CSP systems can be explained by their different maturities and by the different technological approaches each uses. Different approaches imply different efficiency rates and different investment structures. Figure 31 shows the relative costs of parabolic trough and power tower plants. The most significant difference is the relatively greater importance of reflector and receiver devices in power tower systems. This is mainly because very few heliostats have been manufactured to date and they are expensive (>USD 250/m²).

Table 19

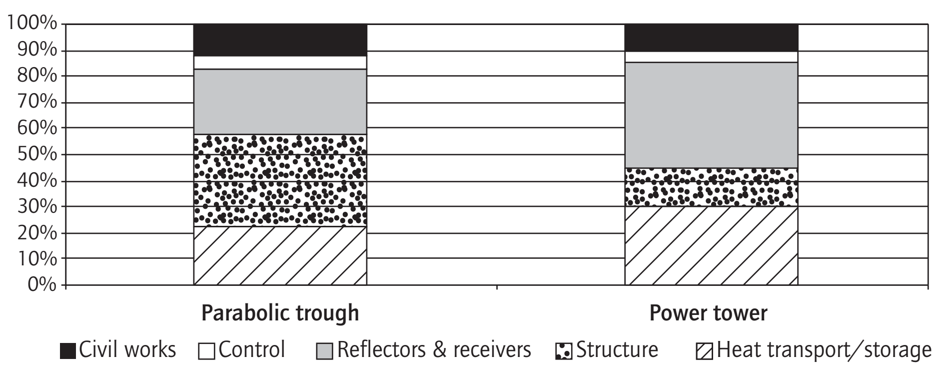
Investment and Generation Costs for CSP Technologies

	Parabolic trough (SEGS type)	Power tower (Solar Two)	Dish/engine system (Stirling)
Investment cost [/kW electricity]	2,800–3,200	4,000–4,500	10,000–12,000
Electricity generation cost [/kWh]	0.12–0.15	0.15–0.20	0.20–0.25

Sources: NET Ltd., Switzerland.

Figure 31

Relative Costs for Parabolic Trough and Power Tower System Components



Note: Based on the SEGS experience at the Kramer Junction Company for parabolic trough and the projected PS10 for power tower.
Source: NET Ltd., Switzerland.

Hybridisation and thermal storage influence both investment and generation costs. Typically, hybridisation and thermal storage increase dispatchability and marketability and result in higher investment costs (see Table 20).

Generation Costs

The cost of investment is one of most important factors determining the cost of CSP. Typically, depreciation accounts for 25-40% of generating cost.

Table 20

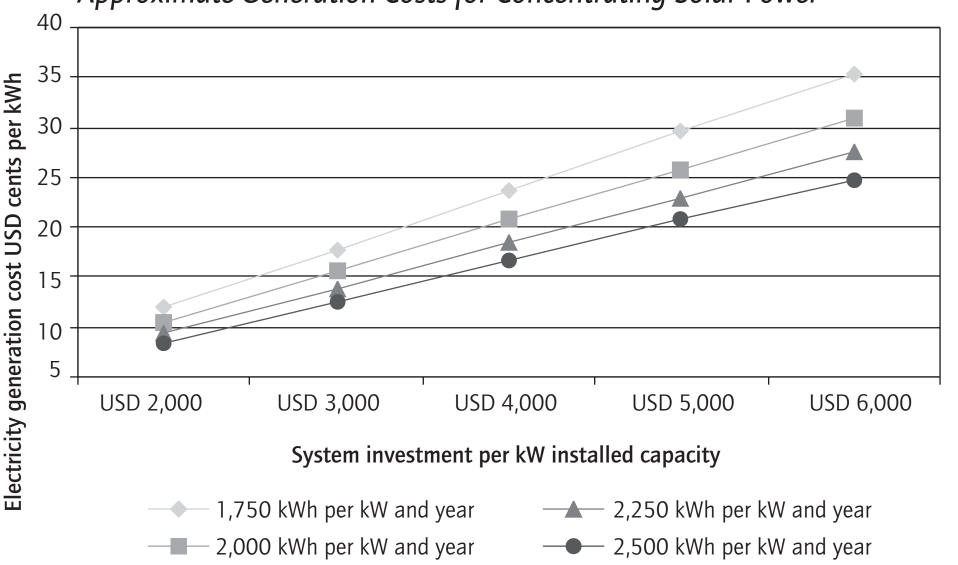
CSP Thermal-Storage Characteristics and Costs, 1997

	Installed cost of energy storage for a 200-MW plant (USD/kW heat)	Lifetime of storage system (Years)	Round-trip storage efficiency (%)
Parabolic trough synthetic-oil	200	30	95
Power tower molten-salt	30	30	99
Parabolic dish battery storage	500 to 800	5 to 10	76

Sources: DOE.

Figure 32

Approximate Generation Costs for Concentrating Solar Power



Note: O&M costs are assumed to be 10 % of system investment. Amortisation period is 15 years, and the discount rate is 6%.

Sources: NET Ltd., Switzerland.

Operation and maintenance costs (10-15%) are relatively high compared to other renewable technologies. The lifetime of a CSP plant is intended to be 20 to 30 years. However, some components may have to be replaced more frequently.

The remainder of the generation costs depend mostly on the solar irradiation level. Electrical output generated by CSP plants is roughly proportional to the incident light onto the active area. Hence, a CSP plant receiving 1,700 kWh of solar irradiation per year and per square metre will produce less electricity per year and per square metre than the same plant receiving 2,200 kWh of solar irradiation per year and per square metre.

The best cost-competitiveness is achieved in areas where radiation levels are particularly high, i.e. more than 1,700 kWh per square metre. Many areas in the world have an arid or semi-arid climate, providing optimal conditions for CSP. The cost of concentrating solar power generated with up-to-date technology is between 10 and 15 USD cents per kWh.

- **Industry**

The CSP industry currently includes about 25 companies that design, sell, own and/or operate energy systems and power plants based on the concentration of solar energy. CSP companies include energy utilities, independent power producers or project developers, equipment manufacturers, specialised development firms, and consultants. While some companies only offer CSP products, many offer related energy products and services (see Table 21).

Table 21

Participants in the CSP Industry in the US and Europe

Participants	USA	Europe
Energy utilities	3	4
Independent power producer	4	2
Project developers	4	4
Development and equipment manufacturers	15	5
Consultants	4	2

Source: NET Ltd., Switzerland.

An example of a CSP industry is the Industrial Solar Technology Corporation (IST), a full-service solar energy company which designs, manufactures, installs and operates large-scale, state-of-the-art parabolic trough collector systems for industrial and commercial water heating, steam generation and absorption cooling. IST operates mainly in the US, but is active worldwide. Flabeg Solar International (FlabegSolar), is active in solar-thermal feasibility studies and development in Europe (Spain and Greece), Africa (Morocco and Namibia) and the Middle East (Iran). FlabegSolar has also developed a performance and costing model for solar fields.

The US CSP industry is dominated by developers and equipment manufacturers who have very strong R&D programmes. The European CSP industry, especially public utilities in Spain, Germany and Italy, also has a strong interest in R&D, particularly in the development of volumetric air receivers, heliostats and Stirling engine technology. The CSP industry has invested and continues to invest many millions of dollars in CSP technology and market development. International competition is likely to emerge, particularly between the industries in the US and Europe.

The European Solar Thermal Industry Association (ESTIA) is seeking to achieve active collaboration between industry, government and international organisations. In the US, the Solar Energy Industry Association and the Department of Energy (DOE) have helped create Solar Enterprise Zones in Sunbelt states. These economic development zones aim to help large-scale solar electric projects and assist private companies in developing 1,000 MW of electricity from CSP projects over a seven-year period. Elsewhere, in the Middle East, southern Africa and South America, areas which have some of the largest potential for CSP, governments and utilities are interested in developing this potential, and some are planning semi-commercial demonstration plants. CDM and JP funding under the Kyoto Protocol and the Global Environment Facility are possible sources of added funding for such plants, as the development of indigenous renewable resources is an option to be considered for countries with the necessary resource base.

Market

Initially, SEGS technology was able to enter the market in an era of high and rising energy prices. However, as energy prices fell in the late 1980s, renewable energy technologies such as CSP could not compete without subsidies. Between 1984 and 1991, Luz International Ltd. constructed nine commercial Rankine-cycle SEGS plants in the Mojave Desert of California. These plants ranged in capacity from 14 to 80 MW of electricity and totalled 354 MW of installed capacity. The first plant included a large thermal-storage reservoir and no back-up heat source. The remaining eight plants use natural gas as the back-up heating fuel for a maximum of 25% of the energy input (as limited by U.S. federal law to qualify as a solar plant). These plants use no thermal storage. The power was sold to Southern California Edison (SCE) under a long-term contract. Size, performance and efficiency increased with each successive plant and costs were reduced. Over the series of plants electricity costs were lowered by more than half.

Demonstration pilot plants with a total capacity of around 30 MW have also been built, but despite the success of the nine SEGS, no new commercial plants have been constructed since 1991. At the end of the 20th century, operating CSP capacity was about 370 MW of electricity with an output of nearly 1 TWh per year.

- **Environment**

  CSP technologies cause comparatively little adverse impact on the environment. Specific issues relate to the use of heat transfer fluids (HTF), water and land.

  - **The Heat Transfer Fluids (HTF)** used in parabolic troughs is an aromatic hydrocarbon, biphenyl-diphenyl oxide (classified as non-hazardous by U.S. standards). If spilled, soil can be contaminated, requiring clean-up. In addition, there is some level of HTF vapour emissions from valve packing and pump seals during normal operation. No hazardous gaseous or liquid emissions are released during operation of the solar power tower plant. Salt used as HTF is non toxic and can be recycled if necessary. The environmental impact of dish/engine systems is minimal. Stirling engines are known for being quiet, relative to internal combustion gasoline and diesel engines. Emissions from dishes/engines are quite low. Other than the potential for spilling small amounts of engine oil, coolant or gearbox grease, these systems produce no effluent when operating with solar energy.
  - **Water availability** can be a significant issue in the arid regions best suited for CSP plants. SEGS plants in the Mojave Desert showed similar water consumption to a conventional Rankine cycle power plant (15,000-20,000 m^3/MW per yr).
  - **Land use:** Centralised CSP plants require a significant amount of land that typically cannot be used concurrently for other purposes. In order to minimise the impact on the natural environment, parcels of marginal and fallow agricultural land should be used. A study for the U.S. State of Texas showed that land use requirements for parabolic trough plants are comparable to those of other renewables technologies such as wind or biomass, and lower than fossil resources when mining and drilling are taken into account.

If CSP plants are hybridised with a conventional fossil plant, emissions will be released from the non-solar portion of the plant.

Prospects for Concentrating Solar Power

Parabolic trough plants are the most mature CSP technology available today and are most likely to be used in the near term. Power towers, with their possibility of thermal storage, offer the promise of dispatchable, solar-only plants with high annual capacity in the medium to long term. Dish engines are smaller and more modular, presenting the opportunities for a wide array of energy services in sunny areas.

- **Cost Reduction Opportunities**

Early trough plants produced power for about USD 0.25/kWh in niche markets. As continuing R&D improved plant performance and lowered O&M costs, and as economies of scale for larger plants were achieved, power costs from the most recent plants dropped to about USD 0.12/kWh, the lowest-cost solar power in the world. While the costs of new plants built with advanced technologies may initially be slightly higher than the recent trough plants, they may drop with the construction and successful operation of the first few advanced plants, demonstrating a learning curve similar or even more pronounced than that seen at the SEGS plants. This could result in costs of about USD 0.10/kWh within five years. The industry's trough technology roadmap lays out a detailed strategy to combine technology advances in receivers, reflectors and structures, thermal storage and plant optimisation to reduce costs to less than USD 0.05/kWh in 15 to 20 years. If this occurs, CSP in areas with high insolation could be reasonably competitive with conventional resources in those markets by 2020.

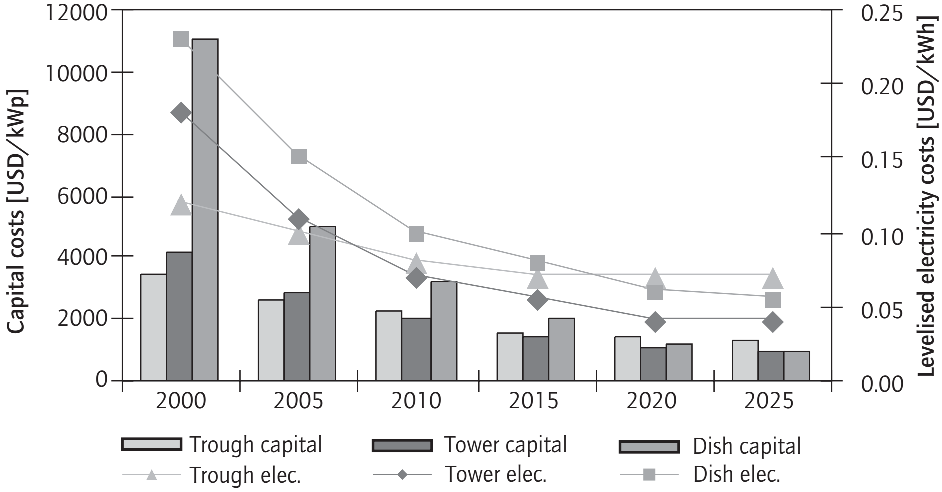
Figure 33 shows past and predicted capital and electricity costs for each CSP technology. The relationship between capital cost and electricity cost depends on many factors, in particular the hours of system operation, debt and depreciation time. For that reason, dish systems will have a higher electricity cost than power tower systems even if the future capital cost for both systems is predicted to be very close.

Cost reduction typically comes from four areas:

- **R&D:** Performance improvements through R&D reduce the cost of enhanced and optimised components and subsystems. Efforts are focusing mainly on reflectors and receivers, thermal-storage capability, heat transfer fluid (HTF), hybridisation and the power cycle.

Figure 33

Current and Forecast CSP Capital and Electricity Costs



Source: NET Ltd., Switzerland.

- **Increased component size:** The increase in the aperture of the collector in the SEGS plants developed by Luz International contributed to the cost reductions achieved by SEGS plants. In power tower systems, heliostat size may also be increased in order to achieve similar cost reductions.

- **Manufacturing volume:** Mass production offers great potential for cost reduction. SunLab estimates that it could bring costs down by 15% to 30%. In dish/engine systems, the manufacturing process also offers great potential for cost reduction. Because CSP employs conventional technology and materials (glass, concrete, steel and standard utility-scale turbines), production capacity could be scaled up to several hundred megawatts per year using existing industrial infrastructure. In order for economies of scale to be realised, manufacturing processes should be simplified and the level of technology reduced, allowing for manufacturing to take place in areas where labour and materials are inexpensive.

- **Plant size:** In large-scale solar-thermal power plants, one of the easiest ways to reduce the cost of solar electricity from CSP technology is by increasing plant size. Based on the SEGS experience, the current capital cost for a parabolic trough system is estimated at USD 3,500 /kW for a 30 MW plant and USD 2,450/kW for a 200 MW plant in a developed country. Studies have shown that doubling the size of a trough solar field reduces the capital cost by 12-14%. O&M costs for larger plants will typically be less on a per kilowatt basis. Power plant maintenance costs will be reduced with larger plants, but solar field maintenance costs will depend more on solar field size. The O&M costs for the 30 MW complexes of SEGS III to VII are currently between 3 and 3.5 USD cents per kWh. SunLab estimates that O&M costs for a new design of 30 MW plant would be one-third lower at 1.9 cents/kWh. O&M costs for a 200 MW plant would be somewhat over 1 cent per kWh.

Each CSP technology offers specific cost-reduction opportunities that are analysed in detail in the following paragraphs.

Parabolic Trough

In the 1990s, a co-operative research project by the SEGS operators and the DOE/SunLab CSP program improved O&M procedures, reduced parasitic power requirements and improved collector efficiency, reducing O&M costs by 30%. Improved absorber surfaces coupled with design improvements have allowed the industry to begin production of a new receiver which could improve trough plant performance by an additional 20% without increasing costs.

Potential for further cost reduction exists, particularly in heat transport, such as direct solar generation in parabolic trough collectors (DISS). Implementation of the improvements expected in the DISS projects could achieve a 20 to 30% reduction in the cost of electricity generated by trough plants.

An alternative design such as the Integrated Solar Combined Cycle System (ISCCS) has the potential to reduce solar power cost by 20 to 25%, mainly through reduced O&M costs. Net annual solar-to-electricity efficiency will be improved because solar input will not be lost waiting for the turbine to start up, and because average turbine efficiency will be higher since the turbine will always run at 50% load or above.

Thermal storage may also represent an opportunity for improvements. A molten-salt system similar to the one used in Solar Two deserves evaluation. In such a system, heat is collected by synthetic oil (pumped through the collector field) and then transferred to the salt via an oil-to-salt heat exchanger. Another cost-saving development for the medium term is the use of advanced molten-salt (nitrate salt) as heat transfer fluid (HTF), which would allow the elimination of the heat exchanger.

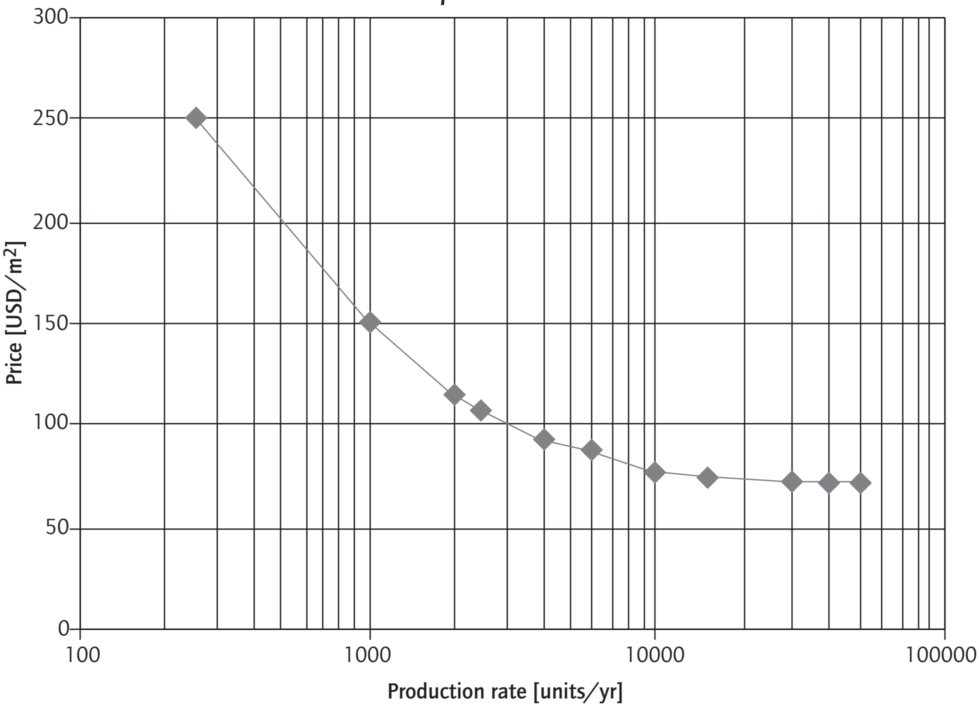
Power Towers

The present economic status of power tower technology is difficult to evaluate since no commercial power plant is operational. However, the capital cost for the first molten-salt power towers is likely to be in the range of USD 4,000 - 4,500/kW.

As is true for parabolic troughs, further improvement of power tower performance can be achieved by increasing the size of the plants. Like many CSP components, the price of heliostats should come down significantly through economies of scale with respect to manufacturing volume, as shown in Figure 34.

Figure 34

Heliostat Price as a Function of Annual Production Volume



Source: US DOE, 1997.

More improvements may be achieved due to developments in receiver efficiency and heliostat manufacturing techniques which will increase the reliability of power tower systems – these lessons, learned from Solar Two, are being applied to Solar Tres in Spain. The new configuration could reduce the cost of heliostats by 45%. Lessons learned from Solar Two are also being applied in the development of a new thermal-storage system. Design innovations have influenced all Solar Tres system elements and have resulted in two insulated tanks (hot and cold) storing 6,250 tonnes of molten nitrate salt with capacity for 24 hour-a-day full electrical energy production (with 16 hours of storage). The thermal storage will raise annual plant capacity from 20-22% for Solar Two over 60% for Solar Tres. Long term developments in thermal-storage technology include the formulation of organic heat transfer fluid.

Dish/Engine Systems

At the Plataforma Solar Almería (PSA), the EuroDish project aims to bring the system cost down from the current USD 11,000/kW to USD 5,000-6,000/kW. The major cost-reduction potential lies in the manufacturing process and in the efficient production of modular parts. Remote control and monitoring, the use of low-cost elements like cheaper drive and control systems, and an enhanced procedure for manufacturing the solar receiver should also deliver cost reductions. The first prototype started operating in February 2001 and has already reduced costs to USD 5,000/kW. Since this is only a prototype, cost reductions have to be proven by further project experience. However, the EuroDish targets seem realistic.

In the medium to long term, installed system costs are expected to decrease dramatically as series production of dish units increases. At the same time, annual efficiencies of dish/engine systems are expected to rise in conjunction with greater reliability and availability.

Hybrid operation (including the use of hydrogen fuel) has been demonstrated in recent dish/Stirling testing. Advanced hybrid heat pipe receivers are being developed to allow concurrent solar/fossil operation; however, hybrid operation has proved very difficult with dish/Stirling systems.

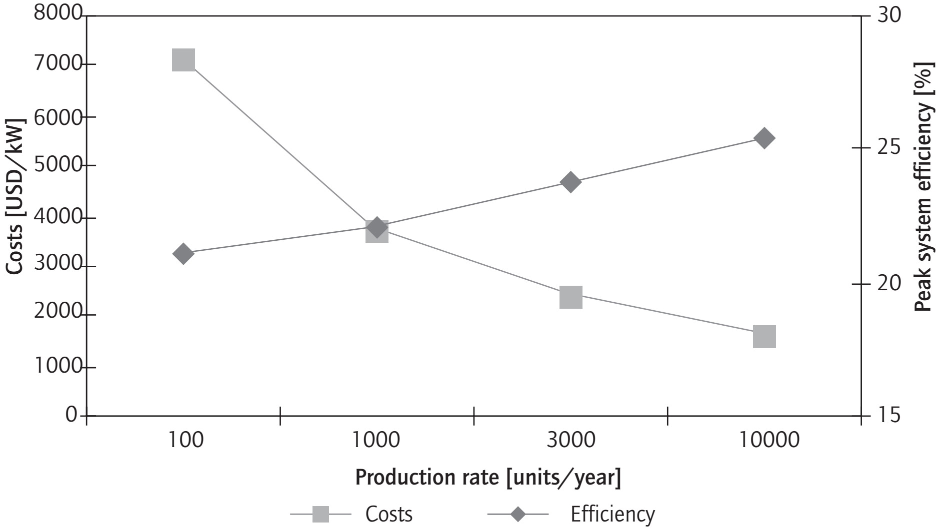
Market Opportunities

Market Potential

Because CSP plants can only focus direct solar radiation and cannot concentrate diffuse sky radiation, they only perform well in very sunny locations, specifically in arid and semi-arid regions. CSP technology is most likely to develop in regions with radiation levels exceeding 1,700kWh/m^{2}yr, i.e. southern Europe, North and southern Africa, the Middle East, western India, western Australia, the Andean Plateau, north-eastern Brazil, northern Mexico and the US Southwest. Although the tropics have high solar radiation, it is highly diffuse. Long rainy seasons also make these regions unsuitable for CSP technology.

