Learning in Renewable Energy Technology Development

thesis

Martin Junginger

Learning in Renewable Energy Technology Development

Leren in de ontwikkeling van hernieuwbare energietechnologieën

(met een samenvatting in het Nederlands)

PROEFSCHRIFT

TER VERKRIJGING VAN DE GRAAD VAN DOCTOR
AAN DE UNIVERSITEIT UTRECHT
OP GEZAG VAN DE RECTOR MAGNIFICUS, PROF. DR. W.H. GISPEN,
INGEVOLGE HET BESLUIT VAN HET COLLEGE VOOR PROMOTIES,
IN HET OPENBAAR TE VERDEDIGEN
OP VRIJDAG 13 MEI 2005 DES OCHTENDS OM 10:30 UUR

Door

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geboren op 7 februari 1976 te Braunschweig, Duitsland

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This thesis was realized within the framework of the ‘Stimuleringsprogramma Energieonderzoek’ sponsored by NWO (Netherlands Organisation for Scientific Research) and Novem (The Netherlands Agency for Energy and the Environment). The research was carried out at the Department of Science, Technology and Society and the Copernicus Institute for Sustainable Development and Innovation of Utrecht University, as part of the AIRE-project, coordinated by the Utrecht Centre for Energy research.

CIP GEGEVENS KONINKLIJKE BILBIOTHEEK, DEN HAAG

Junginger, Hans Martin

Learning in renewable energy technology development/
Hans Martin Junginger - Utrecht: Universiteit Utrecht, Faculteit Scheikunde
Proefschrift Universiteit Utrecht. Met lit. opg. – Met samenvatting in het Nederlands.

ISBN: 90-393-0486-6

Cover: De watermolen ”De Eendracht” (bouwjaar 1872) en een Vestas V52 850 kW windturbine (bouwjaar 2003) in Kimswerd, Friesland. Op de achterkant is een technische tekening van een wervelbedverbrandingsketel te zien.

Cover-design: Tim Meyer-König

Meinen Eltern gewidmet

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Chapter 1: Introduction

1. Renewable energy in changing energy systems

The availability of modern energy carriers to fulfill energy needs has been important for mankind ever since the age of industrialization. At present, a number of energy sources are utilized on a large scale: coal, oil, gas cover about 80% and nuclear energy covers about 6% of the global primary energy supply (IEA, 2002; IEA, 2003; Goldemberg and Johansson, 2004). Even though gas, oil and coal reserves may still be available until the end of this century, ultimately it will get increasingly difficult and costly to extract these resources to satisfy an increasing global energy demand. The industrialized world is getting increasingly dependent on the import of oil and gas. This dependence, especially on oil, has had a significant impact on the world economy during the two oil crises in the 1970s, and (though with a lower impact) as recent as 2004. These crises were caused by political instability in the Middle East, and in 2004 also in Russia and Latin America (IMF, 2004; NRC, 2004a; NRC, 2004b). Also, a number of externalities[1] are linked to the use of fossil fuels, such as environmental effects. For example, global climate change (caused by the anthropogenic emission of carbon dioxide (CO_2), a major greenhouse gas) may result in negative long-term effects, and the consequences for human society and ecosystems are potentially severe (IPCC, 2001). Other fossil fuel related emissions include volatile organic compounds, dust, sulphur- and nitrogen oxides, which can also cause global climate change, adversely affect human health and cause local and regional environmental problems such as the formation of tropospheric ozone and acid deposition (Holdren et al., 2000). Nuclear energy also involves environmental and safety issues (e.g. reactor accidents, long-term storage of radioactive waste and proliferation).

1.1. Renewable energy sources

Renewable energy sources (renewables), such as wind energy, biomass energy, solar energy and hydro power are by definition not limited by finite fuel reserves. In terms of global potential, biomass, wind and solar energy each have a technical potential which may cover several times the current global electricity demand (Hoogwijk, 2004). While several factors limit the extent to which these potentials can actually be utilized in the near future, scenarios indicate that renewable energy sources may cover 20-50 percent of energy supplies in the second half of the 21st century (Turkenburg et al., 2000). At present, renewables contribute about 14% global primary energy consumption. Main renewable energy contributions are traditional, mainly non-commercial biomass such as fuel wood, crop residues and dung (9.3%), hydropower (2.3%), and modern use of biomass (1.4%). All other renewables combined (e.g. onshore and offshore wind energy and solar photovoltaic (PV) energy, geothermal energy and solar heat) contribute about 0.8% (IEA, 2002; Goldemberg and Johansson, 2004). While most renewable energy sources display some negative environmental impacts[2], there is substantial evidence that the overall external cost of the past and current use of fossil fuels are significantly higher than those of renewable energy (Rabl and Spadaro, 2001). As most renewable energy potentials are distributed more evenly over the globe than for example world oil resources, the exploitation of renewable energy sources can also increase security of energy supply (i.e. less dependence on import of fossil fuels). Therefore, in this thesis,

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[1] An externality exists if some negative (or positive) impact is generated by an economic activity and imposed on third parties, and that impact is not priced in the market place (Pearce, 2001).

[2] For example, large-scale hydropower may disturb local ecosystems, wind turbines produce noise and may cause the death of birds and have an impact on landscape, and biomass energy plants emit (depending on the biomass fuel and plant type) limited amounts of particulate matter and sulfure dioxide (SO_2).

the focus lies on technologies that are developed to extract energy from renewable sources: what progress is made in the development of these technologies and how does this influence their application.

Currently, fossil fuels fulfill a number of (energy) services, covering demand for electricity, heat and cooling, providing fuels for transportation and supplying the feedstock for materials such as synthetic fibers and plastics. While renewable energy sources (and especially biomass) have the broad scope to provide these services as well (see for example Faaij (1997), Patel (1999) and Hamelinck (2004)), this thesis focuses only on renewable electricity. Electricity is one of the most important energy carriers of modern energy systems, and global electricity demand is expected to increase faster than any other energy end-use (IEA/OECD, 2002). This increase is especially high in countries with strongly growing economies like China and India, but also OECD[3] countries display a long-term trend to higher electricity consumption. Renewable electricity may be of major importance to cover this rising demand in a sustainable way.

The presumed advantages of renewable energy have been the key drivers over the last three decades for many western governments to explore the possibilities of renewable energy and to stimulate its development and use. In this context, the EU (European Union) has issued a number of policy documents, such as the white paper on renewable sources of energy (European Commission, 1997), the biofuels directive (European Parliament, 2003) and the renewable electricity directive (European Parliament, 2001). The aim of the latter is to increase the overall contribution of renewable electricity to gross electricity consumption within the EU from 13.9% in 1997 to 22% in 2010. Overviews of past and future European policy to stimulate renewable electricity within the EU can be found in the recent literature (e.g. Blok, 2004; Johansson and Turkenburg, 2004). One member country with both a long history in renewable electricity and ambitious targets for future applications is the Netherlands.

1.2. Renewables in the Netherlands

In the Netherlands, targets and research programs for a number of renewable energy technologies were formulated during the eighties. In the third Energy Report of the Netherlands, published in 1995, a policy goal of 10% contribution from renewable energy sources[4] in 2020 in the Netherlands was set (Minister of Economic Affairs, 1995). An elaborate description of the history of renewable energy development in the Netherlands is given by Verbong et al. (2001). Various RD&D (Research, Development and Demonstration) programs, investment subsidies, electricity production subsidies, tax exemptions and other policy instruments have been formulated and applied over the last decades. As a result of these policy measures, the domestic renewable electricity supply increased by almost a factor of six from 1989 to 2003 (see Figure 1). The contribution of renewables to Dutch gross electricity production increased by about a factor of four in the same time period, given the simultaneous increase in electricity demand.

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[3] Organization for Economic Co-operation and Development. Its thirty member states include most EU countries, the United States of America, Canada, Mexico, Japan, South Korea, Australia and New Zealand.

[4] Defined as 10% of total domestic energy consumption in the Netherlands in 2020. In 2003, this contribution was 1.5% (CBS, 2004).

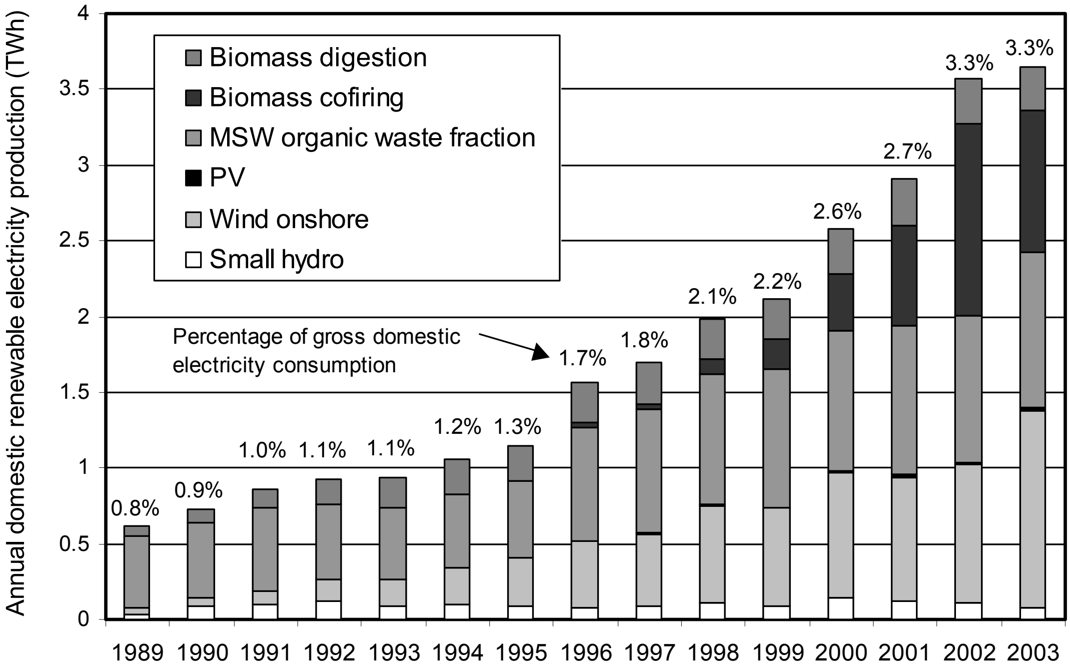

Figure 1 Annual renewable electricity production in the Netherlands during 1989-2003, and contributions per technology (CBS, 2004). The percentages refer to the share in gross Dutch electricity consumption. The target for 2010 is 9%.

The contributions of different sources to the renewable electricity supply changed over time. While Municipal Solid Waste (MSW)- incineration was dominant in 1989, today onshore wind energy and the large-scale co-combustion of woody biomass and residues have also gained large shares. By the end of 2003, about 3.3% of gross electricity consumption was covered by domestic renewable electricity production[5]. For the near future, the Dutch government has set ambitious targets of 9% renewable electricity supply in 2010, and 17% in 2020 (Minister of Economic Affairs, 1995; Minister of Economic Affairs, 1997; Ministry of Economic Affairs, 1999)[6]. With the current rate of increase (an average production increase of about 15% per year, see Figure 1) and a continuing annual increase of electricity consumption with 1.6% (Ybema et al., 2002; Boonekamp et al., 2003), these targets are not likely to be realized. The efforts to accelerate the production and use of renewable electricity can be hindered by several factors.

1.3. Barriers to the penetration of renewable electricity

First*, social and institutional barriers* can significantly slow down the diffusion of renewable electricity into the market. For example, the NIMBY - effect (Not In My Backyard, i.e. local public resistance) has been frequently described in the literature for renewable electricity sources such as wind energy (Krohn and Damborg, 1999; Kaldellis, in press) or biomass energy (Rakos, 1997). Several studies have shown that social-institutional conditions (e.g. spatial planning procedures, building and environmental permit procedures and national and international laws) also can have a high impact on the implementation of wind energy projects (Wolsink, 2000; Agterbosch et al., 2004). *Technical problems* pose a second barrier. At increasingly high penetration levels,

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[5] This does not include imported renewable electricity.

[6] These targets seem relatively modest in comparison to the European target of 22% in 2010. However, the Netherlands has basically no potential for large-scale hydro plants, which constitutes the bulk share in many European countries.

intermittent electricity sources (such as wind and PV electricity) may influence the power system dynamics, though several studies have shown that on short-term time scales (i.e. seconds) impacts on the power system are probably not severe (see: Slootweg, 2003). On the longer term, depending on penetration levels, additional backup-capacity or storage facilities may be required to compensate the fluctuating power output of these technologies (Hoogwijk, 2004). A third (though minor) barrier may be restrictions to prevent negative *environmental damages*. Fourth, a major barrier is *economic competitiveness* with other (fossil) electricity generation technologies. Most fossil electricity generating technologies have been developed over a number of decades up to a century for coal-fired power plants, and have received large amounts of (public) support. Thus, they have at present a technological advantage over renewable electricity options, as the direct electricity production costs are in general much lower. However, also renewable energy technologies have displayed significant production cost reductions in the past few decades. For example, the cost of electricity produced by onshore wind turbines have roughly been reduced by a factor five over the last twenty years, due to the technological development of wind turbines (BTM, 2000). Further cost reductions are expected to be achieved for most renewable electricity technologies, as a result of innovation and technological learning (Turkenburg et al., 2000).

2. Theory of technological learning and experience curves

2.1. Concepts on technological learning and associated cost reductions

Many concepts have been developed to describe the ‘black box’ of technology development and change. An overview of different approaches to technology studies is given by e.g. Luiten and Harmsen (1999), including the neo-classical economic, evolutionary economic, systems of innovation, industrial network, quasi-evolutionary and large-technical systems approach[7]. Below, a brief overview is presented on how technologies develop and diffuse into the market. In addition, the mechanisms behind technological learning are described.

For each new technology, different stylized stages can be described over time using a life-cycle model, from invention, (applied) research, development, demonstration, niche market commercialization, pervasive diffusion and saturation to senescence (see Table 1). Generally, the diffusion follows an S-shaped growth pattern, i.e. slow growth during the invention and RD&D stages, high growth during the niche market commercialization and pervasive diffusion stages, and again low growth during market saturation stage (and negative growth during the senescence stage). Each stage typically takes several decades (Grübler, 1998), but the stages often display significant overlap, and are difficult to separate (Turkenburg, 2002).

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[7] Especially the quasi-evolutionary approach has been developed further in recent years, resulting in concepts like strategic niche management (see e.g. Kemp et al. (1998)), technological regimes (see e.g. Berkhout (2002)), and transition management (see e.g. Geels (2002)), which places technology development in a broader context using a three level approach (*niche, socio-technical regime and landscape*). In this thesis, the focus is mainly on the development of the technological artifact (e.g. a wind turbine or biomass power plant), with some attention to the broader frame of strategic niche management and changing regimes.

Table 1 Stylized stages of technological development and typical characteristics (slightly adapted from Grübler et al. (1999)).

Stage	Mechanisms	Cost	Commercial market share
1. Invention	Seeking and stumbling upon new ideas; breakthroughs; basic research	High, but difficult to attribute to a particular idea or product	0%
2. RD&D[1]	Applied research, research development and demonstration (RD&D) projects	(Very) high, increasingly focused on particular promising ideas and products	0%
3. Niche market commercialization	Identification of special niche applications; investments in field projects; "learning by doing"; close relationships between suppliers and users	High, but declining with standardization of production	0-5%
4. Pervasive diffusion	Standardization and mass production; economies of scale; building of network effects.	Rapidly declining	Rapidly rising (5-50%)
5. Saturation	Exhaustion of improvement potentials and scale economies; arrival of more efficient competitors into market; redefinition of performance requirements	Low, sometimes declining	Maximum (up to 100%)
6. Senescence	Domination by superior competitors; inability to compete because of exhausted improvement potentials	Low, sometimes declining	Declining

1 Grübler et al. (1999) refer to this stage as 'innovation stage'. However, the term 'innovation' is generally used much broader, covering the first and third stage too.

In each of these stages, different learning mechanisms play a role in the improvement of the technology, which typically result in a higher conversion efficiency and reliability, easier use and lower investment, operation and maintenance costs. Different learning mechanisms have been described by, amongst others Utterback (1994), Garud (1997), Grübler (1998; et al., 1999), Kamp (2002) and Dannemand Andersen (2004)[8]. These authors have developed different approaches to conceptualize knowledge and learning. Most authors identify several of the following mechanisms influencing both the production process and the product itself (Neij et al., 2003) behind technological change and cost reductions:

- *Learning-by-searching,* i.e. improvements due to RD&D, is the most dominant mechanism in the stages of invention and RD&D, and to some extent also during niche market commercialization. Often also during the stages of pervasive diffusion and saturation, RD&D may contribute to technology improvements.
- L*earning-by-doing* (Arrow, 1962) takes place especially in the production stage after the product has been designed. Typically, the repetitious manufacturing of a product leads to improvements in the production process (e.g. increased labor efficiency, work specialization and production method improvements).
- *Learning-by-using* (Rosenberg, 1982) can occur as a technology is introduced to (niche) markets. A technology cannot be fully developed inside laboratories and factories. Feedback from user experiences often leads to improvement of the product design.
- *Learning-by-interacting* is related to the increasing diffusion of the technology. During this stage, the network interactions between actors such as research institutes, industry, end-users and policy makers generally improve, and the above-mentioned mechanisms are reinforced

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[8] For renewable electricity technologies, different studies have investigated these mechanisms during the RD&D and niche market commercialization stage, see for example Kamp (2002) and Garud and Karnøe (2003) for wind energy, Raven and Gregersen (2004) for biogas digestion plants, and Schaeffer et al. (2004) for solar photovoltaics.

(Lundvall, 1988). In other words, the diffusion of knowledge itself supports the diffusion of the technology[9].
- *Upsizing* (or downsizing) and redesigning a technology (e.g. upscaling a gas turbine) may lead to lower specific unit costs (e.g. the costs per unit of capacity).
- *Economies of scale* (i.e. mass production) can be exploited once the stage of large-scale production and diffusion is reached. Standardization of the product allows upscaling of production plants, and producing the same product in large numbers.

Often, combinations of these factors occur in each stage, and the contribution of each may change during the development of a technology over time. Also, not all factors may apply to all technologies. Some authors differentiate between effects of (technological) *learning* (such as the first three factors) and *scale effects* (such as the last two factors) (Abell and Hammond, 1979). However, in practice these factors often overlap and are difficult to separate (Neij, 1999a). Also, in most cases both upscaling and mass production of a technology or production process requires many steps[10]. During each step, experience is gained by learning-by-doing and learning-by-using, which is then incorporated in the next generation of the technology[11].

While these factors describe the mechanisms behind cost reductions qualitatively and in hindsight, it is a different matter to quantify the effects of each mechanism separately, and to make projections about their possible contribution in the future when developing a technology. Further knowledge development in this field would be interesting and highly relevant to understand how technological development can be influenced in a cost-effective way. Future projections may be based (at least to some extent) on past achievements, e.g. returns on investment from RD&D expenditures, but RD&D expenditures are no guarantee for cost reductions[12] and returns on RD&D investments may vary. Scaling laws can be used to project potential cost reductions. Yet, upscaling a plant normally requires considerable RD&D expenditures and investments in pilot plants to solve problems arising from the larger scale and to make investment risks known and acceptable. In the end, it is the combination of learning mechanisms causing cost reductions, which makes quantifying the effect of each mechanism separately difficult. A concept, measuring the aggregated effect of these mechanisms is the experience curve approach.

2.2. The experience curve approach

Normally, the technical and economic performance of a technology increases substantially as producers and consumers gain experience with this technology. This phenomenon was first described in the literature in 1936 by Wright (1936), who reported that unit labor costs in airframe

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[9] Somewhat related to this mechanism, Rotmans and Kemp (2003) also mention ‘learning by learning’, indicating that the primary learning processes themselves can improve over time. In addition, Schaeffer et al. (2004) distinguish ‘Learning by expanding’, recognizing the fact that more actors, organizational structures and industrial sectors become involved in, focused on, dependent on and adapted to the new technology. Arthur (1988) calls this mechanism ‘increasing returns on adoption’.

[10] For example, it took over 20 years and over one hundred plants to scale up steel plants from 0.3 to 8 million tons of steel output capacity (Grübler, 1998). A similar trend and time span was found for fluidized bed boilers (Koornneef, 2004). Cost reductions due to mass production are of course not all related to learning. Larger production volumes will for example allow manufacturers to negotiate lower prices for raw materials and reduce relative overhead costs. Yet, it is clear that to design, build and operate larger production plants, learning will be required as well.

[11] This process is documented in detail for the development and upscaling of Danish wind turbines by Neij et al. (2003).

[12] A classic example is German RD&D spending aiming at the development of MW-sized large turbines, which was ultimately unsuccessful. On the other hand, Danish producers developed small-scale kW-sized wind turbines successfully, with little RD&D support.

manufacturing declined significantly with accumulated experience of the workers, and that this cost reduction was a constant percentage with every doubling of cumulative output. When plotted on a log-log scale, he found that this empirical relationship is displayed as a straight line. He noted the particular interest of these curves to investigate "the possible future of airplane cost" (Wright, 1936). Wright's discovery is nowadays called a learning curve, as he only measured the effects of learning-by-doing, and recorded the reduction in labor cost (or actually, the time required to complete a certain task) (Neij, 1999a). Arrow (1962) introduced the notion to general economics that this cost reduction (as a result of learning) was the product of experience. In 1968, the Boston Consultancy Group extended the learning curve concept in two ways (BCG, 1968). First, the concept was applied to the total cost of a product, thereby including other learning mechanisms (such as RD&D and economies of scale), and other cost factors (e.g. cost of capital, marketing, overhead). In order to distinguish them from simple learning curves they were labeled experience curves[13]. Second, the concept was applied not only on the level of a single company, but also to entire industries.

When the cost development of a product or a technology can be described as function of cumulative production, and plotted in a figure with double-logarithmic scale, the result is often a linear curve, the experience curve. The basic experience curve can be expressed as:

$$C_{Cum} = C_0 \, Cum^b \tag{1}$$

$$\log C_{Cum} = \log C_0 + b \log Cum \tag{2}$$

$$PR = 2^b \tag{3}$$

$$LR = 1 - 2^b \tag{4}$$

C_{Cum} : Cost per unit[14]
Cum : Cumulative (unit) production
PR : Progress ratio
C_0 : Cost of the first unit produced
b : Experience index
LR : Learning rate

The progress ratio (PR) is a parameter that expresses the rate at which costs decline for every doubling of cumulative production. For example, a progress ratio of 0.8 (80%) equals a learning rate (LR) of 0.2 (20%) and thus a 20% cost decrease for each doubling of the cumulative capacity. Both terms are used in the literature. Furthermore, in the experience curve approach costs are expressed in real terms, i.e. corrected for inflation, normally using a GDP-deflator. An example of an experience curve is shown in Figure 2, in which an experience curve for solar PV modules is presented.

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[13] Unfortunately, in the literature the term learning curve is sometimes also used as synonym for experience curve.

[14] The term 'unit' is not used as 'unit of measurement' (e.g. centimeters), but to describe the number of products manufactured (e.g. airplanes, cars, computer chips).

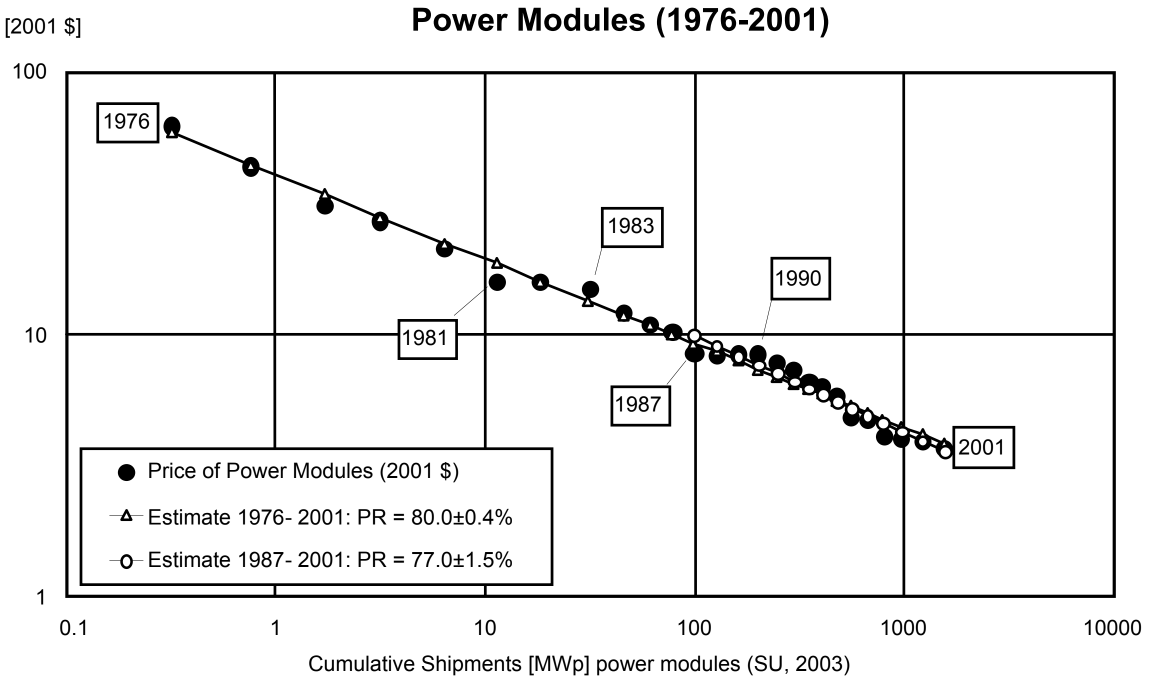

Figure 2 Experience curve for solar PV-module prices (Global Average Selling Price), adopted from Schaeffer et al. (2004). Original data from Strategies Unlimited.

Over the last three decades, experience curves have been devised for many technologies and industries, including shipbuilding, limestone production and steam turbines fabrication; see for an overview: Argote and Epple (1990) or Dutton and Thomas (1984). One field of application is that of (renewable) energy. The application of the experience curve concept to energy technologies requires measuring the output in terms of capacity or energy production, rather than the number of units produced themselves[15].

2.3. Experience curves for (renewable) energy technologies

Experience curves have been devised and discussed for many energy technologies, such as photovoltaic modules and systems (Harmon, 2000; Snik, 2002; Schaeffer et al., 2004; van der Zwaan and Rabl, 2004) (see also Figure 2), combined cycle gas turbines (Claeson Colpier and Cornland, 2002), fuel cells (Tsuchiya, 2002) and ethanol production (Goldemberg, 1996). Especially for the wind energy sector, a number of experience curves have been devised for Denmark (Neij, 1999a), Germany (Durstewitz and Hoppe-Kilpper, 1999), the United States (Mackay and Probert, 1998), and other countries (Lund, 1995; Junginger, 2000; Ibenholt, 2002; Klaassen et al., 2003; Neij et al., 2003). McDonald and Schrattenholzer (2001) present an overview of studies concerning energy technologies.

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[15] The cumulative number of units can only be used, when the units are identical (e.g. one type of airplane or computer chip). Upscaling of a technology (e.g. a wind turbine) causes absolute costs (per wind turbine) to increase, but specific costs (per unit of capacity or electricity production) to decrease. This makes specific costs more suitable for use in experience curves.

Experience curves are used for a number of purposes:

- Experience curves are used by companies to project future costs and to formulate a corporate strategy (see e.g. Abell and Hammond (1979)). The first application of the experience curve concept occurred within corporations.
- Experience curves are also utilized in technology scenarios, like a scenario for global wind energy technology development, see for example the 'Wind Force 12' study (EWEA and Greenpeace, 2002).
- Energy models, economic models and climate change models that are used to assess potential future developments increasingly make use of experience curves to endogenize technological learning and the associated cost reductions of e.g. renewable energy technologies. Examples of energy models using endogenous learning are bottom-up (systems engineering) models such as ERIS (Kypreos and Barreto, 1998), Genie (Mattsson and Wene, 1997), MESSAGE (Messner, 1997, Messner and Schrattenholzer, 1998), MARKAL (Seebregts et al., 1998) and TIMER (Hoogwijk, 2004) and top-down (macro-economic) models such as DEMETER (van der Zwaan et al., 2002), CETA (Peck and Teisberg, 1992) or DICE (Nordhaus, 1993).
- Historic experience curves may be used by policy makers to evaluate the effect of past policy instruments such as investment subsidies or feed-in tariffs. Experience curves may also aid the design and monitoring of new policies (IEA/OECD, 2000). For example, with an experience curve, it may be possible to determine the required level of future support for an emerging technology, so-called learning investments[16]. Policy makers can also use the results of sophisticated energy models with endogenous technological learning to compare entire energy systems. With these models, it can be evaluated how support of renewable energy technologies in the short term may affect the total cost and contribution of these technologies in the entire energy system in the long term.

2.4. Methodological issues regarding experience curve (for energy application)

While the basic experience curve principle itself stands out due to its simplicity, using the experience curve is in practice often not as straightforward as it may seem. The attractiveness of the experience curve approach lies in the possibility to extrapolate the trend lines to make estimates for the future. However, a number of issues have to be taken into account, both concerning the construction of historical experience curves and the extrapolation of experience curves.

1. An experience curve describes the change in **production costs.** In practice, often only **market prices** are available to devise experience curves. According to the Boston Consultancy Group, prices can be used as proxy for costs, but only during the situation of a competitive market, and a constant share in profits (BCG, 1968). This is often not the case during the stages of RD&D and niche market commercialization. Thus, if the experience curve is used for future cost projections in these early stages of diffusion, serious errors may occur (Jensen and Dannemand Andersen, 2004).

2. The experience curve uses cumulative output as a substitute for accumulated experience. This implicates that the concept does not indicate at what time a certain cost level may be reached; this depends on the market growth and diffusion of the technology. An open issue is, whether or not the experience curves flattens out with increasing market penetration, i.e. whether the

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[16] These are future investments required to 'buy down' the costs of a technology to a certain price level until it can compete with conventional technologies (IEA/OECD, 2000).

PR is **constant or not.** Intuitively, one would expect that cost reductions cannot be achieved endlessly. Grübler (1998) argues that costs are reduced relatively fast during the innovation/RD&D phase, but that the PR may change to a higher level (i.e. lower cost reductions) when a technology enters the commercial market. McDonald and Schrattenholzer (2002) argue that a constant PR may depend on an exponential market growth. As soon as the turning point in the S-shaped diffusion curve is reached, and annual production volumes become linear or even decrease, the experience curve will eventually flatten out and the PR may reach unity. On the other hand, it can be argued that cumulative doublings of unit production are achieved with relative ease during the innovation and niche market phase of a technology, but as the market reaches saturation, it may take much longer in time to reach another doubling of cumulative production. Thus, the cost reduction possibilities are also limited by market volume. Cost reduction may then slow down *in time,* and come to halt when the market is saturated or other technologies take over. This however does not necessarily require the PR to change.

3. It is also a question **whether a PR can actively be influenced** by policy measures. Recent findings of the EU-funded PHOTEX-project (Schaeffer et al., 2004) demonstrate that in the last decade, the PR of PV-modules actually decreased from 80% to 77%. This is attributed to increased intensity of policy support measures (see also Figure 2). Schaeffer et al. (2004) argue that the PR is not fixed and that it can actually be influenced by policy measures. Therefore, they plea for a right combination of market deployment policy ("learning investment") RD&D-policy supporting the market development ("investment in learning"), although determining the right combination is problematic. The experience curve itself only describes the empirically-found trend, and does not open the "black box" of underlying mechanism. Several attempts have been made to disaggregate the experience curve, and to describe the effects of RD&D and learning-by-doing[17] separately (see e.g. (Kouvaritakis et al., 2000; Klaassen et al., 2003)). While this approach might yield a more accurate estimation of the past and possible future cost reductions, it also requires detailed data, which may not be available in many cases. Also, the principal question remains, whether it is possible to forecast the effect of RD&D spending separately, even it is for a single technology[12].

4. There is also the issue of **uncertainty** in experience curves, and resulting consequences. Given the empirical nature of the data and related inherent uncertainties, the slope of an experience curve (i.e. the PR) is likely to vary to some extent when key parameters are changed like the assumptions about initial capacity installed, the associated start-off costs, the method of aggregating annual data, correcting for inflation and varying exchange rates[18] and changing the learning system boundaries. As Neij (1999a) and van der Zwaan and Seebregts (2004) report, already small changes in PR can lead to strongly deviating results for (long-term) scenarios and energy models using experience curves to model endogenous learning.

5. Energy technologies are generally designed to produce electricity, heat or other energy carriers at the lowest possible costs. Thus, ideally one would **measure** the **performance** as the cost per

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[17] Note that in this context, "learning-by-doing" stands for all (learning) mechanisms occurring during the phases from niche market commercialization onwards. Thus, it is a much broader term than the specific mechanism with the same title described in section 2.1.

[18] Often, experience curves are devised for one country, and thus one currency, which allows for inflation correction with the national CPI (consumer price index) or GDP (gross domestic product) deflator. As soon as several countries with different currencies are involved, the choice of reference currency and method of converting other currencies to the reference currency can seriously influence the PR (Snik, 2002).

unit of energy (e.g. €/kWh) as function of the cumulative energy production. However, to do so, detailed information is required on the investment costs, O&M costs, possible fuel costs and annual production volumes. Unfortunately, this kind of data is often not available. Instead, the cost reductions are mainly measured by calculating the investment costs per unit of capacity (e.g. €/kW). Using this parameter has however several drawbacks. First, cost of capacity does not include any learning effects in regard to operational experience, higher load factors, less O&M costs etc. Second, higher investment costs may be a trade-off for lower O&M costs, which means that the final energy costs do not necessarily have to be higher. Third, sometimes other, technology-specific characteristics may be better suitable to describe the developing performance of a technology, for example the costs per swept area for wind turbines.

6. With the expansion from a cooperation level to entire industries, the **system boundaries** are enlarged. This has led to experience curves being devised from an industry perspective (cumulative units produced by a manufacturer or an entire industry) but also from a market perspective (i.e. how much is installed in a country) (Neij et al., 2003). While country-specific experience curves may be suited to evaluate local policy measures in the past, they may not adequately measure the actual rate of cost reduction of a technology at present. For example, for the development of railroad technology, the phases from invention to niche market exploitation mainly occurred in the United Kingdom between 1769-1824. Only later on with the beginning of diffusion into the market, railroads spread to other European countries, the US, and finally all over the globe, a process which took over 70 years (Grübler et al., 1999). Nowadays, with much more advanced communication systems, multinational corporations and an internationally orientated research community, inventions and innovations normally spread much faster. Many modern renewable energy technologies (e.g. wind, biomass and solar) are developed and implemented in different countries simultaneously. Thus, the development of new technologies today is often a global (or at least multinational) process already in early stages of the life cycle. But while experience curves for photovoltaic modules have almost exclusively been devised for globally produced/shipped modules, for wind turbines, the large majority of historical studies covers country-specific installed capacities. This is of particular importance, especially when PRs based on national experience curves are used in global energy models. Analyzing parts of a learning system only may provide misleading results and deviations in the PR.

7. It has been empirically found that **PR may depend on the type of technology**. Neij (1999a) distinguishes three categories of technologies: modular technologies (e.g. solar modules), plants (e.g. power plants) and continuous processes (e.g. the bulk production of chemical compounds). Typically, the PR for modular technologies is found to range from 70-95% (average 80%), for plant-like technologies from 82->100% (average 90%), and for continuous processes from 64-90% (average 78%). Within the field of renewable energy technologies, the experience curve concept has been applied so far to modular products mainly, such as PV-modules and wind turbines. Far fewer studies have been performed on cost development of plant technologies, such as biomass power plants, or the cost of energy carriers (e.g. advanced fuel from biomass). Little is known on the kind of learning processes being responsible for experience accumulation and cost reductions in these cases. Thus, for these types of energy technologies and energy carriers, the possibilities and limitations of constructing experience curves and understanding the learning processes involved need to be further explored.

8. In the construction of experience curves for renewable energy technologies, mostly data on **marginal production cost**[19] are used, especially for modular technologies such as wind turbines and PV modules. For these technologies, the investment cost largely determine the overall electricity production costs. Also, after the first few years of operation the electricity production costs for these technologies tend to remain constant (or even rise with increasing O&M costs at the end of the economical lifetime). However, for plants producing a certain commodity (such as biomass plants producing electricity), also significant learning could occur during the operation of the plant. Typically, a plant achieves a rather low load factor in its first year of operation, and only achieves the design load factor after several years, when all start-up problems have been solved. In addition, electricity costs are influenced by fuel costs; these costs may decline over the entire lifetime of a plant as an effect of more efficient supply chains. O&M costs may decline because of automation and efficiency gains on one hand, but rise due to increasing age of the plant on the other hand. Therefore, it may also be interesting to analyze the **average**[19] **production cost** development. Empirically, it was shown that the experience curve approach can also be applied to describe the development of average production costs. For example, average data have been used in experience curves describing the cost development of different chemical commodities, the production of electricity in the United States (BCG, 1968) and the carbon intensity of the global economy (IEA/OECD, 2000).

9. Often within a learning system, different **sub-learning systems** can be distinguished. For example, for the case of PV systems, a subdivision can be made for the PV module costs and the BOS (balance of system) costs (the remaining costs, e.g. the inverter, power control, cabling and installation costs). This approach may also be possible to other renewable electricity technologies, such as offshore wind farms (which may be separated into the wind turbines, marine foundations, electrical infrastructure and installation costs) or biomass plants. By making separate analyses for each subsystem, it may be possible to use the experience curve approach for technologies, which in itself have too short a history to use the concept straight ahead.

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[19] The term *marginal production costs* is used here in the sense that only data from recent shipments of a technology are used, to calculate the production costs of e.g. electricity. The term *average production costs* implies that also the production costs of operating plants built in previous years are taken into account.

3. This thesis

3.1. The AIRE project

This thesis is part of the AIRE project (Accelerated implementation of renewable energy in the Netherlands). The AIRE project aims at providing an integral analysis of the implementation of technologies generating electricity from renewable sources in the Netherlands, taking into account technical, economic, institutional and social conditions. This is expected to support the present Dutch renewable energy policy in this area and possibly also to accelerate the implementation. This multidisciplinary project involves three PhD projects: one at Delft University of Technology and two at Utrecht University[20]. The first project at Delft University, carried out by Dr. Han Slootweg, focuses on the technical implementation of intermittent electricity sources. It treats the impact of wind power on the dynamic stability of a power system. The second project, carried out by drs. Susanne Agterbosch, analyses the relative importance of the dynamic configuration of institutional and social conditions for the emergence and performance of important entrepreneurial groups in the wind power market in the Netherlands. This thesis is written as the third project, focusing on the economic and technological aspects of the implementation of renewable electricity technologies.

3.2. Objective and scope

In the previous sections, the importance of cost-effective renewable electricity technologies for the near future has been shown. Also, the possibilities of technological learning to reduce the production cost of technologies have been highlighted. The experience curve approach is one way to quantify these cost reductions, but many methodological questions need to be addressed when utilizing this approach. Given the range of application of experience curves, especially for policy advice and in energy models, further insights are required on how to deal with these questions. This thesis will further investigate a number of them, especially in regard to the system boundaries, compound learning systems and use for plant-type technologies. The main objectives of this thesis are:

To investigate technological change and cost reduction for a number of renewable electricity technologies by means of the experience curve approach,

To address related methodological issues in the experience curve approach,

and, based on these insights,

To analyze the implications for achieving the Dutch renewable electricity targets for the year 2020 within a European context.

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[20] Project members are Susanne Agterbosch, Walter Vermeulen, Piet Glasbergen, Martin Junginger, André Faaij and Wim Turkenburg (Copernicus Institute, Utrecht University), Erik Lysen (Project coordinator, Utrecht Centre for Energy research (UCE), Han Slootweg and Wil Kling (Technical University Delft), Ree Meertens (Maastricht University) and Maroeska Boots and Piet Boonekamp (Energy research Centre of the Netherlands (ECN). The project is funded by the Netherlands Organization for Scientific Research (NWO) and the Netherlands Agency for Energy and the Environment (Novem), as part of the NWO-Novem Energy Research Stimulation Program.

In order to meet these objectives, a number of research questions have been formulated:

I. What are the most promising renewable electricity technologies for the Netherlands until 2020 under different technological, economic and environmental conditions?
II. To what extent is the current use of the experience curve approach to investigate renewable energy technology development sound, what are differences in the utilization of this approach and what are possible pitfalls?
III. How can the experience curve approach be used to describe the potential development of partially new energy technologies, such as offshore wind energy? Is it possible to describe biomass fuel supply chains with experience curves? What are the possibilities and limits of the experience curve approach when describing non-modular technologies such as large (biomass) energy plants?
IV. What are the main learning mechanisms behind the cost reduction of the investigated technologies?
V. How can differences in the technological progress of renewable electricity options influence the market diffusion of renewable electricity technologies, and what implications can varying technological development and policy have on the implementation of renewable electricity technologies in the Netherlands?

The development of different renewable energy technologies is investigated by means of some case studies. The possible effects of varying technological development in combination with different policy backgrounds are illustrated for the Netherlands. The thesis focuses mainly on the development of investment costs and electricity production costs. Possible additional costs of intermittent renewable electricity sources (such as storage, backup-capacity or grid fortification) with advanced penetration are not investigated although these issues may be important on the longer term (after 2020).

In Table 2, it is indicated which research questions are addressed in each chapter of the thesis.

Table 2 Overview of which research questions are addressed in the respective chapters of this thesis.

	Chapter						
Question	2	3	4	5	6	7	8
I	•						•
II		•					•
III			•	•	•		•
IV		•	•	•	•		•
V						•	•

3.3. Structure of this thesis

Chapter 2 aims to explore the feasible deployment of renewable electricity production in the Netherlands until 2020 by evaluating different images representing policies and societal preferences. Simultaneously, the most promising technologies for different settings are investigated and identified.

In *chapters 3-6*, a number of selected technologies are analyzed in terms of cost reduction achieved in the past, driving factors behind cost reductions and prospects for the future. In addition, in each of these chapters special attention is paid to the application of the experience curve approach.

In *chapter 3*, the historical technological development of onshore wind turbines is investigated. In addition, a number of methodological issues regarding the application of the experience curve approach are discussed. Conclusions are drawn on the suitability of a global experience curve approach for onshore wind farms on a global level. Also it is discussed whether the findings allow for improving policies to stimulate onshore wind penetration in an efficient way.

In *chapter 4*, the ranges of possible cost reductions of offshore wind farm investment costs until 2020 are explored. The investment costs mainly consist of the wind turbine, the foundation, internal and external grid-connection and installation costs. For each of these components, global technological developments and cost reduction trends are analyzed in the offshore wind sector, but also in the onshore wind energy sector, the offshore oil and gas sector, and the high-voltage submarine transmission of electricity. Cost reduction trends are quantified (where possible) using the experience curve concept, or otherwise based on expert judgments. Main drivers for cost reductions are identified and conclusions are drawn on the reduction of investment costs and levelized electricity production costs.

In *chapter 5*, a case study is carried out in Sweden, scrutinizing the learning achieved in wood fuel supply chains of primary forest fuels and the associated reduction in production costs. The varying composition of the fuel supply chain, the changes over time due to technology development and chain optimization, and the resulting reduction in production costs are analyzed. As in previous chapters, special attention is paid to the application of the experience curve approach. Also a brief comparison with developments in Finland is made.

In *chapter 6,* the technological development and performance of biomass energy systems are discussed more in general, using examples from the development of biomass-fuelled CHP plants in Sweden, global fluidized bed boiler development, results from chapter five, and the development of biogas plants in Denmark. The limits of the applicability of the experience curve approach for biomass energy systems are explored, as well as possible adaptations.

In *chapter 7*, the results and insights gained in chapters 3 to 6 are employed to construct an optimistic and pessimistic endogenous technological learning scenario for the generation of renewable electricity until the year 2020. In this study, the effects of (partly) endogenous technological learning on the achievability and cost of the European goal for renewable electricity in 2020 are evaluated using the ADMIRE-REBUS model[21]. As main policy background, it is assumed that from 2012 a harmonized trading system will be implemented, and a target of 24% renewable electricity (RES-E) in 2020 is set and met. For comparison, also the impact of technological learning under continuation of present support policies is evaluated.

Finally, in *chapter 8*, the results from chapters 2-7 are summarized and evaluated. The main lessons regarding the use of the experience curve approach are highlighted, and implications for the implementation of renewable energy technologies in Europe (and especially in the Netherlands) are discussed.

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[21] ADMIRE-REBUS is an acronym for "Assessment and Dissemination activity on Major Investment Opportunities for Renewable electricity in Europe using the REBUS tool". REBUS is an acronym for "Renewable electricity burden sharing". ADMIRE-REBUS is a dynamic simulation model of the international market for renewable electricity. It pays explicit attention to trade barriers, discriminative support policies, risks, and other imperfections inherent in a market in transition.

Chapter 2: Renewable electricity in the Netherlands[1]

Abstract

The Dutch policy goal is to achieve a share of 17% renewable electricity in the domestic demand in 2020, corresponding to 18-24 TWh. It is uncertain whether and under which conditions this aim can be achieved. This paper aims to explore the feasible deployment of renewable electricity production in the Netherlands until 2020 by evaluating different images representing policies and societal preferences. Simultaneously, the most promising technologies for different settings are investigated and identified. First Dutch policy goals, governmental policy measures and definitions of renewable electricity are discussed. Second, a comparison is made of four existing studies that analyze the possible developments of renewable electricity production in the coming decades. Finally, three images are set up with emphasis on the different key factors that influence the maximum realizable potential. Results indicate onshore wind, offshore wind and large-scale biomass plants as most promising, robust options in terms of economical performance, ecological sustainability and high technical implementation rate. In the image with high implementation rates, an annual production of 42 TWh may be achieved in 2020, while under stringent economical or ecological criteria, about 25 TWh may be reached. When only the robust options are considered, 9-22 TWh can be realized. The analysis illustrates the importance of taking the different key factors mentioned influencing implementation into account. Doing so allows for identification of robust and less robust technological options under different conditions.

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[1] Published in: Energy Policy, 2004, 32(9), p. 1053-1073. Co-authors: S. Agterbosch, A. Faaij, W.C. Turkenburg.

1. Introduction

In 1996, in its third white paper on energy, the government of the Netherlands formulated a policy goal of 10% renewable energy (RE) of the total energy supply in the Netherlands in 2020 (Minister of Economic Affairs, 1995). Key drivers for this target were the global warming issue and the expected increased vulnerability of the present energy supply system, which depends increasingly on energy imports. The main emphasis was put on electricity from renewable energy sources, for which a target was set of a 17% contribution to the domestic electricity consumption, which would correspond to about 6% of the total energy demand. More recently, the Dutch government formulated an intermediate target of 9% contribution to electricity consumption from renewables in 2010, in line with the target formulated in the recent EU directive on renewable electricity (EU, 2001). Whether this goal can be achieved depends on amongst other factors on the domestic technical potential of renewable electricity, on the chosen definition or renewable electricity, the specific policy support measures and other factors influencing the actual realizable renewable electricity potential. Previous studies have indicated that these goals may not be reached by the use of domestic renewable electricity alone. Also, the latest governmental policies point out the possible necessity for import of renewable electricity to reach the targets (Ministry of Economic Affairs, 2002).

The aim of this paper is to explore the maximum ranges of the potential of renewable electricity production in the Netherlands until 2020 in several different images, representing different societal and policy preferences. In doing so it aims to identify the most promising options to achieve the goal of 17% renewable electricity.

Following aspects are addressed to meet this objective: first an overview is given of the development of the Dutch governmental support for renewable electricity during the last decade. Second, a closer look is taken at the possible interpretation and definition of '17% renewable electricity in the Netherlands' and implications on the renewable energy potential. Third, assumptions and results of four studies are compared, that aimed to forecast the development of renewable electricity production in the Netherlands, and which that were partially the basis for governmental policy formulation. In this comparison the focus is on assumptions made with respect to economics and technology, the importance of environmental sustainability, the role of governmental policy, and the social and institutional setting[2]. Finally, using the results from this comparative analysis and other studies, three new images for the domestic renewable electricity supply in 2020 for the Netherlands are developed. Each image emphasizes the role of different key factors that influence the implementation of renewable energy technologies. Those factors are characterized by concrete economic, environmental and technological criteria, which are applied in a quantitative techno-economic evaluation of different key renewable energy technologies in the Netherlands. By comparing the different outcomes the ranges for the maximum realizable potential of renewable electricity production are explored. The most promising and robust technologies are identified, and the influence of different criteria and factors on the likely implementation of renewable energy options is quantified.

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[2] The institutional setting consists of regulating mechanisms such as the rule of law and the accountable exercise of power, which influence decision-making processes and behavior of actors. Institutions are continually renegotiated in the continued interplay between human agencies and wider social structures. The interrelated social setting consists of the actors or stakeholders actually involved in a certain (policy) field (O'Riordan et al., 1998).

2. Dutch policy goals and instruments

2.1. Governmental policy of the last decade

The Dutch policy regarding renewable energy sources started after the oil crisis of 1973, when the Dutch government initiated a national research program for the development and application of wind energy (Wolsink, 1996). Until the first half of the eighties, policy mainly focused on R&D, and in the short-term domestic potential of renewable energy sources was deemed to be of little significance. No policies regarding exploitation of this potential were formulated[3] (Minister of Economic Affairs, 1980). This changed however over the next ten years. Specific targets for different technologies were defined. Key examples were the target to have 1000 MW_e of wind capacity installed in 2000, and 300,000 solar thermal boilers in 2010 (Wolsink, 1996; Verbong, et al., 2001). In the third energy paper (1996), the first integral policy goal of '10% renewable energy in 2020 in the Netherlands' was set (Minister of Economic Affairs, 1995). There were two main reasons for this objective: First of all environmental reasons: the global warming issue and the subsequent pressure to seriously cuts down CO_2-emissions. The other key reason was fuel supply diversification; i.e. reducing the dependency on the oil exporting countries. This was to be achieved by importing different primary energy carriers from a diverse set of regions and by increasing the use of domestic, renewable energy sources.

It was estimated that the total domestic consumption of energy in the Netherlands amount about 2880 PJ in the year 2020, the same level as 1990, and that 10% renewable energy would correspond with 288 PJ avoided primary energy (fossil fuel use). The estimated contribution of different renewable energy sources to this goal is presented in Table 1[4]. Furthermore, international targets (Kyoto and EU) were translated into national targets and which materialized in the White Paper on Renewable Energy issued by the Dutch Minister of Economic Affairs (1995) and the Action Plan on Climate Policy[5] issued by the Dutch Minister of Spatial Planning, Housing and Environment (1999).

The Project Bureau Renewable Energy (PDE) was founded after publication of the third energy paper in 1996. The bureau is an initiative of the government and the Dutch energy sector. The main purpose of this bureau is to enlarge the production, consumption and the public support for renewable energy, by means of public campaigns, providing technical, economical and juridical information and by supporting local governmental authorities in starting up renewable energy projects.

In the 'Action Program for Renewable Energy'(Minister of Economic Affairs, 1997), which was released in 1997, and in the Energy Report from 1999 (Ministry of Economic Affairs, 1999)[6], the

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[3] A notable exception is wind energy. In 1980, it was expected that wind would contribute 2,000 MW in the year 2000.

[4] The amount of avoided primary energy is calculated according to the guidelines given in the 'Protocol for monitoring renewable energy' (Novem, 1999) and includes both renewable heat and renewable electricity. Note that in this definition, a reference efficiency of the electricity park is used, e.g. 40% in 1995. This implies that 1 kWh of electrical energy is counted as 2.5 kWh (9 MJ) of avoided primary energy. In 2020, a reference efficiency of 62% is assumed, reducing the same amount of electricity to approximately 1.6 kWh of avoided primary energy.

[5] The Action Plan on Climate Change contains the governmental actions formulated to comply with the reduction targets of the Kyoto Protocol indicating that by the end of the Kyoto budget period, the emissions of greenhouse gasses in the Netherlands should be 6% lower than in 1990.

[6] Every four years the Dutch government publishes an Energy Report, in which the national energy policy is described. It is a strategic document in which the expected consequences of policy strategies are evaluated. Attention is paid to

government presented its preferred mix of policy instruments given the realization of a liberalized energy. Key elements were a consumer driven approach in the renewable energy market (fully liberalizing the green energy market in 2001); voluntary agreements with the energy sector and industry; greening the fiscal system by increasing the energy tax and encouraging research and development through specific programs (Kwant and Ruijgrok, 2000).

Table 1 Avoided primary energy consumption (PJ) by renewables in the Netherlands in 1990, 1995 and 2000, and the policy goal formulated in 1995 for 2000 and 2020 (Joosen et al., 2001).

	Actual realization			1996 Policy goals	
	1990	1995	2000	2000	2020
Wind onshore	0.5	2.6	6.9	16	45
Solar-PV	0	0.01	0.07	1	10
Solar-thermal	0.08	0.2	0.4	2	10
Geothermal	-	-	-	-	2
Heat storage	0.01	0.07	0.5	2	15
Heat pumps (excluding heat pumps utilizing fossil heat)	n.a.	0.2	0.6	7	65
Domestic hydro power	0.7	0.7	1.2	1	3
Energy from waste incineration (organic waste fraction only)	6.3	5.6	11.6	20	45
Biomass	10.8	13.2	16.2	34	75
Hydro power import	-	-	-	-	18
Total	**18**	**23**	**37**	**83**	**288**

2.2. Renewable energy policy support measures

As explained in the action program following the third white paper on energy, the different support measures for renewable energy during the last decade can be divided into three (partly overlapping) categories:

1. *Improve competitiveness*; by supporting research and development of existing and new renewable energy technologies with the objective to improve their competitiveness.
2. *Stimulate market penetration*; by financial regulation – greening the fiscal system and subsidies- and by liberalizing the renewable electricity market.
3. *Encounter political & administrative bottlenecks;* by streamlining planning and building permit procedures.

These three categories will be discussed below in detail.

1. With regard to *improving the competitiveness*, the total government expenditures on renewable energy research almost doubled between 1995 and 1999. In 1999, the annual governmental RD&D spending on renewable energy support was € 39 million (Ministry of Economic Affairs, 2001a)[7], see also Table 2.

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security of supply, consequences for the environment, and the transition-process to a sustainable energy-supply system (ECN, 1999; van Halen et al., 2000).

[7] In the national Energy Research Strategy (EOS) (Ministry of Economic Affairs, 2001a) priorities for governmental support on R&D are formulated. As private sector research is concentrating increasingly on the short term as a consequence of the liberalization and privatization of the sector, the government is shifting its focus supporting actions with a long-term time frame.

2. In the beginning of the nineties *measures to stimulate renewable energy market penetration* were mainly aimed at the renewable energy supply side (i.e. stimulating the increase of renewable energy capacity) using financial incentives, (primarily by subsidizing investments). This policy changed with the greening of the fiscal system halfway the nineties. This shift led to the creation of green funds, accelerated depreciation of investments (VAMIL), a tax credit on renewable energy technologies (EIA) and a number of other financial instruments (see also Table 2). This greening of the fiscal system works in two directions: first, it reduces the costs for renewable energy producers, and second, it increases the ability to pay for renewable electricity by end-users (Kwant and Ruijgrok, 2000). Since the introduction of the Environmental Tax Law, in 1998, households and Small- and Medium-sized Enterprises pay an energy tax on electricity and natural gas (the so-called REB-tax). Producers of renewable energy are eligible for a support payment financed by the revenues of the energy tax. Also, the REB-tax encourages the demand for renewable energy by making energy from fossil fuels more expensive. Between the period of 1999 and 2002, the REB-tax increased from 2.6 to 7.1 €ct/kWh. Therefore, electricity companies are now able to offer renewable electricity at the same or even lower price as electricity from fossil fuels (Greenprices, 2002). In addition, the Dutch small-consumer market for renewable electricity was liberalized by the first of July 2001, which was way ahead of the 'fossil electricity' small-consumer market (for which liberalization is scheduled for January 2004). This enables electricity distribution companies to gain new customers outside their traditional distribution area. These two factors have led to an enormous increase in the demand of 'green electricity'. Currently, this demand cannot be covered by the domestic renewable energy based power generation capacity at this moment[8]; The demand from small-scale electricity users (i.e. households) for renewable electricity has increased from a few thousand households in 1998 to approximately one million households in July 2002 (Greenprices, 2002).

3. A number of different initiatives were taken to *remove political and administrative bottlenecks.* In 1991, the national government created a wind covenant with seven provinces with good wind conditions. The main purpose of the agreement was to create sufficient locations for wind turbines, through focused spatial planning policies of the national and provincial governments. This should support the installation of 400 MW_e in 1995 and 1000 MW_e in 2000. The speed with which the implementation proceeded was however unsatisfactory and the final results turned out to be disappointing (less than 500 MW_e installed in 2000). In 2001, a new wind covenant (BLOW) started, now not only incorporating six different Ministries of the national government and all the 12 Dutch provinces, but also the association of the Dutch municipalities. The aim of this agreement is the realization of 1500 MW_e wind generating capacity in 2010 (Minister of Economic Affairs, 2001a). As another initiative, in the Energy report 2002, the start of a so-called 'MDW-projects' was announced. The aim of such projects is to investigate whether it is possible to shorten and reduce the complexity of the procedures for obtaining planning approval- and building permits.

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[8] This gap is currently covered by increased import of electricity, which however causes a number of connected problems, recently described by Reijnders (2002). The main problem is tax revenues flowing abroad without direct stimulation of new production capacity. By the end of 2002, approximately 80% of all renewable electricity was imported (Brehm, 2002).

Table 2 Governmental financial support measures for renewable energy sources. All amounts are nominal, i.e. not adjusted for inflation. Sources: (Ministry of Economic Affairs, 2001a; Ministry of Economic Affairs, 2002; Novem, 2001; Kwant and Ruijgrok, 2000; Ministry of Economic Affairs, 2001b; Ministry of Economic Affairs; 2001c; Ministry of Economic Affairs, 2002).

Financial instruments	Description and magnitude	Governmental expenditure
R&D support	Support for research in solar-thermal, solar-PV, wind, biomass and other renewable energy technologies	200 M€ (1995-2000)
Green Funds	Investors in 'green projects' can obtain lower interest rates from **Green Funds**. These funds are created by savings of private persons, who are exempted from paying income tax on the interest received.	Green Funds, VAMIL & EIA 65 M€ (1990-2000)
Accelerated Depreciation	From 1996 until 2002 the **VAMIL scheme** offered entrepreneurs a financial advantage because accelerated depreciation was permitted on equipment, which was included in the VAMIL list. The accelerated depreciation reduced tax payments on company profit. However, all energy-related technologies were removed from the VAMIL list in 2003.	
Tax Credit	Since 1997 the **Energy Investment Scheme (EIA**) and the **Environmental Investment Scheme (MIA)** make it possible since 1997 to offset investments in technologies against taxable profit. The tax credit offered varies from 52.5% to 40% (depending on the size of the investment). In 2003, the MIA was abolished for energy-related technologies. Also, in order to apply the EIA, a building permit must now be obtained first.	
Investment credits	The **Subsidy Scheme for the Non Profit Sector (EINP)** consists of a subsidy of 14,5%-18,5% on the investment costs for the non profit sector (private persons, associations and denominations etc.) **The CO_2-Reductionplan** is a special kind of subsidy scheme. The subsidies are distributed on the basis of a tender system. The maximum amount of subsidy is 45% on the investment costs for renewable energy projects. **Decision Subsidies Energy programs (BSE)** aims at the development and application of innovative projects. **Subsidy scheme for active solar thermal systems (ZON)**.	Unknown
Other financial measures	For energy companies and municipalities, so-called environmental action plan **(MAP)-funds** were made available until recently. Investments for renewable energy projects were financed by allowing utilities to charge consumers an extra fee.	179 M€ (1990-2000, paid by consumers)
Taxes	**Regulatory energy tax (REB):** tax exemption for electricity from renewable energy sources. Tariffs (€ct/kWh, value-added tax included): 1999 2000 2001 2002 2003 2.6 4.4 6.9 7.1 3.45	18.5 M€[a] (1998-2000)
Production support	All producers of renewable electricity received 2 €ct/kWh since 1998 until 2002 from the revenues of the REB-tax. (1 €ct/kWh for electricity from municipal solid waste).	151 M€[a] (1996-2000)
Feed-in tariffs	Preliminary **MEP-tariffs** (Environmental quality of the electricity production) in €ct/kWh, as published December 19th 2002, to be applied in the course of 2003 [b] W_{on} W_{off} $B_{<50}$ $B_{>50}$ B_{mix} HPTW 4.9 6.8 6.8 4.8 2.9 6.8	Paid by electricity consumers

a This amount is expected to be much larger in 2001 and 2002 due to the much higher tax exemption and the dramatic increase in consumption of renewable electricity. In July 2002, over 1 million households use renewable electricity. On basis of an average consumption of 3200 kWh/year, this would amount to 227 M€ of lost tax income per year, and another 64 M€ of production support. Therefore the REB-tax exemption was cut by 50% in 2003.

b W_{on} = Wind onshore, W_{off} = Wind Offshore, $B_{>50}$ = Biomass power plants > 50 MW, $B_{<50}$ = Biomass power plants < 50 MW, B_{mix} = mixed waste streams, HPTW = Hydropower < 15 MW, Photovoltaic power, tidal power and wave power.

The actual growth of domestic renewable electricity production over the period 1990-2000 is given in Figure 1. In this timeframe, the share of renewable electricity rose from 0.9% to 2.5% of the domestic electricity demand. In 2000, the overall penetration only reached 37 PJ, less than half of the desired target of 83 PJ. In view of these disappointing results, the Dutch government recently changed a number of policies, which are discussed in the next paragraph.

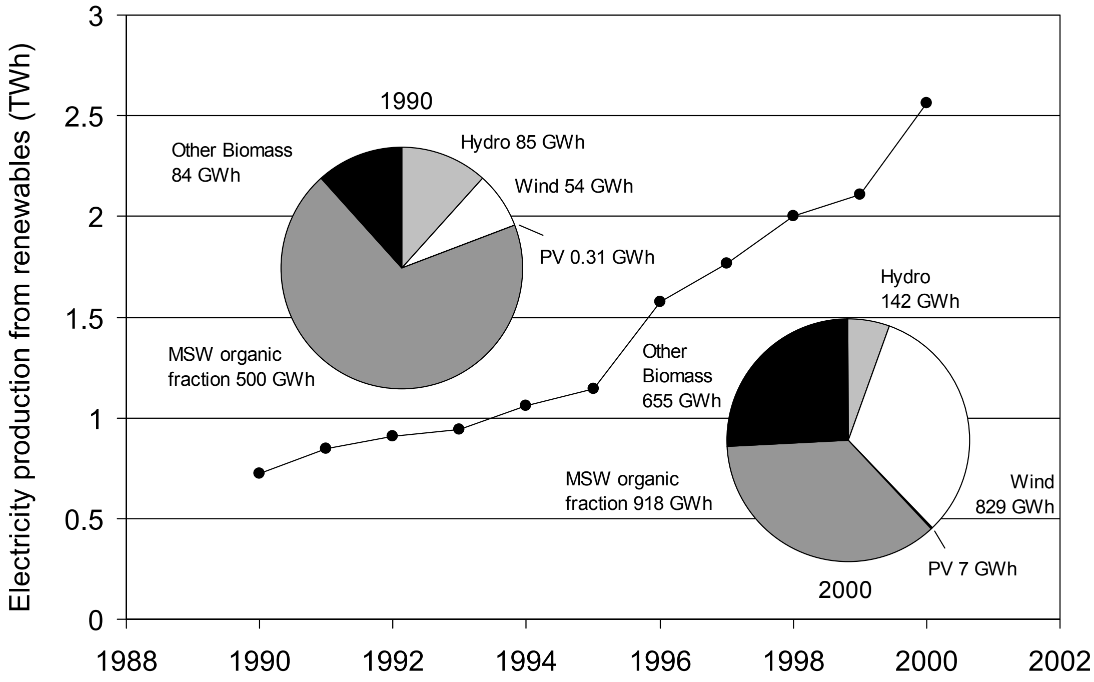

Figure 1 Electricity production from renewables in the Netherlands 1990-2000. Also the composition of the production in 1990 and 2000 is shown 2020 (Joosen et al., 2001).

2.3. Recent developments

The Energy Report of 2002 resulted in a shift from a broad spectrum of renewable energy options towards a focus on energy from biomass and wind. For wind offshore, a policy goal was formulated of 6000 MW_e for 2020. Wind and biomass were also to become spearheads in Dutch government supported R&D activities (Ministry of Economic Affairs, 2001a).