Figure 35

Performance Improvement and Cost Reduction with Increasing Production Rates



Source: NET Ltd., Switzerland.

Regional Factors

Market entry costs for CSP technology are very difficult to quantify using simple formulae because they depend on prices of the alternative energy sources in that specific location and on the availability of incentives. Trough and power tower technology could become competitive (a) at USD 0.06-USD 0.08/kWh as peak power, (b) at USD 0.30/kWh in developing countries for specific industrial and mini-grid applications or (c) in places with very high peak power costs.

A number of projects are currently under development (see Table 22), some of them within the framework of Operational Program No. 7 of the Global Environmental Facility (Egypt, India, Iran, Mexico and Morocco).

Present parabolic trough installed capacity is 354 MW worldwide, though projects under development, plus hybrid installations, may bring that capacity to 650 MW, about 94% of the world's capacity, by 2005. With an expected growth rate of 20%, parabolic trough installed capacity would be 1,600 MW by 2010 and a little more than 10 GW by 2020. Based on these estimates, parabolic trough would still be the leading CSP technology in 2020.

The total experience with power towers has amounted to only 25 MW, the combined output of the Solar One and Solar Two prototypes, both built in the US. No large power tower plants are currently operational. Central receiver technology is entering the commercialisation phase with two projects under construction in southern Spain (Solar Tres and PS10). Other projects already under development may bring the central receiver installed capacity to 135 MW by 2005. Central receivers then might experience a slightly higher growth rate than parabolic trough systems, due to the additional dispatchability from storage. This means that under favourable conditions with a growth rate of about 25% from 2005 to 2020, the central receiver installed capacity would be about 4 GW by 2020.

Table 22

Current CSP Projects

Location	Cycle	CSP technology	Solar capacity [MW electricity]
Australia		CLFR	13
Egypt	Combined Cycle	Investor's Choice	35
Greece	Steam Cycle	Trough	52
India	Combined Cycle	Trough	35
Iran	Combined Cycle	Trough	67
Israel	Combined Cycle	Trough	100-500
Jordan	Combined Cycle	Trough	100-150
Mexico	Combined Cycle	Investor's Choice	40
Morocco	Combined Cycle	Investor's Choice	30-50
Spain	Steam Cycle	Trough (AndaSol 1)	50
Spain	Steam Cycle	Trough (AndaSol 2)	50
Spain	Steam Cycle	Trough (EuroSEGS)	10
Spain	Steam Cycle	Power Tower (PS10)	10
Spain	Steam Cycle	Power Tower (S III)	15
USA	Various types	Various types	1,000

Source: SolarPACES.

The present parabolic dish installed capacity is on the order of 1 MW; although, many projects are planned, which may result in installed capacity of as much as 40 MW by 2005. A SunLab study forecast that parabolic dishes could experience the most rapid expansion among the different CSP technologies, with a growth rate of 40% per year from 2005 to 2020. This means that the parabolic dish cumulative installed capacity would be more than 6 GW by 2020. This enormous growth rate is explained by the fact that huge untapped potential in developing countries could be exploited by parabolic dish systems, which are the most suitable CSP technology for smaller high-value and off-grid remote applications.

SunLab and SolarPACES estimate that in very good locations, CSP technologies will be able to deliver power to large-scale, dispatchable markets for grid-connected peaking or base-load power, and rapidly expanding distributed markets, including both on-grid and remote/off-grid applications. CSP technology could meet requirements of current high-value and niche markets where fuel prices are high (e.g., island systems) or where green power generation has a high value, provided that the level of insolation meets CSP standards.

Table 23

Current, Planned and Forecast Cumulative Installed Capacity for all CSP Technologies [MW electricity]

	2002	2005	2010	2020
Parabolic trough	354	650	1.600	10,050
Power tower	25	135	410	3,850
Parabolic dish	1	40	215	6,250

Source: NET Ltd., Switzerland.

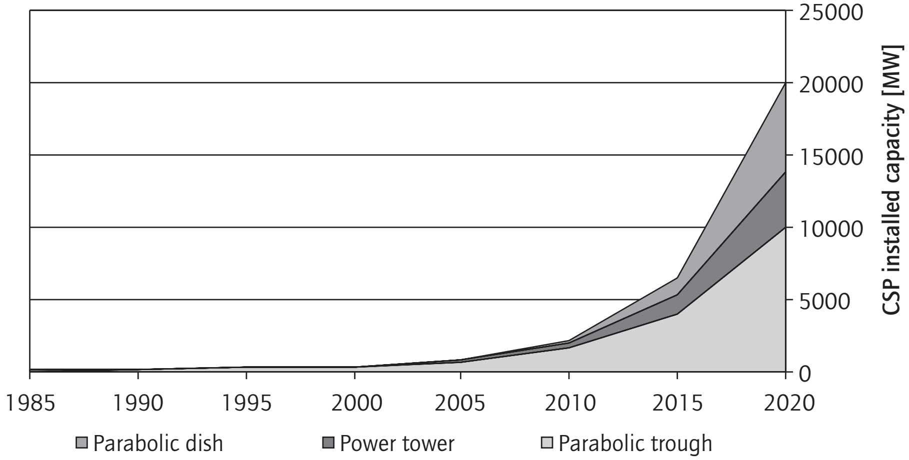
Technology Factors

Based on past parabolic trough experience and cost information from projects under development, the progress ratio for parabolic trough technology in the near future is expected to be around 85% (meaning that every doubling of the volume manufactured leads to a cost reduction of 15%). No new plants have been built since 1991. However, existing plants have continued to improve through reduced O&M costs and advances in generation components.

Power tower technology is unique among solar electric technologies in its ability to store solar energy efficiently and dispatch electricity to the grid when needed. Compared to parabolic trough technology, power tower technology has greater cost-reduction potential (particularly with regard to energy storage) and higher solar-to-thermal efficiency. Therefore it is realistic to assume comparable and even better progress ratios than for parabolic trough technology. Costs are predicted to decrease according to a learning rate close to 20%.

Figure 36

Past and Predicted CSP Installed Capacity



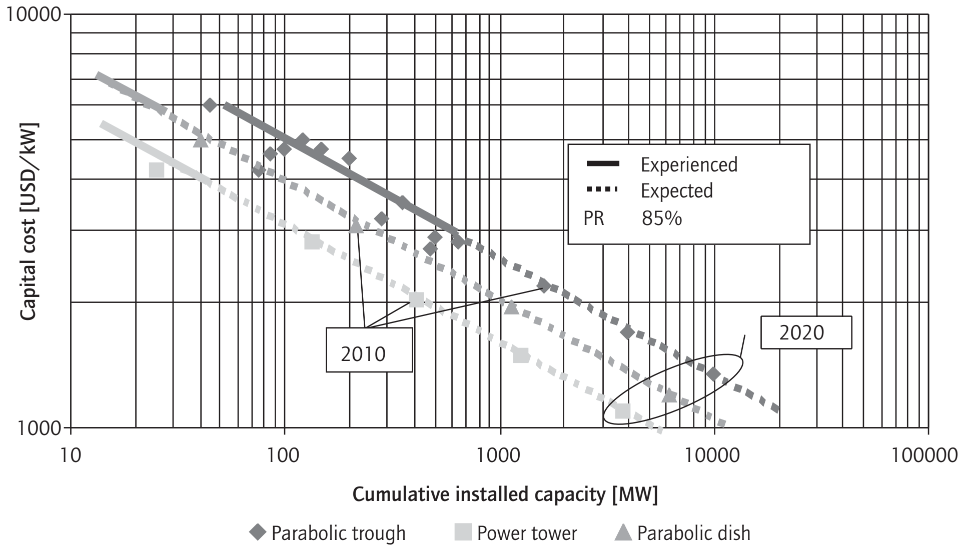
Source: NET Ltd., Switzerland.

Based on the large potential of dish/engine systems, and taking into account lessons learnt during the commercialisation of trough technology, similar or better progress ratios can be imagined for parabolic dish technology compared to parabolic trough technology. Costs are predicted to decrease according to a learning rate in the range of 10% to 25%. This means that with a cumulative installed capacity of around 5,000 MW, electricity from parabolic dish systems could become competitive with other systems for small energy services, and compete with diesel generators or PV in very sunny locations.

Figure 37 provides an overview of possible CSP technology costs in the medium to long term, based on a progress ratio of 85% for the three different CSP technologies and a global growth rate close to 25%, as predicted by the US DOE. Take-off costs would be reached between 2010 and 2020. Studies have shown that CSP costs could drop towards levels similar to those produced by wind power, at which time CSP markets may grow in a similar way to the wind market, although in quite different regions.

Figure 37

Past and Predicted Experience Curves for CSP Technologies



Source: NET Ltd., Switzerland.

Issues for Further Progress

The technical viability of CSP technologies has been demonstrated for parabolic trough technology, and is awaiting further development. Power tower technology requires the development of low-cost heliostats and several new demonstration plants. Parabolic dishes require the development of at least one commercial engine and the maturity of a low-cost concentrator.

- **Technical Issues**

Suggestions for reducing CSP costs have been given by SunLab and SolarPACES. Innovation and research should focus on simplifying components and reducing materials use.

Size

Increasing plant size will increase manufacturing volume and reduce unit costs for both the power block and the solar field. O&M costs for larger plants will be less on a per-kilowatt basis because personnel requirements will be reduced. Power plant maintenance costs will be reduced with larger plants, but solar-field maintenance costs, while lower, will be more directly related to solar-field size. Further cost reduction, due to economy of scale, will be achieved by increasing the collector area.

Table 24

Planned and Predicted Costs for Each CSP Technology: 2005, 2010 and 2020.

	Parabolic trough			Power tower			Parabolic dish		
	2005	2010	2020	2005	2010	2020	2005	2010	2020
Levelised electricity USD/kWh	0.10	0.08	0.07	0.11	0.07	0.04	0.15	0.10	0.06
Capital costs USD/W	2.6	2.2	1.4	2.8	2.1	1.1	5.0	3.2	1.2
O&M costs [USD cents/kWh]	1.0	0.5	0.4	1.2	0.4	0.3	4.0	1.5	0.9
Surface costs USD/m^2	630	315	275	475	265	200	3,000	1,500	320

Source: NET Ltd., Switzerland.

Table 25

Costs for Concentrating Solar Power

Current investment costs in USD per kWp	Low investment costs: 3,000. High investment costs: 6,000.
Expected investment costs in USD per kWp in 2010	Low investment costs: 2,000. High investment costs: 4,000.
Current generation costs in USD cents per kWh	Low cost generation: 10-15. High cost generation: 20-25.
Expected generation costs in USD cents per kWh in 2010	Low cost generation: 6-8. High cost generation: 10-12.

Source: NET Ltd., Switzerland.

Table 26

Cost Reduction Opportunities for Concentrating Solar Power (%)

CSP technology	R&D	Economy of scale I (component size)	Economy of scale II (manufacturing volume)	Economy of scale II (plant size)
Parabolic trough	up to 5	up to 5	up to 10	up to 10
Power tower	up to 10	up to 5	up to 10	up to 10
Dish/engine system	up to 10	up to 10	up to 10	up to 5

Source: NET Ltd. Switzerland.

Table 27

Key Factors for Concentrating Solar Power

Factor	Fact
Variable influencing energy output	Direct irradiation
Limiting factors	Area availability / grid capacity
Capacity installed in 2000 in GW	0.4 GW
Potential in 2010 in GW	2 GW
Future potential beyond term year given	Medium-high
Rule of thumb for conversion ratio* (installed power to electric output)	1 kW –> 1,900 kWh per year

* *Assumptions: solar irradiation 1700 kWh/m² and year, system efficiency 15%.*
Source: NET Ltd., Switzerland.

Improved Plant Design

System design offers another opportunity for cost reduction. Current investigations and pilot projects are combining CSP technology with new designs in gas-turbines and combined-cycle plants (ISCCS). The ISCCS design offers a number of potential advantages over a plant using only fossil fuels. The incremental capital and O&M costs of the ISCCS plant are outweighed by their higher efficiency, reduced start-up losses and dual use of critical system elements, *e.g.* the boiler. Additional opportunities in this area include better management of plant parasitic load and operation, as well as better matching of the solar output to existing turbines.

Further cost reductions will be possible with Direct Steam Generation (DSG), which will eliminate the need for the heat transfer fluid system and reduce the efficiency loss involved with using a heat exchanger to generate steam. DSG will also improve the solar-field operating efficiency due to lower average operating temperatures and improved heat transfer in the collector.

Thermal Storage

Thermal storage has made tremendous progress in recent years. The most advanced thermal-storage technology is the two-tank, molten-salt unit at Solar Two. This technology has not yet been applied to trough systems, but studies have shown the feasibility of developing a molten-salt heat transfer fluid system which will eliminate heat exchanger losses. A thermocline molten-salt system for both power tower and trough is planned for future development. The long-term objective is an advanced organic heat transfer fluid, which will also work as a direct thermal-storage medium. The advantages of such a system will be a low freezing point, low vapour pressure, high thermal stability and low cost.

More advanced thermal storage for power tower will include high-temperature phase change and thermal-chemical approaches to hydrogen generation. Since the dish/engine system does not include thermal-storage capacity, R&D should focus on alternative storage systems using batteries or hydrogen.

Concentrators

The solar concentrator is the most expensive feature of a CSP plant. Better reflective materials, mirror facets, structural design and drives all promise future cost reductions. New reflective materials hold particular long-term promise because they may be cheaper and lighter than glass and result in easier and less expensive manufacturing. Optimisation of concentrator design will reduce structural costs. One innovative concept under development in Australia is the Linear Fresnel Reflector that employs nearly-flat mirrors located very close to the ground. This reduces concentrator wind loads and increases packing density, both of which could reduce system costs.

O&M

Better operation and maintenance can contribute considerably to reducing the costs of CSP technology. R&D will focus on construction and control and communication systems. Maintenance, such as mirror cleaning, must keep the collector field operating at high levels of efficiency and availability, but also be inexpensive and easy. Improved methods of installation will be pursued during the next large-scale project.

Non-technical Issues

Two non-technical issues could have a major impact on future costs and markets for CSP. The development of multiple plants at the same location in a solar power park will reduce the cost of CSP technology because the power park offers reduced O&M, engineering and development costs. Construction costs will also be affected through labour learning-curve efficiencies. Multiple projects will mean multi-year manufacturing runs of solar collector components, resulting in reduced cost per collector.

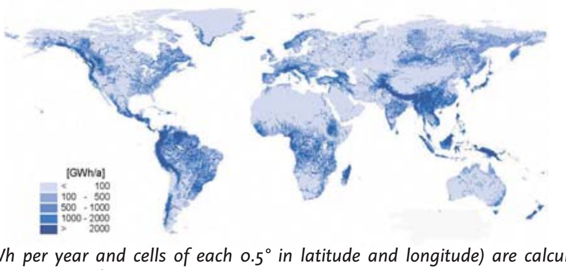
The financial structure of projects is also an important issue. Centralised CSP plants are capital-intensive, and the cost of capital and the type of project financing can have a significant impact on the final cost of power.

Global Renewable Energy Resource Maps

The following six world maps illustrate the potential of hydropower, solar photovoltaics and concentrating power, geothermal power and onshore and offshore wind power.

Plate 1

Hydropower Resource Potential

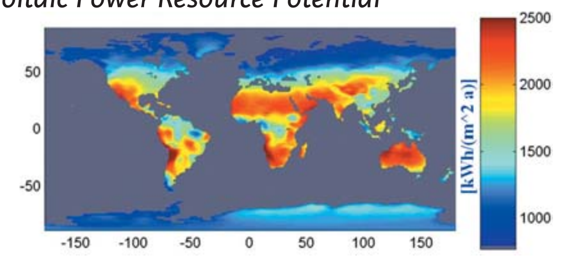


Note: Values (in GWh per year and cells of each 0.5° in latitude and longitude) are calculated by means of differences in altitude and water flow.

Sources: Data on water flow from WaterGAP, Center for Environmental Systems Research, University of Kassel. Data processing and mapping B. Lehner (assisted by G. Czisch), 2003 / to be published

Plate 2

Solar Photovoltaic Power Resource Potential

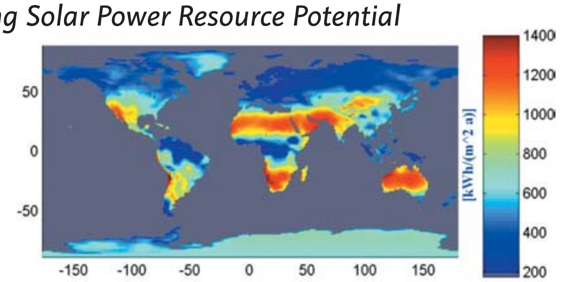


Note: Values (in kWh per m² and year) are given in terms of global horizontal irradiation (data measured from 1983 to 1992).

Sources: Meteorological data from European Centre for Medium Range Weather Forecast (ECMWF). Data processing and mapping by G. Czisch, ISET / IPP, 2000

Plate 3

Concentrating Solar Power Resource Potential

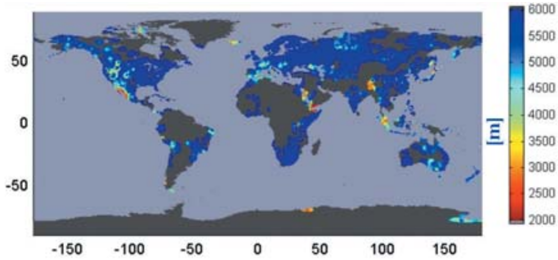


Note: Values are given for the heat output of solar fields SEGS (taking into account wind and ambient temperature)

Sources: Meteorological data from European Centre for Medium Range Weather Forecast (ECMWF) and National Centre for Environmental Prediction (NCEP). Data processing and mapping by G. Czisch, ISET, IPP, 2000.

Plate 4

Geothermal Resource Potential

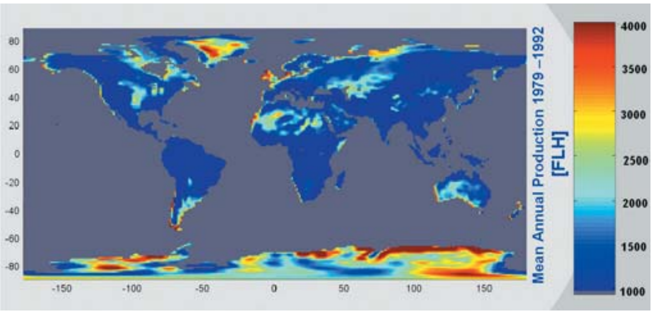


Note: The level of enthalpy is given for a temperature difference of 170K at various depths (in metres). The grey land regions are regions where the next measurement registered is more than 300 km away. The darkest blue indicates regions where the depth of the 170K layer is below 6,000 m.

Sources: Data from International Heat Flow Commission (IHFC). Data processing and mapping by G. Czisch, ISET / IPP, 2000 (assisted by B. Lehner, USF)

Plate 5

Onshore Wind Energy Resource Potential

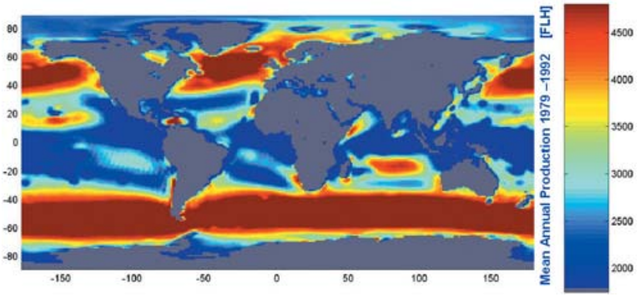


Note: Values are calculated in Full Load Hours based on meteorological data from 1979 to 1992.

Sources: Meteorological data from European Centre for Medium Range Weather Forecast (ECMWF). Data processing and mapping G. Czisch, ISET / IPP, 1999.

Plate 6

Offshore Wind Energy Resource Potential



Note: Values are calculated in Full Load Hours based on meteorological data from 1979 to 1992.

Sources: Meteorological data from European Centre for Medium Range Weather Forecast (ECMWF). Data processing and mapping by G. Czisch, ISET / IPP, 1999.

BIOPOWER

A Brief History of Biopower

Biomass is the oldest form of renewable energy exploited by mankind, mainly in the form of wood burnt to provide heat and light for domestic and productive activities. Traditional use has been primarily based on direct combustion, a process still extensively practised in many parts of the world. Traditional biomass is a dispersed, labour-intensive source of energy. In the past as in the present, increasing human population and/or industrial activity has led to growing energy demand and often destruction of the natural environment. More concentrated and convenient energy sources like non-renewable fossil fuels have substituted for traditional biomass in many areas, although huge rural populations in developing countries are still not served with modern electricity or fuels. While biomass energy has been associated with poor households, it is now increasingly recognised as an important source of energy for many sectors in both industrial and developing countries.

Technology Status

- **Basic Features**

An important feature of bioenergy and bioelectricity is their complexity. Bioenergy varies due to technical, environmental and policy factors, but also by resource type and form. Biological resources are still mainly used for heat production, as in combined heat & power plants (CHP), and can be used and stored in different forms (solid, liquid, gaseous). Biomass energy conversion has both positive and negative environmental impacts: burning of organic and fossil material emits harmful gasses, while the disposal of agricultural and other organic waste utilises otherwise worthless material for energy. Biomass differs from other renewables in that it links the farming and forestry industries, which provide the various feedstocks, to power generation, which utilises the converted fuels. Compared to most other renewable energies, biomass has the key advantage of inherent energy storage.

Conversion

Combustion is the most widely-used type of biomass-derived energy conversion. The burning of biomass produces heat and/or steam for immediate cooking, space heating and industrial processes, or for indirect electricity generation via a steam driven turbine. Most of today's biopower plants are direct-fired systems – the higher the steam temperature and pressure, the greater the efficiency of the overall plant. While steam generation technology is very dependable, its efficiency is limited. Bioenergy power boilers are typically in the 20-50 MW range, compared to coal-fired plants in the 100-1,500 MW range. The small-capacity plants tend to have lower efficiency because of economic trade-offs: efficiency-enhancing equipment cannot pay for itself in small plants. Although techniques exist to boost biomass steam generation efficiency above 40%, plant efficiencies today are typically in the 20% range.