In the third energy white paper renewable energy options in the built environment, such as photovoltaics, solar heaters and heat pumps were expected to contribute almost 30% of the total of renewable energy production in 2020. More recently, those options are considered to contribute substantially only after 2020 (Minister of Economic Affairs, 2001b). As a consequence the direct support for these options was reduced compared to previous years. Furthermore, in spite of the fact that current policy mainly aims to support the domestic renewable energy supply, the Ministry of Economic Affairs now expects that the renewable energy target may not be obtainable by using domestic resources only and will partially depend on imports of electricity. In July 2002, the newly elected government of the Netherlands announced that it would drastically restrict most financial incentives (such as the VAMIL, EIA, and the regulatory energy tax) in order to reduce the free-rider effect (the over-stimulation of investments which would also have been made without any incentives) and to save about € 500 million (Minister of General Affairs, 2002). In the autumn of 2002, the Dutch government fell. Yet, at the end of 2002, the government (while being under resignation) announced that the exemption of the regulatory energy tax for renewable electricity will be cut by 50% in order to reduce imports of foreign electricity, and the generic feed-in tariff of 2 €ct/kWh will be abolished. Plans are that it will be replaced by the so-called MEP feed-in tariffs, which are differentiated by renewable energy technology (see Table 2). These tariffs are fixed for a period of ten years and are only applicable to electricity produced within the Netherlands. The MEP-feed-in tariffs will be financed by all electricity consumers, who have to pay a fee of € 34 per grid-connection (Ministry of Economic Affairs, 2002).

3. The definition of renewable electricity

The aim of this paper is to analyze the domestic potential of renewable electricity and the possibility of achieving the mentioned target of 17% in 2020. The exact definitions of renewable electricity, the goal of 17% renewable electricity, and their implications for various renewable electricity sources will now be discussed and compared. As import may also play an important role in the future, possible ways of importing renewable electricity are also included in the discussion.

3.1. Definition of the share of renewable electricity to total electricity supply

The interpretation of '17%' is depending on the actual total electricity demand in 2020, which is subject to changes. In the latest report of the Energy Research Centre of the Netherlands (ECN) it is expected that the domestic electricity consumption may rise from 105 TWh in 2000 to 124 TWh in 2010 (Ybema et al., 2002). Following the trend and assuming a further annual increase of 1.6%, the total domestic electricity consumption in 2020 may rise up to 145 TWh. This implicates that the absolute amount of renewable electricity required to obtain the 17% goal in 2020 may lie somewhere between 18 – 24 TWh. In the remainder of this document this range will be used for further discussion and comparisons.

3.2. The difference between renewable and sustainable

Regarding the definition of renewable electricity, *renewable* energy (with the main emphasis on the basically inexhaustible character) and *sustainable* energy (also taking into account economic, social and overall environmental sustainability) are often confused. For both expressions, the Dutch word 'duurzaam' is used. The Dutch definition of *renewable* electricity (in the sense that it is inexhaustible) is clearly stated in the Protocol Monitoring Renewable Energy (Novem, 1999). Electricity and heat from the organic fraction of MSW for example is included. This definition is in line with the EU directive on 'promotion of electricity from RES' (EU, 2001), and used in national statistics when calculating the contribution of renewable electricity. However, the law on environmental taxes (Minister of Finance, 1994) gives a more narrow definition of renewable electricity, which has a more '*sustainable*' character (in the sense of overall sustainability). Energy from the organic fraction of MSW is excluded, and thus also from the tax exemption (REB) described in the previous paragraph. Yet, electricity from waste streams like contaminated demolition wood, or chicken and pig manure from the intensive bio-industry is currently eligible for the REB-tax exemption. The (overall environmental) sustainable character of these forms of renewable electricity is currently disputed (Schöne, 2001). Another example is the environmental sustainability of wind power, which is considered to be very much dependent on the exact location of the wind park. For instance, plans for a 300 MW_e wind park located at the border of the Wadden Sea nature conservation area were strongly opposed by several environmental groups (Martin, 2001), and are now on hold.

3.3. Domestic and imported electricity

Finally, as the aim of this paper is to determine the potential for domestic production of renewable electricity, it is important to distinguish clearly between renewable electricity from domestic sources and from possible forms of import. There is no official Dutch definition of 'renewable electricity import', and no international agreements currently exist on how for example two countries may account the import / export of electricity for their national renewable electricity policy goals. In the Dutch Protocol monitoring renewable energy (Novem, 1999) it is defined that renewable energy should be *accounted to the geographical location where the extraction or exploitation takes place*, which is a rather broad and vague definition. Therefore, in this analysis an attempt is made to classify various forms of domestic and imported renewable electricity.

3.3.1. Domestic renewable electricity

Logically, all electricity produced from Dutch PV-plants, wind farms and hydro plants account for domestic renewable electricity. For biomass, this would mean electricity produced from biomass, which was cultivated in the Netherlands[9]. A more complex case is the electricity derived from the combustion of organic waste. The Netherlands is a large net importer of wood and paper (Lafleur and Fraanje, 1997; Hekkert et al., 2000), which in turn contributes a large fraction of the biomass that is combusted in waste incineration, plants which produce power and heat. A rough calculation indicates that 60% of this biomass fraction may have been imported (Dornburg, 2001). If this type of biomass was to be considered as 'imported' (and thus the electricity derived from it), this would imply that in the year 2000 about 17% of all renewable electricity in the Netherlands might be from foreign origin. Also biomass that is imported especially for conversion to electricity clearly falls under this category[10]. Yet, the import of biomass is considered here as *domestic* renewable electricity. The main argument is that the conversion from primary biomass to electricity is carried out within the Netherlands and the same reasoning is normally applied for electricity production from imported fossil fuels such as coal or oil.

3.3.2. Forms of imported renewable electricity

Electricity import through the high-voltage grid is an example of import that has grown tremendously in 2001 (Scheepers, 2001). It is estimated that at the end of 2002, up to 80% of all renewable electricity falling under the REB-tax exemption was imported (Brehm, 2002). It should be stressed that under the RES-E directive, renewable electricity produced outside the EU cannot contribute to national goals (EU, 2001). A new phenomenon is the concept of a European /

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[9] While residues and biomass waste streams are already utilized on a large scale for bio-energy applications, biomass from domestic plantations is currently only used on a very small scale (NUON, 2000).

[10] For example, in 2001 the utility Essent imported about 50,000 tonnes of wood pellets from Canada and Scandinavia for co-firing in the Amer Power station at Geertruidenberg (Hoogendoorn, 2001). Also, a number of studies have been carried out regarding the feasibility of biomass import for energy purposes, revealing a significant potential (Beekes et al., 1996; Agterberg and Faaij, 1998; BTG, 1998; Lako and van Rooijen, 1998; Suurs, 2002). Hypothetically, also he import of liquid biofuels, biogas or hydrogen from biomass could fall under this category. It should be noted though, that the Netherlands also *exported* over one million tons of high-caloric biomass residues and waste of organic waste streams in 2001 (van den Brand, 2001).

international green certificate trading system. In this case, the renewable electricity is produced and consumed elsewhere, but a certificate representing the renewable character of this electricity may be issued and traded nationally or internationally. Although an European or international green certificate trading system is not likely to be implemented in the near future, the Dutch government has already enabled the certification of renewable electricity from a number of European countries. While current Dutch law requires energy companies to physically import renewable electricity from abroad, this may become superfluous under a tradable green certificate system.

In conclusion, the *domestic renewable electricity* potential as defined in the previous paragraphs includes all renewable electricity produced in the Netherlands, also from imported biomass (see also Figure 2). Possible import of electricity or certificates will not be taken into account.

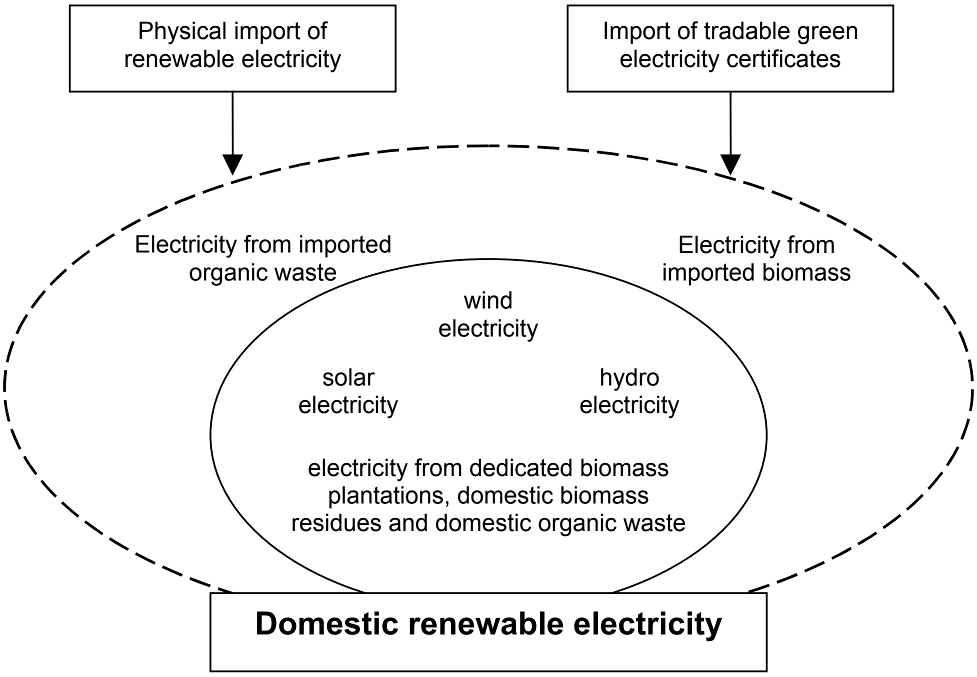

Figure 2 Forms of domestic renewable electricity, and import of physical electricity and certificates.

Summarizing, the Dutch government has set ambitious goals for renewable electricity production in 2020, while during the last decade domestic production capacity only increased slowly. Thus, it is unclear whether and under which circumstances these targets can be achieved. Before this will be further investigated in the images presented in section 5, a number of other studies dealing with future renewable electricity production in the Netherlands are scrutinized and compared in the next section.

4. Prospects of renewable electricity in the Netherlands - expectations of some existing studies

4.1. Description of scenario studies on renewable energy in the Netherlands

Numerous studies have been carried out that investigated the possibilities of individual renewable energy options in the Netherlands. For instance, the Netherlands Energy Research Foundation (ECN) has carried out several studies analyzing the possible developments in the Dutch energy field including renewable energy in 1995 (van Hilten et al., 1996), 1998 (van Hilten, 1998), 1999 (Ybema, 1999) and 2002 (Ybema, 2002). Next to that, there have been many other studies analyzing separate renewable energy options for the Netherlands, such as biomass (Faaij, 1997; van Halen et al., 2000), PV (Alsema and van Brummelen, 1992) and wind, both onshore (Stichting Natuur en Milieu, 2000) and offshore (Bakker, 1997).

In order to analyze the feasibility of the Dutch policy goal for renewable electricity, four studies were selected for further analysis. Except for the REBUS study, all studies are in Dutch and were written for Dutch policy makers (see Table 3). It is therefore interesting to analyze how these studies were carried out, what kind of possible development they foresee for renewable electricity in the Netherlands, and on basis of which arguments. The studies have been compared with respect to the approach followed and their specific results for renewable electricity in the Netherlands. These specific studies were selected, because they deal with the whole spectrum of renewable energy/electricity, and because they applied different approaches on how to assess the renewable energy/electricity potential. Furthermore, they are fairly recent (i.e. not older than the third energy white paper of 1996) and include a time horizon until the year 2020[11]. The studies are compared with the focus on renewable electricity production, i.e. the outcomes for other forms of renewable energy (e.g. heat, biofuels) were not compared.

The following aspects are the focus of the comparison:

- Economical viability
- (Assumed) technological progress, choice of technologies and maximum technical implementation rates
- Social setting, institutional setting and possible governmental policy
- (Overall) environmental sustainability of renewable electricity options

These aspects were selected based on a first scan of the selected studies on what they identified as important aspects. Also many other studies identify these issues as key aspects[12].

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[11] The most recent study partially regarding renewable electricity (Ybema et al., 2002) was not used here, as it solely focuses on 2010.

[12] The importance of economical viability for renewable energy technologies has been analyzed in an immense number of studies. Overviews of the economics of renewable energy sources are given by Johansson et al. (1993) and Turkenburg et al. (2000). The significance of technological development of renewable energy technologies is also described in a number of studies (Grübler et al., 1999; Neij, 1999a; McDonald and Schrattenholzer, 2001). The relative importance of the social and institutional setting and governmental policy see for instance Wolsink (1990; 1996 2000), Jacobsson and Johnson (2000) and Enzensberger et al. (2002). The impact of environmental effects of fossil and renewable energy sources is discussed by Holdren et al. (2000).

Table 3 Description of the studies compared.

Study	Abbreviation	Short description of approach
1) The contribution of ECN to the 3rd energy white paper (van Hilten et al., 1996)	DEN	The DEN-study analyses possible developments for the complete Dutch energy system until 2020, including renewable electricity. Two scenarios (prosperous and trend) are distinguished for renewable energy.
2) Renewable energy in the race to 2050 (Cleijne et al., 1999)	RACE	The RACE-study analyses the costs and the potential of different renewable options for 2020 and beyond, but also focuses on two different scenarios, illustrating the difference between 'only renewable' and 'general environmentally sustainable'.
3) The contribution of renewable energy in the Netherlands in 2020 (Ybema, 1999)	DENL	The DENL study especially focuses on the development of renewable energy in the Netherlands until 2020 under the given governmental policies of 1999. It presents three scenarios (low estimate, best guess and high estimate).
4) Renewable energy burden sharing (Voogt et al., 2001)	REBUS	The REBUS report demonstrates the effects of different European tradable green certificate systems for the year 2010 on the renewable electricity market in Europe (including the Netherlands), but also includes 'long-term renewable electricity potentials' per country. As this potential differs only from the '2010-potential' regarding the offshore wind potential (which is about double the potential of 2010), the assumption that this may be valid for 2020 seems reasonable.

4.2. Study comparison

Economical viability: There are a number of economical decision parameters for technical options, such as the net present value (NPV), the internal rate of return (IRR), the initial height of investment cost, the break-even cost of electricity or the payback time. In the studies compared here, mainly the required internal rate of return (IRR) that projects have to realize is deemed of major importance. An overview of the assumptions for the IRR required is given in Table 4. As can be seen, the assumptions for the desired IRR differ between 5%, e.g. reflecting an environment where renewables are strongly supported by the government, and 11.6%[13], indicative value for a highly competitive liberalized environment.

Table 4 Overview of parameters compared in the four studies.

Study	DEN	DENL	RACE	REBUS
Time frame	2020	2020	2020/2050	2010/2020
IRR (%)	5	11.6	8	8
Technological development	exogenous	endogenous	exogenous	exogenous
Financial instruments	XXX	XXX	XXX	XXX
Communicative and judicial instruments	-	-	-	-
Social setting	-	X	X	X
Institutional setting	-	-	X	X
Sustainable development	-	-	XX	X

X	significance recognized, underlying assumptions and quantification unclear;
XX	significance recognized, underlying assumptions are explicit, quantification unclear;
XXX	significance recognized, underlying assumptions are explicit, quantification is explicit.

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[13] Assuming a debt/equity ratio of 70/30, an expected return on debt of 8% and an expected return on equity of 20%.

The choice of the IRR is specifically important when economic optimization models are used (such as in the DEN and DENL study). In that case, the (relative) economic viability of a renewable energy technology largely determines its diffusion until 2020. Options only penetrate when they fulfill a minimum economic viability, but the penetration rate is much higher when a high economic viability is reached (Ybema, 1999)[14]. Thus, both the choice of technologies and rate of penetration are both determined by costs in these studies.

In contrast, in the RACE study, costs basically do not influence the projected realizable potential. The RACE study uses identical costs in both scenarios included (see Table 3), i.e. the choice for and different penetration of a certain option does not primarily depend on the economic performance, but on its environmental qualities. This causes a different selection of technologies in the sustainable scenario, i.e. more use of biomass streams for gasification options instead of co-combustion options. Only as a secondary step, it is analyzed which part of the renewable/sustainable potentials are also economically viable applying an IRR of 8%.

Finally, in the REBUS-study, a possible electricity supply curve is calculated with a required IRR of 8%. In first instance, no costs limitation is given, i.e. in the supply curve of the Netherlands, relatively expensive electricity from e.g. PV is included. However, the decisive factor is whether or not the cost of electricity is below or above the average price of an international tradable green certificate, and basically all options above this average price are considered not to be realized.

Technological progress, choice of technologies and maximum technical implementation rate: All studies assume that the costs of renewable electricity technologies are going to decline until 2020. Two different approaches for internalizing such cost reductions are found. The DEN, REBUS and RACE studies assume a fixed reduction in costs, e.g. 20% lower investment costs in 2020 compared to current costs. The numbers are often taken from literature, and may be based on expert judgments, bottom-up analyses of technology or simple trend extrapolation.

In the DENL study, a different approach for cost development is chosen for wind onshore, offshore and PV. The study uses the experience curve concept, in which the cost reduction depends on the cumulative production of a technology. With every doubling of the capacity, the costs are reduced by a fixed amount (e.g. 20%). This relation can be described by the progress ratio (see for instance (Neij, 1999a; Junginger, 2000). In the DENL-study, progress ratios for each technology are taken from literature reviews. As starting point, current average investment costs are estimated. As these experience curves depend both on the progress ratio used and the assumed amount of cumulative production until 2020, high and low estimates are used for both variables. By doing so, the study determines a (maximum) range and a best guess for the potential future investment costs of the renewable energy options included.

In terms of the maximum technical installation rate, only the DENL study identifies a possible bottleneck for offshore wind and PV. For offshore wind, the actual bottleneck may be the number of days, on which wind turbines can be installed (due to weather conditions, i.e. days with sufficiently low wave and wind conditions). For PV-modules, the growth in global production capacity and the maximum Dutch market share may be a limiting factor.

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[14] Theoretically, in these kind of models expensive technologies such as PV would not penetrate at all. In order to achieve a minimum diffusion level of PV, very high financial support tariffs (e.g. 0.45 € / kWh) are assumed in the DENL-study.

Assumptions on social setting, institutional setting and governmental policy: Implementation and operation of a technology in society depends on the environment or context in which implementation is to take place. By determining the relative importance of different aspects of the context – for instance the social and institutional aspects - it may be possible to gain further insight into bottlenecks and chances for implementation. The institutional setting consists of regulating mechanisms, which influence decision-making processes and behavior of actors. These include for example the way administrative bodies work, decision-making procedures, opportunities for civic participation and legal requirements. The interrelated social setting consists of the actors involved, e.g. electricity producers, research institutions, energy distribution companies, manufacturers, different social pressure groups, individual households, corporations and policy-making institutions. The perceptions and behavior of these actors combined make up the social system of norms and rules. This context provides essential prerequisites for the possibilities of implementation. The possible impact of the social and institutional setting is recognized in three studies (DENL, REBUS, RACE) and sometimes even emphasized. However, this element is barely or not at all included in model calculations.

The effects of governmental policies on the implementation of renewable electricity technologies are taken into account as far as they have a direct quantifiable effect on the economic feasibility of different renewable electricity options. The emphasis in the studies is therefore put on the financial instruments (e.g. R&D or other subsidies). The possible impact of for example communication strategies is not included in the model calculations.

Different studies, however, show that both social and institutional aspects are important factors for implementation rates. An early study of Jahraus on the influence of local politics in implementation processes states: ‘the decisive factor is the motivation of the operator to invest in this technology, and the acceptance of the utilization of wind energy by investors and the public’ ((Jahraus et al., 1991) p 527, in (Wolsink, 1996)). Another study, on fluorescent lighting, showed that the calculated techno-economical potential was an overestimation of actual investments by consumers, due to barriers like transaction costs, lack of information and psychological aspects ((Krause and Eto, 1988) in (Wolsink, 1996)).

The intrinsic nature of these aspects makes the effect on implementation rates hard to quantify and it is questionable whether these aspects may be adequately incorporated into model calculations at all. The context in which implementation has to take place - the social and institutional setting - is not properly predictable. Stressing the importance of these factors in the study, but not incorporating them in the model calculations may give an inappropriate appearance of certainty. This is also true for ‘best guess’ scenarios, solely based on techno-economical input. Instead, uncertainty ranges should be made explicit.

Environmental sustainability: Although the use of renewable energy sources generally reduces CO_2-emissions, their deployment may also result in negative consequences for the environment and (local) living conditions. Various environmental and societal demands (e.g. emission levels, placement of wind turbines near nature conservation areas, landscape impacts or permitted noise levels) can influence the maximum realizable potential of renewable electricity technologies. Only in the RACE study these limitations are recognized and incorporated in the scenarios. In the REBUS study, ‘unacceptable environmental impacts’ are identified as a relevant factor, but whether and how this factor was taken into account in model calculations is not stated. The DEN- and DENL-study do not mention these factors. Since sustainable development as a whole is a key element of the Dutch governmental policy, it is concluded that except for the RACE study, the resulting diffusion rates may be too optimistic in most studies.

4.3. Analysis and comparison

In Figure 3 the different key results of the studies are presented. Most studies conclude that in prosperous circumstances, the policy goal of 17-24 TWh may be reached, while in most 'best guess' or 'trend' scenarios, this target is not accomplished. However, the approach with which the four studies come to these results differs strongly between the studies. Also, the lowest and highest scenarios differ over a factor three. Elements that explain these varying outcomes are discussed below.

In all studies, except RACE, economic viability plays a key role in the projected diffusion of renewable electricity technologies. Yet, none of the studies evaluates the effects of different IRR on the outcome of the study, while they actually vary significantly between the studies. In addition, the endogenous technological learning approach used in the DENL-study reveals that results may vary substantially when different progress ratios and global diffusion rates per technology are assumed. In the most extreme case, the diffusion of PV varies by a factor of over one hundred in the optimistic and the pessimistic scenario. Different assumptions for technological progress are thus a key factor causing the optimistic and the pessimistic DENL-scenarios to differ by over a factor 2 for the total renewable electricity production (19.7 and 9.1 TWh respectively, see also Figure 3).

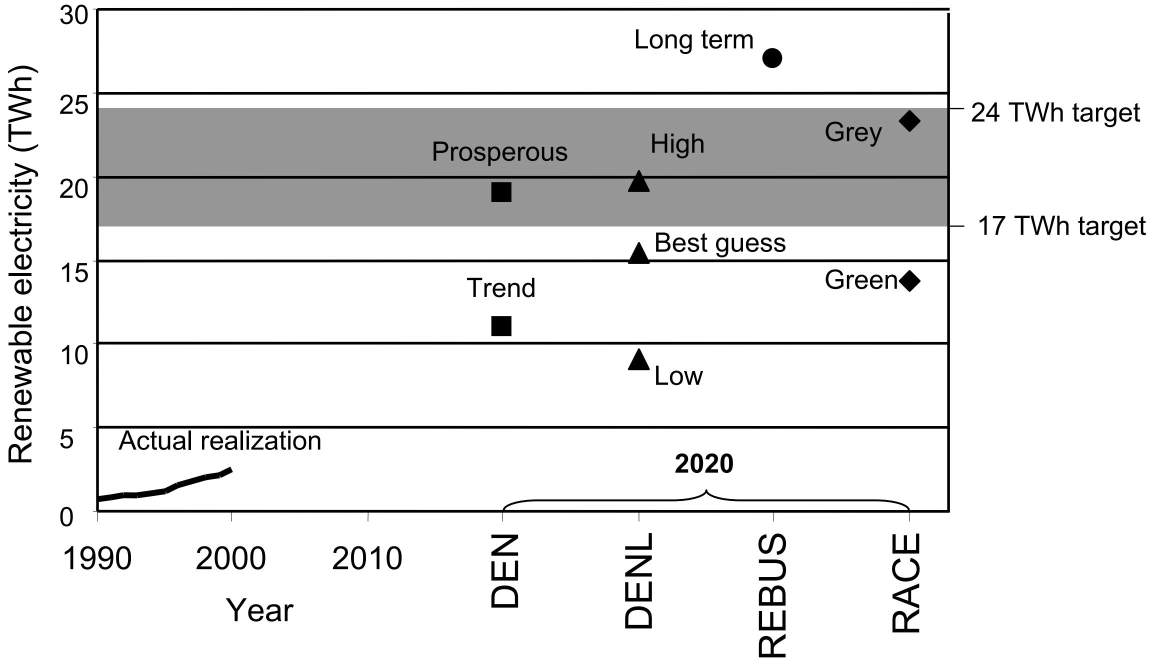

Figure 3 Possible renewable electricity production in the Netherlands in 2020 according to four studies (van Hilten et al., 1996; Ybema, 1999; Voogt et al., 2001; Cleijne et al., 1999).

In the RACE study, the difference between the ‘green’ and the ‘gray’ scenario is caused by assuming stricter sustainability criteria for implementation of onshore wind (thus resulting in less capacity installed), and the use of biomass in CHP plants instead of co-firing it in coal power plants in the green scenario. In a more overall (environmentally) sustainable scenario, renewable electricity production in this study is 40% lower than in the gray scenario. Another difference between the RACE-study and all other studies is, that *before* economical criteria are used, the technologies are selected on basis of environmental sustainability criteria. Consequently, different technologies (i.e. co-firing of biomass in coal plants vs. use in new gasification plants), and different spatial distributions are observed (i.e. placement of wind turbines based on favorable wind conditions vs. least impact on nature protection area’s).

The reason why the REBUS study projects the highest renewable electricity production in 2020 of all studies is explained by the assumed large capacity of offshore wind, and a very optimistic view on the onshore wind potential. Finally the difference between the trend and the prosperous scenario in the DEN study is caused by the assumption that (unspecified) governmental policies will stimulate biomass cultivation, wind offshore and additional PV penetration in order to achieve the policy target for renewable energy.

As was mentioned before, the DEN, DENL and RACE study were written by assignment of Dutch policy makers. Thus, the outcomes of the different studies were used as input to formulate new policies. Most studies focus on the current policy regarding the financial support for renewables. While important, the effects of possibly failing policies regarding in relation to the institutional and social setting are neglected. How the effects of institutional and social setting can be quantified adequately in terms of effects on realizable renewable electricity potential is uncertain (see also Table 5).

Summarizing, the studies described here show that leaving out one or more key parameters leads to incomplete analysis, yet integrating all key factors into one quantitative forecast is difficult and may lead to a false suggestion of accuracy. In the following section, an attempt is made to compose images (i.e. visions) that incorporate the aspects mentioned in table 5. Each image focuses on the impact of one key aspect, without neglecting the other aspects.

Table 5 Key factors determining the realizable potential of renewable electricity and the possibility of quantification.

Key factor	Can effects be quantified in terms of realizable potential?
Economic viability	Yes. Given a set of economic decision criteria and known cost reduction, the economic viability can be quantified.
Technological progress	In a limited way. Estimates for technological progress and related investment costs vary greatly. This has significant effects on the outcome of the models, yet in most studies little attention is paid on these uncertainties.
Governmental financial policy measures	Yes, can be incorporated/expressed in the economic viability of renewable electricity projects.
Environmental sustainability	In a limited way. Environmental effects of proven technologies (i.e. onshore wind) are known rather well. For new technologies (i.e. offshore wind), this is more difficult.
Maximum technical implementation rate	Within limits. It is often possible to make assumptions on how many units of a technology may be produced and installed within a given time frame, though this may also depend on the technological progress.
Institutional and social setting	No. No direct method was found of translating institutional and social barriers in quantitative reductions of the realizable potential.

5. Setting up new images

5.1. Methodology

In the following sections an attempt is made to develop three new images based on different assumptions regarding the key factors of which the effects on production and costs of renewable electricity can be quantified. In each image, one key factor is dealt with in a rather extreme way. Subsequently, the ranges of the *maximum* realizable domestic renewable electricity[15] in 2020 may be indicated. This approach of sketching extreme images has several advantages. First of all, robust technologies, which appear to be important in each image, can be identified. Vice versa, it can be made explicit which technologies may only thrive under certain conditions. This method does not provide a best guess for the realizable renewable electricity potential, but can highlight which degree of penetration may be achieved under certain pretexts. Finally, the most promising options from this analysis can be further examined regarding possible barriers within the social and institutional setting. As pointed out in the previous paragraph, first selecting technologies on economical criteria, and then looking at environmentally sustainable options may lead to a different set and contribution of the various technologies than when the selection is done in a reverse order. By varying this order and the weight of the key factors in the different images, we aim to illustrate the different possible outcomes.

The three images are set up in a number of consecutive steps: As a first step, three factors, being economic viability, maximum implementation speed and ecological sustainability, are used as basic settings for making three different images of Dutch the renewable electricity supply in 2020. The other two factors (governmental financial support and technological progress) influence the economic viability and the maximum technical implementation rate in all images. Social and institutional settings are explicitly not taken into account, because of the mentioned difficulties to quantify them. Second, corresponding story lines are written, sketching possible policies and conceivable underlying driving forces for the three images. As a third step, in each image the technical potential is limited per technology by the criteria of the central key parameter. For example, in the ‘economic image’, only wind turbines with high electricity yields are feasible, while in the sustainable image wind turbines are only placed far from nature protection areas (see also Table 6). Specific data (e.g. cost and efficiency data of renewable electricity technologies, progress ratios for cost reduction potentials, criteria for the sustainable implementation of renewable electricity technologies etc.) applicable for each scenario were obtained from literature and from interviews. After determining the impact of the key factor, the limits caused by other key parameters are taken into account. For instance, the theoretical sustainable potential of PV-systems may be very large, but until 2020 it is limited by the maximum implementation speed. Finally, from the resulting potentials and corresponding costs, renewable electricity supply curves were devised for each image. Figure 4 depicts the various factors, which are used to produce the three different images.

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[15] In this paper, the definition for renewable energy will be used as described in the ‘Protocol Monitoring Renewable Energy’ (Novem, 1999), see also section 3.2.

A general ‘story line’ for each image is described in section 5.2. A more detailed description of the input data used (i.e. cost data, technical potentials, efficiencies etc.) and the applied approach is given per technology in section 5.3.

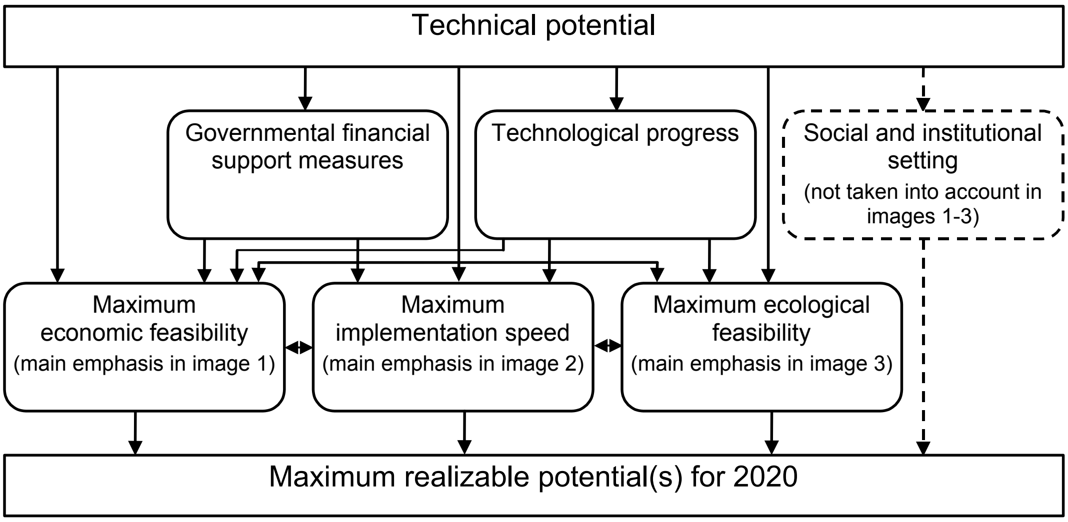

Figure 4 Key factors limiting the realizable potential for 2020 as used in the images 1, 2 and 3.

5.2. Image backgrounds

Image 1, renewable electricity at lowest economic cost. In this image it is presumed that only the domestic renewable resources which can compete economically within a European market or green tradable certificates are realized. It is assumed that government support for renewables is harmonized with the rest of the EU, and is mainly based on the revenues from green certificate trading. The general governmental view is ‘leave it up to the market’.

In order to determine economic viability for each available renewable electricity option, a required internal rate of return of 11.6% is assumed[13]. Next, it was assumed that all projects with marginal electricity costs of above 9 €ct/kWh would not be realized. This was based on the assumption of an average price of 6 €ct/kWh for green tradable certificates (GTCs) in a European green certificate market (Voogt et al., 2001) and a reference electricity price of 3 €ct/kWh[16]. For comparison, at the Dutch situation, the combined tax exemption of 3.45 €ct/kWh, feed-in tariff for renewable electricity of 2.9-6.8 €ct/kWh (see Table 2) and a price of electricity of approximately 2-3 €ct/kWh would lead to economic viable production price levels of 8.4-13.3 €ct/kWh.

Image 2, Maximum renewable electricity implementation. In this image, all possible renewable energy options are fully exploited, mainly limited by the maximum technical implementation speed. Where possible, the technology with the highest (conversion) efficiency and largest CO_2 emission reduction effect are selected – largely disregarding costs, but also other environmental/societal criteria. This image represents a situation where a very large percentage of either the renewable energy goal or CO_2 emission reductions have to be achieved domestically. Driving force could be the diversification of domestic fuel supply, e.g. to reduce the dependency on oil and natural gas.

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[16] It must be noted that the price of 6 €ct/kWh was calculated for the year 2010 (Voogt et al., 2001), and may be different in 2020 due to changing supply and demand patterns. However, due to the absence of estimates for an average green certificate price in 2020, this number was used here.

Key instruments in such a scenario could be a renewable portfolio standard that is specified for each technology in terms of a minimum share, as well as energetic efficiency standards. In this way, technologies with high energy conversion efficiencies are preferred over technologies with lower efficiencies but possibly better economic performance. In addition R&D expenditures to develop these technologies may need to be increased.

Maximum technical implementation rates for renewable electricity technologies are assumed. These are determined by using numbers from literature and extrapolating current growth trends. In terms of technological development, more optimistic growth rates for global cumulative capacity and different progress ratios were assumed (where the concept of experience curves was applicable) than in images 1 and 3. In other cases, various estimates from literature for technology development were used.

Image 3: Environmentally sustainable electricity. The background for this image is that while global warming is still a major problem, other environmental problems such as land-use, airborne-emissions, biodiversity etc. also become essential policy priorities. Strict criteria for renewables are handled regarding public acceptance and environmental impacts. This may severely limit parts of the renewable energy potential in the Netherlands. Governmental policy could include high investment subsidies, specific feed-in tariffs for the selected technologies and tax deductions for green investments. This is incorporated in the assumed IRR of 5%.

In order to internalize this ‘maximum sustainability demand’, the criteria of key number of Dutch environmental organizations (e.g. the World Wildlife Fund and Greenpeace) with respect to renewable electricity technologies were utilized in image 3 (Schöne, 2001). These criteria include for example restrictions on the placement of wind turbines, or lower emission levels of biomass plants. This clearly incorporates the ecological demands of sustainability and the subsequent limitations for exploiting renewable electricity potentials, but not necessarily broad societal acceptance of renewable energy technologies and the problems posed by the institutional setting. As was pointed out in the previous sections, this is difficult to quantify, and therefore not taken into account in this image. However, it is at least likely that the general public is more likely to accept technologies favored and promoted by environmental groups.

Not all NGO’s have identical viewpoints. For instance, while large NGO’s such as Greenpeace and the World Wildlife Fund prefer a rapid expansion of offshore wind (Schöne, 2001), an NGO called ‘the North sea’ prefers a step-by-step approach to gain as much information as possible on effects on flora and fauna before large-scale deployment. In general, the viewpoint of the larger NGO’s has been adopted here.

Different domestic potentials of renewable electricity are presented in Table 6. A general overview of the assumptions per image is given in Table 7. The detailed assumptions and input data per technology are described in Section 5.3.

Table 6 Domestic potentials for renewable electricity in 2020.

Potential	Wind onshore (MW$_e$)	Wind offshore (MW$_e$)	Biomass (domestic, PJ$_{th}$)[a]	Biomass (plant cap. MW$_e$)[b]	PV (MW$_p$)	Hydro power (MW$_e$)
Currently utilized (2000)	466	0	40	ca. 350[c]	12	37
Max. technical potential	3000-6000	10000-56000	146	>5300	70000	100
Economic potential[d]	>3000	>4400	142	1,080	0	53
Max. potential limited by production / installation capacity and technological development until 2020	>6000	3250-4400	142	5300[e]	1200-1800	100
Max. environmental sustainable potential	700-2500	100/ 3000[f]	40	Min. emissions, high efficiency	20000-60000	53
'Best guess'[g]	2214	2600	65-75	750	580	53
Range found in scenario studies for 2020	700-3100	500-2600	44-166	329-2270	16-2000	37-100

a Only domestic biomass and organic waste.

b Electrical (co-firing) capacity of power plants. In all cases the processing capacity is sufficient for all domestic biomass. Capacity specifically built for the conversion of imported biomass is excluded.

c Including the organic fraction from municipal solid waste (about 194 MW$_e$ of the total 424 MW$_e$).

d At an required internal rate of return of at least 11.6%, and a maximum costs of electricity of 9 €ct/kWh.

e Based on a maximum co-firing capacity of 20% for all existing coal-fired and gas-fired electricity plants, and a maximum of 3200 MW$_e$ new stand-alone capacity of (B)IG/CC plants.

f Nearshore / offshore.

g All number derived from the best guess – scenario DENL-study, corrected for biomass import.

Table 7 Overview of parameters limiting the potential of renewables in the three images used in the electricity supply curves.

	Required IRR (%)	Maximum allowed cost of electricity (€ct/kWh)	Technological progress and maximum penetration rate	Importance of ecological sustainability
Image 1	11.6	9	medium progress	medium
Image 2	8	-	high progress	low
Image 3	5	-	medium progress	high

5.3. Input data

Wind onshore: There has been much discussion on the technical potential of onshore wind, but most studies assume at least 2500-3000 MW for the Netherlands (van Wijk and Coelingh, 1993; Fu et al., 1994). Concerning the theoretical maximum implementation rate, the technical potential could easily be reached until 2020 (in Germany alone, several thousand megawatts of wind capacity have been installed in less than ten years). Also the economic viability is rather good, as costs may decline further with the increasing global deployment of wind energy and the gained experience as even the costs of 'inland' locations are expected to end up between 4-7 €ct/kWh in 2020 (Ybema, 1999), while at top coast locations costs between 3-3.5 €ct/kWh may be achieved, thus making onshore wind a relative attractive economic option in all three images (see also Table 8). According to a recent study of a Dutch environmental organization (Stichting Natuur en Milieu, 2000) there is 'environmentally sustainable' space for about 2100-2250 MW in total, which meet criteria regarding environmental and landscape aspects. This estimate is used for image 3.

Table 8 Assumptions for technology development and resulting investment costs for wind onshore, wind offshore and PV.

		Wind onshore	Wind offshore	PV
Average current investment cost (€/kW)		990-1190	1400-1600	7500-8250
Assumed global capacity in 2020 (GW)[a]	high estimate	170	17	60
	average estimate	140	14	38
Assumed progress ratio	high estimate	87%	85%	75%
	average estimate	90%	90%	80%
Resulting investment costs 2020 (€/kW)	positive estimate	630-755	1100-1260	1370-1510
	average estimate	725-870	1200-1370	2325-2560

[a] Estimates on global capacity in 2020 and progress ratios are adopted from Ybema (1999).

Wind offshore: The technical potential on the Dutch continental shelf, including the area within the nearshore zone, (within 12 miles of the coast) is estimated to be between 10-56 GW$_e$ (Bakker, 1997; Matthies et al., 1995). However, within the near-shore 12-mile zone, the Dutch government has already decided that only a 100 MW$_e$ experimental park will be built. All future parks will have to be built outside the 12-mile zone. Yet, in the images 1 & 2 it is assumed that nearshore parks may be realized due to better economic conditions (i.e. lower water depths). The maximum amount that can be installed until 2020 may range between 3250 MW$_e$[17] (Ybema, 1999) and 4400 MW$_e$ (Voogt et al., 2001). The lower limit is used in image 1, the upper limit used in image 2.The economic viability strongly depends on further development of the technology, but also on the water depth and average wind speeds. As a very conservative estimate, even in deeper waters offshore wind turbines are expected to be economically feasible below or around a cost of electricity of 9 €ct/kWh (de Noord, 2001). Other studies assume 6-7 €ct/kWh for future offshore wind parks.

In image 3, wind parks are only allowed outside the 12-mile zone. Even if the maximum water depth is limited to 20 meters, an area remains of 600 km^2 in which approximately 3,000 MW$_e$ may be placed (Scheepers, 2001). In order to further minimize environmental impacts, preferably large wind parks should be built, and expansion of wind offshore should be gradual (Langendijk, 2001).

PV: In the gross technical potential for PV includes 115-430 km^2 of suitable roof surface (Alsema and van Brummelen, 1992; Corten and Bergsma, 1995) and 220 km^2 of degraded agricultural land (see Table 6). The latter are not included in image 3, as a clear preference exists for multi-functional land use (e.g. use of PV on roofs). The potential area for PV on noise barriers/other areas is negligible in comparison to the potential on roofs of dwellings. There are no environmental objections against the use of PV. In the images 2 and 3, the major restraint is the maximum rate with which PV-systems can be produced and installed. Assuming that the Netherlands can install 2-3% of the total global cumulative production until 2020 and assuming a global installed capacity of 60 GW$_p$ in 2020[18], this limits the potential to 1200-1800 MW$_p$, and thus at least a factor 10 smaller than the environmental potential. The biggest bottleneck by far in image 1 is the cost of PV. Cost

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[17] This maximum installation rate is based on a maximum of 100 MW that can be installed per year for the period 2000-2005, 150 MW per year between 2005-2010, and 200 MW per year between 2010-2020, limited by the number of days in which offshore building activity is possible. As the current construction of the Horns Ref wind park of 160 MW, these estimates seem rather conservative.

[18] The share Dutch of global PV capacity is currently about 1% (in 2000, about 12 MWp were installed versus a global capacity of 1.06 GW). Thus, increasing this share by a factor 2-3 is assumed to be an upper limit. As most optimistic annual growth rate for the installed PV capacity, 22.5% is used, resulting in 60 GW$_p$ in 2020.

estimates for PV vary widely from 20-30 €ct/kWh in 2020 in the Netherlands, still making it an expensive option. PV is therefore not realized at all in image 1.

Biomass – dedicated crops, residues and waste: A number of studies on the available amount of waste streams, biomass residue streams and biomass cultivation in the Netherlands are available. The basis for the quantities of biomass streams assumed in this study was the second scenario of the Marsroute study (Zeevalking and Koppejan, 2000), with additional data for biomass residue streams (Faaij, 1997) and for assumptions for possible biomass cultivation in the Netherlands (Londo, 2002; Faaij et al., 1998).

There are numerous factors influencing the availability and costs of various biomass streams. The available area for biomass cultivation may vary from 22500-300000 ha (van der Reepe, 2001). In image 1, cultivation of biomass was not deemed feasible due to the relative high costs. Also, the import of biomass (which was not considered at all in the images) may strongly influence the cost and availability of cultivated biomass. As an average estimate, in scenario 2 and 3, an annual production of about 1 million ton cultivated biomass dry matter was assumed, based on 100000 hectares and an average yield of 10 tonnes (dry)/ha.

The definition of which streams are 'sustainable' may change over time. For example, conversion of sewage sludge is nowadays associated with high emission levels. If these emissions can be lowered due to technology improvements, the opinion on its environmental sustainability may change (Schöne, 2001). Similar arguments are possible for contaminated wood and various other waste streams. Another issue is the value of waste streams. In literature, negative prices are often cited for waste streams. In this study, prices for waste streams were set to zero, as large-scale utilization of (and thus demand for) these streams often leads to increased prices. In Table 9, and overview of the available streams and quantities is given.

Table 9 Overview of various kinds of biomass streams and available quantities. Sources: (Zeevalking and Koppejan, 2000; Faaij, 1997; Londo, 2002).

biomass	examples	quantity (PJ_{th})
Cultivation	poplar, willow miscanthus and SRC crops	11.7
Biomass residues	verge grass, wood prunings, various agricultural residues	39.7
Waste streams	contaminated demolition wood, chicken manure, sewage sludges,	50.3
Organic fraction of waste streams	Municipal solid waste, industrial wastes	52

Biomass – technology development and available plant capacity: The available biomass streams were allocated to the available technologies by a computer optimization model based on (Dornburg and Faaij, 2001). This model allows for optimization for either energy yields or costs, and contains in total 12 different biomass-to-electricity conversion options and a diversity of biomass streams[19]. Assumptions on the maximum potential biomass conversion capacity also depend on three factors: the amount of current capacity, the amount of possible co-firing capacity (based on existing and new fossil fuel power plants) and the amount of stand stand-alone power plants. In 2000, about 350 MW_e of electricity production capacity could be credited to renewable biomass sources (including the organic fraction of MSW-incineration plants and co-firing of biomass in fossil fuel plants). Regarding the maximum technical co-firing potential, both coal- and gas-fired plants can process

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[19] The original model also contained options for heat and recycling. Also, streams were spatially allocated per province in the Netherlands. These options not used in this study.

biomass waste streams[20]. In the Netherlands, currently 4170 MW$_e$ coal-fired capacity and 6000 MW$_e$ gas-fired capacity exist. As a rough indication, at 20% co-firing (on LHV-basis) this would result in 830 and 1200 MW$_e$ co-firing capacity. However, the exact method of co-firing (direct, indirect) and the maximum co-firing fraction depend both on the specific plant conditions and on the biomass composition. These factors also strongly influence (additional) investment costs of co-firing. In the images, it was assumed that the coal-fired capacity remains constant until 2020[21], while capacity of natural gas plants and electricity imports may rise to meet increased demand as described in section 3.1. Finally, when regarding stand-alone plants, not the number of plants that can technically be built until 2020 is decisive, but which conversion technologies may be commercially available[22]. In the images, mainly data from Dornburg and Faaij (2001) and Zeevalking and Koppejan (2000) was used for technology assessment. Dornburg and Faaij are more optimistic with regard to the investment costs, the applicable biomass streams and the capacity factor for large-scale biomass-integrated gasifiers / combined cycle plants (BIG/CC's). Therefore, the data from Zeevalking and Koppejan have been used for image 1, and data from Dornburg and Faaij for image 2 and 3. Also, for all co-firing options, in image 1 only the additional investment costs were used in cost calculations, while in image 2 & 3 average investment costs were used (i.e. a part of the initial investment cost of the plant is accounted for the additional biomass co-firing capacity). Furthermore, in image 3 extra costs for emission reduction are applied, based on the most stringent emission levels for waste incineration (Bergsma et al., 1999). An example of the different technology development and cost estimates is given in Table 10.

Table 10 Comparison of assumptions for a BIG/CC and a co-firing option.

		Dornburg & Faaij	Zeevalking & Koppejan
BIG/CC (150 MW$_e$)	electric efficiency 2000^a	48	43
	electric efficiency 2020	59	46
	investment cost 2000^a €/kW	1950 €/kW	1950 €/kW
	investment cost 2020 €/kW	1370 €/kW	1760 €/kW
Gasification and co-combustion in a coal power plant (120 MW$_e$)	electric efficiency 2000	35	35
	electric efficiency 2020	35	35
	investment cost 2000 €/kW	2340 (910 + 1430)^b	910^c
	investment cost 2020 €/kW	2340 (910 + 1430)^b	820^c

a Costs and efficiencies for 2000 are based on estimates, as no BIG-CC of 150 MW$_e$ currently exist.
b Average investment cost.
c Additional investment cost.

Hydropower: The technical potential for hydropower in the Netherlands is small. Also, hydropower technology is fully mature, and little cost reductions and efficiency improvements are to be expected. The technical potential is about 100 MW$_e$ (van Hilten et al., 1996) (the potential used in Image 2), while the economic potential is estimated at 53 MW$_e$ (used in Image 1), 15 MW$_e$ more than the current capacity installed. The sustainable hydropower potential was also assumed to be 53 MW$_e$, but requires additional investments for fish-protection measures (van Zanten, 2001).

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[20] Natural gas combined cycle (NGCC) plants can co-fire biomass via firing gas in gas turbines or heat recovery steam generators after gasification of biomass.

[21] Though a number of coal-fired plants are scheduled to be closed down before 2020, it is possible to prolong their lifetime until 2020 (van Halen et al., 2000).

[22] In Table 6, a maximum stand-alone potential of 3200 MW$_e$ is adopted from (Ybema, 1999). In the images, the actual amount of new capacity is limited by the amount of available biomass, and a maximum of 2600 MW$_e$ is reached in image 2.

5.4. Results and discussion

The quantitative results for the three images are shown in Figure 5 and Figure 6. A more detailed overview of wind capacity (by location) and biomass capacity (by technologies) is given in Figure 7 and Figure 8.

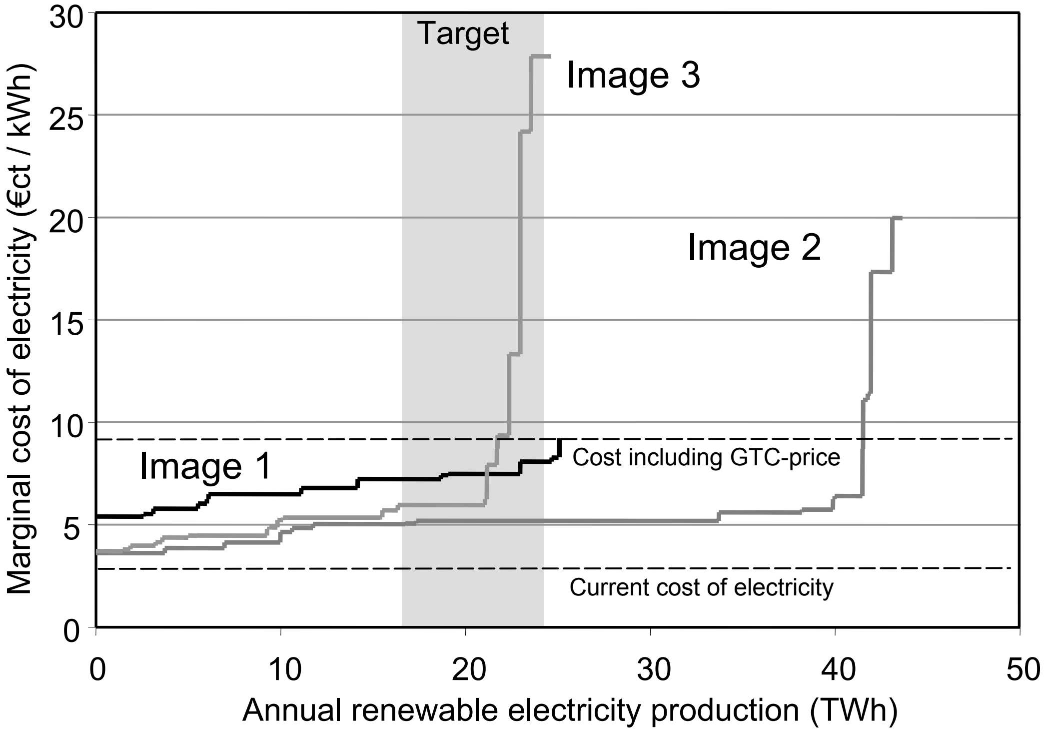

Figure 5 Supply curves of the renewable electricity production in the three images.

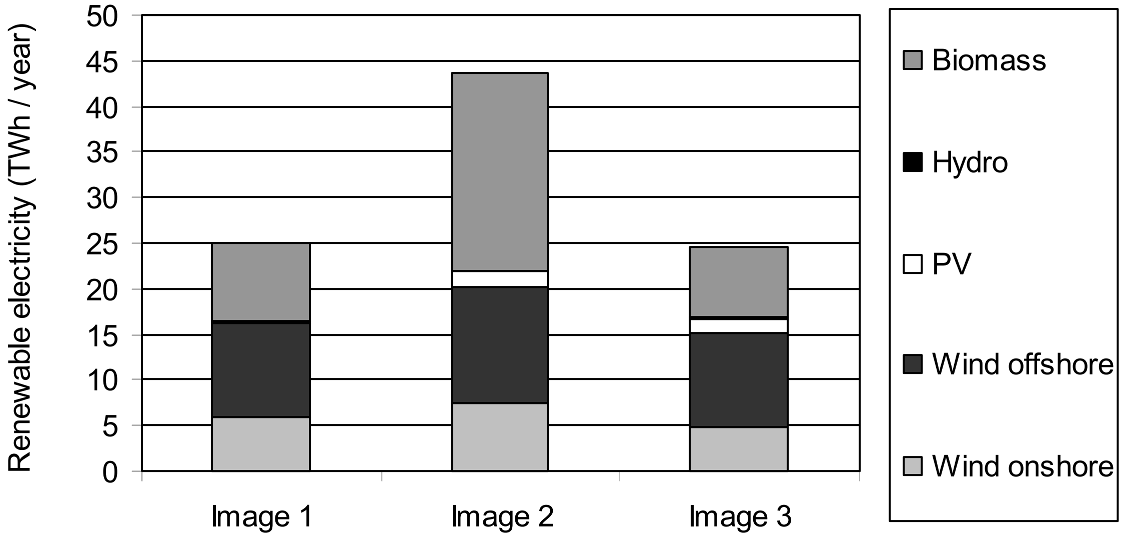

Figure 6 Contribution of renewable electricity technologies in each image.

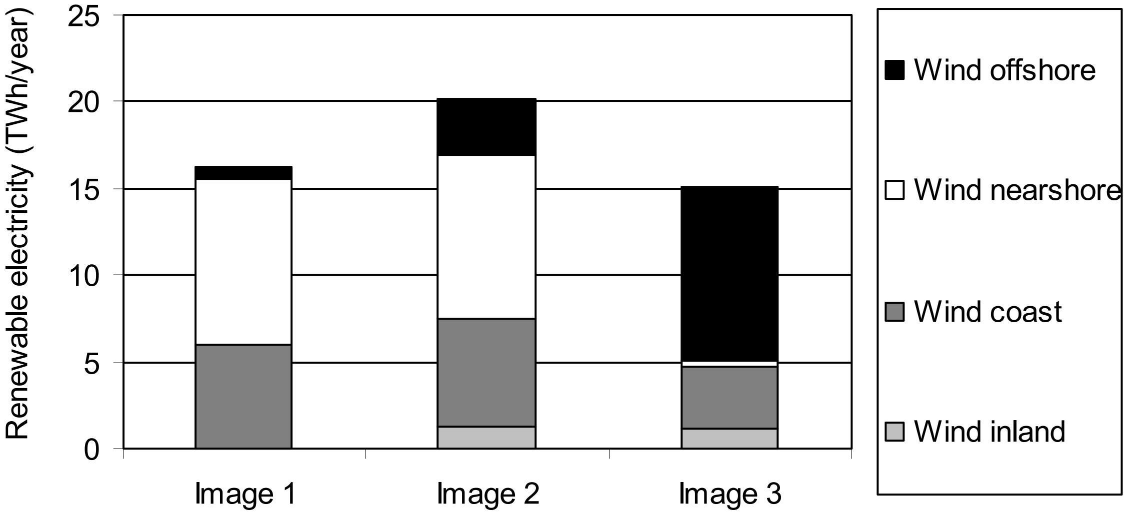

Figure 7 Composition of the wind energy contribution in the images.

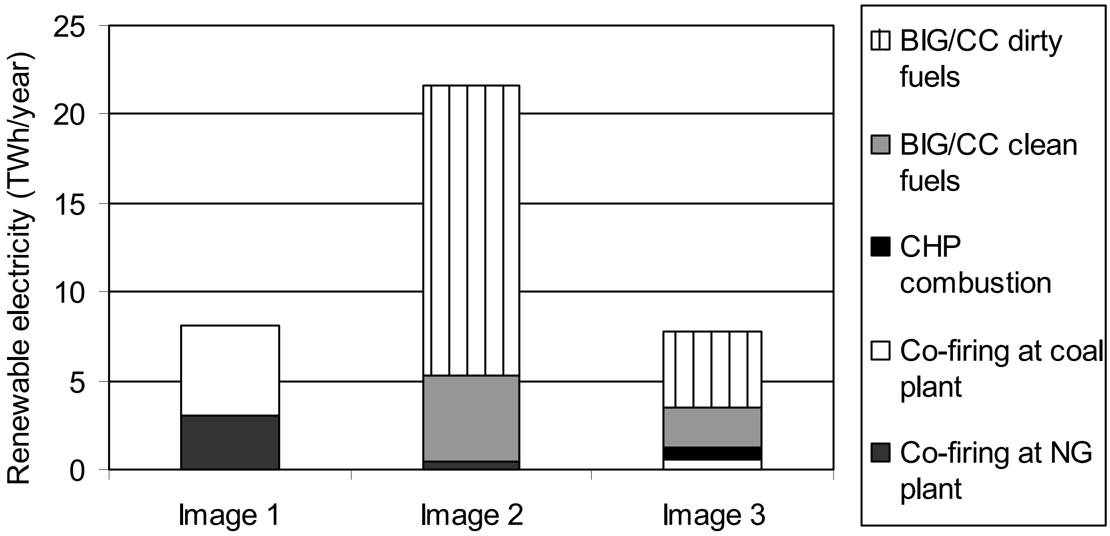

Figure 8 Composition of the biomass energy contribution in the images.

For image 1 the high required IRR makes low-investment strategies for biomass most attractive. This means that existing coal and natural gas plants are fully used to co-fire biomass waste streams. Profitable onshore wind parks in coastal regions are fully exploited. Nearshore wind parks are permitted, as this may also be the case in other European countries (Belgium, Germany) and the aim is for a level playing field for renewable energy is assumed. Hydropower is extended up to its economic potential. PV is not stimulated with subsidies and diffusion is negligible. In general, this image favors large-scale centralized production because of the lower costs. In total, 25.0 TWh per year may be produced before the 9 €ct/kWh boundary is reached (see Figure 5).

In image 2, wind onshore, nearshore and offshore are fully exploited – diffusion is ensured by favorable legislation for renewable energy projects. Waste separation and conversion of biomass waste streams with highly efficient BIG-CC's or co-firing in existing NG-plants is used on large scale, also fuelled with indigenous cultivated biomass. Photovoltaics are strongly stimulated, and the maximum penetration rate is the limiting factor. In general, this image also favors large-scale centralized production, due to higher conversion efficiencies. The maximum production per year lies at 43.6 TWh.

Finally, in image 3, deployment of wind onshore is more limited, as the public perception is that wind should be realized far from shore, where environmental and societal impact is limited. Biomass use is limited to 'clean streams' such as cultivated crops in the Netherlands and clean biomass residues (verge grass etc.). Streams such as chicken manure are no longer available, as this sector is assumed to phase out in this image. Due to the required high overall efficiency next to large BIG-CC's, small and medium-sized biomass fuelled CHP-systems may be feasible. Next to the efficiency gain, gasification plants also prevail over combustion options due to their lower emissions. In addition, photovoltaics are strongly stimulated for both large-scale and small-scale projects, and the maximum penetration rate is the limiting factor. Thus, decentralized generation of electricity plays a larger role in this image in contrast to the previous two images.

A number of comments have to be made with regard to the images given. All images show larger potentials than in the studies discussed in paragraph 3.1. This is mainly caused by the approach of emphasizing only one key aspect and looking at maximum ranges, while in the previously discussed studies, several key factors are integrated for composing scenarios. In quantitative terms, the higher penetration of wind offshore and the increased utilization of biomass waste streams are mainly responsible for these higher potentials.

Wind offshore clearly is a robust option, as it has a significant share in all three images. The largest uncertainties of this yet unproven technology are the successful technological development, and the assumptions on the maximum installation rate until 2020. Regarding the onshore wind potential, environmental criteria and available space are, as expected, the main limiting parameters, but with 2100-2200 MW_e less severe than assumed in the RACE-study, making it an important and relatively robust option in all three images (see also Figure 7). Concerning biomass, two different technologies are evident: different forms of co-firing as most economical options, or large-scale (stand-alone) gasification plants as most efficient technologies. In all images, either large-scale co-firing in coal plants, NGCC plants or BIG/CC plants contribute substantially to the total renewable electricity production (see also Figure 8). The successful development of these technologies, especially gasification of contaminated waste streams, is crucial in these images. In addition, both the quantity of available biomass and the varying 'sustainable character' of various biomass streams may be a bottleneck for exploiting the full potential. For photovoltaics, both costs and the maximum implementation rate are bottlenecks keeping it from contributing a large share in images 1 & 2. In image 3, PV might contribute up to 7% of the total supply. Finally, hydropower is simply limited by the technical potential and may at most contribute 0.3% in image 3.

In each of the chosen images, offshore wind supplies at least 10.3 TWh, onshore wind 4.8 TWh, and large-scale biomass installations 6.5 TWh, adding up to a 'robust' potential of 21.6 TWh. However, the spatial locations of wind turbines onshore, nearshore and offshore differ between the three images, as do the technologies used for large-scale biomass plants. When looking at the options, which are exactly the same in all three images, only 3.6 TWh onshore wind, 1.1 TWh offshore and 4.3 TWh large-scale biomass remain, adding to a total minimum production of 9 TWh.

6. Conclusions and recommendations

As was shown in section 4, leaving out one or more key parameters may lead to an incomplete analysis, while integrating all key factors into one quantitative forecast is difficult and may lead to a false indication of accuracy. In the chosen approach, a number of direct key factors determine a 'maximum realizable sustainable energy potential' for 2020 and incorporated in different images. In all three images produced in this analysis, the upper limit of the government target of 24 TWh is reached. In other words, strict environmental criteria or high economic demands alone are not necessarily insurmountable barriers for reaching the 17% target. It is emphasized that it was not the intention to develop a best-guess scenario, and that no integration of the three images into a single scenario was performed. The chosen approach of highlighting different extreme developments makes such a full integration into one scenario rather unsuitable. Nevertheless, as an integral result onshore wind, offshore wind and large-scale biomass plant are determined as robust options in terms of ecological sustainability, economical performances and high possible technological progress. When adding up these robust potentials, the range of 9-22 TWh suggests that at least a large part of the 17% target can be achieved using these robust options, and policy support should primarily focus on these options. The recent change in policy from a tax exemption (for which foreign renewable electricity production is also eligible) to feed-in tariffs (only applicable for domestic production) may provide the required economical setting for further renewable capacity expansion of domestic wind onshore and biomass. However, as other support schemes (such as the accelerated depreciation of investments) no longer apply, the development of offshore wind farms may require additional incentives, especially given the high risks involved in investing in this yet unproven technology.

Next to the key factors chosen here, there are other (minor) factors, which may influence the penetration of renewables. As was pointed out before, the availability of cheap and / or sustainable biomass from abroad may play an important role for the overall electricity-from-biomass potential, but also for the viability of biomass cultivation in the Netherlands. Overall electricity capacity and the overall electricity demand may also influence the possibilities for additional renewable capacity. Another limitation, which has not yet been included here, is the maximum amount of capacity that can be integrated into the grid, in particular for intermittent sources[23].

Main uncertainties in the images lie in the different rates of assumed technological progress for the technologies. Further detailed research is required whether the assumed increase in efficiency and cost reductions can actually be reached, and which factors may be crucial to achieve this. Especially for offshore wind, with a huge potential in all images, the possible cost reductions need to be further investigated.

Another focus point for further research is the social and institutional setting for onshore wind, offshore wind and large-scale biomass options. As these options clearly show the largest

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[23] This seems however not an impenetrable barrier. Electricity from biomass is not an intermittent source, and electricity output from hydropower can be predicted well in advance. While the large-scale grid-integration of huge quantities of offshore wind will most likely require either electricity storage or backup power, a recent report sketching an electricity road map for the Netherlands finds that at least 15% of the total electricity demand can be supplied by renewable electricity without any major technical complications (KEMA, 2002).

quantitative potential for the Netherlands, it is recommended that the possible barriers caused by social and institutional settings should be scrutinized further. With the given maximum ranges we hope to provide a base for governmental steering, acknowledging the inherent uncertainty of the context. It finally is a political choice to decide whether or not and how to steer on the dynamic social and institutional setting.