Co-firing means that biomass can substitute for a portion of conventional fossil fuel in an existing power plant furnace. Often, the biomass is chipped wood that is added to the feed coal (wood being 5-15% of the total) and combusted to produce steam in a coal power plant. Co-firing is well-developed in the US but is still undergoing research as electricity companies examine the effect of adding biomass to coal, in terms of specific power plant performance and potential problems. Because much of the existing power plant equipment can be used without major modifications, co-firing is far less expensive than building a new biopower plant. Compared to the coal it replaces, biomass produces less sulphur dioxide (SO_2), nitrogen oxides (NOx) and other air emissions. After "tuning" the boiler for peak performance, there is little or no loss in efficiency from adding biomass. This allows the energy in biomass to be converted to electricity with the high efficiency (in the 33-37% range) of a modern coal-fired power plant.

Pyrolysis is the process of decomposition at elevated temperatures (300-700°C) in the absence of oxygen. Products from pyrolysis can be solid (char, charcoal), liquids (pyrolysis oils) or a mix of combustible gases. Pyrolysis has been practised for centuries, *e.g.* the production of charcoal through carbonisation. Like crude oil, pyrolitic, or "bio-oil", can be easily transported and refined into a number of distinct products. Recently, the production of bio-oil has received increased attention because it has higher energy density than solid biomass and is easier to handle. Bio-oil yields of up to 80% by weight may be obtained by the process of fast or flash pyrolysis at moderate reaction temperatures, whereas slow pyrolysis produces more charcoal (35% to 40%) than bio-oil. A main advantage (with respect to energy density, transport, emissions, etc.) of fast pyrolysis is that fuel production is separated from power generation.

Gasification is a form of pyrolysis carried out with more air and at higher temperatures in order to optimise the gas production. The resulting gas is more versatile than the original solid biomass. The gas can be burnt to produce process heat and steam or used in internal combustion engines or gas turbines to produce electricity. It can even be used as a vehicle fuel. Biomass gasification is the latest generation of biomass energy conversion processes and offers advantages over direct burning. In techno-economic terms, the gas can be used in more efficient combined-cycle power generation systems, which combine gas turbines and steam turbines to produce electricity. The conversion process - heat to power - takes place at a higher temperature than in the steam cycle, making advanced conversion processes thermodynamically more efficient. In environmental terms, the biogas can be cleaned and filtered to remove problematic chemical components.

Anaerobic digestion *(AD)* is a biological process by which organic wastes are converted to biogas - usually a mixture of methane (40% to 75%) and carbon dioxide. The process is based on the breakdown of the organic macromolecules of biomass by naturally-occurring bacteria. This bioconversion takes place in the absence of air, thus anaerobic, in digesters, *i.e.* sealed containers, offering ideal conditions for the bacteria to ferment ("digest") the organic feedstock to produce biogas. The result is biogas and co-products consisting of an undigested residue (sludge) and various water-soluble substances. Anaerobic digestion is a well-established technology for waste treatment. Biogas can be used to generate heat and electricity through gas, diesel or "dual fuel" engines at capacities of up to 10 MW. About 80% of industrialised global biogas production stems from commercially exploited landfills. The methane gas produced at landfills can be extracted from existing landfills by inserting perforated pipes through which the gas travels under natural pressure. If not captured, this methane would eventually escape into the atmosphere as a greenhouse gas. Another common way of producing biogas by AD is by using animal manure. Manure and water are stirred and warmed inside an air-tight container (digester). Digesters range in size from around 1m3 for a small household unit to as large as 2,000m^3 for a large commercial installation.

Feedstock

Bioenergy is renewable but there is some argument about what feedstocks can be considered renewable, for example there is much controversy over the inclusion of municipal solid waste (MSW) in this category. Unlike other renewables, biopower is based on biofuel and therefore shares some important characteristics with fossil fuel systems.

The logistical chain and the economics of a biomass system depend entirely on both the location (*e.g.*, climate, soil, crop) and the conversion technology. The economics are very site-specific (see next section on costs). Biomass resources tend to be available in rural areas – with the exception of municipal and industrial wastes.

Costs

The cost of generating electricity from biomass varies, depending mainly on the type of technology used, the size and investment of the power plant, as well as the cost of the biomass fuel supply.

Investment Costs

The investment costs for biopower plants can be as low as a few hundred USD per kW for co-firing, and as high as several thousand USD per kW. Co-firing investment levels are very site specific and are affected by the available space for storing feedstocks, by the cost of installing reduction and drying facilities and by the type of boiler/burner modifications required. Co-firing investment costs indicated in Europe vary between USD 500 to 1,000 per kWp. Even lower investment costs are reported by the US Biopower program.

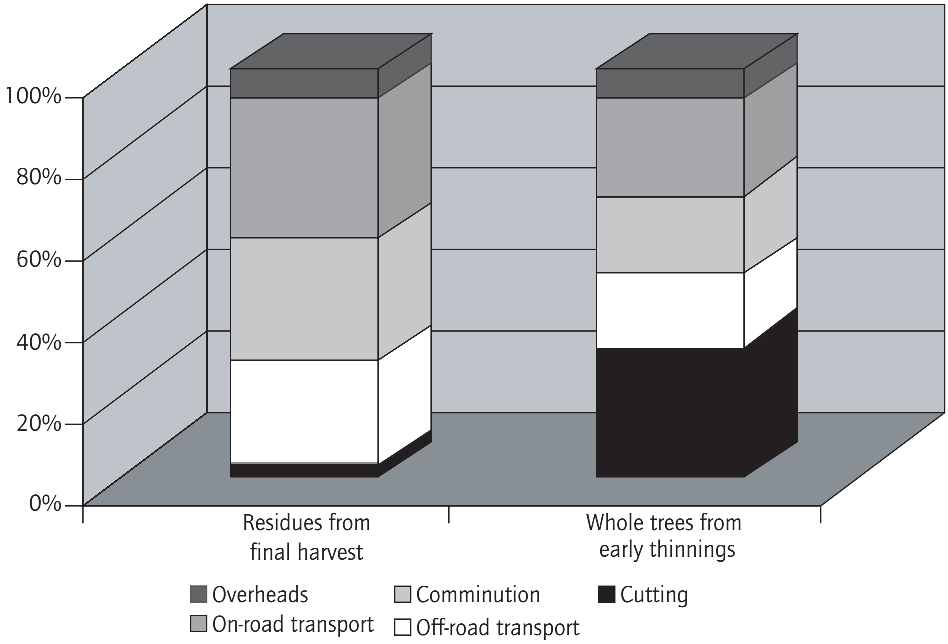
Feedstock Costs

Feedstock costs vary depending on the type of biomass and the transport distance. Bulky biomass tends to be more expensive than compact biomass. The most economical condition is when the energy is used at the site where the biomass residue is generated (*e.g.*, at a paper mill, sawmill or sugar mill). Feedstock costs usually increase disproportionately above a certain level of biomass needed. Therefore, the upper limit of a biopower plant is between 30 and 100 MW, depending on the geographical context and the sources of feedstock.

Feedstock costs for anaerobic digestion are different, as the feedstock (MSW or organic waste from farms) becomes a source of revenue to the plant operator. In these cases, “tipping fees” are charged to the disposer of waste and is part of the revenues of the electricity plant.

Figure 38

Typical Approximate Cost Structure of Forest Chips in Finland, 2002



Note: Price at plant, excluding VAT.
Source: Helynen S., VTT/Finnish Wood Energy Technology Programme.

Generation Costs

Based on system investment needed and electrical output yielded annually, generation costs can be given for a range of biomass applications (see Figure 39). Very low generation costs (slightly above 2 USD cents per kWh) occur with co-firing, where relatively little investment is needed. Higher generation costs (10-15 USD cents per kWh) can be found at innovative gasification plants.

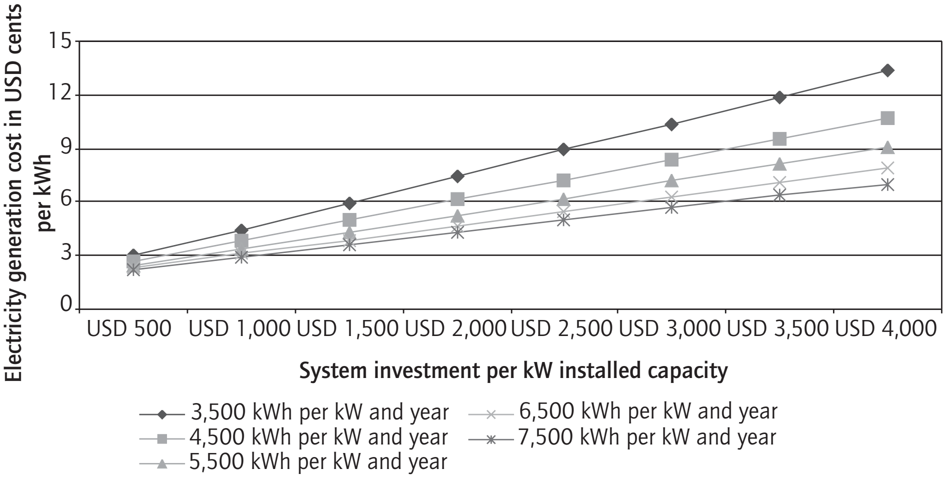
Further examples illustrate the range of biopower generation costs:

- USD 0.021 per kWh for co-firing with inexpensive biomass fuels in the US;
- USD 0.09 per kWh for direct-fired biomass power plants in the US;
- € 0.017 per kWh (heat price € 0.02 per kWh) for a large CHP plant with installed capacity of 60 MW electric output /120 MW thermal output and fuel from wood/peat in Finland;

- € 0.185 per kWh for 1-MW biopower plant with forest timber wood in Germany;
- € 0.07 per kWh for 20-MW biopower plant with discarded timber in Germany.

Figure 39

Approximated Generation Costs for Biopower



Note: O&M costs are assumed to be 8% of system investment. Fuel costs are 1.5 USD cents per kWh.
Source: NET Ltd., Switzerland.

Industry

There are few specialised biomass technology manufacturers, but the main equipment manufacturers see biomass as a secondary activity. Thus, if biomass is not sufficiently profitable, it is relatively easy for these companies to stop biomass activities and produce systems for other fuels. On the other hand, the biopower industry relies heavily on the agricultural sector and steady supply of inputs.

The Nordic countries in the EU are likely to become major producers and exporters of equipment and services for biomass power generation. This is due to their strong position in the related timber, paper and pulp industries; their abundance of domestic biofuel supply; and national policies that have historically favoured bioenergy. This combination has resulted in:

- Danish companies being the world market leaders for straw-fired boilers;
- Finnish companies being market leaders for multifuel fluidised-bed boilers;

- Swedish forestry harvesting systems being the world market leaders;
- The development of the majority of advanced bio-gasification technologies taking place in the Nordic countries.

Other countries in the EU are also developing biomass technologies and capabilities, largely in response to environmentally-driven legislation and incentives.

The biomass power industry in the US is mainly located in the Northeast, Southeast and on the West Coast, representing a USD 15 billion industry. More than 200 companies outside the wood product and food industry sectors generate biopower in the United States. Where power producers have access to very-low-cost biomass supplies, the use of biomass in the fuel mix enhances their competitiveness in the marketplace. This is particularly true in the near term for power companies choosing to co-fire biomass with coal to save fuel costs and earn emissions credits.

As mentioned, forestry and agriculture play a crucial role in the biopower industry. In the US, for instance, the forest products industry uses 85% of all wood waste for energy. Most of the generated power is consumed on-site, but some manufacturers sell excess power to the grid. The use of crop residues and livestock manures as fuel can improve the economics of farming while solving some of the most intractable environmental problems in agriculture today. The advent of energy crops for power production might open a new market for agriculture.

Market

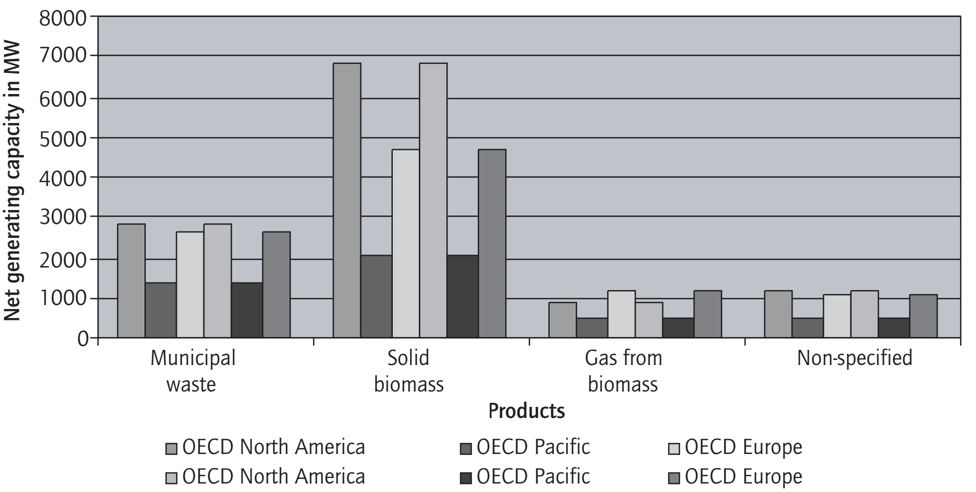
No exact data is available on how much biomass contributes to the global energy supply, but estimates are around 13% of primary energy supply worldwide and around 3% for the industrialised countries. Many developing countries depend on biomass to supply most of the energy needed for heating and cooking. For example, biomass supplies 70-90% of Africa’s energy needs and about one-third of China’s and Brazil’s. Industrial applications in industrial countries include CHP, electricity generation, space and domestic heating, small industrial applications and decentralised energy applications. In some OECD countries, biomass plays an important role in energy and electricity supply, for instance in the US, Japan, Finland and Sweden. Finland (see Table 28) and Sweden have large woodland areas and important pulp and paper industries which help make bioelectricity a large and competitive contributor to national electricity supply.

Net generating capacity in OECD countries in 2000 was around 13.6 GW for solid biomass, 2.6 GW for gas from biomass, 6.8 GW for municipal waste and

2.6 GW for non-specified renewables and wastes. From these figures provided by IEA's *World Energy Outlook 2002*, it can be assumed that worldwide biopower capacity is around 37 GW. Electricity generation from solid biomass has been steadily increasing in the European Union over the course of the last decade with growth averaging 2.5% per year (see Figure 40). The market in the European Union has become particularly dynamic (see Figure 42).

Figure 40

Net Generating Capacity in MW for Three OECD Areas and Four Products, 2000



Source: IEA, Renewables Information 2002.

Table 28

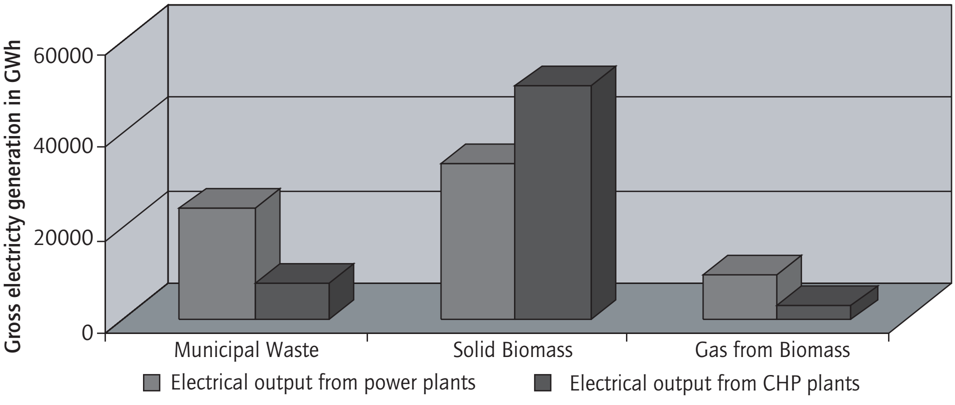
Primary Energy Sources in Finland, 2001

Source	% primary energy share	% primary energy share for electricity production
Solid wood	9.7%	4.5%
Peat	6.2%	6.8%
Black liquors	9.8%	6.1%
Total biomass	25.7%	17.4%

Source: Helynen S., VTT, Finnish Wood Energy Technology Programme.

Figure 41

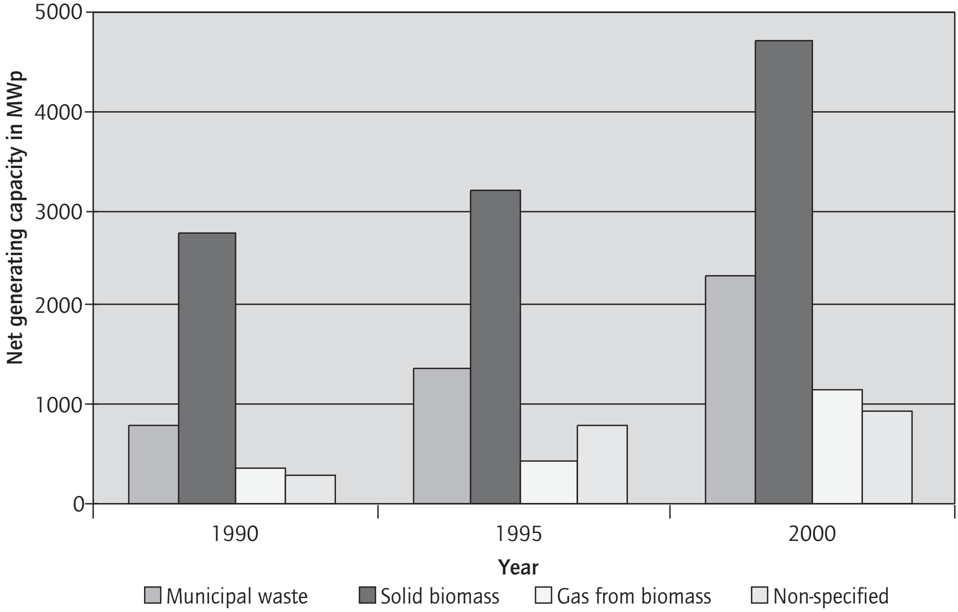
Gross Electricity Generation in GWh for Three Products in OECD Countries, 2000



Source: IEA Renewables Information 2002.

Figure 42

Development of Net Generating Capacity in MW in the European Union



Source: IEA, Renewables Information 2002.

Environment

Environmental issues for bioenergy include land and soil use, transport, particulates and emissions:

- **Emissions and particulates:** The life cycle of biomass is neutral regarding CO_2 emissions, even when fossil fuels are used in harvesting and transporting biofeedstocks. Biomass also offers the possibilities of closed mineral and nitrogen cycles. Environmentally hazardous sulphur dioxide (SO_2), which is produced during combustion of fossil fuels, is not a major problem in biomass systems due to the low sulphur content of biomass (< 1% compared to 1-5% for coal). The incomplete combustion of fuel wood produces organic particulate matter, carbon monoxide and other organic gases. If high-temperature combustion is used, nitrogen oxides are produced.

- **Energy crops:** Crops grown especially for energy production need to be researched, not only to maximise yield, but also to determine their effects on soil depletion and the effects of the use of fertilisers in the process.

- **Waste:** Using waste for energy production makes sense, but should be used in conjunction with waste reduction programmes. An additional environmental benefit from the use of residues such as municipal solid waste and slurry is that these polluting substances are eliminated from landfills.

- **Transport and energy balance:** Biomass has a relatively low energy density compared to fossil fuels. Fuel transport increases its costs and reduces net energy production. Locating the energy conversion process close to a concentrated source of biomass, such as a saw mill, sugar mill or pulp mill, lowers transport distances and costs. The production and processing of biomass can require significant energy input, such as fuel for agricultural vehicles and fertilisers. Biomass processes need to minimise the use of energy-intensive and fossil fuel-based inputs, and to maximise waste conversion and energy recovery.

- **Land and water resources:** The use of land and water for biomass production may compete with other uses.

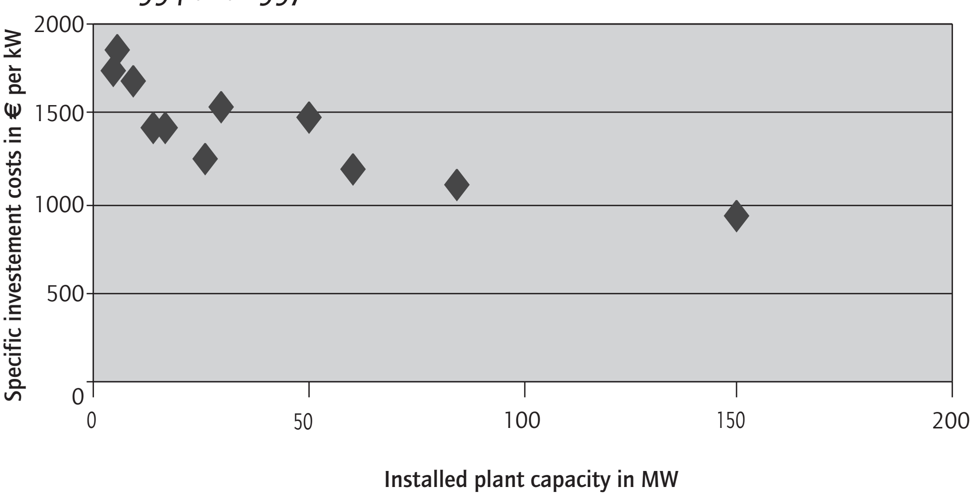
Prospects for Biopower

• Cost Reduction Opportunities

Generally, cost reductions are achieved through technological improvements; however, it is very difficult to draw a clear and homogenous picture of biopower costs and reductions. One of the main reasons for this difficulty is the great diversity of biopower technologies, fuels, conversion processes and system designs. Furthermore, biopower is strongly influenced by local climate and industrial patterns. Some system components come from traditional non-biopower industries and other components are specifically designed for biopower.

Figure 43

Investment Costs for Wood-Fired Rankine Power Plants in Finland, 1994 and 1997



Source: IEA Bioenergy.

Due to the diversity of biopower plants, some examples may help in understanding cost-reduction opportunities. An example of cost reductions related to forest chips as feedstock in Finland is illustrated in Figure 44.

Example 1: Biomass Integrated Gasification and Combined Cycle (IGCC) Plants

Once a technology has reached the stage of the prototype or pioneer plant, a number of improvements can be made on an incremental basis in a commercial context. For biomass IGCC, progress in techno-economic terms (higher conversion efficiency and lower capital costs) is expected through increased capacity and temperature as well as through improved gas-cleaning processes and steam conditions. Doubling plant capacity brings about investment cost reductions of some 20% per kW. Economy of scale is greater in the smaller classes (2 to 40 MW) and less for higher-capacity classes. Nevertheless, power generation costs may in some cases become more expensive with increasing plant size due to increasing biomass transportation costs.

Example 2: 2 MW Biopower Plants

Analysis and comparison of the near-term potential of three 2-MW biopower plants (rankine/steam cycle, gasification (gas-engine) and pyrolysis-diesel) show that:

- Efficiency is expected to increase by around 30% for all the technologies involved;
- The cost-reduction potential in absolute and relative terms is highest for currently more expensive technologies. More precisely, investment cost-reduction potential is 38% for the gasification power plant and 13% for the rankine/steam cycle plant;
- Increasing annual operating time leads to lower generation costs per kWh, especially for the rankine/steam cycle and gasification (gas-engine) plant.

Table 29

Summary of Near-term Potential Improvements for 2-MW Power Plants (%)

	Rankine power plant		Gasification - gas engine		Pyrolysis diesel	
	Base	Future	Base	Future	Base	Future
Power plant efficiency	17.5	23.0	33.0	38.0	38.0	43.0
Gasification efficiency			72.5	85.3		
Liquid product efficiency					65.0	73.3
Overall efficiency	17.5	23.0	23.9	32.4	24.7	31.5
Investment costs (USD/W electricity)	2.3	2.0	4.2	2.6	3.6	2.7

Source: IEA Bioenergy.

Table 30

Generation Costs for 2-MW Power Plants (USD cents per KWh)

	Current generation cost based on 5,000 h annual operating time	Current generation cost based on 7,000 h annual operating time	Near-term generation cost based on 5,000 h annual operating time	Near-term generation cost based on 7,000 h annual operating time
Rankine power plant	12.5	10.5	10	8.5
Gasification - gas engine	19	14	12	9.5
Pyrolysis-diesel	16	14.5	12.5	11

Source: IEA Bioenergy.

Example 3: Co-generation Power Plants

Analysis and comparison of the near-term potential of the three biopower co-generation plants – a) Rankine 2.0 MW electricity output /6.8 MW thermal output, b) gas engine 5.0 MW electricity output /6.0 MW thermal output and c) pyrolysis-diesel 6.2 MW electricity output /6.5 MW thermal output – show that:

- The overall efficiency increase is expected to range from 2.3% for the rankine plant to 12.8% for the pyrolysis-diesel plant;
- The cost reduction potential in absolute and relative terms is highest for currently more expensive technologies. More precisely, co-generation costs could be reduced by about one-third for the gas engine and pyrolysis-diesel plants and by about one-tenth for the rankine plant.

In the medium to long term, it is anticipated that gasification/turbine systems will be able to produce electricity at up to twice the efficiency of today's biomass power plants, i.e. up to 45%. These very-high-efficiency systems will result from technical improvements that are only possible at a larger plant size. Projections for bio-gasification combined-cycle plants show electricity costs close to those of conventional fossil fuel fired power plants.

Currently, biomass power plants are limited to between 30 MW and 100 MW, depending on fuel sources and geographical context. Increased generating efficiency through advanced combined-cycle technology will further reduce the fuel required for power production, resulting in greater generating capacity.

Table 31

Summary of Near-term Potential Performance for Co-generation Power Plants

	Rankine power plant		Gasification - gas engine		Pyrolysis diesel	
	Base	Future	Base	Future	Base	Future
Power production MW electricity output	2.0	2.0	5.0	5.0	6.2	6.2
Heat production MW thermal output	6.8	5.8	6.0	5.7	6.5	6.5
Production efficiency %	17.5	23.0	23.9	32.4	24.7	31.5
Overall efficiency %	88.0	90.0	85.0	90.0	58.5	66.0
Power-to-heat ratio	0.30	0.35	0.83	0.88	0.95	0.95

Source: IEA Bioenergy.

Table 32

Co-Generation Costs of Bioelectricity

Co-generation costs in USD cents per kWh (approximate values)	Current generation cost based on 5,000 h annual operating time	Current generation cost based on 7,000 h annual operating time	Near-term generation cost based on 5,000 h annual operating time	Near-term generation cost based on 7,000 h annual operating time
Rankine power plant	7.5	5.5	7	5
Gasification - gas engine	11.5	9	8	6
Pyrolysis-diesel	13	12.5	9.5	8.5

Note: Rankine power plant 2.0 MW electricity output /6.8 MW thermal output, gas engine 5.0 MW electricity output /6.0 MW thermal output and pyrolysis 6.2 MW electricity output /6.5 MW thermal output.
Source: IEA Bioenergy.

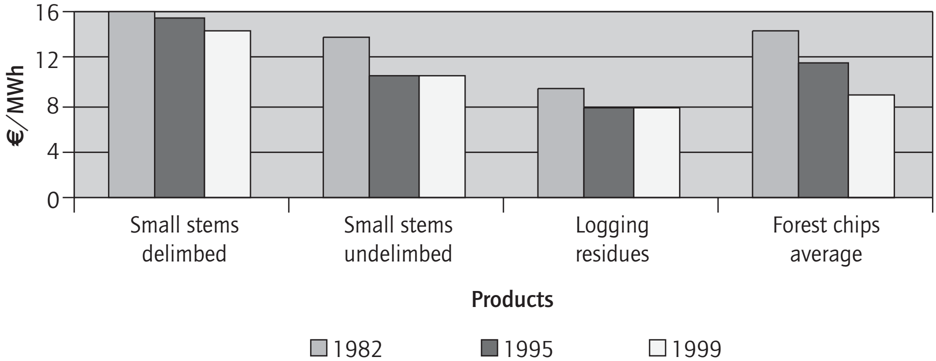
Feedstock

Improving feedstock and the fuel supply chain is essential for a more efficient and cost-competitive biomass electricity. As an example, the main reasons for reductions in the cost of electricity produced from forest chips in Finland were:

- timber harvesting was fully mechanised, allowing cost-efficient recovery of logging residues;
- small-tree chipping was partly replaced by logging residue chips with new machinery and methods that were developed by intensive R&D;
- increased demand for forest chips led to use of more efficient chippers at full capacity;
- logistics were improved along the whole chain of chip production.

Figure 44

Cost Reductions Related to Forest Chips in Finland



Source: Wood Energy Technology Programme in Finland.

Market Opportunities

Market Potential

Natural global biomass replacement represents an energy supply of around 3,000 exajoules (3×10^{21} J) per year, of which somewhat less than 2% is currently used as fuel. Theoretically, biomass could supply about half the present world primary energy demand in a sustainable manner by the year 2050.

A key attribute of biomass is its natural storage of energy and consequent availability upon demand. Through photosynthesis, plants take up carbon, which can be stored in the plant material if it is harvested before the plant decomposes. Such harvested plant material can then be kept until the energy stored is needed. Other forms of renewable energy are dependent on variable environmental conditions such as wind speed or sunlight intensity.

The main biomass resources are:

- agricultural residues and wastes (straw, animal manure, etc.);
- organic fractions of municipal solid waste and refuse;
- sewage sludge;
- industrial residues (*e.g.*, from the food and paper industries);
- short-rotation forests (willow, poplar, eucalyptus);
- herbaceous ligno-cellulosic crops (miscanthus);
- sugar crops (sugar beet, sweet sorghum, Jerusalem artichoke);
- starch crops (maize, wheat);
- oil crops (rape seed, sunflower);
- wood wastes (forest residues, wood processing waste, construction residues).

In the long term, energy crops could be a very important biomass fuel source. At present, however, wastes (wood, agricultural, municipal or industrial) are the major biomass sources.

Technology Factors

Biomass offers many applications for power generation, from co-generation to distributed generation. In some areas, biopower can compete with conventional base-load power in the 30-100 MW range or provide electricity for specific services. Worldwide biopower generation capacity is expected to grow by more than 30 GW by 2020.

Co-firing offers power plant managers a relatively low-cost and low-risk way to add biomass capacity. When low-cost biomass fuels are used, co-firing systems can have payback periods as short as two years. According to US DOE, a typical coal-fuelled power plant produces power for about USD cents 2.3/kWh. Co-firing inexpensive biomass fuels can reduce this cost to USD cents 2.1/kWh. Interest in co-firing is growing in the US, in some of the developing countries like China, where coal firing plays an important role, and in some European states (Nordic countries and the Netherlands). Biomass can substitute for up to 15% of the total energy input by modifying little more than the burner and feed intake systems. Since large-scale power boilers in the current 310 GW portfolio in the US range from 100 MW to 1.3 GW each, the biomass potential in a single boiler ranges from 15 MW to 150 MW. Today's co-firing systems range from 1 to 30 MW of biopower capacity. The way the biomass is fired depends upon its proportion in the fuel mix: a) for minor quantities (2-5%), the biomass can be mixed with the coal at the inlet to the mill, b) for larger quantities (5-25%), the biomass should be shredded finely and fired through dedicated burners - implying some expense and energy, and c) for major quantities (above 25%), the substantial impact on the furnace and the ash behaviour will probably necessitate gasifying the fuel and firing it through a gas burner - implying substantial expense. To summarise, the advantages of co-firing biomass are reduced capital costs, high conversion efficiency and reduced emissions.

Multipurpose or polygeneration: "External" industries, like pulp and paper, produce inexpensive organic material which is available for power generation for their own industrial processes. Transportation costs are low or non-existent. These industries are an important part of the biopower sector.

Modular systems basically employ standard technologies mentioned earlier, but on a smaller scale. They are appropriate for small-scale power plants at biomass supply sites and can be used in villages, on farms or for small industry. These systems have been developed and demonstrated. Off-grid (modular) systems can provide energy services in remote areas where biomass is abundant and electricity is scarce. There are many opportunities for these systems in developing countries.

Developing countries: Many developing countries present interesting markets due to rapid economic growth, high demand for electricity/electrification, environmental problems and significant agricultural/forestry residues. China and India are expected to experience strong electricity demand growth. Off-grid modular systems and co-firing are of particular interest in these countries. Co-firing may improve the economic and ecological quality of many older coal-fired power plants, which predominate in developing countries. Although most biomass in developing countries is used for cooking and space heating, a significant amount is also used in industry for process steam and power generation. These industrial uses are almost exclusively in the agro and wood-processing sectors. Until recently, the priorities for these generators were the disposal of residues and the lowest capital cost commensurate with the required availability. Efficiency was never a priority because there were few customers for any surplus electricity. With more efficient generating equipment, these agro-processing plants could sell biopower at relatively competitive costs. For example, a typical sugar mill could export approximately 8 MW of electricity output by implementing simple improvements. This output could be doubled by the installation of more advanced technology.

Refurbishment/upgrading: Existing plants can be economically refurbished and/or upgraded. An example is the McNeil Station in Burlington (USA), originally built as a wood-burning 50 MW power plant in the early 1980s. It recently became host to field verification tests for an innovative biomass gasifier. With help from the U.S. Department of Energy's Biopower Program, the gasifier will generate electricity more efficiently, and with less pollution, than conventional boiler/turbine technology.

Residues and waste management: The most economic forms of biomass for generating electricity are residues. These are the organic by-products of food, fibre and forest production. Common examples are bagasse, rice husks and sawdust. Low-cost biomass sources are also common near manufacturing centres where clean wood waste materials are available in large quantities, for example pallet and crate discards. Besides other conversion technologies already mentioned above, anaerobic digestion schemes offer compelling solutions to waste disposal problems and mainly produce biogas for energy use and a digestate that can serve as fertiliser or soil conditioner.

Technology learning: The great diversity of biopower technologies, fuels, conversion processes and system designs, as well as the dependence on local climate and industrial patterns, may explain why no representative experience curve has ever been drawn for biopower. Costs and cost-reduction opportunities vary greatly. Co-firing, for example, requires only modest investments and generation costs are low, provided fuel is inexpensive. Eliminating waste is sometimes the main project benefit, with electricity just a by-product. Since the elimination of waste is in itself a valued activity, the cost of this electricity is very low. Gasification offers increased efficiencies. New types of small modular systems are also being developed. These technologies are currently expensive, but their cost reduction potential is considerable.

Market Growth Factors

It is difficult to draw a clear picture of the biopower market due to the diversity of technologies and applications as well as the scarcity of data. Current and potential markets for bioenergy are very fragmented. It is clear, however, that many market opportunities exist for biopower. It is important to remember that in Europe most biomass-to-electricity schemes were developed in the pulp, paper and forest industries, where significant synergies and the need for waste management were critical success factors.

In the coming years, biopower is likely to progress steadily, with an annual global capacity increase of 4%. The price of natural gas, one of biopower's main competitors, will be an important factor.

Table 33

Cost Reduction Opportunities for Biopower (%)

	R&D	Economy of scale I (components size)	Economy of scale II (manufacturing volume)	Economy of scale III (plant size)
Biopower	Up to 10	Up to 5	Up to 5	Up to 5

Source: NET Ltd., Switzerland. Percentages are within a decade based on expected technology learning and market growth.

Table 34

Cost Figures for Biopower

Current investment costs in USD per kW	• Low investment costs: 500 • High investment costs: 4,000
Expected investment costs in USD per kW in 2010	• Low investment costs: 400 • High investment costs: 3,000
Current generation costs in USD cents per kWh	• Low cost generation: 2-3 • High cost generation: 10-15
Expected Generation costs in USD cents per kWh in 2010	• Low cost generation: 2 • High cost generation: 8-10

Source: NET Ltd., Switzerland.

Table 35

Key Factors for Biopower

Factor	Fact
Variable influencing energy output	• Biomass growth (fuel)
Limiting factors	• Area availability • Material availability
Capacity installed in 2002 in GW	• 37 GW
Potential in 2010 in GW	• 55 GW
Future potential beyond term year given	• High
Rule of thumb for conversion ratio* (installed power to electric output)	• 1 kW –> 5,400 kWh per year • 1 kg of biomass –> 1.6 kWh

** Assumptions: U.S. data with 60 million tons of biomass per year converted into 37 billion kWh of electricity with 7 GW installed capacity.*
Source: NET Ltd. Switzerland

Issues for Further Progress

● Technical Issues

The most important technical issues for biopower relate to feedstock logistics and conversion technologies.

Feedstock

Agricultural residue harvesting systems are almost fully mature and few new developments are foreseen. Forestry residue systems are developing rapidly, and the main priority is now the development of more cost-effective chipping and transport. New methods should be found to avoid double handling and to increase the density of the biomass and hence transportation efficiency. Energy crops are still in the early stages of development, although progress has been made. Research must be continued on plant breeding and on more cost-effective mechanisation.

Conversion Technologies

More mature technologies (combustion, anaerobic digestion, biogas, sugar/starch fermentation, biodiesel) will still benefit from mass-to-energy efficiency improvements, advanced reactor designs and a better understanding of process economics. Technical problems of emerging technologies (advanced combustion, gasification) and promising technologies (pyrolysis, bioconversion of cellulosics) must be addressed, *e.g.*, standardised solid biofuels, ash effects, agro-residues and energy crops, gas cleaning and bio-oil refining. The environmental impact of all types of biomass conversion systems must be minimised.

● Non-technical Issues

Two non-technical issues will greatly affect the future growth of biopower. First, biomass-related strategic decisions are affected by and may affect different policy areas, including agriculture, food, forestry and national conservation areas. Biomass utilisation can positively affect the generation of green power, the use of locally available resources and employment in forestry and agriculture. However, an action or decision in one policy area may affect other areas and hinder biomass utilisation.

Second, public acceptance can be improved by labelling, by the use of environment-friendly materials and components and by life-cycle analysis confirming the "green" image of biopower. The socio-economic and ecological externalities of biomass use should be quantified to assess possible benefits. Education and information campaigns are also important.

GEOTHERMAL POWER

A Brief History of Geothermal Power

Geothermal energy can be defined as heat that originates within the Earth. The heat has two sources: the original heat produced from the formation of the earth by gravitational collapse and the heat produced by the radioactive decay of various isotopes.

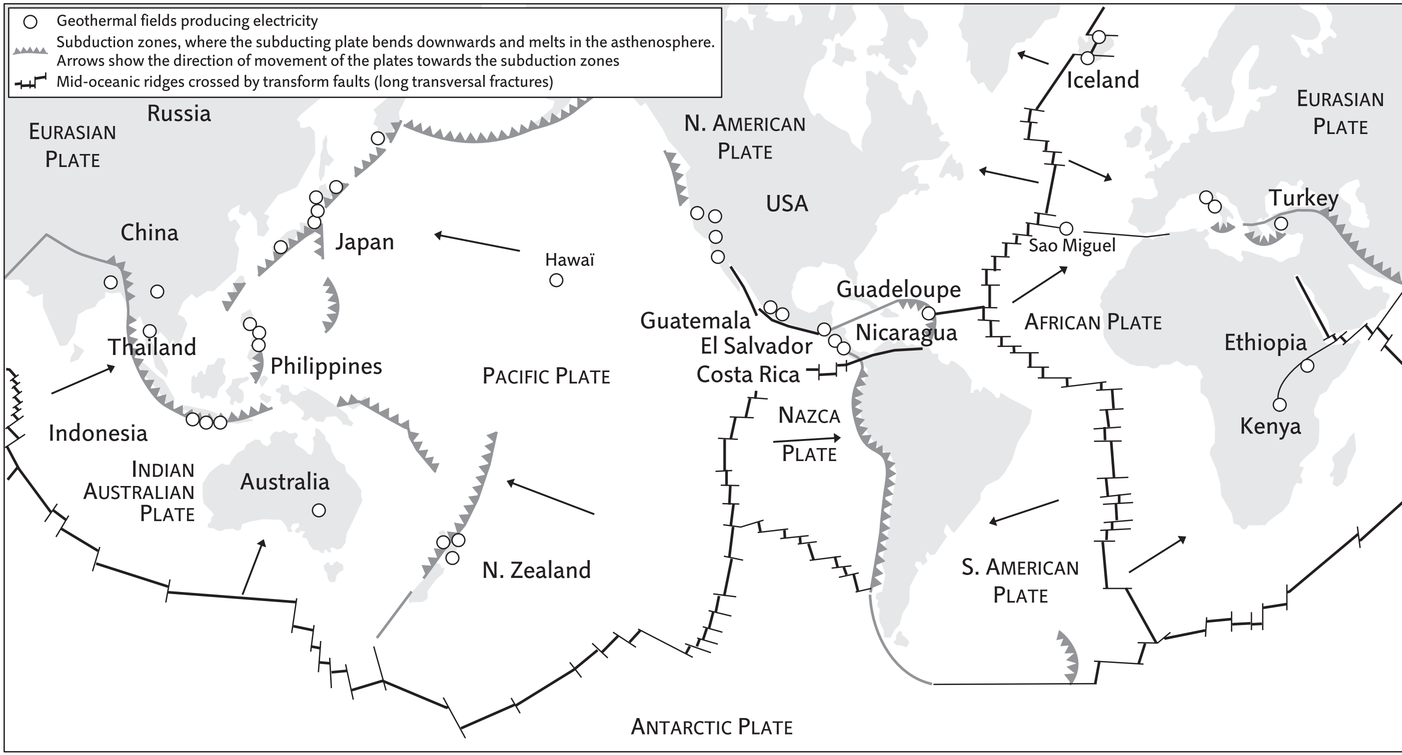
In the early part of the 19th century, geothermal fluids were already being exploited for their energy content. A chemical industry was set up in the zone known today as Larderello in Italy to extract boric acid from the hot waters issuing naturally or from shallow boreholes. The boric acid was obtained by evaporating the hot fluids in iron boilers, using wood from nearby forests as fuel. In 1827, Francesco Larderel, founder of this industry, developed a system for using the heat of the boric fluids in the evaporation process, rather than burning wood from the rapidly depleting forests. Exploitation of the natural steam for its mechanical energy began at the same time. The geothermal steam was used to raise liquids in primitive gas lifts and later in reciprocating and centrifugal pumps and winches, which were used in drilling activity or in the local boric acid industry. The first successful commercial project for generating electricity from geothermal steam was in Larderello, Italy in 1904. A 250-kW geothermal power plant began operating there in 1913 and commercial delivery of geothermal electricity to nearby cities started in 1914. By 1942, installed geo-electric capacity had reached 127 MW. The first commercial geothermal power plant using a liquid-dominated, hot-water reservoir started operation in 1958 in Wairakei, New Zealand. Geothermal electricity production in the United States started in 1960. Today the US leads the world in geothermal power, with about one-fourth of all geothermal generation: about 16 TWh from 2 GW of installed capacity in 2002.

Technology Status

Geothermal technology depends on the type and location of the natural resource. Since it is not practical to transport high-temperature steam over long distances by pipeline due to heat losses, most geothermal plants are built close to the resource. A geothermal system consists of three main elements: a heat source, a reservoir and a fluid - the last being the carrier for transferring heat from the source to the power plant. The heat source can be either a very-high-temperature (> 600°C) magmatic intrusion that has

Figure 45

World Pattern of Geothermal Power and Tectonics



Source: Dickson and Fanelli.

reached relatively shallow depths (5 to 10 km) or, as in certain low-temperature systems, the Earth's normal temperature, which increases with depth. The heat source is natural, whereas the fluid and the reservoir can be introduced to the subterranean media by the project.

Geothermal power plants tend to be in the 20 MW to 60 MW range and the capacity of a single geothermal well usually ranges from 4 MW to 10 MW. Typical minimum spacing of 200m to 300m is established to avoid interference. Three power plant technologies are being used to convert hydrothermal fluids to electricity. The type of conversion depends on the state of the fluid (steam or water) and on its temperature:

- Dry steam power plants use hydrothermal fluids primarily in the form of steam. The steam goes directly to a turbine, which drives a generator that produces electricity. This is the oldest type of geothermal power plant and was originally used at Larderello in 1904. This steam technology is still very effective and is used today at The Geysers in Northern California, the world's largest single source of geothermal power.
- Flash steam power plants use hydrothermal fluids above 175°C. The fluid is sprayed into a tank (separator) held at a much lower pressure than the fluid, causing some of the fluid to vaporise rapidly, or "flash" to steam. The steam then drives a turbine.
- Binary-cycle power plants use hot geothermal fluid (below 175°C) and a secondary (hence, "binary") fluid with a much lower boiling point than water - both passing through a heat exchanger. Heat from the geothermal fluid causes the secondary fluid to flash to steam, which then drives the turbines. Because this is a closed-loop system, virtually no emissions are released into the atmosphere. As moderate-temperature water is by far the most common geothermal resource, most geothermal power plants in the future will be binary-cycle plants.

The total energy efficiency is 97% for CHP but only up to 7-10% for electricity production. Because geothermal power plants operate at relatively low temperatures compared to other power plants, they eject as much as 90% of the heat extracted from the ground into the environment. The minimum temperature for electricity generation is 90°C. The lowest-temperature commercial geothermal power plant in the US has a resource temperature of 104°C. Below this critical temperature threshold, the required size of the heat exchanger would render the project uneconomical. The efficiency of conversion from heat to electricity drops to 2% for fluids at 85°C and is almost zero for fluids below 60°C.

Despite the relatively low efficiency in power generation, geothermal has several positive features. Geothermal electric plants can operate 24 hours per day and thus provide base-load capacity. The power generation is not intermittent like solar or wind - except for some seasonal differences in cycle efficiencies because, in winter, heat is rejected to a lower sink temperature and thus the plant output is higher. This is especially true for air-cooled binary plants.

A relatively new concept in geothermal power is Hot Dry Rock (HDR), also known as Hot Wet Rock (HWR), Hot Fractured Rock (HFR) and Enhanced Geothermal Systems (EGS). The basic concept is to increase the permeability of the natural fractures of the basement rocks, install a multi-well system, force the water to migrate through the fracture system ("reservoir") by using enhanced pumping and lifting devices and, finally, use the heat for power production. HDR is expected to contribute to further geothermal development in the decades to come.