7. Acknowledgement

Veronika Dornburg is thanked for extensive help with the biomass optimization model. Remko Ybema, (ECN) Manuel de Noord, (ECN), Walter Ruijgrok (KEMA) and Sible Schöne (WWF) are thanked for helpful information and comments.

Chapter 3: Global experience curves for wind farms[1]

Abstract

In order to forecast the technological development and cost of wind turbines and the production costs of wind electricity, frequent use is made of the so-called experience curve concept. Experience curves of wind turbines are generally based on data describing the development of national markets, which cause a number of problems when applied for global assessments. To analyze global wind energy price development more adequately, a global experience curve is composed. First, underlying factors for past and potential future price reductions of wind turbines are analyzed. Also possible implications and pitfalls when applying the experience curve methodology are assessed. Second, an approach is presented to establish a global experience curve and thus to determine a global progress ratio for the investment cost of wind farms. Results show that global progress ratios for wind farms may lie between 77-85% (with an average of 81%), which is significantly more optimistic than progress ratios applied in most current scenario studies and integrated assessment models. While the findings are based on a limited amount of data, they may indicate faster price reduction opportunities than so far assumed. With this global experience curve, it may be possible to improve the reliability of describing the speed with which global costs of wind power declines.

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[1] Published in: Energy Policy, 2004, 33(2), p. 133-150. Co-authors: A. Faaij and W.C. Turkenburg.

1. Introduction

The wind energy sector is one of the fastest-growing energy sectors in the world. From 1991 until the end of 2002, global installed capacity has increased from about 2 GW (EWEA, 1997) to over 31 GW (Milborrow et al., 2003), with an average annual growth rate of about 26%. During this period, both prices of wind turbines and cost of wind-generated electricity have been reduced (Turkenburg et al., 2000). In spite of these developments, electricity derived from wind is not yet able to fully compete with electricity produced from fossil fuel. However, this may change in the near future (Turkenburg et al., 2000). To forecast future cost development of both wind turbines and wind electricity, use is made of the so-called experience curve concept. This concept analyzes cost development of a product or a technology as a function of cumulative production. On the basis of recorded data on these parameters, a historic experience curve can be devised. If the trend of this curve may be extrapolated into the future, it can help policy makers to estimate when a technology may reach a certain price level.

The technical and economic performance and productivity of a technology typically increase substantially as producers and consumers gain experience with this technology. This phenomenon was first described in literature by Wright (1936), who reported that unit labor costs in airframe manufacturing declined significantly with accumulated experience of the workers. Technological learning has since then been described for many different industries (Dutton and Thomas, 1984; Argote and Epple, 1990).

The concept of experience curves has also been applied widely within the energy technologies area. Recent examples are PV modules (Harmon, 2000), combined cycle gas turbines (Claeson Colpier and Cornland, 2002), fuel cells (Tsuchiya, 2002), ethanol production (Goldemberg, 1996) or carbon sequestration technologies (Riahi et al., 2002). An overview of studies concerning energy technologies is given by McDonald and Schrattenholzer (2001). Especially for the wind energy sector, experience curves have been devised for Denmark (Neij, 1999b), Germany (Durstewitz and Hoppe-Kilpper, 1999), the United States (Mackay and Probert, 1998), and other countries (Lund, 1995; Ibenholt, 2002; Klaassen et al., 2003).

Experience curves can be used for the following different purposes:

- Experience curves are used on a *company level* to project future costs and to formulate corporate strategy (see e.g. (Abell and Hammond, 1979). The first experience curves (in fact: learning curves[2]) were used to measure the influence of different inputs on the production costs of a standardized product within a factory.
- *National policy makers* may use experience curves to evaluate the effect of past subsidies such as R&D subsidies or investment subsidies. Also, experience curves can be used to estimate learning investments, i.e. the future investments required to ‘buy down’ the costs of a technology to a certain price level until it can compete with conventional technologies. A discussion of experience curve for various technologies and their application for policy is given by Wene (IEA/OECD, 2000).
- Experience curves are also utilized to construct *scenarios* for global wind energy technology development. An example is the recently published Wind Force 12 by EWEA and Greenpeace (2002).

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[2] The term learning curve refers to the cost reductions of a standardized product within a single firm, while an experience curve may also describe cost reductions of non-standardized products on a national or global level (Neij, 1999a).

- *Energy models and climate change models* increasingly make use of experience curves to endogenize technological learning and associated cost reductions of renewable energy technologies. Examples of energy models using endogenous learning are ERIS, MESSAGE, MARKAL (Seebregts et al., 1999) and DEMETER (van der Zwaan and Gerlagh, 2002).

The scope of using experience curves can range from a single manufacturer of wind turbines with a time horizon of a few years (see for example (Milborrow, 2002b) to global energy models with a time horizon of up to a century (Seebregts et al., 1999). However, a number of problems occur with using experience curves for the abovementioned applications are observed. For example, there are different types of experience curves, like for wind turbines, wind farms, wind electricity, which cannot be compared directly. Also, local policy support measures or geographical differences may be sources of uncertainty. Yet, in many scenarios and energy models, global cost reductions of wind turbines are modeled by experience curves based on *national* results.

In this chapter, the attempt is made to set up a *global* experience curve for global wind farm price development. The applicability of this curve in energy models and scenarios is also discussed. In order to do so, a brief introduction is given to the experience curve theory and some general methodological issues in section 2. In section 3, the underlying factors are scrutinized that have caused price reduction of wind turbines and wind farms in the past, and key factors for possible future price reductions are identified. Subsequently, possible methodological pitfalls are evaluated (especially concerning setting correct system boundaries) in section 4. Based on these considerations an approach is developed for a global experience curve in section 5. In section 6, the data selection is described for the global experience curve, while in section 7 the results of the global experience curve for wind farms are presented and discussed. Finally, in section 8, conclusions are drawn on the developed methodology and on the global experience curve.

2. A brief introduction to experience curve theory and technological learning

2.1. General experience curve theory

A basic experience curve can be expressed as (Neij, 1999a):

$$C_{Cum} = C_0 \, Cum^b \tag{1}$$

$$\log C_{Cum} = \log C_0 + b \log Cum \tag{2}$$

$$PR = 2^b \tag{3}$$

$$LR = 1 - 2^b \tag{4}$$

C_{Cum}	:	Cost per unit	C_0	:	Cost of the first unit produced
Cum	:	Cumulative (unit) production	b	:	Experience index
PR	:	Progress ratio	LR	:	Learning rate

The definition of the 'unit' may vary: in many cases a unit is a product (for example a car or an airplane). In relation to energy technologies, more often the unit is the capacity of an energy technology (e.g. the capacity of a gas turbine) or the amount of electricity produced by a technology (see also section 4.1). The progress ratio (PR) is a parameter that expresses the rate at which costs decline each time the cumulative production doubles. For example, a progress ratio of 0.8 (80%)

equals a learning rate of 0.2 (20%) and thus a 20% cost decrease for each doubling of the cumulative capacity. The advantage of using the term ‘learning rate’ rather than the term ‘progress ratio’ is that a 'higher' learning rate means a faster decrease of costs, while a 'higher' progress ratio means a slower decrease of costs and thus is somewhat misleading. However, as the term Progress Ratio is used more frequently in literature, it is used throughout this paper.

There are a number of possible factors that may cause cost reductions such as (Abell and Hammond, 1979; Grübler, 1998):

- Learning-by-doing and learning-by-using, leading to increased labor efficiency, work specialization and methods improvements,
- Innovations caused by RD&D (learning-by-searching), leading for example to the use of new materials or the introduction of new production processes,
- Improving the network interactions between research institutes, industry, end-users, policy makers etc. (learning-by-interacting), allowing for the better diffusion of knowledge,
- Standardization of the product, allowing upscaling of the production plant (i.e. mass production)
- Redesigning and upsizing (or downsizing) of the individual product (e.g. upscaling a gas turbine leads to lower specific costs per turbine)

In many cases a combinations of these factors occurs, and in addition the contribution of each may change during the development of a product over time. For example, in the early development phase, RD&D expenditures may have a significant impact on cost reductions, while typically during the market penetration, cost reductions due to mass production dominate learning. Also, not all factors may apply to all products. For example, it is possible to upscale a gas turbine, reducing specific investment costs, but it is not possible to upscale a unit of electricity. Some authors also differentiate between effects of (technological) learning (such as the first three factors) and scale effects (such as the last two factors). However, in practice these factors may overlap and may contribute to cost reductions simultaneously. Recently, attempts have been made to divide up the basic learning curve into a two-factor learning curve (2FLC), in which cost reductions depend on both cumulative production and RD&D investments (Kouvaritakis et al., 2000; Klaassen et al., 2003). While this approach may yield a more accurate estimation of the past and possible future cost reductions, it also requires detailed data, which may not be available in many cases. This chapter focuses on the analysis and application of the one-factor experience curve.

2.2. General methodological issues

A number of methodological issues with regards to the experience curve theory have been discussed in literature (IEA/OECD, 2000). An important issue concerns the relationship between costs and prices during the development and market introduction of a new product. In an ideal situation, production costs should be used for devising experience curves. However, often only price data are available. Price data however are not only based on the production costs, but also on the marketing strategy, the demand for the product, the amount of competition, the height of available subsidies, et cetera. The Boston Consulting Group described a possible relationship between prices and costs during the introduction of a new product (BCG, 1968, see also Figure 1). The model is divided into four phases: in the first phase a manufacturer introduces a new product at a price lower than the production costs in order to create a market. With increasing production volume, costs decline rapidly while prices are dropping at a lower rate. During this ‘umbrella’ phase, increasing profit margins may attract competitors producing the same product. Commonly, the prime producer will have a dominant position in the market and is able to determine the market price for an extended amount of time. Later, a shakeout occurs, and prices decline rapidly for a short period of time. Finally, in a stable phase, both prices and costs decline at the same speed, i.e. relative profit margins are constant. In this model, only in the last phase are the slopes of both cost and price curves identical and only then prices can be used to estimate cost reduction rates. Once a stable situation is reached, this does not necessarily guarantee that this situation will remain so forever. Depending on factors like changing demand, changing number of suppliers or declining government support a new ‘umbrella’ or ‘shakeout’ phase can occur.

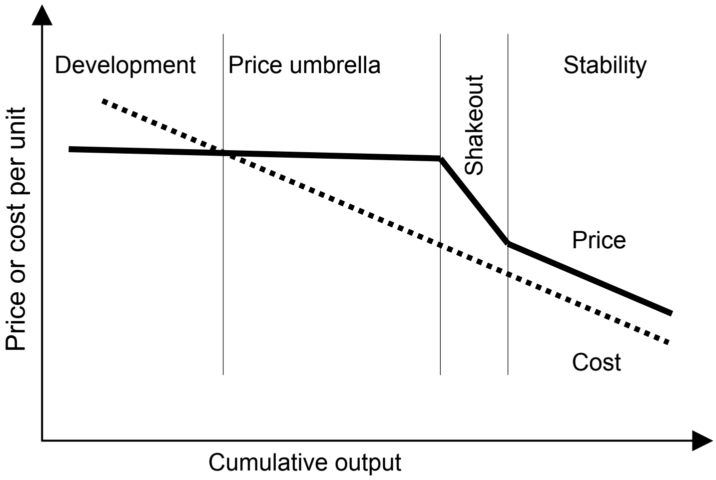

Figure 1 Relationship between costs and prices during market introduction of a new product (adopted from BCG (1968)).

Another issue which has also been proposed to cause a kink in the experience curve is that the PR may increase over time once the product has become sufficiently mature (i.e. that saturation effects occur and the learning effect diminishes). For example, it is suggested that the PR of gas turbines may have changed from 80% in the RD&D phase to 90% in the commercialization phase (Nakicenovic et al., 1995). This observation can be supported by the expectation that cost reductions cannot continue indefinitely, and that a certain minimum cost level must exist. On the other hand, many experience curves are known in which no such kink occurred over many doublings of cumulative production, even long after commercialization (Abell and Hammond, 1979). In regard to this issue, one should note that in the basic experience curve formulas, time is not included as a variable, i.e. cost reductions depend only on cumulative volume of units produced. However, the speed with which cumulative production doubles will decline with increasing market penetration. For example, while the installed capacity of a new technology such as wind turbines may double every 3-4 years, a doubling of capacity for well-developed technology (such as coal-fired power plants) may take several decades. McDonald and Schrattenholzer (2002) argue, that in such case knowledge depreciates over time, i.e. knowledge gained ten years ago is not as valuable as recently gained knowledge. Such knowledge depreciation will occur in the case of non-exponential growth of production as a function of time, and causes the experience curve to flatten out gradually. However, exogenous developments (for example the reduction of labor requirements in plants due to the regulation of processes by computers or continuously decreasing costs of raw materials) may cause further cost reductions, thereby reducing the effects of knowledge depreciation. Summarizing, cost reductions observed over time may slow down, yet the PR of a technology may, but does not necessarily have to change. There are also other reasons why PRs may vary, e.g. due to structural technology changes. For a more elaborate discussion, see IEA/OECD (2000).

Finally, it should be noted that experience curves are simply empirically observed relations. There is no natural law causing costs to decline with cumulative production, and thus the explanatory and predictive "power" of experience curves is limited. Yet, this phenomenon has been observed a great number of times (Argote and Epple, 1990), and there are a number of factors which may cause cost reductions, as listed in section 2.1. Therefore, before analyzing the experience curves for the wind energy sector, in the next section, first take a look is taken at the actual reasons why prices of wind turbines have fallen in the past and whether opportunities may exist to further reduce prices in the future.

3. Reasons behind price reductions of wind turbines and wind farms

3.1. Historic factors behind price reductions of wind turbines

The production cost of both wind turbines and the production cost of electricity from wind have been greatly reduced over the last decades, and subsequently so have prices[3]. The upscaling of the size and capacity of wind turbines has been a key driver behind this. (Neij, 1999b) described how turbines with increasing size penetrated the Danish market, and were already replaced by newer models only two or three years later. While in 1985, the 55 kW turbine was the dominant turbine type, it subsequently had been replaced by several larger turbine classes (such as 150 kW and 500 kW turbines). Each new turbine class had lower specific costs per kW than the previous one (which was also true for the German market as shown in Figure 2), and a higher yield per unit of swept area[4]. Besides the growth in swept area and turbine capacity, not only the costs per unit of installed capacity fell, but also the costs of electricity per swept area (Neij, 1999a)[5].

The upscaling of turbines had the advantage that the setup of every new turbine class was based on past experiences, but also allowed a slow introduction of new technological developments, such as the application of pitch-regulation, the use of synchronous generators, the development and use of new materials for blades that grew larger and larger, development of power electronics, and the specialization of standard components from other industry sectors for the wind energy sector such as gear boxes, transformer stations and inverter stations (EUREC, 2002).

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[3] In this section factors are described that have reduced *production costs*. However, in absence of available production costs, these trends can only be supported using published turbine list prices and prices of turnkey wind farms. As discussed in section 2.2, this is basically only possible in the presence of a competitive market. Possible drawbacks of using prices are described in section 4.3.

[4] Upscaling a wind turbine does not necessarily lead to specific cost reductions, as is the case for e.g. a gas turbine. With increasing size, the ratio between swept area (i.e. the electricity yield) and total mass (i.e. material costs) becomes increasingly unfavorable. Only through technological innovations (e.g. lighter materials) and increased productivity can this disadvantage be compensated.

[5] It should be noted, that nowadays turbines under 600 kW are hardly manufactured anymore. The price increase that can be observed in Figure 2 for turbines smaller than 600 kW from 1995 onward stems from the fact that some manufacturers still offer these turbines, but maintain the same nominal price. Thus, in real terms, prices of small turbines increase due to inflation.

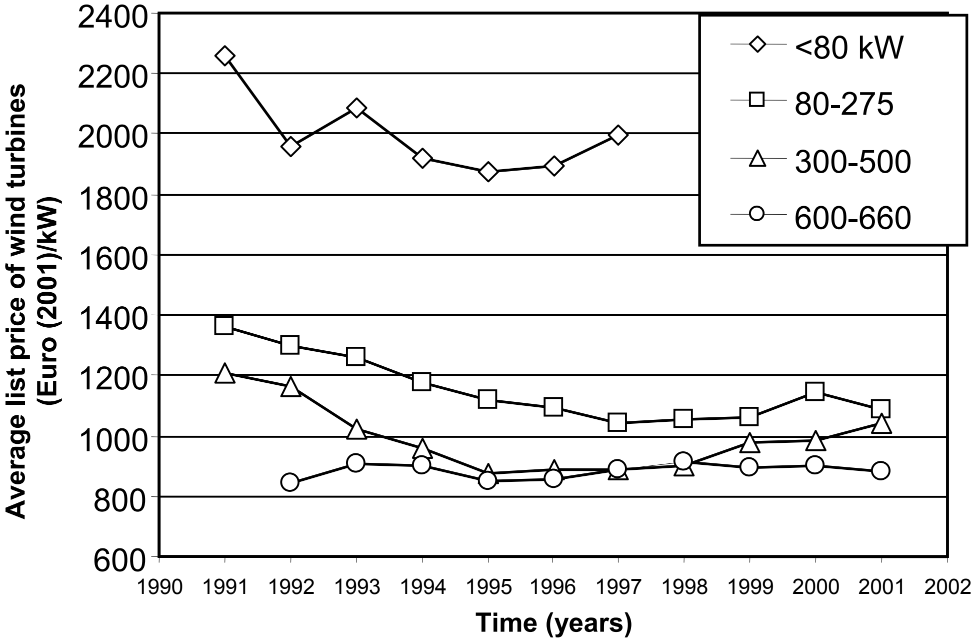

Figure 2 Average list price development of small and medium-sized wind turbines 1991-2001. Source: German list prices, (BWE, Editions 1991-2002), adjusted for inflation using German GDP-deflators (IMF, 2002). Exchange rate: 1 € = 1.956 DM.

3.2. Current developments

Since the introduction of the 600 kW turbine in 1995, the trend of decreasing turbine list prices with increasing turbine size seems to be diminishing. While the upscaling of turbines still continues[6], there is no clear reduction of the specific prices per kW of turbines in the range above 1 MW in comparison to the 600-750 kW turbines, see Figure 3 and Figure 4. Prices remain between 800-1000 €/kW. The exception is formed by wind turbines between 1.5-1.8 MW; with an average list price of 1000-1100 €/kW, significantly higher than both smaller and larger turbines. As these observations were only based on German list prices, turbine orders from other countries were also analyzed (see Figure 4). While the prices of these numbers generally lie below the German list prices (for a possible explanation see section 4.3), there is again no clear trend of decreasing costs with increasing turbine size.

However, for investors, it is not the cost per capacity but the cost of electricity that determines the economic attractiveness of a wind park. Therefore, the electricity production and cost of electricity with increasing turbine size were investigated. Under reference conditions[7], the annual number of kWh produced per kW installed capacity can vary strongly per turbine class. This is due to a large variety in available rotor diameter (i.e. the swept area) and tower height. The yield from 1.5 MW turbines varies between 1900-3100 kWh/kW/year under the chosen reference conditions. Most turbines from 600 –1500 kW produce slightly less between 1800 and 2900 kWh/kW/year under the same conditions (BWE, 2002). Consequently, the higher investment costs of 1500 kW turbines are not necessarily offset by higher electricity production (see Figure 5).

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[6] In 2002, prototypes of 3.6 MW (GE Wind Energy, Barrax, Spain) and 4.5 MW (Enercon Magdeburg, Germany) turbines have been installed, though these turbines are mainly developed for offshore application.

[7] Average wind speed 5.5 m/s at 30 m height, Rayleigh parameters: k=2, z_0=0.1 (BWE, 2002).

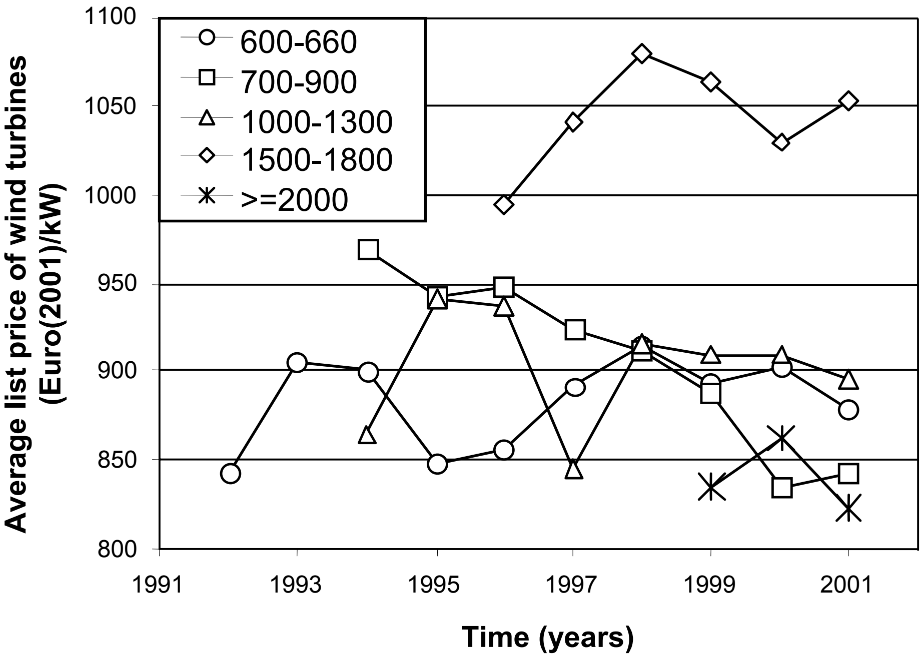

Figure 3 Average list price development of medium sized and large wind turbines 1991-2001. Source: German list prices, (BWE, Editions 1991-2002), adjusted for inflation using German GDP-deflators (IMF, 2002). Exchange rate: 1 € = 1.956 DM.

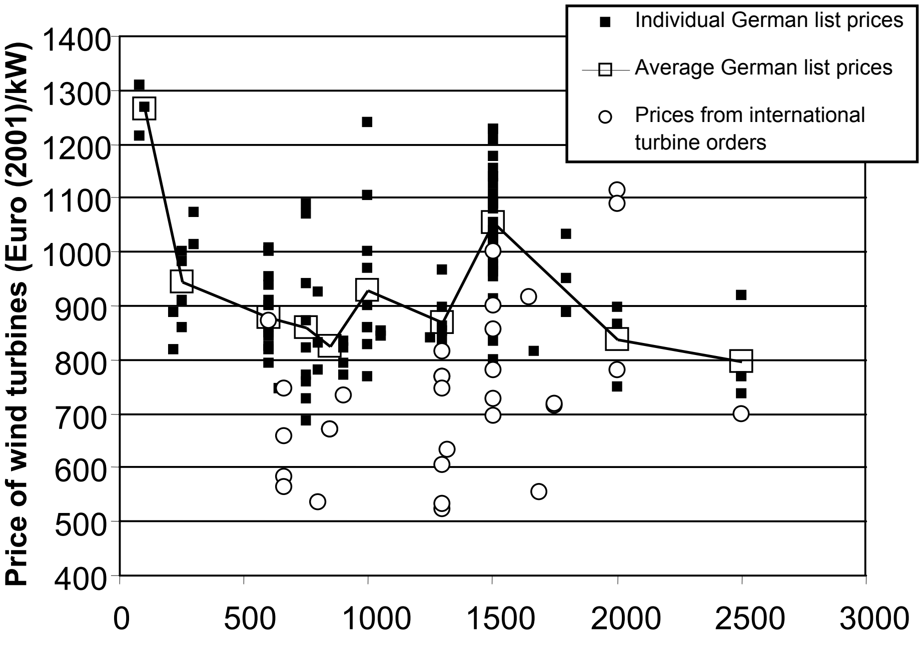

Figure 4 List prices of wind turbines in 2001 in Germany in relation to turbine size. Source: German list prices, (BWE, 2002), adjusted for inflation using German GDP-deflators (IMF, 2002), Exchange rate: 1 € = 1.956 DM. Additionally, turbine prices from orders in various countries are given (Windpower Monthly, 1990-2002), adjusted for inflation using the advanced economies GDP deflator (IMF, 2002).

In fact, turbines in the 600-900 kW range appear to perform equally or even better than the 1500 kW turbines. Yet, these observations do not directly indicate that the generation costs of electricity shall not decline further with increasing turbine size. First of all, not only the list prices of turbines but also other investment costs such as foundations, grid connection, project planning etc. contribute to total investment costs. The share of these costs may be smaller when using bigger turbines. Second, when comparing the final costs of electricity, these also depend on the annual operation and maintenance (O&M) costs, which were not taken into account here and which also appear to be slightly in favor of the larger turbines[8].

It is concluded, that the potential of cost reduction by upscaling wind turbines seems to become less significant in comparison to earlier achievements. Consequently, turbines in the 600-900 kW range are not likely to become 'extinct' in the near future, such as the turbines below 600 kW did. Also a number of other factors support this assumption. Turbines up to 1 MW offer easier transportation due to the suitable size of the turbine components. Also, due to visual impacts the hub height may have to be limited to certain levels (such as in some provinces of the Netherlands). Furthermore, these turbines may be more suitable for deployment in developing countries due to local grid restrictions (Loy, 2002).

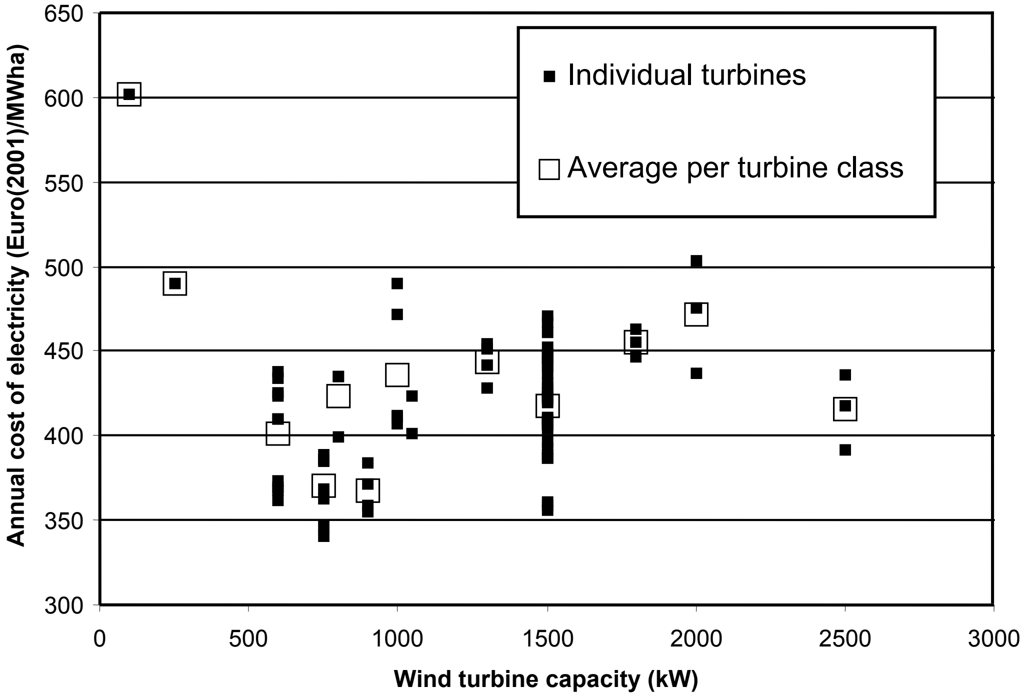

Figure 5 List prices of wind turbines divided by their annual electricity output as a function of turbine size. Data from BWE (2002). Ref. situation: av. wind speed 5.5 m/s at 30 m height, Rayleigh parameters: k=2, z_0=0.1. Variation per turbine class (especially for 1500 kW turbines) is caused by different tower heights and different rotor diameters.

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[8] O&M costs are usually 1-3% of the investment costs per year at the beginning of the lifetime, but may increase later on. O&M costs on average appear to be lower for 1.5 MW turbines (about 13 €/kW/year) than for 500-840 kW turbines (about 19-23 €/kW/year) (Durstewitz and Hoppe-Kilpper, 2002). Depending on specific project and site conditions, this may yet result in more favorable production costs of electricity for larger turbines.

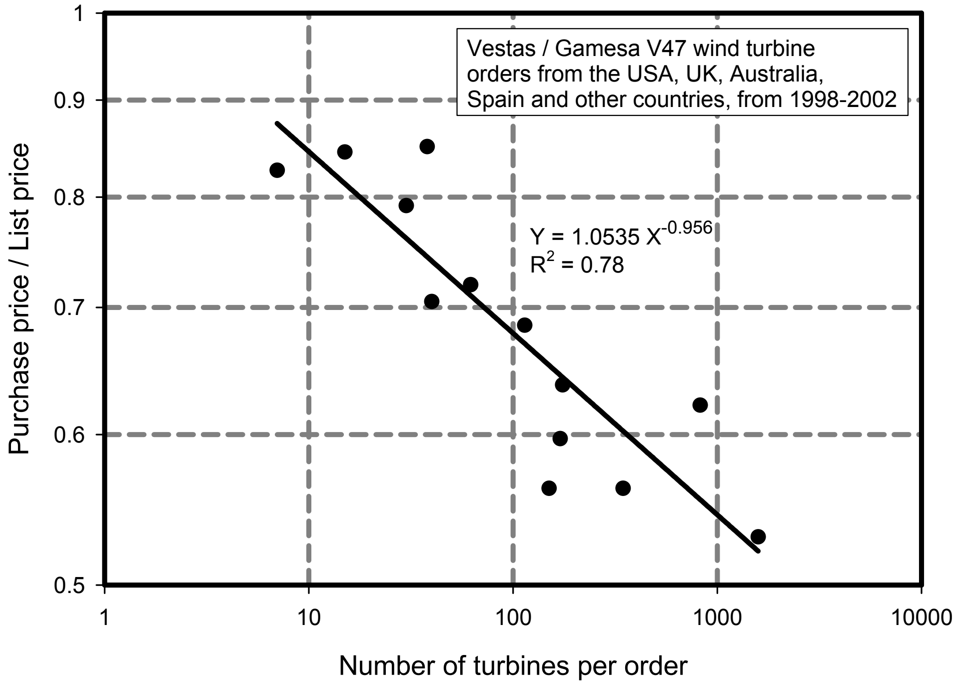

Figure 6 Reduction of purchase price (normalized against German list prices) with increasing order size. Data sources: (Vestas, 1998-2002), (Windpower Monthly, 1990-2002), and various other literature. For the data point of 1600 V47 turbines, the original order also included 200 V66 turbines. Equal prices / kW for both turbine types were assumed. All data was converted to Euro (2000) adjusted for inflation using the advanced economies GDP deflator (IMF, 2002).

3.3. Future developments

Mass production is likely to play a significant role for future cost reductions. In the last five years, wind farms of several hundred MW capacity have been realized in Spain and the USA. Ordering a large number of turbines makes obtaining large rebates possible, as the following example shows. Single order volumes of more than one hundred turbines were found for the Vestas V47, 660 kW turbine. With approximately 3,000 units built by the end of 2001 (Vestas, 2000; Pjengaard, 2002), and further large orders placed after 2001, this turbine is one of the most produced turbines in the world. As can be seen in Figure 6, with order volumes between 500-1600 turbines the purchase price may decrease to 55% of the list price (Vestas Wind Systems A/S, 2000)[9], i.e. 485-515 €/kW versus a list price of 915 €/kW for a single turbine as shown in Figure 6[10]. There is a clear correlation between the order size and the obtainable rebates. The relation may have different reasons. First of all, a single order for 1600 turbines enables a production plant to operate continuously for an extended period of time (i.e. several years). This creates a number of advantages, such as bargaining power for long-term supply contracts for raw materials (steel etc.). Second, the labor costs, which have already been substantially reduced from seven to two employees per MW sold (over the period of 1992-2001 of a major turbine manufacturer (Milborrow, 2002b)), may also come down further depending on the location of the production plant. Order sizes of 500 turbines and above are exceptional at present and the prices quoted of

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[9] The particular order for 1600 Vestas V47 turbines were ordered from Gamesa Eólica S.A. Gamesa Eólica S.A. manufactures turbines on the basis of Vestas technology, but specially optimized for the actual customer and the Spanish market. Until the end of 2001, Vestas Wind Systems A/S owned 40% of Gamesa Eólica S.A.

[10] Note that figure 6 is not an experience curve. On the x-axis, the volume of single orders is given, not cumulative volume of these orders.

around 500 €/kW are not representative for average turbine prices. However, given the prospects of large (offshore) wind farms of hundreds of MW each, mass production may be a significant driver for further cost reductions over time.

Summarizing, it was found that until recently, price reductions of wind turbines were mainly achieved by the upscaling of the individual turbines. It is expected that significant future price reductions may now especially be achieved by producing the same turbine type on a large scale. This conclusion is supported by a study from (BTM, 2000), estimating that a total of 15% of cost reductions will be achieved by 2004 compared to 1999. Of this cost reduction, 35% will be due to design improvements (i.e. weight reduction), and 50% due to economies of scale and manufacturing optimization. BTM also confirms that in 2004 turbines between the 750-1000 kW size are still likely to be the cheapest choice.As there clearly exist possibilities to reduce prices further, the experience curve approach may provide an insight as to how these reductions may develop in the future. For that purpose, in the next section, the applicability of the experience curve for wind energy is scrutinized.

4. Analysis of possible methodological pitfalls

While in the last section, underlying reasons behind cost reductions of wind turbines were discussed, this section focuses on how the experience curve concept has been used in the past to analyze historic cost reductions and how it may be used to analyze the rate of future cost reduction in the wind energy sector.

4.1. System boundaries and types of wind experience curves

First of all, before setting up an experience curve, the boundaries of the learning system should be clearly defined. For example, an experience curve may be devised for the manufacturing of wind turbines. In this approach, the production cost per kW are set against the cumulative shipment of wind turbines in terms of capacity. Another learning system depicts the turnkey installation costs of wind farms as a function of cumulative installation of wind farms. Typically, 65-85% of total costs are based on turbine costs. The remaining parts consist of foundations, grid-connection, project management etc. (see Figure 7)[11]. Thus, the wind turbine learning system is a subsystem of the wind farm learning system. Finally, when devising an experience curve for electricity from wind, the turnkey investment costs will have a major influence on the costs of electricity, but again other factors are of importance as well. So the wind turbine and wind farm learning systems are subsystems of the 'electricity from wind' –system (see Figure 7). Following the experience curve theory, the cost of electricity should be plotted against the cumulative electricity production.

After reviewing literature, in the case of wind energy four different kinds of experience curves were found (see also Table 1). For an overview of studies applying different type of experience curves see Table 2[12]. Most experience curves found in literature analyze the cost reduction of wind turbines

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[11] An analogy may be drawn with PV-systems, where the PV modules are a major contributor of total costs, but also inverters, cables and support structure (known as balance-of system (BOS) components). In experience curve theory, this is called a compound system (IEA/OECD, 2000). An example of such a 'compound' learning curve is discussed in Lako (2002a) for offshore wind turbines, where a division is made between the learning for turbines, offshore construction and cabling & grid connection.

[12] Another recent study uses another classification, identifying five different types of experience curves (Neij et al., 2003). Types I and III are further divided between a production and market perspective, and by different countries, time periods and turbine sizes.

per unit of capacity versus the cumulative capacity produced or installed. However, there are also curves scrutinizing either the cost reduction per kWh versus the cumulative electricity production (type II), or versus the cumulative capacity (type III). Type III relates the performance of the total system (the production cost of wind electricity) to the experience of one of its subsystems (the cumulative installation of wind farms), which should not be done according to Wene (IEA/OECD, 2000) (but may yet be useful for e.g. policy analysis). In addition, a type IV experience curve was found (EWEA and Greenpeace, 2002), where the decline of electricity costs is presented as a function of the cumulative number of turbines installed[13].

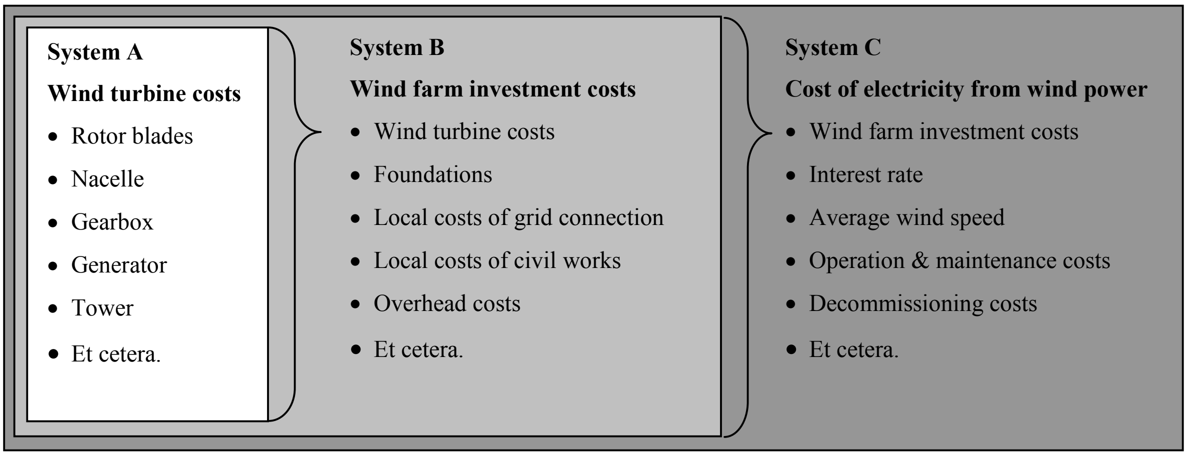

Figure 7 System boundaries for different wind energy learning systems. Learning system A is a subsystem of learning system B, and system B a subsystem of system C. For each system, major components influencing costs are indicated.

Progress ratios derived from different kinds of curves cannot be compared directly. For example, the type IV experience curves used in the recent Wind Force 12 study (EWEA and Greenpeace, 2002) uses an initial progress ratio of 85%. With the data provided in Wind Force 12, type I, II and III experience curves can also be set up. These result in progress ratios of 90.5% for type I and III, and 94% for type II (see also Table 3). In other words, using the same source data but different system boundaries, four different experience curves and three different progress ratios can be derived. As another example, the progress ratio of wind turbines produced and wind farms installed (system A and system B in Figure 7) cannot be compared directly either as the costs of wind turbines may change at a different speed than the cost of the other components (e.g. foundation and grid connection).

Table 1 Four types of experience curves.

Type	X-axis	Y-axis
I	The cumulative capacity installed or produced (kW)	Price of capacity (€/kW)
II	The cumulative number of kWh produced	Price of electricity (€/kWh)
III	The cumulative capacity installed or produced (kW)	Price of electricity (€/kWh)
IV	The cumulative number of wind turbine units installed/produced	Price of electricity (€/kWh)

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[13] This approach is based on the argument that experience is typically gained by the number of units built, and not the number of cumulative MW. However, wind turbines have grown larger over the last 20 years, and so prices per turbine have actually increased. Thus, the costs still have to be expressed as costs per capacity in order to find a decreasing trend. This method has also the drawback that for future scenarios (such as the Wind Force 12 study), additional assumptions have to be made regarding the further growth and average size of future wind turbines.

Table 2 Overview of experience curves for wind energy published in recent years.

Author	PR (%)	Time frame	Region	Cum MW $^{I, III}$ / TWh ^{II} installed ^{i} / produced ^{p}	Av. ann. growth rate	n	R^2
Type I							
(Mackay and Probert, 1998)	85.7	1981-1996	US	20-1750 (±) ^{i}	34.7%	6.5	0.945
(Durstewitz and Hoppe-Kilpper, 1999)	92	1990-1998	Germany	60-2850 ^{i}	62.0%	5.6	0.949
(Neij, 1999b)	92	1982-1997	Denmark	n.a.	n.a.	n.a.	n.a.
(Neij, 1999b)	96 ^{a}	1982-1997	Denmark	2-3000 (±) ^{p}	63% (±)	10.6 (±)	n.a.
(Neij, 1997)	96 ^{a}	1982-1995	Denmark	2-1800 (±) ^{p}	69% (±)	9.8 (±)	0.83
(Seebregts et al., 1998)	87 /90 ^{b}	n.a.	Denmark	n.a.	n.a.	n.a.	n.a.
(Lund, 1995)	85	n.a.	Denmark	n.a.	n.a.	n.a.	n.a.
(Neij et al., 2003)	92-94	1981-2000	4 countries ^{c}	Turbines produced in a country	n.a.	n.a.	n.a.
(Milborrow, 2002b)	84.7	n.a.	Danish manufacturers	60-8000 (±) ^{p}	n.a..	7.1.	n.a.
(Neij et al., 2003)	89-117	n.a.	Several WT manufacturers	Produced wind turbines	n.a.	n.a.	n.a.
(Neij et al., 2003)	89-96	1981-2000	4 countries ^{c}	Turbines installed in a country	n.a.	n.a.	n.a.
Type II							
(IEA/OECD, 2000), based on EU Atlas project data	82	1980-1995	EU	0.02-20(±)	59% (±)	6.6 (±)	n.a.
(IEA/OECD, 2000), based on data from Kline & Gipe	68	1985-1994	US	2-30(±)	35% (±)	3.9 (±)	n.a.
Type III							
(Dannemand Andersen and Fuglsang, 1996)	80	1981-1995	Denmark	7-2500 ^{p}	52.2%	8.5	n.a.
(Neij, 1997)	91 ^{b}	1980-1991	Denmark	7-1280 ^{p}	68.3%	7.5.	n.a.
(Ibenholt, 2002)	92-103	1991-1999	Germany	70-4400(±) ^{i}	68% (±)	6.0 (±)	n.a.
(Ibenholt, 2002)	88-93	1984-1999	Denmark	15-1800(±) ^{i}	35%(±)	6.9 (±)	n.a.
(Ibenholt, 2002)	75	1991-1999	UK	10-360(±) ^{i}	57%(±)	5.2 (±)	n.a.
(Neij et al., 2003)	87-88	1981-2000	4 countries ^{c}	Type III, for specific electr. production by a country	n.a.	n.a.	n.a.
(Neij et al., 2003)	83	1981-2000	4 countries ^{c}	Type III, for levelized electr. production by a country	n.a.	n.a.	n.a.

±	Data estimated from a figure, as exact numbers were not given.
n	Number of doublings of cumulative production on x-axis.
R^2	Correlation coefficient.
n.a.	Data not available.
a	Only four Danish producers; only turbines>=55 kW.
b	Based on data from (Dannemand Andersen and Fuglsang, 1996).
c	Based on data from Denmark, Germany, Spain and Sweden. Depending on market perspective or production perspective, and different time periods, the range of PRs may differ. See for a complete overview (Neij et al., 2003).
i	Based on the number of MW actually **i**nstalled in the region.
p	Based on the number of MW **p**roduced in a country (of which part may be exported).
I, II, III	See Table 1.

Table 3 Calculation of different progress ratios on basis of the wind force 12 scenario. All figures from EWEA and Greenpeace (2002).

Year	A	B	C	D	E
2001	56,000	24,900	54.50	879	4.15
2002	64,500	33,400	127.60	851	4.02
2003	75,125	44,025	224.00	821	3.88
2004	86,193	57,306	349.50	795	3.75
2005	100,027	73,908	511.40	768	3.63
2006	117,321	94,660	718.70	739	3.49
2007	137,274	120,600	982.80	713	3.37
2008	161,219	151,728	1,314.80	686	3.24
2009	187,900	189,081	1,728.80	662	3.13
2010	219,917	233,905	2,240.80	638	3.01

A	Cumulative number of wind turbine units (the average wind turbine size increases over time).
B	Cumulative installed capacity (in MW).
C	Cumulative electricity produced (in TWh).
D	Cost of capacity (in €/kW).
E	Cost of electricity (€ct/kWh).

Experience curve type I (column B vs. D) : PR = 90.5% (calculated result)
Experience curve type II (column C vs. E) : PR = 94.0% (calculated result)
Experience curve type III (column B vs. E) : PR = 90.5% (calculated result)
Experience curve type IV (column A vs. E) : PR = 85.0% (from EWEA and Greenpeace (2002))

4.2. Geographical differences

Another issue is comparing experience curves based on the number of turbines produced against experience curves based on the number of turbines installed. Comparison between two countries may give misleading results. For example, in the US apparently a lower type I progress ratio is observed (85.7%) (Mackay and Probert, 1998) than most studies on Denmark, especially the studies of Neij (92-96%). However, it is noted that in the Danish experience curves, all wind turbines *produced* are given, while in the US all capacity *installed* is given. There is a significant difference between learning curves based on turbines *produced* and turbines *installed* in a country, as the following hypothetical example will show. It is assumed that the progress ratio of manufacturing wind turbines in a producing country is 92%. It is also assumed that at first 60% of all wind turbines produced are exported to and installed in another country and that exports drop from 60% in the first stage to 20-25% in later stages. Yet, the price of wind turbines in both countries remains the same. Based on these assumptions, an *apparent* progress ratio of 88.4% (R^2=0.994) can be calculated for the importing country, while the actual progress ratio remains 92% (See Figure 8). In other words, the *average growth rate* of installed capacity in the importing country was lower than in the producing country, while *prices remained the same*. In such a case, the *PR must be lower* for the importing county than for the producing country. Consequently, the differences in system boundaries makes a simple comparison of the two countries problematic.

In general, it can be stated that when a large (international) learning system exists (implying global price levels), analyzing parts of this system (i.e. countries) will yield distorted progress ratios, as the growth rate of wind turbine capacity in each country does not match the global growth rate.

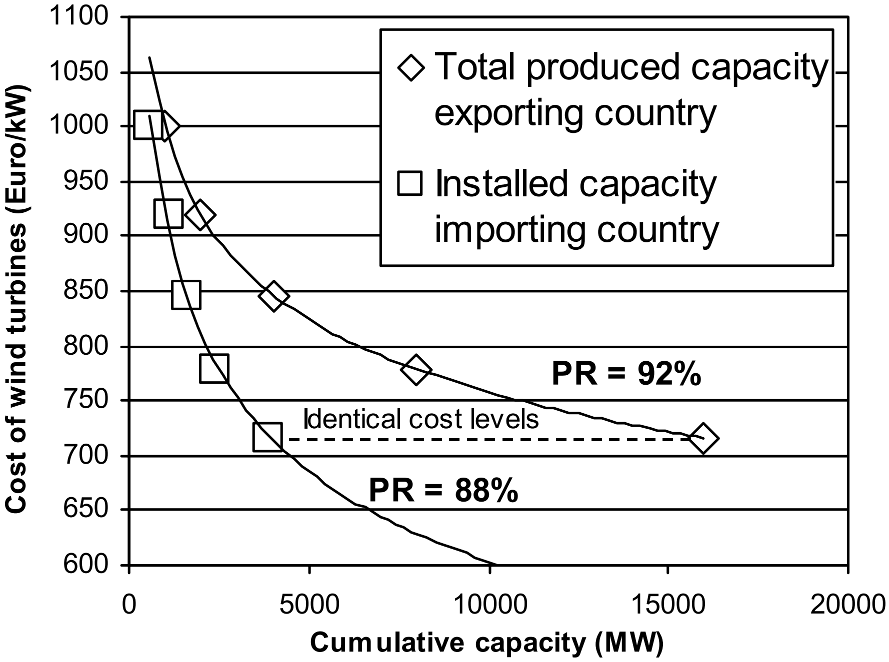

Figure 8 Hypothetical example of 'apparent' progress ratios caused by importing technology. While cost levels are identical in the exporting country and the importing country, the rate of production by the one does not match the rate of installation by the other. It appears that the latter learns faster in this example, while in fact this is caused by a difference in system boundaries.

4.3. The possible influence of policy measures: the case of the German market

As mentioned previously, an experience curve should ideally be based on production costs. Prices can suffice, if there is sufficient market competition. In that case, it can be assumed that profit margins are relatively small and stable and prices will drop at the same speed as costs (see also Figure 1). However, market prices may also be influenced by changes in demand and by governmental support measures. The possible effects of policy measures are illustrated by the developments in Germany described below.

As is shown in Figure 9, between 1991 and 1995 both the average list price of wind turbines and turnkey investment costs of wind farms in Germany have declined steadily by about 8-9% per year. However, average prices remained rather stable since 1995. In fact, as shown in Figure 9, the price of the cheapest turbine available even increased during 1995-1999. There are a number of possible explanations for these trends. In Germany, more and more wind parks are situated in inland areas with lower wind speeds, due to a lack of appropriate sites near the coast. While in 1993, 70% of all new wind parks (in terms of capacity) were installed in coastal regions, this share has dropped to a mere 10-15% in 1999 (Durstewitz and Hoppe-Kilpper, 2002). Lower wind speed locations require turbines with higher hub height and larger blade diameters, increasing the costs per kW. This may explain only partially why average prices of turnkey wind-parks remained stable, as it does not account for the fact that the price of the cheapest wind turbine actually increased between 1995 and 1999. This may partly be due to the fact, that early models of the 600-700 kW turbines had a number of design flaws (for example under-dimensioned gear-boxes), which had to be corrected, causing an increase in wind turbine costs. Yet, this cannot fully explain a continuous rise over five years.

The most likely explanation is the relatively high German feed-in tariff for wind electricity. Feed-in tariffs have fluctuated from between 8.5-9.5 €ct/kWh from 1991-2001 (in real terms, base year 2001), and are currently 9 €ct/kWh (Durstewitz and Hoppe-Kilpper, 2002)[14]. This feed-in tariff is one of the highest in Europe and facilitated an impressive growth in installed turbine capacity. It also caused a large demand for wind turbines, which in turn most likely caused prices of wind turbines and additional investment costs (such as land rent, project development costs etc.) to remain stable. This observation is confirmed by (Stump, 2002), who finds that the prices of wind turbines are to some extent determined by feed-in tariffs, and that the high demand for wind turbines was not beneficial to price reductions. Another study found that in Germany a clear relationship exists between the specific investment costs of a wind farm and the quality of the site, i.e. at a location with high wind speeds, specific investment costs for a wind farm are much higher than at a site with low wind speeds (Durstewitz and Hoppe-Kilpper, 2002). The study also indicates that especially project developers may increase ‘soft’ investment costs to maximize profits.

Thus, it appears that due to the high feed-in tariffs the need for further learning and cost reductions were (at least temporarily) eliminated in Germany. However, one must also mention the fact that the feed-in tariff system allowed an impressive growth of installed wind capacity in Germany, at present more than one third of the global installed capacity. It is concluded that in this case historic data cannot be used to determine the actual speed with which the technology learns.

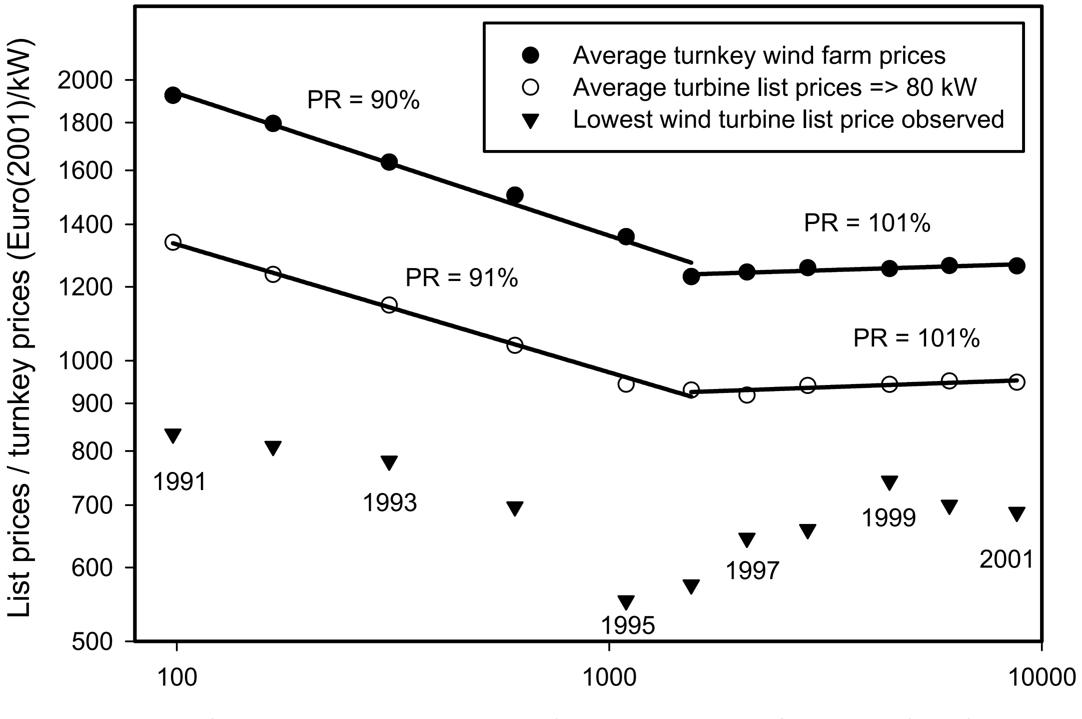

Figure 9 German experience curves for average wind turbine list prices and turnkey wind farms in the period 1991-2001. In addition, the cheapest wind turbine list price in different years is given. All prices are adjusted for inflation using German GDP-deflators (IMF, 2002). Exchange rate: 1 € = 1.956 DM. Data sources: (BWE, Editions 1991-2002; IWR, 1994-2001), own data collection, mainly from Windpower Monthly and various internet sites (e.g. (IWR, 1998-2002)) and (Neumann et al., 2002).

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[14] It has been announced that the feed-in tariff will be reduced annually by 1.5% to about 7.9 €ct/kWh in 2010 (Durstewitz and Hoppe-Kilpper, 2002). Assuming an annual inflation of 2%, this implies a real reduction of feed-in tariffs of 3.5% annually, which is less than the annual reduction of turbine prices of 8-9% before 1995 in Germany.

4.4. Impact of exchange rates and inflation correction on experience curves

A basic principle of using experience curves is adjusting nominal data for inflation. When the learning system considered is within a single country, the national GDP-deflator is commonly used to correct the nominal values. However, when *comparing* data from different countries, one has to deal with both different rates of inflation, and fluctuating exchange rates. Normally, these two developments are coupled. However, the exchange rate also depends on other factors. As a result, currencies can be 'undervalued' or 'overvalued' in comparison to a major currency such as the US Dollar or the Euro. This makes choosing the reference currency problematic: depending on the selected reference currency, the progress ratios obtained may differ significantly. For example, Snik (2002) found that for an experience curve of Japanese PV modules given in US Dollars, the calculated Progress Ratio is about 82%. If the same data are presented in Japanese Yen, a Progress ratio of 76% is obtained. This is a significant difference when these numbers are used for predicting global cost reduction potentials. While there is no perfect solution for this issue, acknowledging the differences in PR by choosing different reference currencies will indicate what error margins are to be taken into account.

Summarizing, it has been shown that the correct choice of system boundaries, selection of appropriate data and the choice of reference currencies are important factors when establishing experience curves. In the next section, an approach is presented on how to overcome these bottlenecks.

5. Setting up global experience curves: methodological setup

As mentioned in the introduction, experience curves are frequently used in global energy and climate change models. Yet, in the case of wind energy, these models mainly adopt progress ratios from experience curves describing local markets. As shown in section 4, this may cause a number of pitfalls and methodological problems. In comparison, for other technologies, global experience curves have been established[15]. Thus, an attempt is made to establish a global experience curve for wind as well. In order to do so, it is first discussed why it is basically possible to devise a global experience curve, and second describe the requirements for preparing such a curve.

5.1. Global learning system

For a global experience curve, one should make sure that it actually concerns a reasonably homogeneous learning system, i.e. that technological innovations are available in the entire geographical area. The global wind market is dominated by seven turbine manufacturers: Vestas, Enercon, NEG Micon, GE Wind (formerly Enron Wind), Gamesa, Bonus and Nordex. Together, in the year 2002 these companies were holding a global market share of approximately 78% (BTM, 2002), as shown in Figure 10. In terms of countries, the 'big five' (Germany, Spain, Denmark, the USA and India) have been at the top for the last decade. In these countries currently over 80% of the worldwide wind-based power generation capacity is installed (Milborrow et al., 2003) (see also Figure 10). On local markets, local producers may play a minor role as well, such as Repower, DEwind, and Fuhrländer in Germany or Made and Ecotecnia in Spain. Yet the 'big seven' suppliers dominate most wind markets, especially the Danish suppliers. With the exception of Enercon, these

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[15] For example, for photovoltaic modules, several authors have established global experience curves, e.g. Mackay and Probert (1998) and Harmon (2000).

manufacturers also use similar technology (horizontal axis wind turbines, variable speed, pitch regulated, utilizing a gearbox and a asynchronous generator). All producers offer wind turbine models in the same size categories (roughly 600 kW-2 MW) and deliver these turbines all over the world. For example, the Vestas V47 660 kW turbine has been installed in countries like New Zealand, Australia, the USA, South Korea, Spain, Germany, the UK and Italy. Thus, as the big manufacturing companies deliver turbines all over the world and basically use the same technology concepts, it can be concluded that the knowledge and technology present in these companies is applied on a global level, and that there is to a large extent "global learning". In terms of wind farms, the other components (such as foundations and grid-connections) are more subject to local learning. Yet, many wind farms are built by the wind turbine producers (i.e. delivering turnkey wind farms) and thus 'export' knowledge on these components as well.

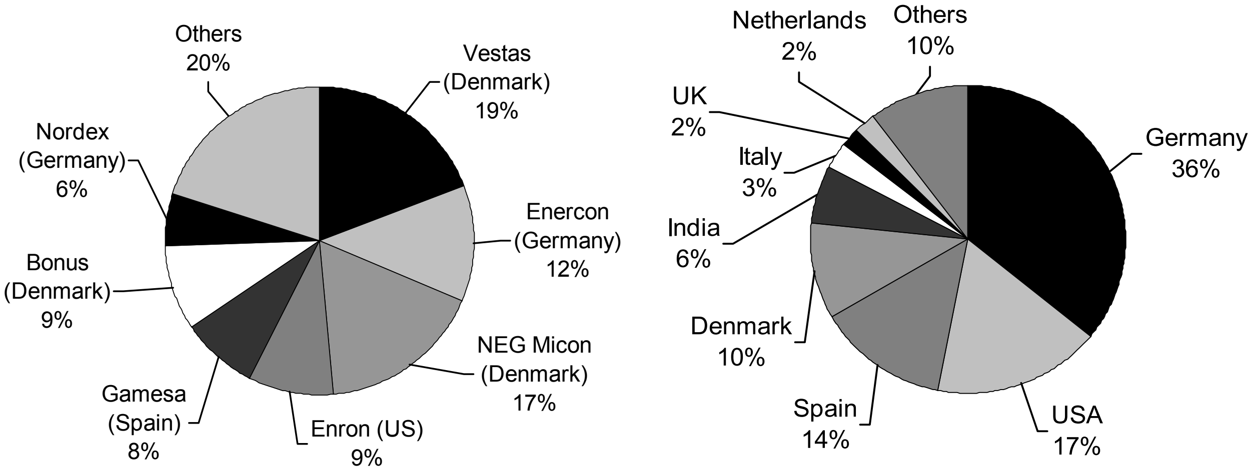

Figure 10 Distribution of the worldwide produced wind capacity at the beginning of 2002 over wind turbine manufacturers (BTM, 2002) and over countries (Milborrow et al., 2003).

5.2. Data selection requirements

The second issue is the selection of appropriate data. The careful selection of data for composing a global experience curve is crucial for the validity. The authors suggest that the data should meet the following requirements:

1. When using price information, these should stem from a competitive (market) environment to avoid distortions from (too) high profit margins.
2. The time period during which capacity was installed should be sufficiently long (e.g. five years or longer), and there should ideally be no large gaps in the time series used.
3. The market considered should be internationally oriented, i.e. open for imports from all major manufacturers, with little or no obligations to involve local producers.
4. Last but not least, there simply must be sufficient data available to devise an experience curve.

6. Setting up global experience curves: data selection

As was discussed in the previous sections, there are several types of experience curves (i.e. system boundaries) for wind energy, e.g. wind turbines, wind farms and electricity from wind. Unfortunately, due to lack of data setting up a global experience curve for *wind turbines* is not possible. Except for the German list prices, no other data could be found that annually inventories list prices of wind turbines. Though incidentally, order volumes of wind turbines are published, too little information is available to construct a global turbine experience curve. With regards to an experience curve for *cost of electricity from wind*, there was also not enough data available. In addition, wind speeds may very strongly depend on the site, interest rates may differ per project, and numerous other reasons may cause a range of electricity cost figures. Therefore, it is not attempted to develop an experience curve for electricity from wind either. However, especially in recent years, the turnkey costs of a number of wind farm projects have been issued for Spain, the US, Australia, the UK and other countries. Therefore, this chapter focuses on experience curves for *global wind parks*.

6.1. UK data

Given the criteria set in the previous section, data from the UK seemed to be well suitable. In the UK, the NFFO/SRO-system required the electricity supply companies to provide a proportion of their supply from renewable energy sources. From 1991-1999, several bidding rounds were held, where project developers could subscribe. Bids were assessed on a competitive basis and an upper threshold selected after a predetermined deadline. While this system failed to stimulate a large capacity expansion (in contrast to the German feed-in tariff system), costs of electricity dropped strongly from 1991-1999 (Hill, 2002; IEA, 1999). Due to this competitive bidding system, it is likely that turbine manufacturers offered turbines at low profit margins.

Second, in the UK over the last decade about 500 MW of capacity have been installed (with annual additions varying between 10-80 MW) (BWEA, 2002), thus data is available over an extended period of time[16]. An additional advantage is that the techno-economical potential of wind energy in the UK is much larger than 500 MW, which means that the availability of windy sites has not substantially diminished (as has been the case in Germany and Denmark). Consequently wind farm costs in the UK are not likely to have risen due to higher towers and larger rotor diameters, as may have been the case in Germany. The size of turbines installed varies. Most existing wind parks built between 1995 and 1999 utilize wind turbines of between 500-700 kW. More recently, large turbines up to 2.5 MW have also been installed. The average size of the wind farms is rather small (4-7 MW), and thus the data from the UK may be seen representative for small wind parks.

Third, the United Kingdom basically does not have a domestic wind turbine industry, apart from some plants manufacturing components of wind turbines from international manufacturers. Most turbines had to be imported, with the possible exception of certain components, e.g. towers. From 1991-2001, more than twelve international manufacturers installed wind turbines in the UK, Vestas having the largest share (BWEA, 2002). Thus, it is likely that the turbines reflect world market prices.

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[16] For the UK data was obtained from the following sources: IEA (1998; 1999), Milborrow (2002a), Wind Power monthly articles (1990-2002) and BWEA (Hill, 2002).

6.2. Spanish data

A shortcoming of the UK data is the very small average plant size. Specific investment costs tend to decline with increasing wind farm size as the share of grid connection, project planning and other overhead costs become smaller. Therefore, it was also attempted to find data for large-scale wind farms. Possible data-sources for relatively large-scale wind parks would be either the USA or Spain, which both have wind farms of over 100 MW capacity. As not enough wind farm price data over an extended period of time could be found for American wind farms, Spain was chosen as a second source of data.

In contrast to the UK, Spain hosts some of the largest wind farms in the world[17]. Thus, the data found for Spain may be more representative for large wind farms. The dominant turbine type in Spain is 600-700 kW. The operating capacity in Spain at the beginning of 2002 was about 3300 MW (Milborrow et al., 2003), while the total technical potential is estimated to be approximately 15000 MW (Ayuso Ortiz et al., 2002).

Yet, the Spanish data is somewhat less suitable because of two factors. First, a number of national turbine manufacturers dominate the market (such as Ecotecnia, Made and Gamesa-Eolica), though some of them (such as Gamesa-Vestas, Bazan-Bonus and Taim-NEG Micon) cooperate with foreign wind turbine manufacturers. Gamesa Eolica (using Vestas Technology), NEG-Micon and Enron Wind supplied over 80% of all wind turbines installed in Spain in 2001 (Ayuso Ortiz et al., 2002). Nonetheless, according to a recent article in Wind Power Monthly (McGovern, 2002) there are over 40 facilities for the production of turbines and components in Spain, which makes adaptation of the national production capacity to new technological developments more difficult and more costly. While turbines above 1 MW are now being introduced, their pace of entry has been slower in Spain than elsewhere. Second, Spain has a feed-in tariff similar to the German system. Even though the electricity tariffs paid are lower than in Germany[18], there are also cases in Spain where artificial increase of investment costs due to rocketing land rent fees and "discretionary administrative royalties" are known of (Dinica, 2002). Thus, the data from 1998 onwards (when the Royal decree was issued) may also be on average too high. On the other hand, average investment costs in Spain are (significantly) lower than for example in Germany, and have continued to decline even after the introduction of high feed-in tariffs. As little other data on large wind farms are available, Spanish data were used for incorporating large-scale wind farms in composing a global experience curve, taking into account the limitations described above[19].