Costs

As for other renewable energy systems, the costs of a geothermal plant are heavily weighted towards up front investments. The resource type (steam or hot water) and temperature, as well as reservoir productivity, influence the number of wells that must be drilled for a given plant capacity. Power plant size (rated capacity) and type (single-flash, binary, etc.), as well as environmental regulations, determine the capital cost of the energy conversion system.

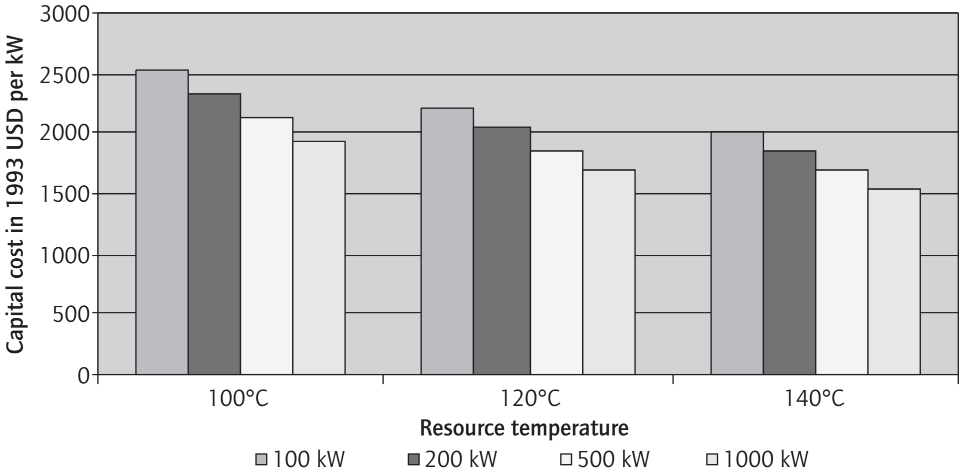
Investment Costs

According to US DOE the initial cost for the field and power plant varies from USD 1,500 to 5,000 per installed kW in the U.S., USD 3,000 to USD 5,000 per kW for a small power plant (<1 to 5 MW), and USD 1,500 to USD 2,500 kW for larger plants (> 5 MW), depending on the resource temperature and chemistry. In Europe, costs vary from below € 1,000 to over € 10,000, depending on plant size and location. The costs of HDR, which is still in the development phase, vary from € 16,000 to 18,000 per kW and are expected to fall to € 2,000 to 3,000 per kW by 2010 according to European Commission estimates.

Costs vary greatly according to type of technology, size and resource. The impact of resource temperature and plant size on the capital cost of binary power plants as shown in Figure 46, range from USD 1,500 to USD 2,500. This does not include exploration and drilling costs.

Figure 46

Capital Costs for Small Binary Geothermal Plants



Source: DiPippo. Data excludes resource development.

Geothermal project management and costs have some unique aspects related to the different phases of (a) leasing and exploration, (b) project development and feasibility studies, (c) well-field development, project finance and construction and start-up operation, (d) commercial operation, and (e) field and plant expansion. Unlike other renewables, bringing a geothermal power plant into operation can take ten years or more, due to the uncertainty and complexity of obtaining exploration licences and permits. The typical time between order and industrial operation after permits is one to three years. The entire project is evolutionary, with each phase of development dependent upon the success of the prior one. Multidisciplinary teams are needed to manage a geothermal project at each stage, from exploration to full operation.

Two cost examples are given in more detail below. The first relates to a small-scale power plant explored by Entingh et al., the second to a large-scale plant presented by McClain. The small-scale plant has system costs of USD 2,200 per kW installed, capital recovery costs of USD 158,650 and O&M costs of USD 63,000, resulting in generation costs of USD 0.105 per kWh. O&M costs for geothermal plants are relatively high compared to other renewables.

Table 36

Technical Data for a Small-Scale Geothermal Power Plant

Resource temperature	120°C
System net capacity	300 kW electricity
Number of wells	2
Capacity factor	80%
Plant life	30 years
Rate of return on investment	12%/year
Production	2.1 GWh/year

Source: Entingh et al., 1994.

Table 37

Capital Costs of a Small-Scale Geothermal Power Plant (300 kW)

Exploration	200,000
Wells	325,000
Field	94,000
Power Plant	659,000
Total	1,278,000

Source: Entingh et al., 1994.

Table 38

Operation and Maintenance Costs of a Small-Scale Geothermal Power Plant (300 kW).

	USD
Field	32,000
Plant	26,000
Back-up system	5,000
Total	63,000

Source: Entingh et al., 1994.

An example of a large scale power plant is described in more detail below, showing the different phases and their related costs. Costs may vary from USD 50 to 150 million for a 50-MW plant.

Exploration and leasing: This phase is normally divided into site assessment, leasing and land acquisition, exploratory drilling, and well testing. In general, site assessment as well as leasing and land acquisition are low-risk activities with relatively low costs, ranging from USD 50,000 to USD 500,000. Exploratory drilling and reservoir assessment, as in the oil and gas field, are high-risk activities: if an adequate resource is not found, the entire project is cancelled. A wide range of issues must be addressed: geological data, geophysical surveys, approval process for drilling, road building, mobilising a drilling rig, well testing, and physical and chemical data collection. The cost can easily range from USD 0.75 to USD 2.5 million per exploration well. The entire programme can cost from USD 3 to USD 6 million.

Project development and feasibility studies: If the previous phase gives satisfactory results, a further series of activities can be carried out: compilation of a reservoir assessment report; negotiation of a power sales contract; approval of construction of wells, steam and water lines and power plant; and finalisation of design and cost/revenue estimation. The cost range is from USD 0.25 to USD 2.3 million, with the highest expenses for pre-construction permits and environmental approval.

Well-field development and project finance, construction, start-up: This phase is rather complicated and time consuming. Activities like drilling and power plant construction can overlap and require careful scheduling. Construction time is only 12-16 months for the power generating plant, but well drilling (depending on the number of drilling rigs operating in parallel) can take several years. Overall well-field development for a standard 50-MW project with ten production wells, two injection wells and two reserve wells, at an average cost of USD 2 million per well (depending on depth), can reach USD 32 million. Power plant engineering, design, construction, and start-up are complicated but not unique to geothermal; the oil industry and other mining companies face similar challenges.

Commercial operations and field and plant expansion: As noted earlier, geothermal plants have an availability factor of 98%, and can be operated at full load 24 hours a day with energy efficiency of about 97% for CHP and 7-10% for electricity production. It is common to develop multiple power plants or subsequent units over time. However, before installing a second unit at the same site, it must be ensured that new wells will not affect the productivity of existing ones.

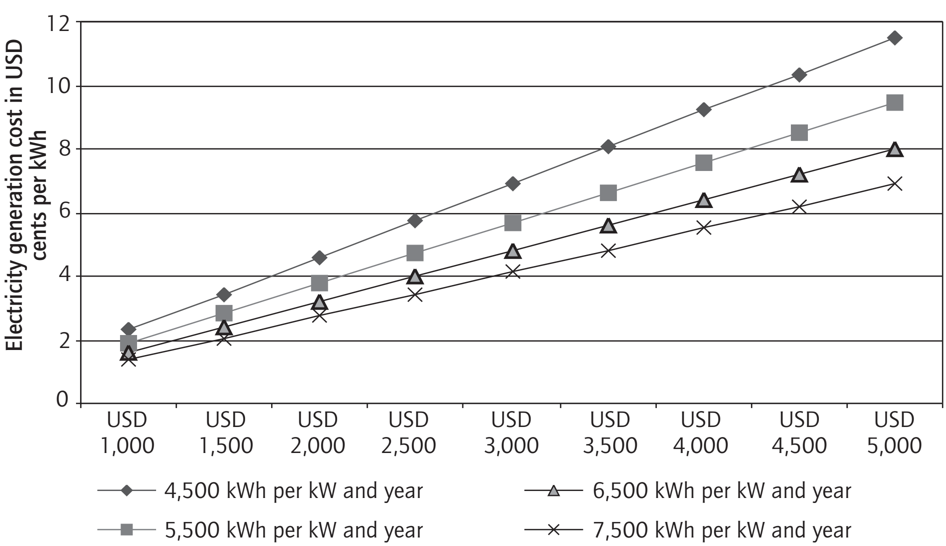
Generation Costs

Generation costs depend on a number of factors, but particularly on the temperature of the geothermal fluid produced, which influences the size of the turbine, heat exchangers and cooling system. US sources (DOE, Lund) report current costs of producing power from as low as 1.5 to 2.5 USD cents per kWh at The Geysers, to 2 to 4 USD cents for single-flash and 3 to 5 USD cents for binary systems. New constructions deliver power at 5 to 6.5 or 8 USD cents per kWh, depending on the source. The latter figures are similar to those reported in Europe. Generation costs per kWh are € 0.05 - 0.09 for traditional power plants (liquid-steam water resources) and € 0.20 - 0.30 for HDR.

Based on system investment needed and electrical output yielded annually, generation costs can be given for a range of applications (see Figure 47). Very low generation costs (in the range of 2 to 3 USD cents per kWh) occur with installations characterised by low investment costs (up to USD 1,500), high energy output (over 6,000 kWh per kW per year) and low O&M costs. The latter can be considerably higher according to the type of plant and resource. "Traditional" plants, such as The Geysers in California, produce geothermal power at costs as low as 2 USD cents per kWh. New plants in many areas in the world can produce power at 5 USD cents per kWh or less.

Figure 47

Approximate Annual Generation Costs for Geothermal Power



Note: Based on system investment needed and electrical output yielded annually. O&M costs are assumed to be 6.5% of system investment. Amortisation period is 15 years, discount rate 6%.
Source: NET Ltd., Switzerland.

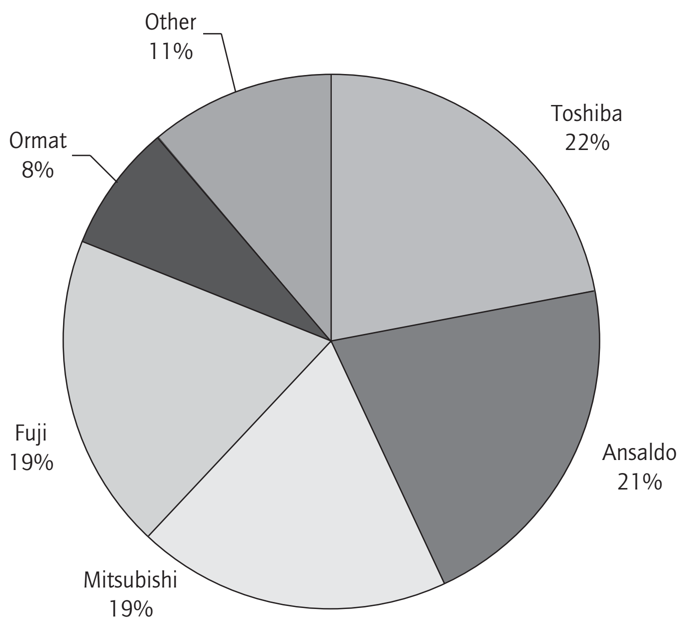
Industry

The international geothermal power industry is dominated by five large firms: three Japanese companies, one Italian, and one Israeli-American. The three Japanese companies and the Italian one have comparable market shares (see Figure 48).

Competence in underground engineering (prospecting and exploration, valorising geothermal fields, etc.) is found mainly in the US, Japan, the Philippines, Mexico, Italy, New Zealand, Iceland, France. Turnover for the geothermal electricity sector in 1999 was in the region of € 1,600 million, with an estimated 40,000 and 45,000 people employed in the construction, installation and maintenance of geothermal plants.

Figure 48

Market Share Based on Geothermal Capacities Installed, 1995-2000



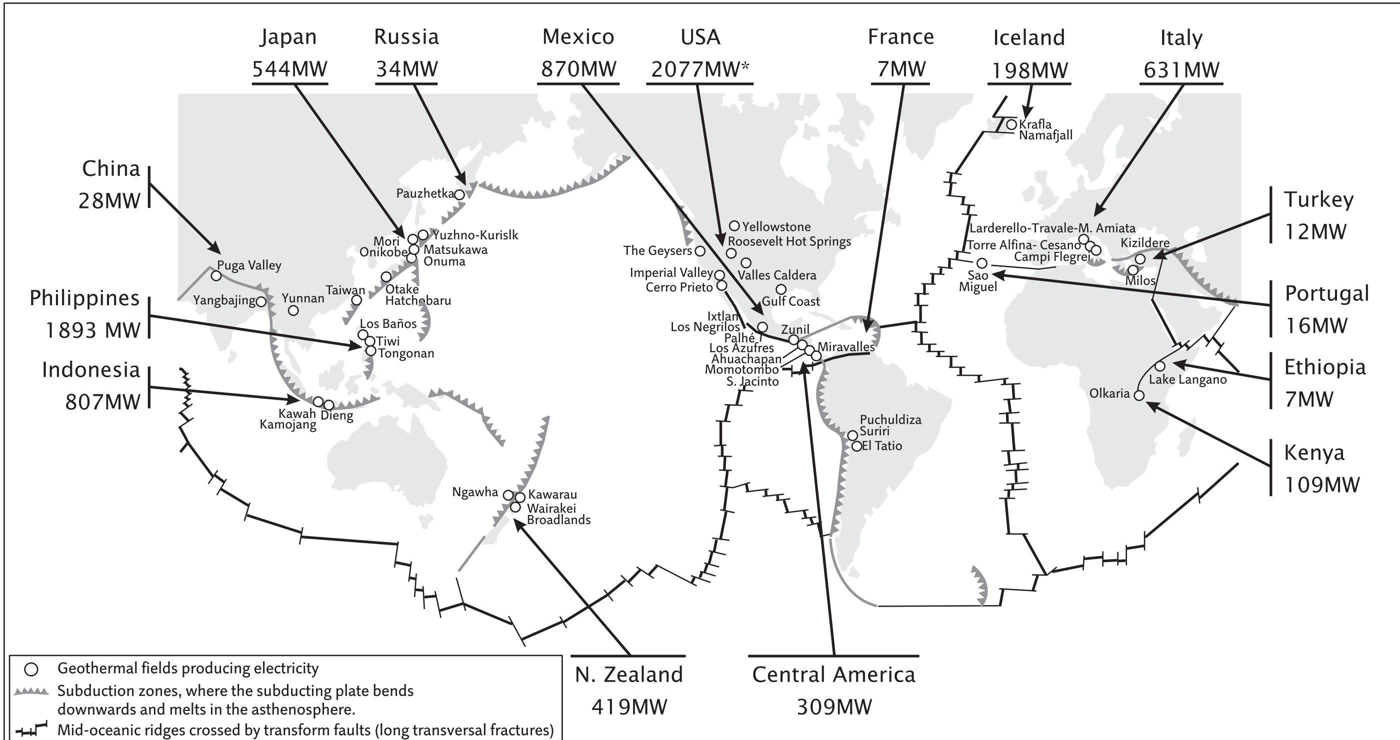
Source: EurObserv'ER.

Market

Geothermal power projects have been established in relatively few countries, as shown in Figure 49. Most geothermal development (more than 90% of worldwide installed capacity) is in the US, the Philippines, Mexico, Italy, Japan, Indonesia and New Zealand.

Figure 49

Locations of Cumulative Geothermal Power Capacity Installed, 2000



Source: Data from Huttrer.

Table 39

Geothermal Power Production and Installed Capacity, 2000

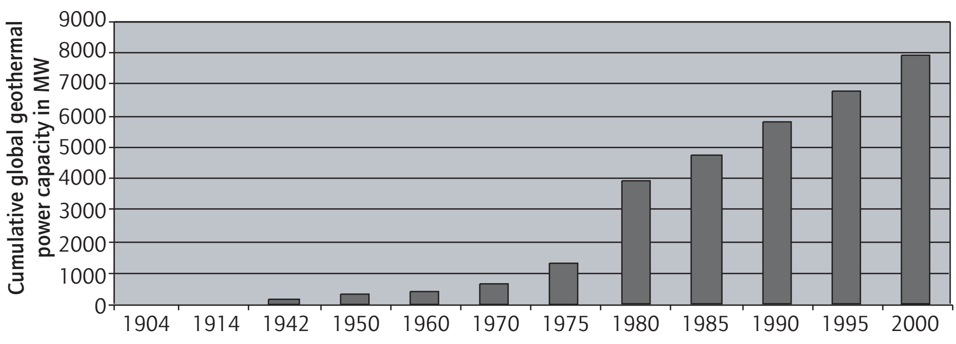
	Production in TWh	Installed capacity in MW
USA	15.5	2,228
Philippines	9.2	1,909
Mexico	5.7	755
Italy	4.4	785
Japan	3.5	547
Indonesia	4.6	590
New Zealand	2.3	437
Rest of world	4.1	723
Total	49.3	7,974

Source: Huttrer.

Global installed geothermal electric capacity has been steadily growing, with about 3.9 GW in 1980, 4.8 GW in 1985, 5.8 GW in 1990, 6.8 GW in 1995 and almost 8 GW in 2000. The annual growth rate has been around 5%.

Figure 50

Worldwide Development of Geothermal Electric Power



Sources: Lund and Huttrer.

More recently, Asia and Central and South America have shown particularly strong growth in relative terms. These are also the areas where geothermal power can play a significant role in the energy balance: the share of geothermal power with respect to total electric power installed is 10% or more in the Philippines, El Salvador and Nicaragua.

Environment

Table 40 summarises the probability and relative severity of the effects on the environment of geothermal direct-use projects.

Table 40

Probability and Potential Severity of Environmental Impact of Geothermal Direct-Use Projects

Impact	Probability	Severity
Air quality pollution	L	M
Surface water pollution	M	M
Underground pollution	L	M
Land subsidence	L	L-M
High noise levels	H	H-M
Well blowouts	L	L-M
Conflicts with cultural and archaeological features	L-M	M-H
Social-economic problems	L	L
Chemical or thermal pollution	L	M-H
Solid waste disposal	M	M-H

Source: Lunis and Breckenridge.
L = Low; M = Moderate; H = High.

Environmental concerns related to geothermal energy use include:

Pollutants: Geothermal energy produces non-condensable gaseous pollutants, mainly carbon dioxide, hydrogen sulphide, sulphur dioxide and methane. Carbon dioxide is a natural compound present in the fluids used in geothermal power plants. However, the level of CO2 discharge from these plants is much lower than from fossil-fuelled power stations. The condensed geothermal fluid also contains dissolved silica, heavy metals, sodium and potassium chlorides, and, sometimes, carbonates; but, modern emission controls and re-injection techniques have reduced these impacts to a minimum. Geothermal energy has a net positive impact on the environment because it pollutes less than conventional energy.

Wastewater: Discharge of wastewater is also a potential source of chemical pollution. Spent geothermal fluids with high concentrations of chemicals such as boron, fluoride or arsenic should be treated, and/or re-injected into the reservoir. However, the low-to-moderate temperature geothermal fluids used in most direct-use applications generally contain low levels of chemicals and the discharge of spent geothermal fluids is seldom a major problem. Sometimes these fluids can be discharged into surface water after cooling. The water can then be cooled in special storage ponds or tanks to avoid modifying the ecosystems of natural bodies of water.

Ground subsidence: Extraction of large quantities of fluids from geothermal reservoirs may result in ground subsidence. Subsidence should be monitored systematically, as it could damage the geothermal plant and other buildings in the area. In many cases, subsidence can be prevented or reduced by re-injecting the geothermal wastewater.

Seismic activity: The withdrawal and/or re-injection of geothermal fluids may trigger or increase the frequency of seismic events in certain areas. However these are micro-seismic events that can only be detected by instrumentation. Exploitation of geothermal resources is unlikely to trigger major seismic events.

Sustainability: Geothermal energy is usually classified as renewable and sustainable. “Renewable” describes a property of the energy source, whereas “sustainable” describes how the resource is used. On a site-by-site basis, geothermal energy is renewable if the use of energy is adapted to the natural rate of energy recharge. Usually geothermal power plants can operate for about 50 years at a site (sometimes longer), implying a decline of the heat content of the geothermal reservoir, which subsequently needs a recovery period of several decades.

Noise: Geothermal plants produce noise pollution during construction, e.g. by drilling of wells and the escape of high-pressure steam during testing. Noise is usually negligible during operation with direct-heat applications. However, electricity generation plants produce some noise from the cooling tower fans, the steam ejector and the turbine.

Visual impact: Geothermal plants are often located in areas of high scenic value, where the appearance of the plant is important. Fortunately, geothermal power plants take up little area and, with careful design they can blend well into the surrounding environment. Wet cooling towers at plants can produce plumes of water vapour, which some people find unsightly. In such cases, air-cooled condensers can be used.

Prospects for Geothermal Power

Cost Reduction Opportunities

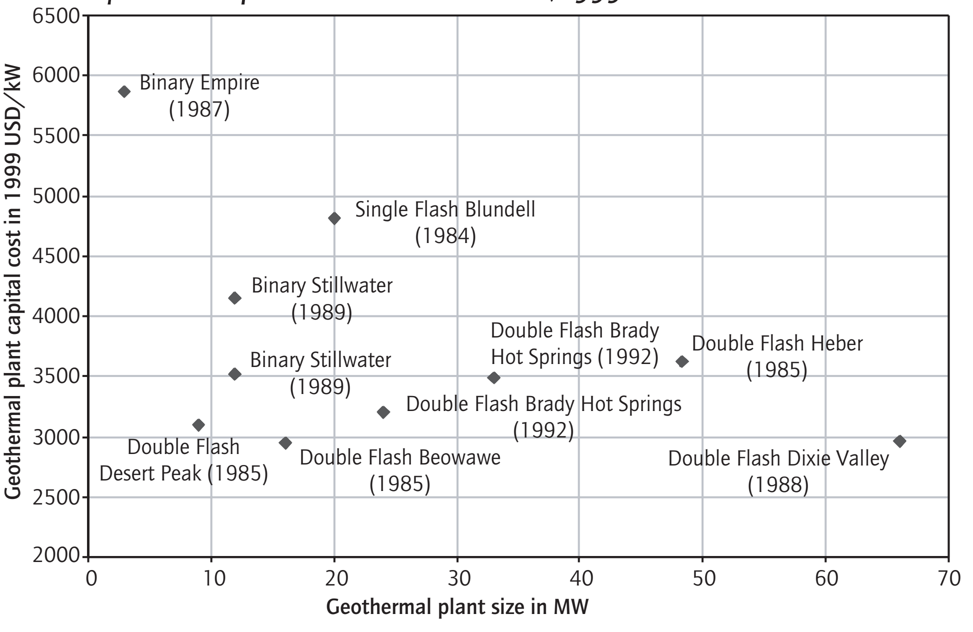
Because costs are closely related to the characteristics of the local resource system and reservoir, costs and cost reductions cannot be easily assessed on a general level.

Binary-cycle power plants or Hot Dry Rock systems are more expensive in terms of kWh generated (see Figure 51) than conventional geothermal systems, but these new techniques use resources that would have been uneconomical in the past. Binary-cycle power plants are suitable for small-scale applications and lower-temperature resources.