For both the experience curve based on the British and on the Spanish data, the conversion from nominal to real prices was carried out using the advanced economies GDP deflator of the IMF (IMF, 2002). The choice for the advanced economies deflator was deemed the most appropriate when looking at global wind prices development.

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[17] In Spain 12% of installed capacity is in wind farms is below 15 MW, 40% is in wind farms between 15-25 MW, and 48% of installed capacity is in wind farms over 25 MW in capacity. Several parks around and above 100 MW exist. The most dominant turbine type is 600-700 kW (Ayuso Ortiz et al., 2002).

[18] Since 1998 producers can choose between either a fixed tariff of about 6.3 €ct/kWh, or a bonus of 2.9 €ct/kWh on top of regular feed-in tariffs (Ayuso Ortiz et al., 2002). These are lower than tariffs in Germany. Note also that feed-in tariffs do not necessarily result in market distortions. In Germany prices dropped until 1995, even though feed-in tariffs were in place since 1991. The constant prices probably only occurred after actual costs became significantly lower than the feed-in tariffs.

[19] For Spain data was used from (IDAE, 1999; Coira, 1996), articles from Windpower Monthly (1990-2002) and various articles from Spanish newspapers (Energia Eolica, 2002).

7. Setting up global experience curves: results and discussion

7.1. Results

The global experience curves devised with data from the UK and Spain is shown in Figure 11. The calculated PR using British data is 81% and using Spanish data is 85%. When only using the data from 1991-1998 for Spain (omitting data possibly influenced by policy measures), the Progress ratio is 82%. This confirms the assumptions that recent cost reduction rates have declined at a slower pace and that probably only the data until 1998 are a better proxy for cost reduction than the whole data set. As expected, the Spanish investment costs are lower than British investment costs. This is likely due to the larger average wind farm size in Spain, allowing on average for cheaper turbines and a relatively smaller share of other investment costs (see also Figure 12). The difference between average turbine costs in Spain (615 €/kW) and the UK (670 €/kW) is smaller, and can be explained by the different order sizes (see section 3.3).

As can be seen in Table 5, the correlation coefficient (R^2) is better for the UK data (0.97) than for the Spanish data (0.87-0.90). Compared to other energy technology experience curves the correlation for the UK data is very good, while the correlation for the Spanish data is about average (McDonald and Schrattenholzer, 2001).

A key observation is that these progress ratios are significantly lower than those used in many studies describing the possible development of wind capacity (and electricity) costs over the next 20 years or so (see also Table 4). This may also imply, that prices may actually decline faster than anticipated in most scenarios or models. This can be illustrated by a simple calculation. Let us assume that current average wind farm investment prices lie around 1000 €/kW. Let us also assume that globally the installed cumulative capacity will double four times by 2020[20]. Under these circumstances and using a progress ratio of 92%, prices will drop to 716 €/kW by 2020. In the case of a progress ratio of 82%, prices will drop to 452 €/kW, i.e. 37% lower investment prices. When assuming very optimistic growth expectations (such as the Wind Force 12 scenario), applying a progress ratio of 82% would result in investment prices in 2010 of 463 €/kW, less then half of the current prices.

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[20] For comparison, the global wind capacity has doubled four times within the last decade. Yet, it is unlikely that these growth rates can be sustained for another 20 years.

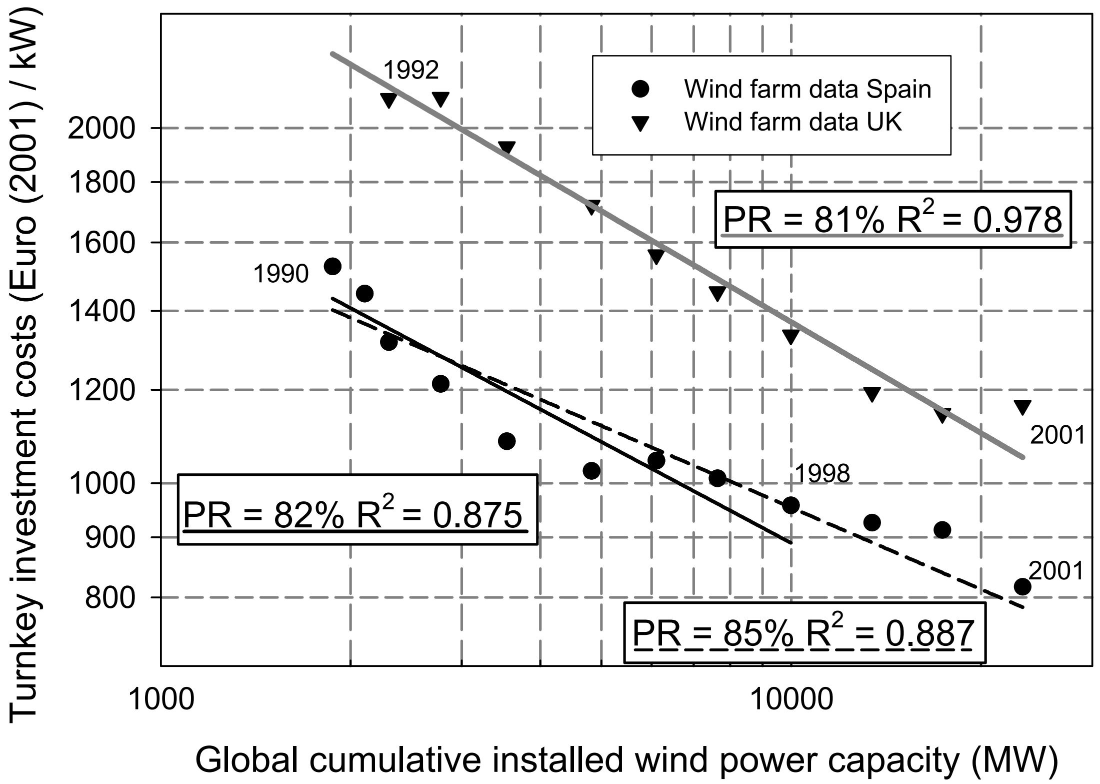

Figure 11 Global experience curves for wind farms, using data from British and Spanish wind farms. All data are adjusted for inflation using the advanced economies GDP deflator (IMF, 2002). The dotted line uses Spanish data from 1990-2001, the solid black line uses data from 1990-1998. The data set for the UK runs from 1992-2001.

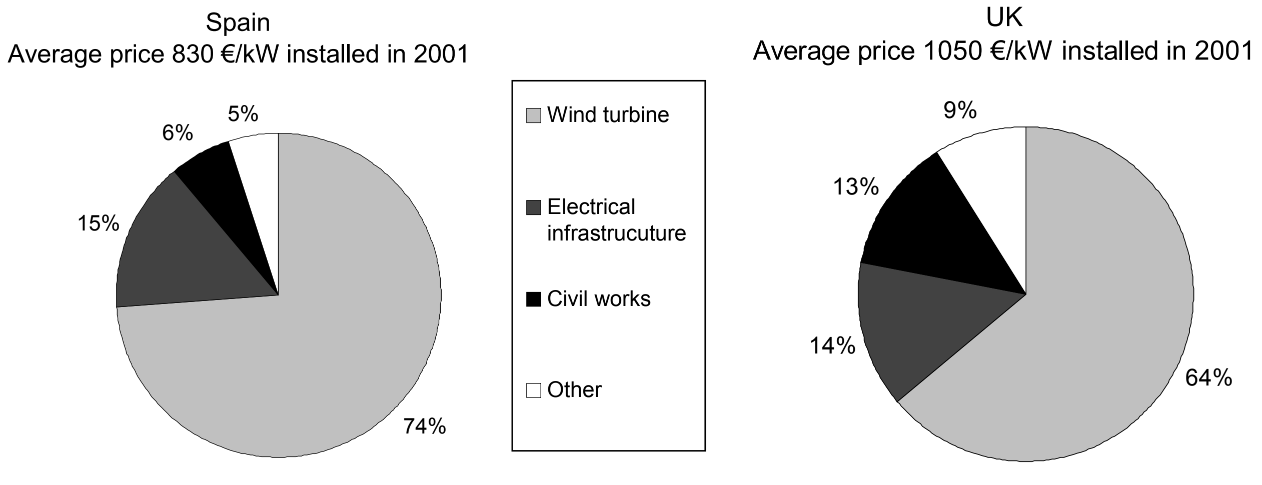

Figure 12 Average distribution of turnkey investment prices of Spanish and British wind farms. British data based on a 5 MW wind farm, Spanish data based on a 20 MW wind farm. These sizes represent the average wind farm size in each country. Data sources: (Ayuso Ortiz et al., 2002; BWEA, 2002).

Table 4 Examples of scenario studies and Integrated Assessment Models utilizing the experience curve concept, and their applied PRs.

	PR used (type I)
Global Wind Penetration Scenarios	
Neij (1999b)	93-97%
Wind Force 12 (EWEA and Greenpeace, 2002)	90.5-100%[a]
Integrated Assessment models	
(Seebregts et al., 1999)	
Reduced MESSAGE global	85%
MARKAL	89-90%
ERIS global	88%

a The Wind Force 12 study uses a PR of 85%, based on experience curves based on the number of turbines installed, see also section 4.1. After 2010 in this scenario the PR changes in several steps from 90.5% to 100%.

Especially in integrated assessment models, where technological progress is modeled endogenously, faster cost reduction may lead to higher deployment rates, thereby further reducing investment costs. As was shown by Gerlagh and van der Zwaan (2002), uncertainties in the progress ratio seriously affect the robustness of this kind of macro-economic models.

7.2. General discussion

The chosen approach has a number of limitations:

- Wind farm costs depend to a certain extent on local conditions. Factors like land availability, distance to the grid, accessibility and average wind speeds may differ strongly between wind farms, but also between countries. Also the size of the wind park may influences the specific costs. When using average data, these variations become less extreme. Spanish wind farms are an example in which the turbines, on average, represent a relatively high share of the total investment costs. In contrast, in the UK, especially civil works and other costs (e.g. project management and financing, legal costs), make out a relatively large share of total investment costs (see Figure 12).
- While the market for wind turbines is a global one, cost reductions for other components such as grid connection and civil works, but possibly also project financing and O&M costs may depend much more on local learning.
- Large wind farms may be on average cheaper to build, but in densely populated areas it may also entail that possible sites are more scarce and building permits more difficult to obtain. This can result in longer project realization times, which in turn may negatively affect the economic performance of a project.
- As explained in section 2, progress ratios for wind farms and wind turbines cannot be directly compared. Only when the speed of the reduction of costs for all other components of a wind farm (such as civil works and electrical infrastructure) is identical to the speed of the cost reduction of turbines are the two progress ratios the same.
- As discussed in section 4, the choice of reference currency and GDP-deflator may also influence results. In order to check the sensitivity of the progress ratios, the same experience curves were also established using the local British/Spanish GDP-deflators. The resulting progress ratios are lower for both the UK and Spain, due to the fact that the inflation rate in both countries (especially in Spain) was higher than the average advanced economies inflation rate (see Table 5).

Table 5 Overview of different progress ratios depending on time frame and GDP-deflator.

	Advanced Economies GDP deflator		National GDP-deflator	
	PR	R^2	PR (%)	R^2
UK 1992-2001	81	0.978	79	0.980
Spain 1990-2001	85	0.887	80	0.907
Spain 1990-1998	82	0.875	77	0.905

7.3. Comparison with other recent findings

Finally, the results are compared with those of the recently published EXTOOL-study (Neij et al., 2003). In the EXTOOL-report, a great number of experience curves have been set up both for wind turbines and wind farms, on basis of the capacities installed in several countries, such as Germany, Denmark, Sweden and Spain. From this work, the authors conclude that the progress ratio for total installation costs of wind farms on a country-basis is about 90%, with the specific PRs for Denmark, Spain and Sweden being 92%, 91% and 96% respectively. These numbers differ significantly with our findings for the global experience curve. However, the difference can be explained by a difference in system boundaries. For example, Spain has had a higher average growth rate of installed capacity (on average 87% per year) than the global capacity (on average 24% per year) from 1990-2001. As argued in section 4.2, a higher growth rate at identical price levels results in higher PRs. When using the EXTOOL price data from 1990-2001 (and the Spanish GDP-deflator) for Spain, but using global instead of Spanish installed capacity, (i.e. again using Spanish data as substitute for world prices) a PR of 80% is found, which corresponds well with the value of 80% found in this paper (see Table 5).

8. Conclusions and Recommendations

8.1. Methodology

With respect to the experience curve, the analysis has shown that the choice of time frame, geographical area, GDP-deflator etc., can cause significant differences in the resulting progress ratios. As experience curves have been established for many different energy technologies, each using data from different countries and different time frames, the authors recommend paying more attention to methodological limitations and the uncertainties involved. In the case of wind farms, it was shown that progress ratios may range from 77-85% depending on the timeframe, choice of country (i.e. wind farm size) and chosen GDP-deflator. Even though this range was narrowed down to 81-82% using the most appropriate GDP-deflators and time frames, no single PR for wind farms was determined. Rather it is suggested to limit the range to between 77-85% (with an average of 81%) and to use this uncertainty interval for different scenarios.

While national experience curves in the authors view are well suited for evaluating local policy measures, the approach developed here is considered more suitable for developing global scenarios and integrated assessment models. Given the significantly lower progress ratios obtained by our approach compared to most other progress ratios, and consequently the far more optimistic view on the cost reduction of wind parks, further research is recommended to confirm these findings. Possibly, data from other markets with a long history like US or Denmark should also be investigated.

As discussed in section 2, it is possible that PRs may change over time, e.g. in case of non-exponential growth as a function of time. In the case of wind energy, most scenarios expect that exponential growth of the global installed wind farm capacity will continue for some time (e.g. 10-20 years). Thus, no imminent depreciation experience is expected during this period, so that the experience curve for wind parks may be extrapolated for e.g. scenario purposes at least during this time frame.

8.2. Cost reduction options for wind turbines

As was shown, economies of scale may be one of the main drivers for future cost reductions. While development of new concepts may also significantly contribute to further cost reductions, large onshore wind farms (and also possibly offshore wind farms) may benefit from the effects of mass production.

8.3. Policy recommendations

Besides methodological and scientific conclusions, there are also lessons for policy makers to be learned. As the analysis has shown, governmental support may have strong effects on price reductions of wind turbines. While generous feed-in tariffs clearly stimulate the deployment of new capacity, it may also stimulate free-rider behavior and cause prices to stagnate. On the other hand, while the UK has seen the largest reduction in costs, the actual capacity deployed is mediocre compared to Spain or Germany. When developing new policy instruments to stimulate wind power, attention should be paid to avoiding the umbrella-effect, while at the same time not discouraging investments. A possibility that should be investigated is the reduction of feed-in tariffs according to the speed that prices decline down the experience curve. For example, currently global wind capacity doubles approximately every three years. Assuming a progress ratio of 80%, this would implicate that feed-in tariffs can also be reduced by about 20% over the same time period. When at a later time global capacity would grow at a slower pace, feed-in tariffs might be reduced at a slower pace as well. On the other hand, such an approach may result in increased uncertainty for investors and may thus discourage investments in wind energy technology. Therefore, such an approach should be developed in more detail.

Finally, when analyzing future cost reductions, it seems that especially large-scale wind parks may achieve lower investment costs. Thus, policy measures might be better aimed at stimulating larger wind farms. This may also require different policies and different actors than thus far considered.

9. Acknowledgements

The author would like to thank the following persons for helpful advice and supplying data: Allison Hill (BWEA), David Milborrow (WPM), Joe Metti (Blayney Wind Farm, Australia), Juan Ramon Ayuso Ortiz (IDEA), Mona Klausen Koch (WPM), Norbert Stump (Forschungszentrum Jülich), Ole Hejn Pjengaard (Vestas Denmark), Thomas Sundqvist (Lulea University of Technology), Ulla Meixner (Reconcept) and Valentina Dinica (TU Twente). Erik Alsema, Susanne Agterbosch (Copernicus Institute, Utrecht University) and an anonymous reviewer is thanked for helpful comments on an earlier draft.

Chapter 4: Cost reductions prospects for offshore wind farms[1]

Abstract

The economics of offshore wind farms are presently less favorable than for onshore wind energy. Consequently there is a strong need for significant cost reductions in order to become competitive. About 70% of the electricity cost of offshore wind farms is determined by the initial investment costs, which mainly consist of the wind turbines, foundations, internal and external grid-connections and installation. Possible cost reductions until 2020 are explored for each of these components. Technological developments and cost reduction trends in both the offshore and onshore wind sector are analyzed. Information is also taken from offshore oil and gas sector and from the experience with high-voltage submarine transmission of electricity. Where possible, cost reduction trends are quantified using the experience curve concept, or otherwise based on expert judgments. Main drivers for cost reduction appear to be (a) design improvements and upscaling of wind turbines, (b) the continuing growth of onshore wind capacity, and (c) the development and high utilization rates of purpose-built installation vessels. Other factors are: reduction of steel prices, technological development of HVDC converter stations and cables, standardization of turbine and foundation design, and economies of scale for the wind turbine production. It is concluded that under different growth scenarios, investment costs of offshore wind farms may decline about 25-39% by 2020. Assuming an identical decline of annual O&M costs, the levelized electricity production costs are reduced from 6.8-7.2 to 4.2-5.4 €ct/kWh.

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[1] Published in Wind Engineering, 28(1), p. 97-118. Co-authors: A. Faaij and W.C. Turkenburg.

1. Introduction and rationale

Compared with onshore wind farms, offshore wind farms have several advantages. First of all, due to the larger wind speeds at sea, offshore wind farms may yield up to 50% more annual electricity than onshore wind farms of equal capacity and type. Second, onshore wind farms often meet public resistance from visual impact, noise production and shadow casting; for offshore locations, with sufficient distance to shore, these issues are far less important. Third, for some countries, the available technical potential is very large compared with other renewable electricity options. For example, on the Netherlands' continental shelf, estimates of wind farm technical potential range from 15 GW (Matthies et al., 1995) to over 60 GW (Kooijman, 2002), but onshore, the upper limit may be about 3 GW (van Wijk and Coelingh, 1993; Junginger et al., 2004a). In Europe, present offshore wind capacity contributes less than 1% of the total wind capacity installed, yet the European Wind Energy Association (EWEA) estimates that offshore wind energy may contribute up to 50 GW in 2020 in Europe, which would equal one third of the total installed wind capacity as targeted by EWEA for the year 2020 (EWEA, 2003). These expectations are in line with planned developments and ambitious targets in Germany and the United Kingdom. Other European countries, e.g. Ireland, The Netherlands, Denmark, Sweden and Belgium, are also planning and developing offshore wind farms. Offshore capacity additions are expected to increase from the present 100-200 MW/y to 900 MW/y in 2007 (Douglas-Westwood Limited, 2002).

Nevertheless, the economics of offshore wind farms are currently less favorable than onshore wind farms. While electricity from onshore wind farms at windy sites can almost compete with the cheapest fossil fuel based electricity production, offshore wind farms still need significant cost reductions in order to so compete. The larger costs are due to large investment costs. Also operation and maintenance costs are higher than for onshore farms. Thus, policy makers, energy companies and the wind turbine industry need to know the total cost reduction potentials and trends of offshore wind farms, including technological developments, and when these may be achieved.

Ongoing RD&D efforts and developments in the offshore wind sector have been described recently in detail elsewhere, see e.g. Halliday (2001). Many are related to the re-design of wind turbines and improved prediction of short-term wind-electricity production. Furthermore, studies analyze the impending integral design of wind farms (see e.g. (Kühn et al., 1998; Bulder et al., 2000)). For beyond 2010, few studies have been found, e.g. as published by DTI in the UK, which indicates that the cost of electricity from offshore wind farms may decrease from the present 8 €ct/kWh to 4-6 €ct/kWh in 2020 (DTI, 2002)[2]; however no specific assumptions and driving factors are given. Milborrow briefly discusses various factors for cost reductions, and gives quantitative estimates of cost reduction possibilities per component for 2012 (Milborrow, 2003). Chabot analyzed possible cost reduction of French offshore wind farms by 2015 and 2030 (Chabot, 2002). Lako (2002a) estimated the cost reduction potential for nearshore and offshore wind farms to 2030.

Most of these studies focus on cost reductions caused by improved designs of wind farms. However, also other factors, e.g. 'learning-by-doing', standardization and economies of scale, may contribute to cost reductions. In addition, it is likely that developments in other industrial sectors also reduce wind farm costs.

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[2] At an exchange rate of 1 £ = 1.6 €.

This paper explores the ranges of possible cost reductions of offshore wind farms by a bottom-up analysis of technological improvements and cost reduction options. Hence, important underlying drivers are identified for cost reductions. This encompasses drivers directly related both to the development of offshore wind farms and to exogenous developments in other industries, such as the offshore oil and gas sector, the high-voltage submarine transmission of electricity, and the cost development of the main raw materials used, especially steel. This study focuses on the initial investment costs, because these constitute the major part (more than two-thirds) of the total cost of electricity production (see section 2). The time frame is the year 2020.

In section 2, current development and economics of offshore wind farms are considered briefly. In section 3, the methodology to investigate potential cost reduction is described. Trends and cost reduction possibilities in different sectors are analyzed in detail in section 4. Section 5 presents a synthesis of different developments and two scenarios of how offshore wind farm investment costs may develop to 2020. Finally, in section 6, the methodology and results are discussed and some general conclusions are drawn.

2. Development and economics of offshore wind farms

The first ‘offshore wind turbine’ was installed in 1991 in Sweden, only 250 m from shore. Since then, about ten offshore wind farms have been built in Denmark, Sweden, The Netherlands and the UK. The first offshore wind farms in the early nineties were basically only upgraded onshore turbines. Only since the last five years, specifically designed offshore turbines are used, built to last and perform longer in the harsh offshore environment. As in the onshore wind sector, a major driving factor behind cost reductions achieved in recent years has been the increasing height, rotor diameter and capacity of wind turbines. While the first offshore turbine had a capacity of 220 kW, currently installed wind turbines all have a capacity of at least 2 MW. Various prototypes in the range of 2.75-5 MW are currently tested and likely to be deployed in the near future. Concurring with offshore turbine developments, different concepts for foundation structures are tested, such as tripod structures, box caisson structures, and steel monopiles, depending on water depth and soil properties (Zaaijer and van Bussel, 2002).

As can be seen in Figure 1, early investment costs were around 2500 €/kW, but have decreased to a current 1200-1850 €/kW (see Figure 1a). This cost range is also found for a number of projected offshore wind farms in Germany, the UK, Denmark and the Netherlands. As the locations tend to move further offshore with higher average wind speeds, the (calculated) capacity factor increases from about 25% to a maximum level of 38-41% (see Figure 1b). Significant reductions of investment costs have been achieved already, even though in general the location of wind farms is shifting from sheltered, low water depth locations close to shore towards more distant locations (>20 km) in deeper waters (>20 m). Yet, compared to onshore wind farms, both investment costs and final cost of electricity produced are higher. For onshore wind farms, the wind turbine costs make up approximately 75% of total investment costs. In the case of offshore wind farms, this percentage is only about 30-50%.

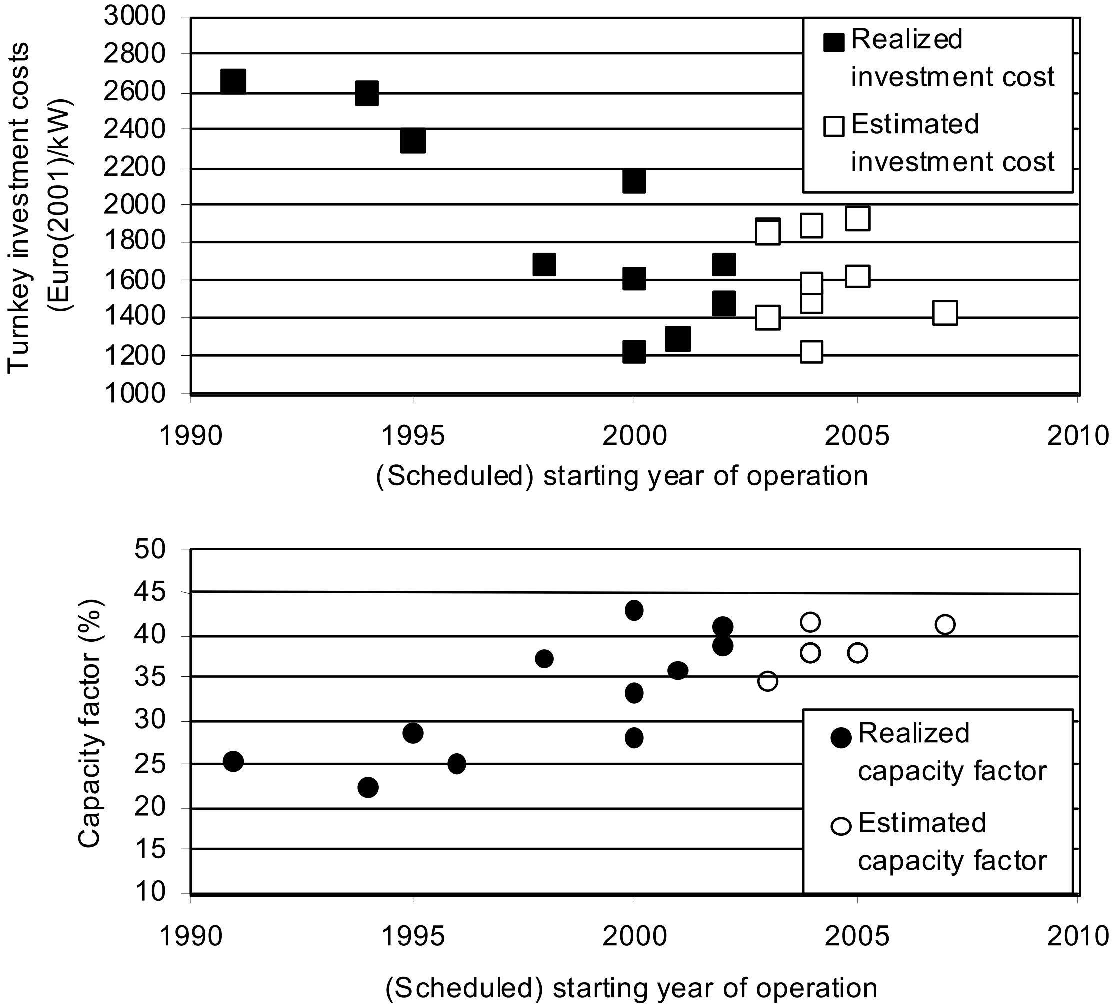

Figure 1 Development of a) turnkey investment costs and b) capacity factors of realized and some planned offshore wind farms. Own data collection and data from Lako (2002b).

Table 1 gives an overview of the contribution of the different components to total investment costs. As can be seen, the share of the different contributions may vary, depending on assumptions such as on wind speeds, annual O&M cost developments, and specific site conditions. Typically, for offshore wind farms, the share of foundation, grid-connection and installation costs are much higher compared to onshore wind farms.

The final costs of electricity include capital costs (i.e. interest and discharge of the investment cost) and the costs of operation and maintenance (O&M). For offshore wind farms, the investment costs contribute approximately 68-75% to the total cost of electricity (CA-OWEE et al., 2001; Kooijman et al., 2001). Cost of electricity of existing wind farms range from about 6-12 €ct/kWh (Barthelmie and Pryor, 2001), depending on site conditions, chosen interest rate and economic lifetime. This is higher than the range of 3-8 €ct/kWh for onshore sites (CA-OWEE et al., 2001).

Table 1 Comparison of onshore and offshore wind farm investment costs. Ranges found in literature (de Noord, 1999; Barthelmie and Pryor, 2001; CA-OWEE et al., 2001; Kooijman et al., 2001; Douglas-Westwood Limited, 2002; Henderson et al., 2003).

	Onshore	Offshore
Total turnkey investment costs	800-1100 €/kW	1200-1850 €/kW
Wind turbine	65-75%	30-50%
Foundation	5-10%	15-25%
Internal grid and grid connection to shore	10-15%	15-30%
Installation [a]	0-5%	0-30%
Others [b]	5%	8%

a In many publications, the installation costs are not listed separately, but are allocated to the other components.

b Miscellaneous items such as engineering costs, project management, interest during construction, et cetera.

3. Approach and methodology

In order to identify cost reduction opportunities, a bottom-up approach is followed. For each component of the investment cost, it is aimed to determine quantitative cost reductions achieved in the past for components similar to the ones used in offshore wind farms. Simultaneously, literature was scanned and interviews were held with experts in the field to identify qualitative reasons behind past and potential future cost reductions, and to obtain estimates for quantitative reduction possibilities when no quantitative cost reduction trends could be found.

Quantitative analysis of cost trends: Typically, the unit cost of a technology decreases with increasing penetration of the technology. This phenomenon has been frequently been observed historically, starting with serial production of airplanes at the beginning of the last century. A special empirical observation is that costs tend to decline a more or less fixed percentage with every doubling of the cumulative production. This behavior can be may be used to make projections for future cost reductions and can described mathematically by means of an experience curve:

$$C_{Cum} = C_0\, Cum^{b} \tag{1}$$

$$\log C_{Cum} = \log C_0 + b \log Cum \tag{2}$$

$$PR = 2^{b} \tag{3}$$

C_{Cum} : Cost per unit
C_0 : Cost of the first unit produced
Cum : Cumulative (unit) production
b : Experience index
PR : Progress ratio

The progress ratio (PR) is a parameter that expresses the rate at which unit costs decline each time the cumulative shipments double. For example, a PR of 0.8 implies that after one cumulative doubling, unit costs are only 80% of the original costs, i.e. a 20% cost decrease. For an example of an experience curve of onshore wind farms, see Figure 2. The definition of the ‘unit’ may vary: in many cases a unit is a product (for example a car or an airplane). In relation to energy technologies, more often the unit is the capacity of an energy technology (e.g. the capacity of a wind turbine, which is also used in this study) or the amount of electricity produced by a technology. The experience curve concept has been used and applied for many different energy technologies; for an overview see McDonald and Schrattenholzer (2001). Especially for onshore wind turbine cost development, several studies have been published. For an extensive overview and an in-depth discussion on the application of the experience curve concept for onshore wind energy conversion systems, see Junginger et al. (2004b).

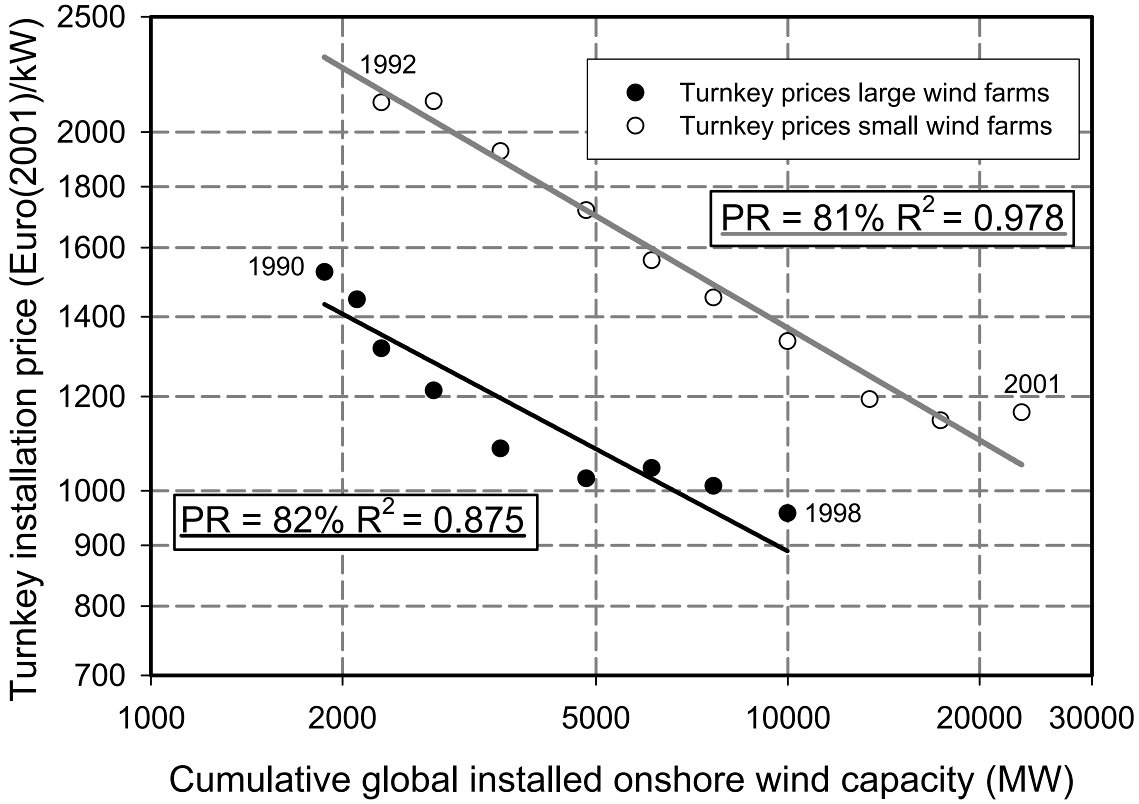

Figure 2 Global experience curves for onshore wind farms (slightly adapted from chapter 3 / Junginger et al. (2004b)). Data for large wind farms from Spain, for small wind parks from the UK.