Major contributions can be expected from R&D for new approaches or for improving conventional approaches and smaller modular units will allow economies of scale on the manufacturing level. Within the power plant, considerable economies of scale occur on the level of component and plant size.

Figure 51

Capital Costs for US Geothermal Plants, 1999



Source: Data from Di Pippo.

The following are areas where R&D can improve the techno-economic performance of geothermal power:

- **Plant refurbishment** can increase the plant's efficiency and availability, taking account of the thermodynamic characteristics of the geothermal fluid for any given site.
- **Generating electricity** from low-to-medium temperature geothermal fluids and from the waste hot water coming from the separators in water-dominated geothermal fields has made considerable progress. By selecting suitable secondary fluids, binary systems have recently been designed to utilise geothermal fluids temperatures of 85/90°C to 175°C. For example, one company is exploring the use of the Kalina cycle, a binary cycle that uses a mixture of ammonia and water as the working fluid. This cycle has the potential to extract one-third more energy from the geothermal fluid than a conventional cycle.
- **More automation** to decrease labour costs for O&M.
- **Reservoir management** aimed at increasing the production rate and lifetime will thus improve the sustainability of the resource (e.g. injection, re-injection, well stimulation). An example is the reservoir depletion problem at The Geysers (USA) where reclaimed wastewater is transported from several communities and injected into the reservoir. This approach not only prolongs the life of the geothermal resource by slowing the loss of the reservoir volume over time, but also provides a solution to wastewater disposal problems.
- **Expansion of the explored zone**, which in general is less risky than exploring a brand-new area.
- **Development of more accurate and lower-cost methods for finding and mapping geothermal resources.** Recent accomplishments include instrumentation that can operate in hotter environments, and more accurate field survey procedures. Before drawing up a geothermal exploration programme, all existing geological, geophysical and geochemical data should be collected and integrated with any data available from previous studies on water, mineral and oil resources in the study area and adjacent areas. This information frequently plays an important role in defining the objectives of the geothermal exploration programme and leads to a significant reduction in costs and less financial risk for project development. In general, only a small portion of an area's geothermal potential has been explored and exploited.

- **Drilling:** The cost of drilling a well can be a significant portion of the overall plant cost. Drilling research has focused on means to reduce the costs of drilling through hard rock in high-temperature, corrosive environments. Recent accomplishments include the development of slim-hole drilling that reduces costs by up to 50%, and improved drilling control and tools.
- **Enhanced geothermal systems:** R&D is expected to bring about new and improved processes and designs like Hot Dry Rock (HDR), currently being tested in several areas.

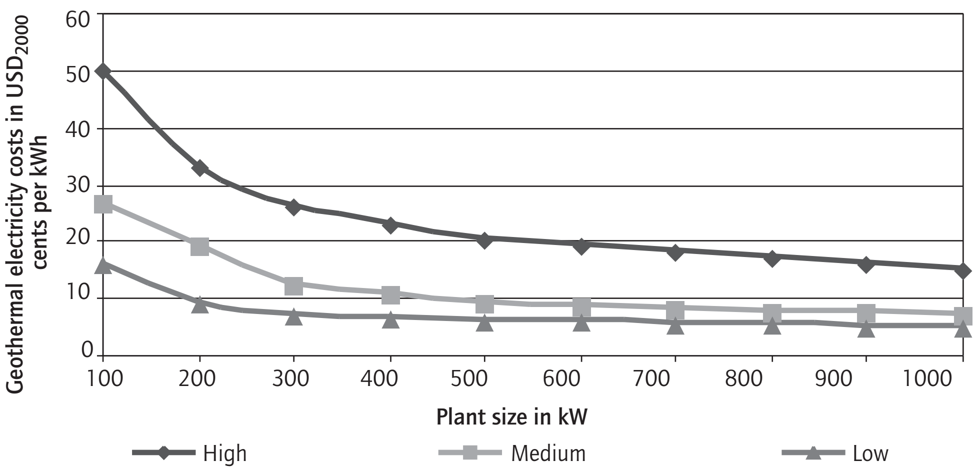
Grouping generation plants can result in considerable economies of scale. By bundling efforts, project costs per geothermal power plant can be lowered.

For smaller plant units under 5 MW, and especially below 1 MW (see Figure 52), the cost per kW goes up significantly because of a loss in economies of scale (equipment, component size), and because the fixed costs associated with exploring a site and drilling wells are divided by a smaller number of kilowatts. In addition, some minimum fixed O&M costs associated with operating a plant become significant when divided by a smaller plant capacity.

However, small-scale plants can be built in a factory as skid-mounted units and shipped anywhere in the world. Thus, quantity (manufacturing volume) and quality can be increased and costs lowered.

Figure 52

Generation Costs in Relation to Plant Size in USD cents /kWh (in USD $_{2000}$)



Sources: Vimmerstedt and Entingh.

Market Opportunities

Market Potential

Like the energy of the sun, the energy within the earth is immense and has a lifetime measured in billions of years. However, geothermal energy is accessible in limited areas, and unlike the use of sunlight, tapping into local sources of the earth's heat can result in a temporary decrease in the amount of energy locally available. Even with re-injection of the geothermal fluid, the heat content of the reservoir gradually declines. The recovery period for a geothermal resource depends on how it is used. Resources tapped for electricity generation could provide energy for 50 years or more if properly managed. Typically, the plant equipment reaches the end of its useful life before the resource is depleted. Continuous long-term use of geothermal energy for electricity generation would require the periodic construction of new plants at new sites, while previously-used reservoirs recover.

About 0.2% of the surface in Europe has "very good suitability" for geothermal power (Iceland, Azores, Canaries, pre-Apennine belt of Tuscany and Latium, Aeolian islands, Aegean islands and Western Anatolia). About 2.5% presents "good suitability" (areas on the border of the above-mentioned regions, Massif Central, Rhine Graben, Campidano Graben, Pannonian Basin and the island of Lesbos). In these areas, several GW of geothermal power capacity could be installed in the coming decades and support rising power demand.

The geothermal potential capacity over the next 30 years is more than ten times the capacity currently installed. The U.S. Geothermal Energy Association predicts for several world regions the potential capacity for the next 30 years as 22 GW in Central America, 10 GW in East Africa, 16 GW in Indonesia, 8 GW in the Philippines and 23 GW in the U.S. World potential capacity for geothermal power generation is estimated at 85 GW over the next 30 years, about 10 times current installed capacity.

Technology Factors

Geothermal power plants supply more than 10% of the national power in some countries, in those countries where geothermal resources are abundant and competitive. In addition to these large-scale, cost competitive applications, small-scale applications are approaching the cost range where geothermal can compete for special applications and/or power supply in remote areas. In these areas, geothermal plants might provide base-load electricity. Following are areas for market growth:

Large-scale applications (usually > 5 MW): As shown above, geothermal power can play a particularly significant role in the energy balance of some areas in developing countries (with rapidly increasing energy demand) because geothermal is competitive with conventional alternatives. Additionally there is a large technical potential in some areas in the industrialised world. Several dozen megawatts will be installed every year in Europe and the US over the next decades, due to energy security or environmental benefits of geothermal power.

Developing countries and remote areas: Opportunities for small geothermal projects exist in many areas of the developing world, including Latin America, the Caribbean, Indonesia and the Philippines as outlined by Vimmerstedt. Small-scale geothermal power plants (< 5 MW) could supply electricity in remote areas. However, governmental support is needed for small geothermal projects because they face special financial and operational challenges, for instance, relatively high project finance costs and difficulty in establishing and supporting an operation and maintenance infrastructure for small plants in remote areas. These difficulties may be mitigated by bundling small projects. The widespread use of small geothermal units demonstrates the technological feasibility of small systems, but does not demonstrate operational or economic feasibility for remote applications.

Small-scale plants (usually < 5 MW, sometimes < 1 MW): Despite their higher energy costs, small-scale plants offer a number of potential advantages. Skid-mounted, modular units can be built in a factory and shipped anywhere in the world. A plant owner can start with a small investment and add modules as needed. Small plants can be designed to operate automatically in order to reduce O&M costs. Small plants can become attractive in regions where low-cost shallow wells are possible and where the exit brine from the plant can be used for direct-heating applications. The advantage of small mobile plants is most evident for areas without ready access to conventional fuels or where alternative systems are costly. For example, a 300-kW geothermal binary plant at Fang, Thailand, supplies power at 6.3 to 8.6 USD cents per kWh, as reported by Lund, compared to the alternative of diesel-generated power at 22 to 25 USD cents per kW. Another opportunity is for small communities that may be near a thermal reservoir, but are by-passed by high-voltage transmission lines. The expense involved in serving these communities is prohibitive, since the step-down transformers needed to tap electricity from high-voltage lines cost some USD 675,000 each, including installation, and the simplest form of local distribution of electricity, at 11 kV using wooden poles, costs a minimum of USD 20,000 per kilometre, as reported by Aumento.

Mini-grid applications: Small plants may be especially well-suited to mini-grid applications in developing nations where the competing generation is by imported diesel fuel, as mentioned above.

The multi-purpose approach was originally used in the earliest geothermal power plants in Larderello which extracted boric acid from the waters. Combining geothermal power production with other processes may provide sufficient financial incentives to make geothermal plants economic. The recovery of minerals and metals from geothermal brine can add value to geothermal power projects. For example, a new plant at Salton Sea in California extracts zinc from the heated brine that is brought to the surface to generate electric power.

Illustration: Geothermal Power in Mexico

Geothermal development in Mexico is a joint effort between the Mexican Electric Company (CFE) and the nation's Electrical Research Institute (IIE). Substantial progress has been made over this period in the development and application of the geothermal resource. Around 550 geothermal zones have been identified in the whole national territory of around two million square kilometers, where over 1400 geothermal points can be seen in 27 out of the 31 states in the country.

Three geothermal fields are currently being commercially exploited: Cerro Prieto in Baja California, Los Azufres in Michoacán and Los Humeros in Puebla. Total installed capacity for electricity generation is 758 MWe, which represents around 2.3 % of the total generating capacity in Mexico. Estimates by the national electric utility (CFE) set proven high temperature (temperature higher than 150°C) hydrothermal reserves at around 2000 MWe. Reserves with good probability are estimated at 4000 MWe, while possible reserves are in the range of 6,000 MWe.

Exploitation of high temperature geothermal resources offers Mexico a number of benefits, including generating costs in the range of 0.04-0.05 USD/kw, and plant factors above 80%. Non-electrical applications are also consideration to improve project profitability.

Technology Development

Geothermal power technology has been steadily improving. Although no clear trend toward lower energy costs can be shown for the plants producing electricity in the low-cost range of USD 0.02 per kWh, new approaches are helping utilise resources that would have been uneconomic in the past. This is true for both the power generation plant and the field development.

Drawing an experience curve for the whole geothermal power sector is difficult, not only because of the many site-specific features having an impact on the technology system, but also because of poor data availability. Despite the fact that Larderello has the most experience with geothermal power plants, no reliable, installation cost data are available covering the long term.

Geothermal technology development, related cost reductions and improved performance depend on R&D and on a supportive market framework. In the late 1970s and 1980s, geothermal development was given special stimulus in the US where DOE funding for geothermal research and development was for some time over USD 1995 100 million per year. In addition, the Public Utility Regulatory Policies Act (PURPA) mandated the purchase of electricity from facilities meeting certain technical standards regarding energy source and efficiency. PURPA also exempted qualifying facilities from both state and federal regulation under the Federal Power Act and the Public Utility Holding Company Act. Furthermore, California's Standard Offer Contract system for PURPA-qualifying facilities provided renewable electric energy systems with a relatively firm and stable market, allowing the financing of capital-intensive geothermal energy facilities. When R&D funding decreased and programmes were changed or halted, geothermal progress slowed. Although the US is still the world leader in geothermal power, project development stalled because geothermal could not compete with conventional power, which became cheaper when fossil fuel prices declined.

Future technology development depends greatly on enhanced exploitation of new resources and applications. R&D concerning the Kalina cycle and HDR can help reduce costs of the binary-cycle power plant and exploit additional resources. Up-scaling of the plant and the manufacturing process can also help. However, the lowest energy costs already achieved are not likely to drop dramatically in the future – only incremental improvements are foreseen.

Market Growth Factors

Geothermal power might be expected to grow at a steady pace between 5% and 10% annually, thanks to competitive and attractive applications (mainly large-scale in energy-driven markets and small-scale in remote areas). Assuming an average growth rate of 6%, global cumulative geothermal power capacity would reach 14 GW in 2010.

Based on country update papers for the World Geothermal Congresses held in 2000 and 2003 worldwide geothermal capacity could be projected to reach 20.7 GW in 2020 (Lund). In another assessment, the combined efforts of the US DOE and industry could result in 15 GW of new capacity installed in the US within the next decade, assuming that a cost level of USD 0.03 per kWh can be achieved. For Europe, forecasts for installed capacity range from 1.5 to 2 GW by 2010 and from 2 to 3 GW by 2020. These figures are optimistic and can only become reality if leading countries commit themselves to support geothermal power. The regions of Asia and the Americas are likely to contribute most to the development of geothermal capacity.

Table 41

Cost-Reduction Opportunities for Geothermal Power (%)

	R&D	Economy of scale I (components size)	Economy of scale II (manufacturing volume)	Economy of scale III (plant size)
Geothermal power	Up to 10	Up to 5	Up to 5	Up to 10

Source: NET Ltd., Switzerland. Data shown in % within a decade based on expected technology learning and market growth.

Table 42

Cost Figures for Geothermal Power

Current investment costs in USD per kW	• Low investment costs: 1,200 • High investment costs: 5,000
Expected investment costs in USD per kW in 2010	• Low investment costs: 1,000 • High investment costs: 3,500
Current generation costs in USD cents per kWh	• Low cost generation: 2-5 • High cost generation: 6-12
Expected generation costs in USD cents per kWh in 2010	• Low cost generation: 2-3 • High cost generation: 5-10

Source: NET Ltd., Switzerland.

Table 43

Key Factors for Geothermal Power

Factor	Fact
Factors influencing energy output	• Enthalpy (temperature gradient)
Limiting factors	• Site availability
Capacity installed in 2002 in GW	• 8.5 GW
Potential in 2010 in GW	• 14 GW
Future potential beyond term year given	• Moderate to good
Rule of thumb for conversion ratio* (installed power to electric output)	• 1 kW -> 6,100 kWh

** Based on global capacity of around 8 GWp and electricity generation of 49 TWh in 2000.*
Source: NET Ltd., Switzerland.

Issues for Further Progress

- **Technical Issues**

Exploration Techniques

Exploration can be improved by the use of enhanced geophysical methods, integrated modelling, slim-hole drilling for reservoir characterisation and high-temperature tracer technology.

Resource Assessment

Resource knowledge should be updated, using new, harmonised assessment techniques, computational methods and site selection tools. Constraints such as land-use restrictions, other relevant legislation and market availability should be identified.

Field Development

Drilling costs can be reduced by the use of new techniques and high-temperature tools.

Reservoir Development Techniques

Reservoir development can be improved through the use of submersible pumps and new methods to limit scaling and corrosion of equipment.

Power Generation Technology

Combined cycles can be integrated in order to enhance utilisation of the intense heat associated with electricity production. New power cycles should be developed or existing ones optimised in order to improve efficiency and reliability, with special focus on small units for low-temperature cycles.

Environment

Methods to mitigate environmental impact should be developed and applied in order to increase local public acceptance and improve the eco-balance.

System

Perhaps the most challenging technical problem is the corrosion and scaling of those parts of the system that come into direct contact with the subterranean medium. New materials and techniques must be developed to lower the cost of replacing corroded parts. Hot Dry Rock/Enhanced Geothermal System technology should be intensively researched and tested, especially the aspects of artificial fracturation, reservoir monitoring, and circulation loop.

• Non-technical Issues

A number of non-technical issues will also impact future market development. Information on geothermal energy should be disseminated at various levels, from decision makers to potential consumers and the general public. Local markets should be identified in order to take advantage of opportunities. Import/export rules for equipment need to take into account the fact that geothermal equipment is servicing renewable energy. Codes and standards should be developed with respect to grid access and connection. Local restrictions concerning permits and land use could be reduced by clear rules.

Local geothermal resource potential for power generation and for direct uses should be assessed. Policies, laws and regulations should be developed to allow investment in the development of indigenous geothermal resources.

Continued government-funded research and close collaboration with industry in exploration of reservoirs, drilling and energy conversion are needed to further lower the cost of geothermal power production, although in the best locations geothermal is now competitive with conventional energy.

WIND POWER

A Brief History of Wind Power

The use of wind energy dates back many centuries, perhaps even thousands of years. In many cultures, windmills were built for milling grain and pumping water. Some windmills became typical of the cultural landscape in many areas especially in Europe. The step from mechanical to electrical use of wind energy was made in the USA. In 1888, Charles F. Brush developed an automatically operating wind machine performing a rated power of 12 kW direct current. The rotor had a diameter of 17 metres and 144 blades made of cedar wood. Small-scale stand-alone systems continued to be the main focus of wind power applications for another five decades. The first AC turbine was built in the 1930s in the USA. At first, further use of wind power suffered from the less expensive grid power but interest in wind energy grew through energy emergencies such as World War II and the oil crisis in the early 1970s. The development of modern wind power machines has been led by Denmark, Germany, the Netherlands, Spain, and the USA. Through these developments, wind power has become an important electricity option for large-scale on-grid use.

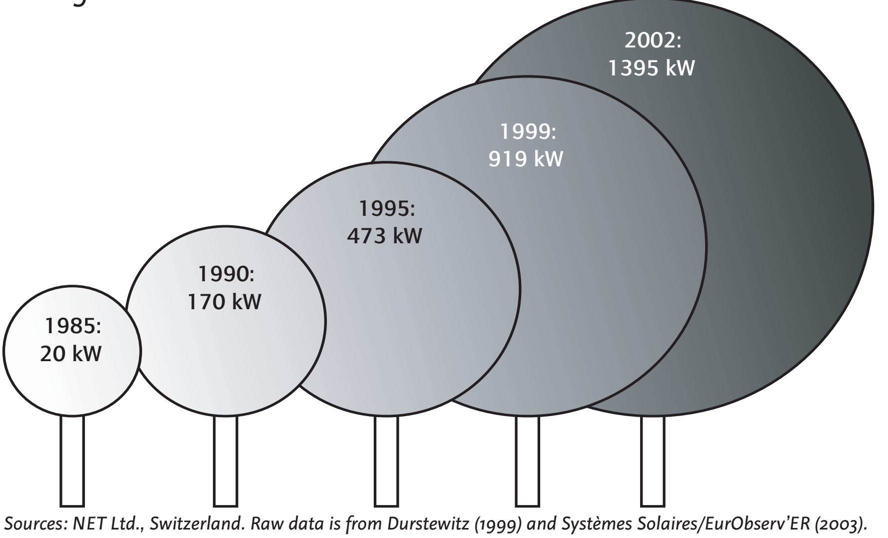
Technology Status

The main components of a wind turbine are the rotor, generator, directional system, protection system and tower. Wind spins the rotor blades, driving the turbine generator. Sometimes gearing is used to increase the rotation speed for electricity generation. The generator transforms the mechanical energy from the rotating blades into electricity. Electricity is then transferred to the grid or a storage system. Generator designs vary according to the system and wind regime. A directional system enables horizontal axis machines to swing into the wind: a tail assembly is often used for small machines, whereas a “servo mechanism” orients large machines to the direction of maximum power. Modern wind turbines are usually equipped with a protection system (variable orientation of blades, mechanical brakes, shut-down mechanisms) to prevent damage during excessive wind loads. The tower raises the turbines well above the ground in order to capture wind with higher speed and less turbulent currents.

Commercial and technological development has been closely related to turbine size (see Figure 53). From ten metres in diameter (typically with 22 kW to 35 kW of installed power) in the mid-1970s, wind turbines have grown to diameters of 80 metres and more (with multi-MW installed power). Technology development has resulted, furthermore, in variable pitch (as opposed to fixed blades), direct drives (as opposed to classical drive trains), variable-speed conversion systems, power electronics, better materials and better ratio of weight of materials to capacity installed. One major trend is toward increasing rotor diameter in order to develop turbines and wind farms for offshore applications. The other major trend is toward larger markets for small-sized systems, *e.g.* in developing countries. The use of small grid-connected machines (10 kW) in the built environment and farms in the US is relatively new.

Figure 53

Average Turbine Size at Market Introduction



Sources: NET Ltd., Switzerland. Raw data is from Durstewitz (1999) and Systèmes Solaires/EurObserv'ER (2003).

Costs

Investment Costs

Costs of wind turbines and plants depend on the system (components and size) and the site. Typical turnkey installation costs* are around USD 400 per m² of swept area or USD 850 to 950 per kW for on-land wind turbines and farms, of

*. There is some difference of opinion about the correct way to benchmark energy technologies. For wind turbines, for instance: *price per square meter of rotor area* or *price per kWh produced are both used.*

Table 44

Commercial and Technological Development of Wind Turbine Technology in the Last Three Decades

Phase	Manufacturing	Research	Codes and Standards
Before 1985 Rotor diameter < 15 m	Pioneering and conceptualisation phase with small enterprises and companies from different backgrounds (shipbuilding, gearboxes, agriculture machinery, aerospace, etc.) developing and producing turbines based on simple design rules. Large firms contracted for developing MW turbines failed because of non-viability of this size machine at this early date.	Focus mainly on theoretical problems and technology, e.g. horizontal and vertical axes, size between 5 kW and 3 MW, different numbers of blades (1 to 4)	Absence of international standards, quality control, detailed load analyses, grid quality requirements
1985 to 1989 Rotor diameter 15-30 m	Technology maturing (California boom, then collapse) Production of small series Many start-up enterprises and restructuring partly concurrent with California boom and collapse	First design codes and national standards	Basis for all current design codes laid in this period
1989 to 1994 Rotor diameter 30-50 m	Mass production of the successful 500/600-kW turbine class Industry reconstructed	Programmes for developing the 500 kW to 1 MW turbine class	Codes and standards established. Several international benchmarks
Since 1994 Diameter rotor greater than 50 m	Acceleration towards multi-MW classes of turbines - entirely market driven Steady growth in industry	Focus on weak spots in design knowledge, R&D on new topics like short-term wind forecasting	Design codes essentially unchanged Recent codes for short-term wind power prediction

Sources: EUREC Agency/Beurskens, Neij/EXTOOL (2003) and Johnson.

which USD 600 to 800 per kW are for the turbine, including the tower but excluding the transformer. Project preparation costs, excluding costs for grid reinforcement and long-distance power transmission lines, can average 1.25 times the ex-factory costs, as experienced with 600-kW machines in Denmark.

Table 45

Average Investment Costs of an On-land Wind Turbine (600 kW)

	2000/kW
Machine frame, including ring	52.7
Blades	123.8
Hub, including main shaft	56.3
Gear, including clutch	156.0
Generator/controller	85.0
Tower, including painting	112.5
Hydraulics, including hoses	22.5
Yaw gear	16.9
Nacelle cover	32.2
Insulation/cables, etc.	26.0
Estimated assembly cost	22.5
Total machine cost	**715**
Civil engineering infrastructure and grid connection	185
Total investment cost	**900**

Source: DRKW.

Investment costs differ considerably between on-land and offshore applications in both relative and absolute terms. For offshore installations, the foundation amounts to one-third (or more) of turbine costs. Typical turnkey installation costs are now in the range of USD 1,100–2,000 per kW for offshore wind turbines and farms, i.e. 35% to 100% higher than for on-land installations. The investment costs for the Middelgrunden offshore wind farm in Denmark (see Table 46) were € 1,233 per kW, but costs are often higher due to construction and interconnection issues. The relative investment costs for offshore and on-land wind turbines also differ. For on-land, turbines account for 75-80% of the total investment, with the remaining 20% to 25% related to civil engineering, infrastructure and grid connection. In the case of the Middelgrunden wind farm, turbines accounted for 55% of the total investment, and foundations accounted for 19%.

Table 46

Investment Costs of Middelgrunden Offshore Wind Farm

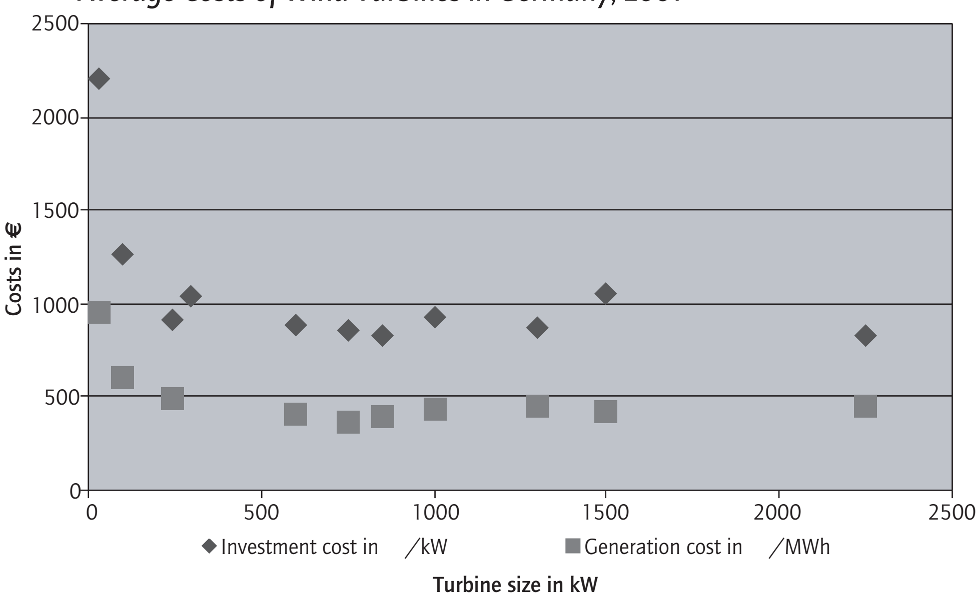
Component	M	/kW	%
Turbines	27.0	675	55
Foundations	9.5	238	19
Internal grid	4.6	115	9
External grid	4.1	103	8.5
Others	4.1	103	8.5
Total	**49.3**	**1,234**	**100**

Source: CADDETre.

Turbine size is a key factor. A size effect can easily be detected in the 100-kW turbine class. In the MW class, no clear trend exists due to, among other factors, the higher development costs for new and better turbines that can yield higher electrical output in specific applications (see Figure 54).

Figure 54

Average Costs of Wind Turbines in Germany, 2001



Note: Based on list prices of turbines, excluding installation/project costs, divided by their annual electricity output; average wind speed 5.5 m/s at hub height of 30 m.

Sources: Junginger, based on data from BWE.

Generation Costs

Generating capacity is primarily determined by the rotor-swept area and the local wind speed (regime), not by installed power. The installed power should be matched to the wind speed and rotor-swept area in order to achieve optimum energy output and the best economy. Machines with the lowest cost per unit of installed power are not necessarily the most economic ones for a particular site. As a rule of thumb, the annual energy output, of modern and properly matched wind turbines is about $e = 3.2 \times V^3 \times AV$ (where V is the annual average wind speed (m/s) at hub height and A is the rotor-swept area in m^2). Doubling the wind speed means roughly an eight-fold higher energy output due to the cubic relation between wind speed and wind power. O&M costs for modern turbines can be up to half a USD cent per kWh. For wind turbines located on difficult terrain, such as offshore or in mountainous regions, this cost is likely to be higher. Availability, defined as the capability to operate when the wind speed is higher than the wind turbine's cut-in wind speed and lower than its cut-out speed, is typically higher than 98% for modern machines.

Based on system investment needed and electrical output yielded annually, generation costs can be given for a range of applications (see Figure 55). Very low generation costs (slightly above 3.5 USD cents per kWh) occur with installations characterised by low investment costs (around USD 800) and high energy output (over 2,000 kWh per kW per year). These installations are found onshore, with excellent accessibility and wind regime. The economics are generally less favourable for inland installations with lower average wind speed and for offshore installations with higher investment costs. As general economic indicators, power generation costs are USD cents 4 to 7 per kWh on land and USD cents 7 to 12 per kWh offshore. In the best locations, wind power can cost less than USD cents 3 per kWh.

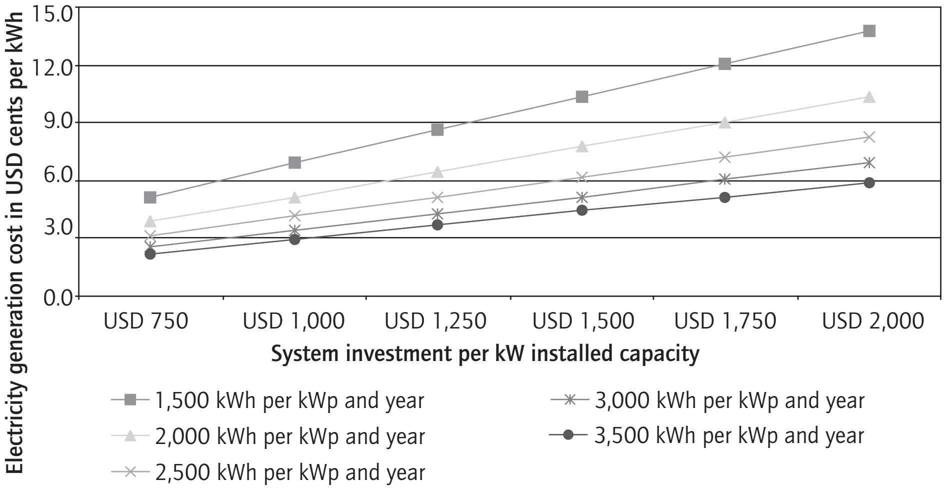
The best cost-competitiveness is in areas with strong wind regimes and where development and installation costs are low. Generation costs are below USD cents 4 per kWh in many coastal and some inland areas with intense but regular wind regimes and good accessibility for plant construction and grid connection.

Industry

The commercial development of grid-connected wind generators started after the oil crisis in the mid-1970s in countries like Denmark, the Netherlands and the US. In the early 1980s, most commercial wind turbines were assembled using a number of standard components such as gearboxes, generators, hydraulic

Figure 55

Approximated Generation Costs for Wind Power



Note: Based on system investment needed and electrical output yielded annually. O&M costs are assumed to be 4% of system investment. Amortisation period is 15 years, and the discount rate is 6%.
Source: NET Ltd., Switzerland.

motors for yaw systems, standard bearings for the main shaft and yaw rim, etc. Only blades and control systems were specially tailored for the wind turbine industry. With increased market volume, more specialised suppliers, including larger companies, are providing tailored components.

Countries with a large installed wind turbine capacity, e.g. Denmark, Germany and Spain, which currently account for 19 of the 30 GW installed wind capacity in the world, also account for most of the world's largest wind turbine manufacturers. The seven biggest manufacturers had a market share of 86% in 2001 with a revenue of € 4.8 billion.

Danish and German wind turbine manufacturers export relatively high shares of their total output. In order to minimise transport costs, more and more turbines are being manufactured by subsidiaries of European companies in other countries. Most of the leading manufacturers of large wind turbines are developing systems for offshore applications.

The top three suppliers for different wind energy segments (<750 kW, 750 kW to 1500 kW, > 1500 kW) are given in the Table 48.

Table 47

Top Ten Suppliers, 2001

Company	Country	MW sold	Market share	Employment
Vestas	Denmark	1630	23.3 %	5,500
Enercon	Germany	989	14.1 %	4,100
Neg Micon	Denmark	875	12.5 %	1,805
GE Wind Energy	USA	861	12.3 %	1,500
Gamesa	Spain	649	9.3 %	1,114
Bonus	Denmark	593	8.5 %	500
Nordex	Germany	461	6.6 %	725
Made	Spain	191	2.7 %	n.a.
Mitsubishi	Japan	178	2.5 %	n.a.
REpower	Germany	133	1.9 %	300

Source: Systèmes Solaires/EurObserv'ER.

Table 48

Top Three Suppliers for Different Wind Energy Segments, 2001

Position	Small-scale turbine class < 750 kW	Medium-scale turbine class 750 kW to 1,500 kW	Large-scale turbine class > 1,500 kW
1	Vestas	GE Wind Energy	Enercon
2	Gamesa	Neg-Micon	Vestas
3	Enercon	Bonus	Bonus

Sources: Systèmes Solaires/EurObserv'ER.

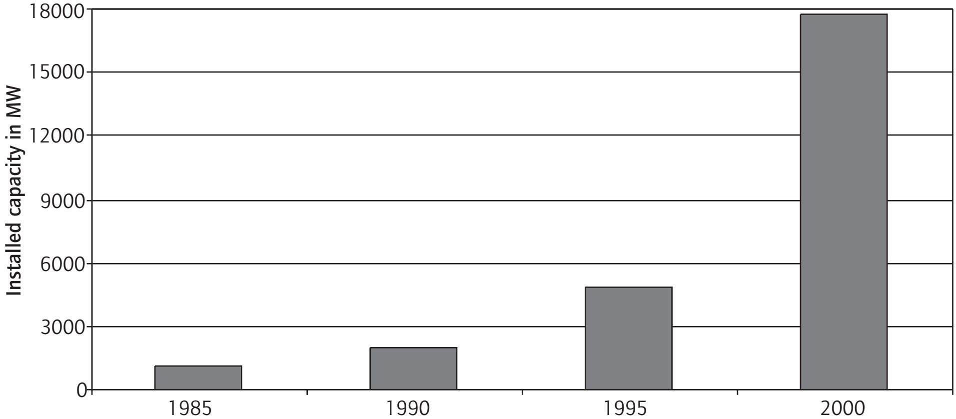
Two distinct trends can be observed. First, the manufacturing industry concentration is driven by economies of scale in turbine manufacturing. Second is the advent of new suppliers in emerging wind energy countries whose governments combine energy policy with industrial policy objectives (Spain, India, Japan).

Market

The installed capacity of wind energy in Europe has increased by a factor of 30 in the last decade (see Figure 56). Europe is a forerunner in terms of technology, industry development and market deployment. The global installed capacity of wind energy technology at the end of 2002 has reached over 30 GW. Installed wind power is distributed very unevenly around the world - 78% of total installed capacity is in only four countries: Germany, Spain, the US and Denmark (see Table 49). Although Europe has taken the lead with strong R&D and price incentive schemes in support of wind investments, other countries such as the US, China and India have enormous wind energy potential and are working hard to establish industries to exploit them.

Figure 56

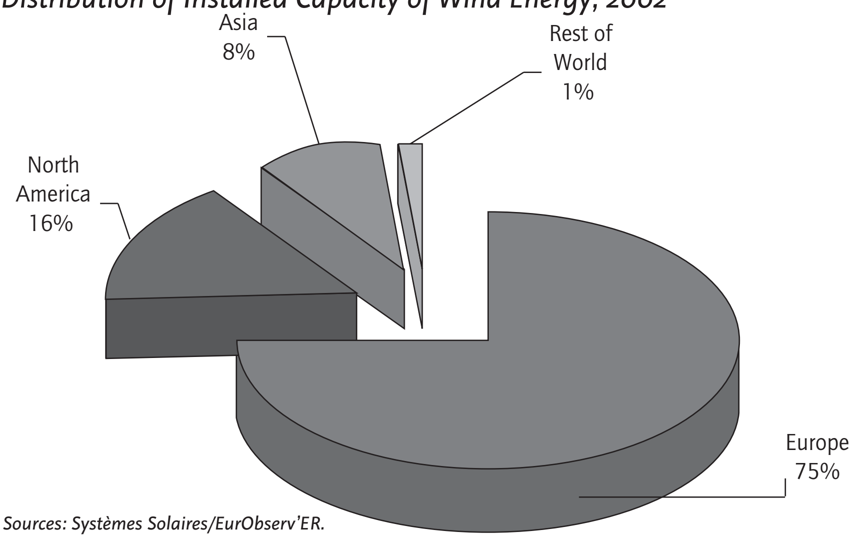
Worldwide Development of Wind Power, 1985-2000



Sources: Systèmes Solaires/EurObserv'ER.

Figure 57

Distribution of Installed Capacity of Wind Energy, 2002



Sources: Systèmes Solaires/EurObserv'ER.

Table 49

Installed Capacity (in MW) of Wind Energy, 2002

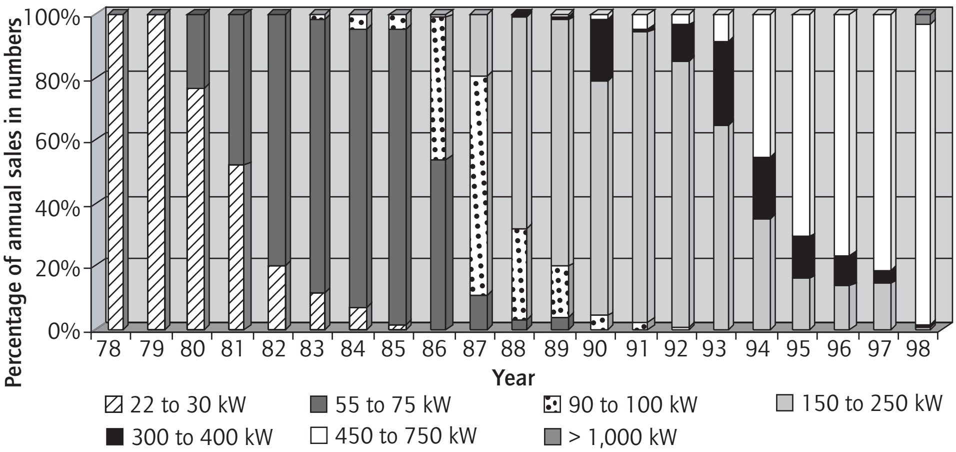
Europe		**22,558**
	Germany	12,001
	Spain	4,144
	Denmark	2,889
	Italy	785
	The Netherlands	677
	UK	562
	Sweden	310
	Greece	276
	Rest of Europe	914
North America		**4,929**
	USA	4,708
	Canada	221
Asia		**2,466**
	India	1,702
	China	399
	Japan	351
	Rest of Asia	14
Rest of World		**426**
Total		**30,379**

Source: Systèmes Solaires/EurObserv'ER.

Until the mid 1980s, wind turbine size was typically less than 100 kW, then in the range of a few hundred kilowatts up until the mid 1990s, when turbine sizes began to range from 0.5-1.5 MW (see Figure 58). Such large scale turbines are often used by on-land wind farm operators and owners of individual, mostly grid-connected wind turbines. In countries with less developed transport and power transmission and distribution infrastructure, this size class remains, or is becoming, dominant. In Germany, average wind turbine size reached 1.4 MW in 2002 and this large-scale turbine size class is becoming very competitive. Virtually all of the capacity is grid-connected. A relatively recent phenomenon in the segment of the smallest turbines is the so-called urban turbine.

Figure 58

Market Share of Seven Generations of Wind Turbine Technology



Source: Danish Energy Agency.

Wind turbines smaller than 500 kW are commonly used for off-grid applications. Especially, but not exclusively, in developing countries, applications for the smallest capacity turbines (typically < 50 kW) include not only power supply for off-grid users but also dedicated services such as mechanical water pumping (still the most common type of wind system application), desalinisation and battery charging.

Offshore wind power generation is taking off in Europe. As the best on-land locations are becoming more difficult to develop, coastal countries are beginning to investigate and exploit near-shore and offshore resources. Denmark, the Netherlands, Sweden and the UK have already amassed experience with near-shore wind farms. New offshore wind farms are expected to have turbines exceeding 1.5 MW. New capacities totalling several GW may be installed in Germany, the UK, Ireland, Denmark, Canada, Belgium and other countries in coming years.

• Environment

For many years, wind energy was considered environmentally sound.

But recently, major social objections (NIMBY – Not In My Back Yard) and landuse concerns related to operation and siting of turbines have been raised. Social acceptance is one of the limiting factors of wind's potential growth.

On the positive side, no direct atmospheric emissions are released during the operation of wind turbines. The emissions during the production, transport and decommissioning of a wind turbine depend mainly on the type of primary energy used to produce the steel, copper, aluminium, plastics, etc. used to construct the turbine. The energy payback time is comparatively short – usually only three to six months. Electricity from wind turbines has very low external or social costs. Almost all parts of a modern wind turbine can be recycled. Wind energy density is low and thus harvesting significant amounts of energy involves large areas of land. As a rule of thumb, wind farms require 0.06 to 0.08 km^2/MW (12 – 16 MW/km^2). However, the actual structures occupy only about 1% of the land on which the turbines are built and the area can still be used for other purposes, such as agriculture and livestock. In most countries, wind power developers are obliged to minimise any disturbance of vegetation (possibly leading to erosion) during the construction of wind farms and their infrastructure in sensitive areas. The International Electrical Committee (IEC) has issued an international standard on wind turbine safety and the wind industry has a good safety profile, to date.

Some negative impacts also need to be addressed. Acoustic emissions from wind turbines have both a mechanical and an aero-acoustic component, both of which are a function of wind speed. Reducing noise originating from mechanical components is a straightforward engineering exercise, whereas reducing aero-acoustic noise is a rather difficult process of trial-and-error. In modern wind turbines, mechanical noise rarely causes problems. The acoustic-source noise from wind turbines needs attention because it is one of the main obstacles to siting wind turbines close to inhabited areas. The turbines' visual impact also limits social acceptance. Wind turbines may disturb the habits of birds and other animals, mainly in coastal breeding and resting sites close to migration routes. Submarine installation works have a considerable impact on the environment during construction, but probably not in the long term. Furthermore, wind turbines may affect the propagation of electromagnetic waves from navigation and telecommunication systems. This possibility requires further study, but preliminary experience suggests that the problem can be managed.

Prospects for Wind Power

- **Cost Reduction Opportunities**

Since the appearance of the first commercial grid-connected wind turbines (typically 22 kW to 35 kW) at the end of the 1970s, the generating cost of wind electricity has been reduced roughly by a factor of 10. Between 1981 and 1995, the generating cost in Denmark was reduced from DKK 1.1/kWh to DKK

0.4/kWh. Investment cost decreased in Germany by 35% and dropped from € 1,400 per kW in 1990 to € 1,120 per kW in 1999. Significant cost reductions were possible in the early phases during the transition from prototypes to medium-scale production. These reductions slowed during the 1990s after design improvements were implemented. The long experience of the Danish wind industry shows that about 75% of cost reductions in the past were due to design improvements and more efficient manufacturing and about 25% were due to improved siting.

Table 50

Average Capacity of Wind Generators in Three Leading Countries (kW)

Year	Germany	Spain	United States
1995	473	297	327
1996	530	420	511
1997	623	422	707
1998	783	504	723
1999	919	589	720
2000	1,101	648	761
2001	1,281	723	881
2002	1,395	790	1,000

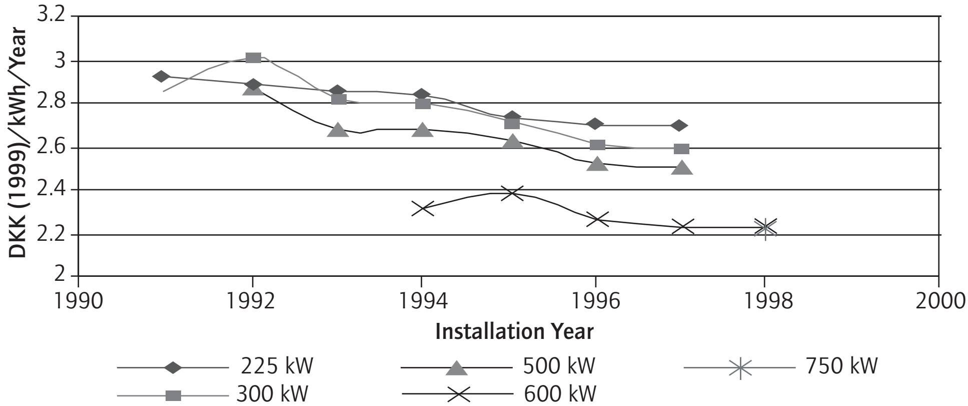
Source: Systèmes Solaires/EurObserv'ER.

The commercial and technological development of wind power is closely related to turbine size. Each generation has been larger than the preceding one, measured in either rated capacity or rotor-swept area. The effect on costs of the installation of larger wind turbines is especially pronounced. Relatively small wind turbines (55 to 75 kW) were overtaken by increasingly larger and more economical turbines, especially the 600 kW and 750 kW size classes. This substitution accounted for a 35% reduction in the specific investment cost of the turbines installed in Denmark between 1990 and 1998. Up-scaling and cost reductions can be achieved by incremental changes and "up-scaled design" on the same platform or by building a new platform with increased capacity, rotor diameter and new technological features. Not surprisingly, the first machines of a new generation can be more expensive per kW of rated capacity but they later become more competitive, thanks to higher electrical output and increased experience and manufacturing volume. Their successful market introduction and learning investments will only happen in an environment of sustained market growth.

Danish data (see Figures 60 and 61) reflect the growing optimum size of turbines and indicate that within a specific class, wind turbines improved their technological performance (*e.g.* with advanced blades). Up-scaling and design improvements are strongly interrelated. Usually, a new generation of turbines is designed conservatively with some extra safety margins.

Figure 59

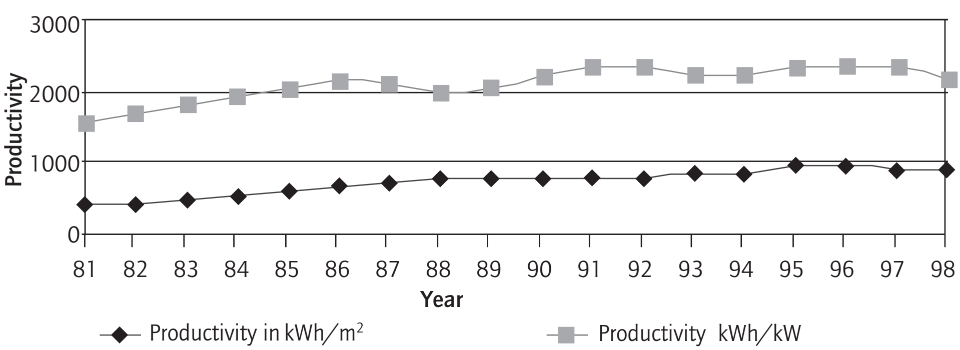
Specific Investment Cost over Time for Different Turbine Size Classes



Source: DEA.

Figure 60

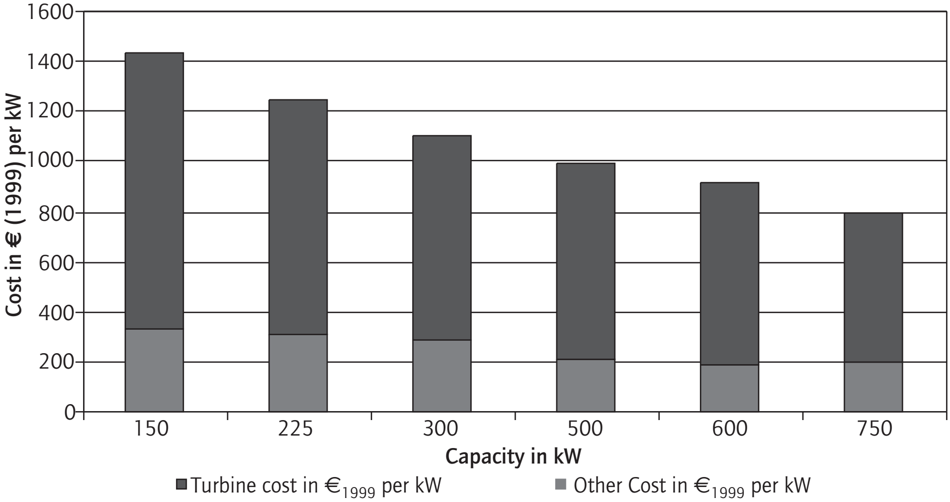
Productivity of Wind Turbines in kWh per m² Rotor-Swept Area and kWh per kW Capacity Installed



Source: DEA.

Figure 61

Specific Investment Cost of Danish Wind Turbines as a Function of Capacity [kW]



Source: DEA.

The following facts illustrate the up-scaling and design improvements world-wide from 1985 to 2000:

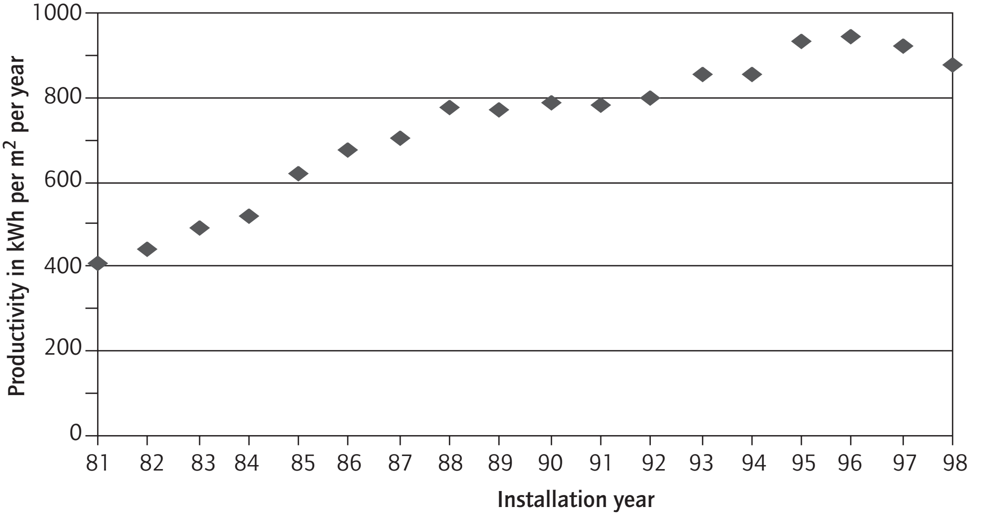
- the average hub height rose from 28 m to 55 m;
- the installed swept area increased from 1.7 m² to 2.5 m² per kW;
- the average installed capacity grew from <150 kW to 980 kW.

The trend towards larger turbines with rotor diameters of more than 90 metres continues. For example, Nordex has developed a 2.3-MW turbine especially for inland sites with medium wind speed, Enercon has installed a 4.5-MW turbine prototype, Neg-Micon offers a 2.75-MW turbine, and GE Wind Energy has just installed a turbine rated at > 3 MW.

R&D activities by government and industry have contributed to major design improvements and increased the techno-economic performance of wind turbines. The overall system efficiency of present commercial wind turbines is close to what is theoretically feasible. Such improvements to overall system efficiency have been achieved by greater aerodynamic efficiency of the rotor blades, the use of high-efficiency electric conversion systems and better matching of the wind turbine rating to the local wind regime.

Figure 62

Development of Energy Output



Source: Energistirelsen; Miljø- og Energiministeriet
Note: per m² Rotor-Swept Area of Danish Wind Turbines.

Ex-factory cost reductions of 15% to 20% can be expected from a combination of the following features in advanced wind turbines:

- Reduction of loads through the use of flexible blades, flexible hubs and variable-speed generator systems. This leads to lower weights and lower machine cost;
- Reduction in the number of components;
- Improved materials featuring higher strength-to-mass ratios and better internal damping.

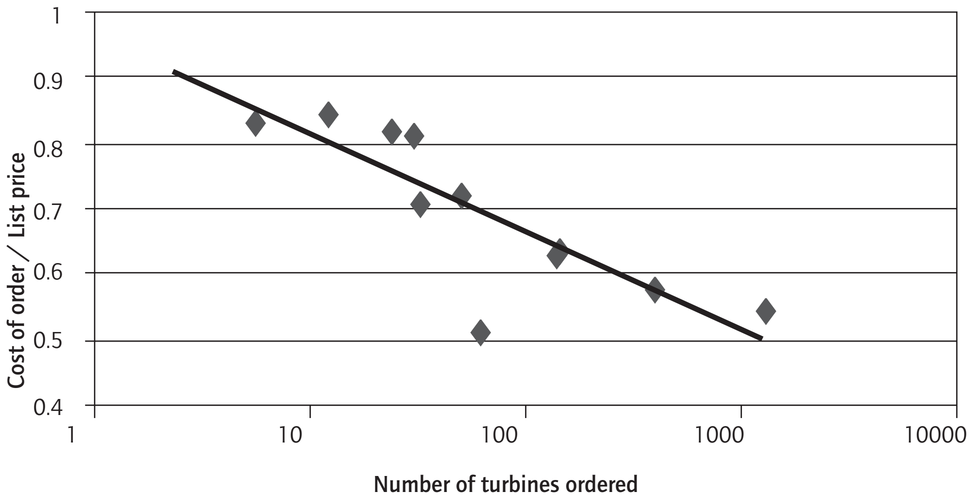
Specific R&D and design improvements are needed for offshore applications to cope with different challenges and to reduce costs, allowing for large-scale use.

Wind energy in Denmark has benefited mainly from the up-scaling of turbines and less from mass production of turbines of a certain size. Mass production will play a small but nonetheless important role in further cost reductions. Mass production has certain constraints: for example, the size of towers can make local production preferable to transport over large distances. On the other hand, economies of scale can be achieved in turbine manufacturing. Furthermore, standardisation of sub-systems to increase the modularity of systems allows for cost reductions in manufacturing and engineering. Examples of potential modular and non-turbine-specific components are inverters, switch cabinets, control systems, sensors and software.

Considerable economies of scale can be achieved by increasing the size of the power generation plant, especially for offshore production. Project preparation costs as a percentage of total costs decreased from 29% to 20% in Denmark from 1989 to 1996 and have averaged 1.25 times the ex-factory cost since then. Wind farms decrease the preparation costs per machine significantly. Furthermore, wind turbine investment costs tend to be lower, due to rebates for greater numbers of machines ordered. An example for Vestas V47 machines is given in Figure 63.

Figure 63

Reduction of Purchase Price for Vestas V47



Source: Junginger.

Market Opportunities

Market Potential

Theoretically, the potential of wind energy is enormous. Suitable areas/sites which may prove economically feasible in the foreseeable future are characterised by higher-than-average wind speed and are depicted on the wind resource maps (See Plates 5 and 6 (Page 101). Favourable wind conditions are mainly found in coastal areas and some regions with mountains or plains.

Some areas that already use wind for a large share of power generation have few suitable sites remaining or face resistance to further expansion from the local population (*e.g.* a few locations in Germany). Considerable uncertainty exists about the penetration levels that can be attained by wind electricity before the intermittent nature of wind energy destabilises the reliability and performance of the grid. This is a major issue confronting the economically feasible potential of wind energy in each country or power grid.

Technology Factors

Depending on market structure, incentive framework and maturity, learning curves for wind energy show progress ratios between 68% and 92%:

- 68% in the USA, 1985-1994;
- 82% in the EU, 1980-1995;
- 92% in Germany, 1990-1998.

The global progress ratio remained fairly constant at 80% from 1980 to 1995, but has slowed since. More recent ratios have ranged from 87% to 94% in several European countries (e.g. Denmark and Germany). The lower learning rates can be attributed to various, often country and segment specific circumstances, for instance:

- maturity of the market;
- reluctance to invest in innovations (e.g. new and bigger turbines) due to uncertain market conditions;
- less suitable sites (*e.g.* more difficult access or lower average wind speed);
- too comfortable feed-in tariffs and high demand that might delay price reductions.

However, other results based on specific installation costs and cumulative global wind capacity show progress ratios of 80% to 85% and corresponding learning rates from 15% to 20%. Wind power is an interesting case for experience curve tool and technology learning, for which the work at IEA EXCETP provides good insight.

Table 51

Cost Reduction Opportunities for Wind Power (%)

	R&D	Economy of scale I (components size)	Economy of scale II (manufacturing volume)	Economy of scale III (plant size)
On-land	up to 10	up to 10	up to 5	up to 10
Offshore	up to 15	up to 10	up to 5	up to 10

Note: Table is in % within a decade based on expected technology learning and market growth.
Source: NET Ltd., Switzerland.

Table 52

Cost Figures for Wind Power

Current investment costs in USD per kW	• Low investment costs: 850 • High investment costs: 1,700
Expected investment costs in USD per kW in 2010	• Low investment costs: 700 • High investment costs: 1,300
Current generation costs in USD cents per kWh	• Low cost generation: 3-5 • High cost generation: 10-12
Expected Generation costs in USD cents per kWh in 2010	• Low cost generation: 2-4 • High cost generation: 6-9

Source: NET Ltd., Switzerland.

Table 53

Key Factors for Wind Power

Factors	Fact
Variable influencing energy output	• Wind speed ($E = 3.2\ V^3$)
Limiting factors	• Site availability • Grid (load) capacity
Capacity installed in 2002 in GW	• 30 GW
Potential in 2010 in GW	• 130 GW
Future potential beyond term year given	• High
Rule of thumb for conversion ratio* (installed power to electric output)	• 1 kW -> 1,500 kWh-2,300 kWh per year

** European average based on 26.8 TWh production and 17.5 GW capacity in 2001 for the lower value (Systèmes Solaires data) and IEA data for the higher value based on production of 57 TWh and capacity of 24.3 GW.*
Source: NET Ltd. Switzerland.

Market Growth Factors

Demand for larger machines is growing for different reasons:

- economies of scale;
- lessened visual impact on the landscape per unit of installed power;
- multi-MW machines are needed to exploit offshore potential.

The 2 to 3 MW power class will probably become established in the coming years assuming generation cost in the USD cents 3-6 range. Experience with these machines will contribute to the optimisation of offshore wind farms with the next generation of turbines between 3 and 5 MW.

Wind energy can be used for both very specific, localised energy services and for bulk power, on-grid production. Provided the wind and site conditions are suitable, applications from autonomous energy supply to grid-connected wind farms are possible. Some of the applications contributing to sustained market growth include:

On-land wind energy in industrialised countries: Single operating machines and wind farms connected to the grid currently have the largest market share (about 85%). Wind turbines and farms are growing rapidly in size and number (grid-connected, on-land for single turbines from 1 MW to several MW and wind farms from 10 MW to several hundred megawatts). The phenomenal growth of wind energy markets has happened in those countries which provide financial support (such as feed-in tariffs or production tax credits), encourage R&D, and /or facilitate regulatory measures to further support wind development .

Offshore wind energy in industrialised countries: Based on growth expectations for the offshore wind park market, leading wind turbine manufacturers consider the multi-MW class to be the most promising market segment. Large turbines are generally more cost-effective.

On-land wind energy in developing countries: Countries with rapidly increasing electricity demand and good sites (see Plate 5 page 101) should consider wind power to be a relatively competitive energy source to add to their energy mix.

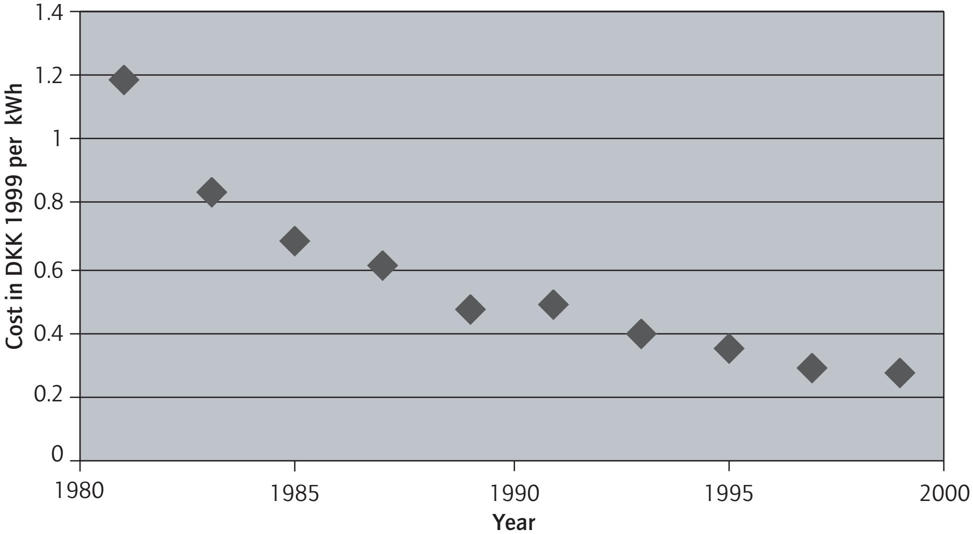
Renovation: A lot of decentralised and single operating machines connected to the grid, especially in the pioneer countries like the US and Denmark, face increasing maintenance costs due to wear and tear. These machines will either be replaced with larger state-of-the-art models or refurbished.

Isolated systems in developing countries: Opportunities for village-scale systems, particularly hybrids with a conventional generator, are expected to increase in coming years. Components that in the past were too expensive or unreliable, such as electronic control components, have improved considerably so that a revival of autonomous systems is probable.

Small stand-alone turbines: Small battery-charging wind turbines for water pumping, heating and other applications are commercially very successful in certain niche markets.

Figure 64

Estimated Costs of Wind-Generated Electricity Over Time



Source: Danish Energy Authority.

Issues for Further Progress

- **Technical Issues**

Turbine Concepts

Turbines can be improved through reduced loads, fewer components and enhanced materials and tools. Loads can be reduced by less conservative design and by using flexible blades and hubs and variable-speed generator systems. This leads to lower weights and lower machine cost. Furthermore, the use of improved materials will provide higher strength-to-mass ratios and better internal damping. The number of components can be reduced by incorporating direct-drive generators, passive blade pitch control in combination with variable-speed drive trains and passive yaw combined with a rotator located downwind. The use of direct-drive generators and power electronics eliminates the need for a heavy and expensive gearbox, reduces noise emission and can improve power quality at the connection to the grid. Dedicated turbine types should be developed for a variety of areas with special wind conditions, *e.g.* inland locations with low wind speed, locations with high wind speed, high turbulence, cold climates (heated, ice-free components), and offshore.

Grid Integration and Intermittency

The intertwined problems of intermittency and impacts on grid reliability present two of the strongest challenges to wind energy's future prospects. When wind is providing too much or too little power, the reliability of the grid is affected. Because wind is based on natural forces, it cannot dispatch power on demand. Because utilities must supply power in close balance to demand, intermittency can limit the amount of capacity of highly intermittent technologies that can be integrated into the grid. Thus, as the share of wind energy increases, integration of wind turbines into the electrical network will need both more attention and investment.

To an extent, technical solutions and business and regularity practices can extend the penetration of wind, though these require not only significant research and development, but also new management techniques. There are two sets of issues: first, the short-term fluctuations and second, the medium and long-term issues of grid reliability when wind power exceeds a certain level of total power supply. On the short-term issues, fluctuations in power output caused by wind gusts may affect the power quality of the network. Short-term power fluctuations may be reduced using variable-speed turbines. Electricity flow controls and supplemental generation from distpatchable systems or storage can be used to further improve power quality. This supplemental generation could include another renewable technology such as hydropower. Better power quality from wind requires technical improvements to deal with harmonic distortion, reactive and inrush currents and instability, as well as grid adaptation.

As to the medium and long-term issues of grid reliability when wind power provides a great deal of the total power supply, further study is required to understand better how to manage intermittent supply and what level can be absorbed. Wind power is one of the intermittent renewable technologies where penetration rates on the grid have caused technical problems (bioenergy CHP is the other). In Denmark, some local regions in Spain, and in Northern Germany, penetration rates of over 15 % (and even up to 50% for a few minutes) have been seen. In some instances, this has caused grid control and power quality problems, but not in other cases. The local conditions that determine at what level intermittent wind will cause problems on the grid need to be studied further. Regardless, these problems require that renewable energy producers, utilities and regulators come together to find optimal solutions.

Wind intermittency is also an issue for off-grid installations. Improving the usefulness of off-grid systems calls for "hybridising" the wind machines with a fossil generator or adding energy storage in a battery. This process is relatively straightforward from a technical perspective; however, the trade-offs for added cost and added usefulness must be addressed on a case-by-case basis.

Wind Turbine Performance Prediction

There is still considerable room for improvement in wind turbine performance prediction. Anemometry, terrain calibration and methods of measuring power-wind speed curves should be improved. Improved forecasting requires real-time acquisition of climatic data and models for meteorological and turbine performance assessment.

Systems

Autonomous and hybrid systems should be enhanced and energy infrastructure and storage need to be addressed. With further development, a variety of technologies offer potential for storage of varying duration. Capacitors, SMES batteries and flywheels could be developed for short-term (minutes, hours) energy storage. In the future, large amounts of energy might be stored over longer periods (days, weeks) by means of pumped hydro, hydrogen and regenerative fuel cells.

Standardisation of Sub-systems

Sub-systems should be further standardised in order to increase modularity and to contribute to reductions in the cost of system design, engineering and production.

Operation and Maintenance

Wind turbines located offshore and in mountainous terrain are subject to potentially very high costs for O&M and loss of availability due to climatic influences. More intelligent wind turbines could have improved self-diagnostic capabilities, thereby reducing downtime and maintenance costs while improving reliability and availability. Longer lifetimes for components and consumables would also be desirable, especially for wind power plants in areas that are difficult to access.

Non-technical Issues

Public opposition to new wind projects has been increasingly mobilised first in dense areas and tourist locations, and now in more densely inhabited areas in Europe. NIMBY (Not In My Back Yard) is a growing social issue for new wind power. New locations, especially offshore and in non-surveyed terrain, should be mapped and assessed to reduce the visual impact on sensitive populations.

Internationally accepted requirements for power performance, safety, noise and other environment-related conditions should be developed in order to reduce trade barriers and administrative and installation costs.

ABBREVIATIONS AND GLOSSARY

€: Euro (European currency unit)

AC: Alternate Current

AD: Anaerobic digestion

BMWi: German Federal Ministry for Economics and Labour

BoS: Balance of System

BWE: Bundesverband Windenergie

CESI: Centro Elettrotecnico Sperimentale Italiano

CHP: Combined heat and power

CNRS-IEPE: Centre National de la Recherche Scientifique - Institut d'Economie et de Politique de l'Energie

CSP: Concentrating Solar Power

DC: Direct Current

DEA: Danish Energy Authority

DISS: Direct Solar generation in parabolic trough collectors

DKK: Danish Kroner

DLR: Deutsches Zentrum für Luft-und Raumfahrt

DOE: U.S. Department of Energy

DRKW: Dresdner Kleinwort Wasserstein

DSG: Direct Steam Generation

EC: European Commission

ECMWF: European Centre for Medium-Range Weather Forecasts

ECN: Energieonderzoek Centrum Nederland

EGS: Enhanced Geothermal System

EIA: U.S. Energy Information Administration

ENEL: Ente Nazionale per l'Energia Elettrica SpA

EPIA: European Photovoltaic Industry Association

EPRI: Electrical Power Research Institute

EREN: Energy Efficiency and Renewable Energy Network

ESHA: European Small Hydropower Association

EU: European Union

EURELECTRIC: Union of the Electricity Industry

EWEA: European Wind Energy Association

EXCETP: Experience Curves for Energy Technology Policy

GEF: Global Environmental Facility

GW: Gigawatt (100,000 kW)

HDR: Hot Dry Rock

HFR: Hot Fractured Rock

HTF: Heat Transfer Fluid

HWR: Hot Wet Rock

IEA: International Energy Agency

IEA-PVPS: International Energy Agency Photovoltaic Power Systems Programme

IEC: International Electrical Committee

IEFE: Istituto di Economia e Politica dell’Energia e dell’Ambiente

IGA: International Geothermal Association

IGCC: Integrated Gasification and Combined Cycle

ISCCS: Integrated Solar Combined Cycle System

J: Joule

KJC: Kramer Junction Company

KW: Kilowatt

KWh: Kilowatt-hours

LEC: Levelised Electricity Cost

MSW: Municipal Solid Waste

MW: Megawatt (103 kW)

NCEP: U.S. National Centres for Environmental Prediction

NCPV: National Center for Photovoltaics (DOE)

NET: Nowak Energy & Technology Ltd.

NREL: National Renewable Energy Laboratory in Golden, Colorado

NSTTF: National Solar Thermal Test Facility

NTUA: National Technical University Of Athens

O&M: Operation and Maintenance

OECD: Organisation for Economic Co-operation and Development

PSA: Plataforma Solar de Almería

PS10: Planta Solar 10 Megawatt

PURPA: Public Utility Regulatory Policies Act

PV: Photovoltaic(s)

REBUS: Renewable Energy Burden Sharing

REMAC: Renewable Energy Market Accelerator

SAIC: Science Applications International Corporation

Sandia: National Laboratories in Albuquerque, New Mexico

SCE: Southern California Edison

SEGS: Solar Electric Generating Stations. SEGS is the generic term relating to parabolic trough employing a Rankine cycle with approximately 75% solar and 25% fossil fuel input.

SFOE: Swiss Federal Office of Energy

SHP: Small Hydro Power

SII: Solar Two / SIII: Solar Tres

TSA: Technology Solar Air

USD: Dollar (U.S. currency unit)

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