The empirical observation of constant PR over many cumulative doublings of capacity has been observed many times in literature. However, while there are numerous qualitative factors that may explain parts of the cost reduction (such as R&D, learning by doing, mass production, standardization, upscaling), there is no natural law determining that the fixed cost decline with each cumulative doubling of production will continue indefinitely. In practice, doublings of cumulative capacity will occur much faster in time during the rapid growth phase[3] than in a later stage, when the market potential is largely satisfied. For example, the cumulative installed capacity of onshore wind, a relatively new technology, increased from approximately 10 MW in 1980 to about 17.7 GW in 2000 (10.8 doublings, (Flavin, 1998; EIA, 2003)), while the global installed nuclear plant capacity, a more mature technology, increased from 136 GW to 366 GW in the same time period (1.4 doublings, (EIA, 2003)). In theory, costs would approach zero with unlimited doublings of capacity, yet in practice, cost reductions are limited by the available market potential.

An unresolved issue is whether or not the PR remains constant over time. It has been suggested that if the technology ceases to grow exponentially, then new knowledge depreciates, which may result in a poorer PR. For example, the costs a technology may decline with a PR of 80% during the rapid expansion of the technology[3]. In the later saturation phase, when little capacity is added annually, the PR may become less benign, e.g. 90%. Yet, there are examples of experience curves with a constant PR both over a large number of cumulative doublings and over time. This study assumes

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[3] The diffusion of a technology often follows an S-shaped pattern: a modest growth at the beginning, followed by a rapid growth that ultimately slows down to a final saturation level (Grübler, 1998).

that experience curves, based on historical data of a specific technology, may be extrapolated for future scenarios, but only if future decreasing unit costs can be justified, and if continuing growth of annual capacity is expected.

The experience curve method cannot be applied directly to offshore wind farms, because, as yet, there are few such operational installations. Experience curves from the cost development of onshore wind farms may be used as proxy for offshore wind farms, but this would not be accurate. A discussed in section 2, the composition of offshore investment costs is different from onshore. Also, the cost reduction potential of specific components may be different. Yet, construction of offshore wind farms can build on the experience from various other industrial sectors, such as offshore oil and gas, and long-distance electricity transmission using high-voltage (submarine) cables. Therefore, the technological developments of the main components of an offshore wind farm are analyzed separately. For the analysis of offshore wind farm investment cost, the following four main components are analyzed separately: (i) wind turbines, (ii) foundations, (iii) grid connection, and (iv) the installation process. Where possible, separate experience curves are devised for these components. With this approach it is possible to use the experience curve for onshore turbines to estimate rates of cost reduction for offshore turbines. Such an approach of using different PRs for different components of the total investment costs has already been used by Harmon (2000) and Lako (2002a), and is also used in a recent EC-funded research project on PV-systems (Alsema, 2003).

Qualitative analysis: Before extrapolating future cost trends, it is necessary to know why costs have reduced in the past, and what factors remain for continuing cost reductions. Such insights may also be a basis for more focused strategies and policies for both policy makers and industry. Sometimes it is not possible to find quantitative trend curves, due to lack of available data. In addition, experience curves are particularly useful when standardized products are concerned. The experience curve concept is less suitable to describe the cost reduction for processes for products or processes, which depend highly on specific local conditions. In these cases, literature was scanned and interviews were held with experts, e.g. from research institutions, offshore contractors and producers of offshore equipment, for qualitative information on past and current trends and possible cost reduction opportunities. Also the experts were asked to estimate ranges of possible cost reductions within their particular expertise.

4. Cost reduction potentials

In this section, learning and cost reduction opportunities are described for the production of wind turbines, the electrical infrastructure and the foundations. Also, opportunities for cost reduction during the installation of wind farms are discussed. Qualitative factors for cost reductions are described, and quantitative estimates of the cost reduction potential are given. An overview of all qualitative trends found is given in Table 2.

4.1. Offshore wind turbines

Current trends in wind turbines that are expected to continue include: increase in size and capacity, faster rotational speeds than on land, larger capacity generators per unit rotor area, and high-voltage generation, possibly directly DC instead of AC (Henderson et al., 2003). The disadvantage of larger turbines is the increasing top weight, and thus the requirement for larger and heavier foundation structures. So far, due to development of lighter materials and optimal design, the weight of blades and nacelles has not increased as cubic functions (as one would expect from increasing volumes), but rather with exponents of 2.3 and 1.5 respectively (CA-OWEE et al., 2001). For example, Vestas recently reported that due to improved turbine design, the top-weight of its 3 MW offshore turbine is identical to the top-weight of its 2 MW turbine, despite the fact that rotor blades are 5 meters longer (Vestas Wind Systems A/S, 2002/2003). Yet, it is not clear for how long upscaling can continue. While estimates for the largest offshore turbine available in 2015 vary between 7.5-15 MW (Op den Velde, 2003), eventually technical and/or economical constraints will stop the upscaling.

Other recent trends are the mass production and standardization of wind turbines, both factors for reducing costs. It has been observed in the past for onshore turbines, that ordering large volumes of identical turbines can result in significant rebates. Compared to the list price of a single turbine, approximately 30% reduction may be achieved when order volumes are about 100 turbines. In the largest order found (encompassing 1600 turbines), the turbines were priced 45% less than the original list price (Junginger et al., 2004b)[4]. As wind turbines are still being scaled up, this effect is likely to occur only after turbines have reached a maximum size. Given the potential very large numbers of turbines in offshore wind farms, this may be a significant factor.

To quantify the cost reduction potential, various experience curves exist for onshore wind farms. While it can be argued that offshore wind turbines increasingly have different technological characteristics than onshore turbines (e.g. due to different O&M requirements, larger tip speeds, different design optimization, different materials), the basic concepts of pitch-regulated, variable-speed, horizontal axis wind turbines are likely to remain the same. Also, it is likely that developments in the offshore wind sector, such as reduced maintenance, are also beneficial for the onshore sector. It is therefore assumed reasonable that similar PRs apply for onshore and offshore turbines. Experience curves and PRs found in literature vary strongly, depending on the chosen system boundaries. For wind farms, PRs between 81% for global experience curves (Junginger et al., 2004b) and 92% for national experience curves (Neij et al., 2003) are reported. As the onshore wind sector is already a global industry, and the offshore sector is likely to develop in the same way (even though most projects for the short-term are situated in Northern Europe and North America), a PR between 81%-85% is assumed for the wind turbine part of offshore wind farms[5].

4.2. Grid connection

Offshore wind farms use HVDC or HVAC grid connections. While for short distances to shore, HVAC connections are more economical, especially for large wind farms located far from shore, HVDC connections may be more attractive to use, as it offers a number of advantages[6]. Not sufficient historic data could be found regarding the cost development of AC marine cables and equipment to derive any meaningful experience curve. In this paper, the focus lies on the possible

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[4] In the particular order, specific prices were about 500 €/kW compared to a list price of 915 €/kW.

[5] In Figure 2, only PR-values of 81-82% are shown for small and large wind farms respectively. Sensitivity analysis in chapter 3 has shown, that a range of 81-85% should be used for scenario analysis.

[6] Compared to HVAC, electrical losses of HVDC connections are far lower, reactive power can be controlled independently at the shore converter stations, there is almost no contribution to fault currents and the entire offshore wind farm can be operated at a variable frequency allowing a possible increase in electricity yield. HVDC may become attractive starting from distances of about 50 km from the shore (CA-OWEE et al., 2001). Cable voltages for both types currently lie in the in the range of 100-200 kV. Cable capacities of existing HVDC interconnectors reach up to 600 MW.

cost reduction possibilities of HVDC connections. The main components of a HVDC connection are the cables, and two converter stations, converting the AC current to DC offshore, and vice versa to feed the electricity in the high-voltage AC grid. Both components are discussed below.

HVDC cables

Currently, the number of HV submarine cables produced is rather low compared to LV cables, as these cables are often specially designed for each project. When larger numbers of standardized high voltage cables would be used in the future, large-scale production may enable cost reductions (Peeters, 2002). For HVDC cables this learning effect may be accompanied by the applicability of cheaper XLPE insulation compared to cables using low pressure oil filled insulation. Application of XLPE could result in a significant cost reduction of HVDC cables.

An experience curve is devised for HVDC cables (see Figure 3) using data from existing projects and cost estimations for large projects. It reveals a very benign PR of 62%, i.e. a rapid decline of investment costs with cumulative production. However, relatively little data was available and the cable costs did not include laying costs. Also, the data of cables using XLPE insulation was not included, as there was too little data available to check whether the application of XLPE insulation will lead to a structural downwards shift of the experience curve (Peeters, 2002).

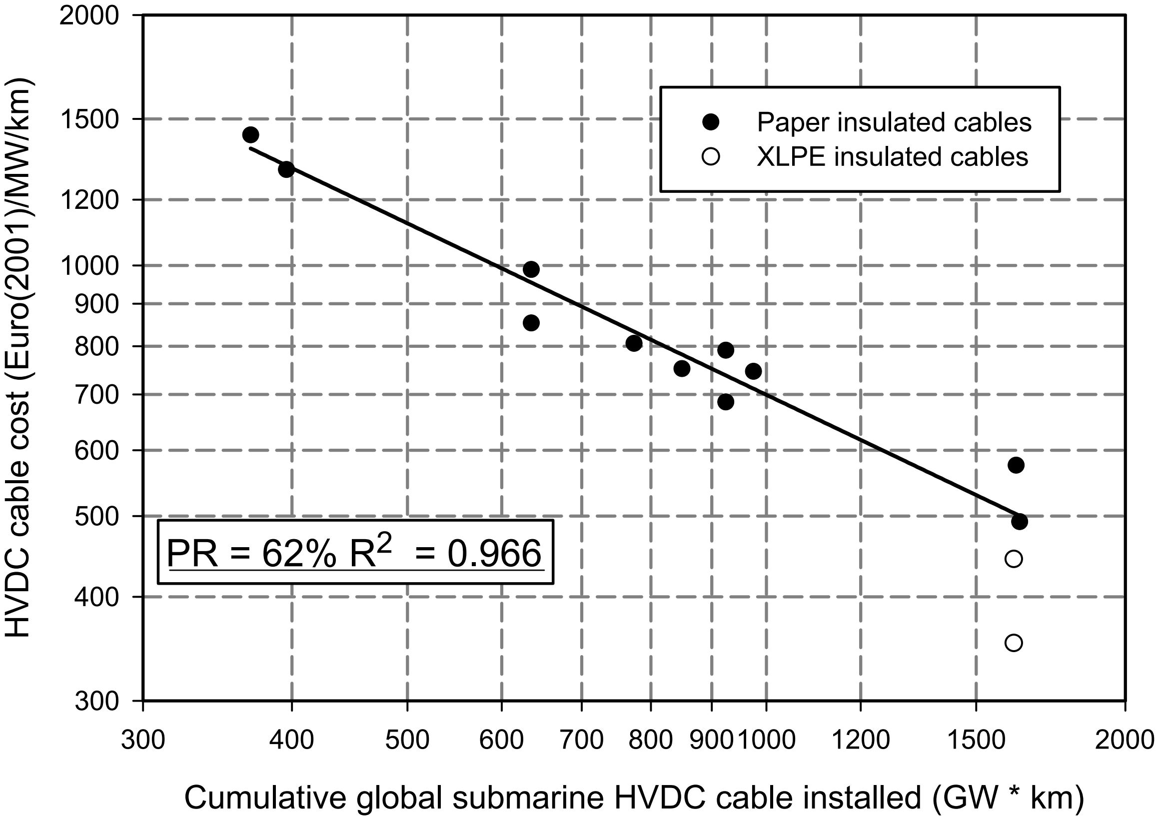

Figure 3 Experience curve for submarine HVDC cables from 1988-2000. Data from Peeters (2002) based on projected cable costs of HVDC interconnectors found in literature and Engvall (2003). The data points for XLPE cables were not included for the experience curve.

HVDC converter stations

Regarding the converter stations, advancements in valve technology[7] and power electronics allows the use of Voltage Source Converters (VSC), which is likely to reduce both costs and required area compared to the current use of thyristors in common HVDC converter stations. Also, advances in control, protection and communications technology are deemed feasible and cost effective. Finally, standardization of design could reduce project administration, engineering, manufacturing and construction costs[8]. Another possibility to reduce costs would be to combine future HVDC submarine interconnectors between Germany and Scandinavian countries and the UK and the Netherlands with the grid connection of offshore wind farms (van der Tempel et al., 2002). As this opportunity is only available for a limited number of sites and would require a multi-terminal DC system (which do not currently exist), this possibility was not included in this analysis.

An experience curve was devised for HVDC converter stations (see Figure 4). The PR of 71% indicates relatively high rates of cost reductions. Again, some adjustments had to be made. First, as the costs of converter stations do not increase linear with the rated capacity, all project data was normalized to a standard 500 MW converter station using a scaling approach[9]. Second, it is difficult to compare project data, as often turnkey costs either include or exclude a number of services, and market circumstances for individual projects may differ[10]. For these reasons, a number of unreliable data points were excluded form the analysis.

Internal grid connection

The internal grid connection (i.e. the connection of the separate wind turbines to a central transformer station) only contributes a minor share to total investment costs. No data on possible cost reductions of medium-voltage submarine cables was found. Therefore, costs were assumed to be constant at about 60 €/kW installed capacity.

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[7] For an explanation of HVDC terminology, see for example Woodford (1998).

[8] For a more elaborate description of cost reduction opportunities, see Peeters (2002).

[9] For a detailed description, see Peeters (2002).

[10] For example, the project data of Gotland II (Sweden) and CU (USA) contained no/limited AC switchyards, while the Itaipu project (Brazil) also included four 300 Mvar synchronous compensators (ABB Sweden, 2003) (see Figure 4). Thus, the turnkey price of the first two projects may be slightly too low, and slightly too high for the third project. In case of the Gezhouba project, (the first large HVDC project in China), competition to get the order was severe and the turnkey price far below production costs (ABB Sweden, 2003). For a list of HVDC interconnectors, see Peeters (2002).

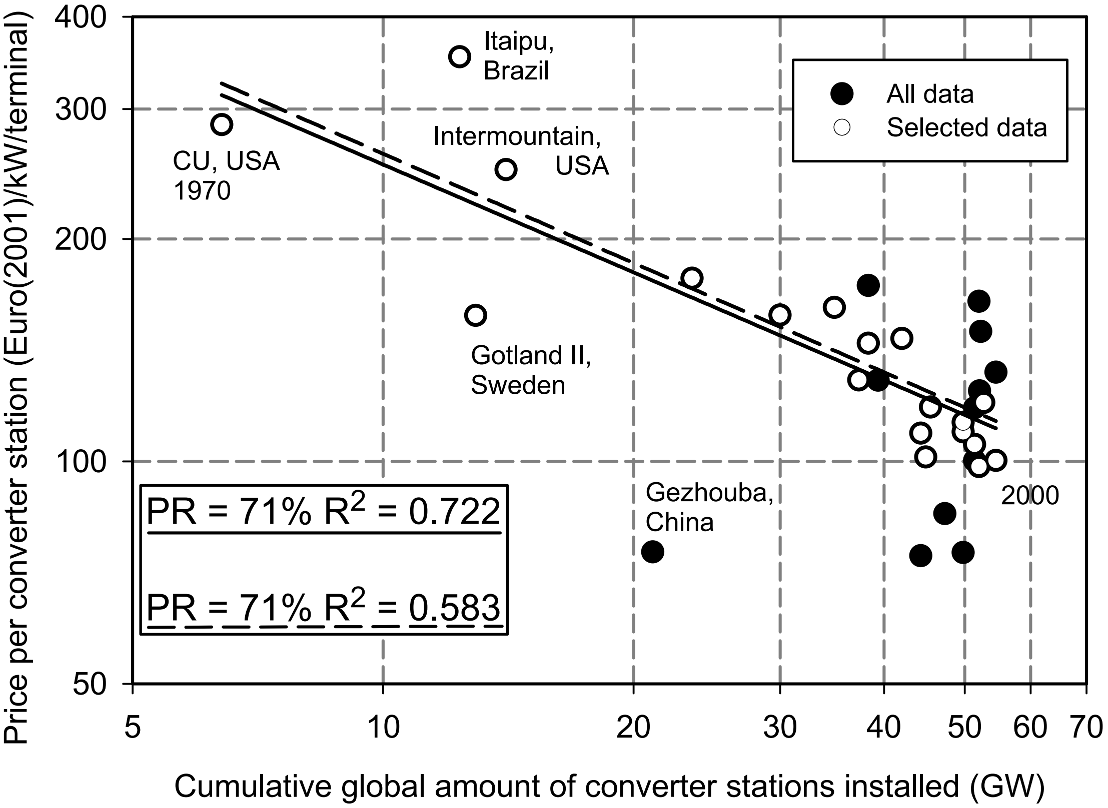

Figure 4 Experience curve of HVDC converter stations 1970-2000 (based on Peeters (2002), Carlsson (2003) and Engvall (2003) and own data collection). All stations were normalized to 500 MW. For some older projects, name and location is given. Where required and possible, cost estimates were made for missing components. Based on the reliability and completeness of the data, a number of points were selected for an improved experience curve.

4.3. Foundations

Over the last ten years, two main foundation types have been used for offshore wind turbines: either concrete gravity based structures or driven/drilled steel monopiles. For the future, also other types of foundations are envisioned, e.g. suction caisson (bucket) foundations, guyed towers, floating foundations, and self-installing concepts, using telescopic towers. Here, the monopile and tripod foundation are investigated in more detail, as these are likely to be the two dominant types used in the near to midterm future (Henderson et al., 2003). Both structures have been built since the middle of the 20th century, and hundreds of offshore jacket structures have been installed in water depths between 20-50 m in the North Sea over the last 40 years alone (Mather, 2000), yielding a huge amount of experience regarding the design and building of offshore structures and foundations.

Regarding the production process, most experts judged that no further significant cost reductions are likely to occur in the long-existing, highly automated production process of monopiles (Hendrikx, 2003). Tripod / jacket structures however were so far basically custom-made for each oil- or gas platform, requiring more production steps (for example welding). If a large number (e.g. forty or more) identical structures were to be ordered, experts judge that cost reductions due to the effects of mass production might reach up to 20% compared to the costs of a single structure (Meek, 2003). Regarding the foundation design, using 'soft-soft' structures[11] (i.e. a low eigenfrequency of the support structure) may result in significantly lighter foundations and tower (thus reducing material costs). Cost reduction opportunities may be 20% compared to soft-stiff monopile design solutions (Kühn, 1999), yet this design needs to be proven in practice.

No experience curve for the production costs of monopiles and tripods was devised, as obtaining quantitative cost data over an extended timeframe was difficult to obtain. Instead, the cost development of the main raw material used (steel) was investigated. Currently, the production costs of monopile foundations consists roughly of 45-50% material costs (steel), and 50-55% production costs (Hendrikx, 2003). According to a major producer of offshore steel structures, the price of construction steel has fluctuated between 400-550 Euro/tonne of steel in nominal terms over the past thirty years (Hendrikx, 2003). Corrected for inflation, steel prices have fallen about 60% over this time period. This agrees well with Gielen and van Dril (1997) and data from the US Geological survey (Kelly and Fenton, 2003)[12]. While short-term price fluctuations may occur, it is assumed for the long-term that steel prices will follow the general production cost trend of 1-2% per year. This results in a cost reduction of 5-10% of the foundation costs until 2020.

4.4. Installation

Over the past ten years, offshore wind farms have been installed mainly using vessels, barges and cranes from the offshore oil and gas sector. One problem with respect to identifying cost reduction trends for offshore installation activities is that day rates of transport and installation vessels (such as jack-ups, barges, cranes tugs et cetera) have been fluctuating strongly over time, depending on demand. For example, during the period 1977-1986, day rates of both jack-up rigs and semi-submersibles were directly linked to the oil price[13], causing day rates to jump from about 25 k$/day in 1979 to about 70 k$/day in 1981, and falling back to less than 20 k$/day in 1987 (Sanderson, 1988). Similar price fluctuations for jack-up vessels have also been observed recently (Anonymous, 2002). Thus, it is questionable whether it is realistic to expect actual price reductions in the future.

However, the dependency on oil prices may become far less with the development of purpose-built vessels designed specifically for the offshore wind sector. Contrary to traditional oil and gas platforms, several tens or even hundreds of structures have to be installed over an area of often several square kilometers for offshore wind farms, usually only within a limited time window. Thus, the ability to both install a wind turbine and to move quickly to the site is crucial for efficient installation. Purpose-built ships have been developed, with sufficiently high cranes and sufficient lifting capacity to handle the increasing size and weight of offshore turbines and jack-up legs that can be used and retracted fast (Op den Velde, 2003). At Horns Rev and Nysted wind farms (Denmark), the world's two largest offshore wind farms built until the end of 2003, for the first time

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[11] The offshore wind turbine and foundation structure is sensitive to excitation caused by a rotation speed of the rotor (1P) and the blade passing frequency (3P). These two periods must be avoided to ensure that resonant response does not occur. Currently, most wind turbines and foundations are designed in soft-stiff combinations.

[12] Though the reasons behind the technological changes and cost reductions are not discussed here, it is worth mentioning that over the last 150 years, five major process technologies for steel production have been in use (Grübler, 1998), and still new innovations and process technologies are entering the market (Luiten, 2001). Therefore it is deemed reasonable to assume that continued technological innovation will cause steel prices to decline also over the next 20 years.

[13] A high oil price justified investments in new oil platforms, and thus increased demand for jack-up rigs and semi-submersibles.

purpose-designed ships were used for turbine erection, both by the same contractor. The experiences gained during the installation of these two wind farms are described below.

At Horns Rev[14], built in 2002, two installation vessels were used. Each vessel carried a total of two wind turbines in the 'bunny-ear' configuration (i.e. each turbine consisting of the nacelle with two blades mounted, two tower section and a single turbine blade). Between May and August, 80 turbines were installed. Average installation time[15] was reduced from over three days per turbine for the first few turbines to a final average of 1.4 turbines per day. This data was used to compute the marginal installation time per turbine, and plotted in a learning curve (see Figure 5 and Appendix 1). This resulted in a PR of about 77%, i.e. a reduction of marginal installation time by 23% with every doubling of turbines installed. A number of factors contributed to the learning efforts: first of all, clearly the time required to erect the turbine was greatly reduced by 'learning-by-doing'. It was also partly due to modifications of the lifting tools at the beginning of the installation period following the installation of the first turbines. In addition, the supply of turbines at the onshore harbor dock was not optimal at the beginning of the installation period, but improved later on (Møller Jensen, 2003).

The second wind farm was installed during the summer of 2003 at Nysted[16] (Denmark), The turbines installed were similar to the ones at Horns Rev in terms of capacity (2 vs. 2.3 MW), dimensions (hub height from sea level 70 vs. 69 m, rotor diameter 80 vs. 82 m), mass (both about 258 tonnes), and number of turbines (80 vs. 72). Yet, there are some differences with the Horns Rev situation. The transporting distance from harbor to wind farm site was significantly longer (10 instead of 2.5 hours for a one-way trip). Also, only a single vessel was used at Nysted wind farm, which however was able to carry four entire turbines instead of two.

In Figure 6, a comparison is given between the two installation periods. As the number of turbines installed in both parks was about roughly the same, the installed capacity doubled once with the second wind farm. Given the learning curve from Horns Rev and neglecting the differences mentioned above, the installation time required per turbine should theoretically decrease 23%. When taking the derivative of the fitted power function for the first and the last turbine of the Nysted wind farm (see appendix 1 for justification), this decrease is 24%, which correspond rather well with the expected 23%. As the equipment is based on day-rates, the decrease in installation time can be translated into cost reductions.

As these examples show, with regard to the turbine installation (possibly in combination with foundations), it still has to be determined whether (different combinations of) the rotor blades, nacelle, tower and foundation should ideally be assembled onshore or offshore (Herman, 2002). This may largely also depend on local circumstances, such as the distance to shore and local working conditions, the type of foundation and the size of vessels and turbines. Clearly, when using larger turbines, again a lot of 'learning-by-doing' will likely be involved.

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[14] Located in the North Sea, about 14 km from shore, 37 km from Esbjerg harbor in a water depth of 6 – 14 m. The HVAC cable to shore is 21 km long.

[15] The average installation time is here defined as the total number of days divided by the total number of days since the start of the operation (see also appendix 1, equation (5)). Thus, this includes the actual time for installation, but also travel time from and to the harbor, loading time at the dock and possible downtime due to problems at the harbor or bad weather. The actual erection time of the turbine was reduced from 17 hours for a single tower, to less than 4 hours for an entire turbine (Møller Jensen, 2003; Thomsen, 2003).

[16] Located in the Baltic Sea, about 6-9 km South of Nysted, 160 km of Nyborg harbor in a water depth of 6 – 10 m. The HVAC cable to shore is approximately 11 km long.

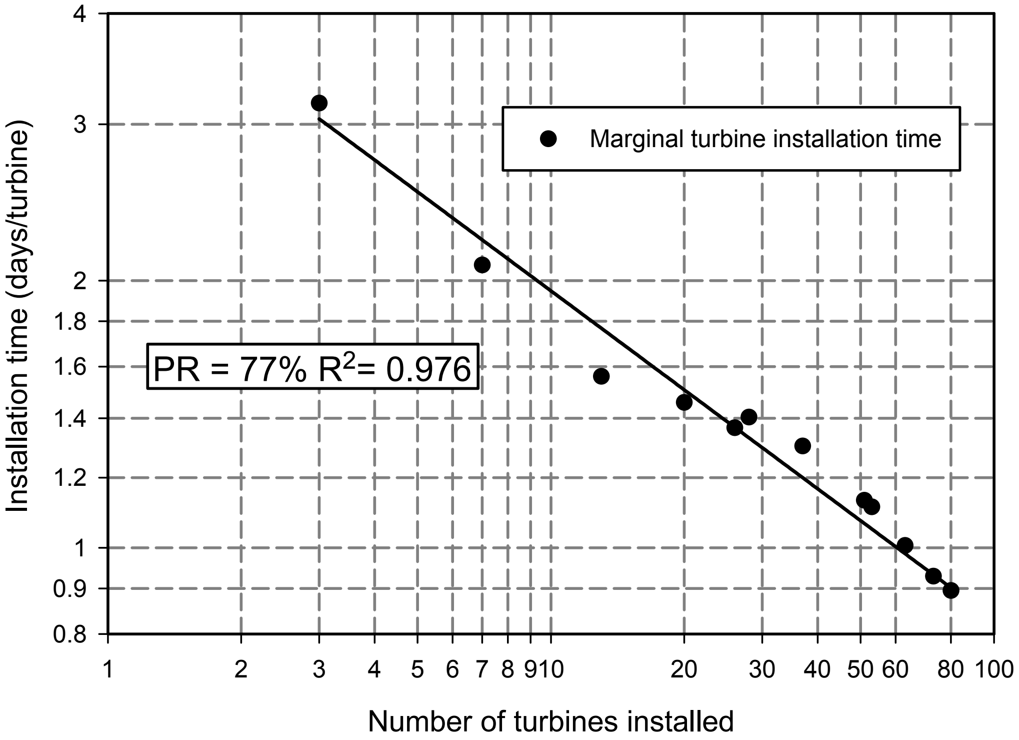

Figure 5 Learning curve for turbine installation (including loading at the pier, transport and erection at the site) at Horns Rev wind farm during summer 2002. Data from Møller Jensen (2003) and Elsam A/S (2002).

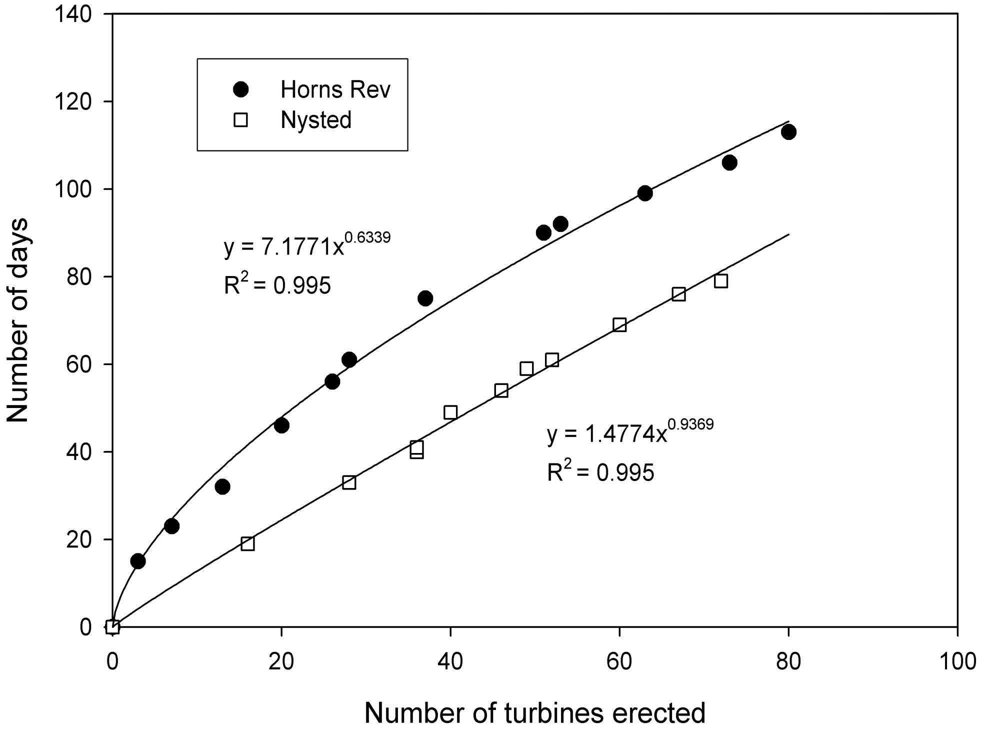

Figure 6 Comparison of installation speeds between Horns Rev wind farm and Nysted wind farm. Data from Vølund and Woller (2003), A2SEA (2003) and Anonymous (2003).

Finally, it should be remarked that during the installation of both wind farms a number of days were lost due to bad weather such as high wind speeds or thunderstorms. In the case of Horns Rev, the weather was far worse at the first half of the installation period than in the second, thereby increasing the installation speed in the second half, but this has of course little to do with actual learning.

Foundation installation

At Horns Rev, no observable reduction in marginal installation time was recorded for foundation installation (no data was available for Nysted). This may be due to the fact that considerable experience from the offshore oil and gas industry already exists. For example, during the last decades skirt-pile driving time has been reduced from 18 to 10 hours through replacing steam hammers by hydraulic hammers (Meek, 2002). The same is assumed for other installation activities, such as cable laying or scour protection. This does not imply that no cost reduction at all may occur in the future. As described in section 4.1, standardization of foundations and turbines may be beneficial for lowering installation costs. Until now, each new wind farm used different foundations, with a different pile diameter. This is likely to be the case for the next 5-10 years, as wind turbines will become bigger, and thus foundations will increase in size as well. If at a certain point an ideal turbine size is reached, standardization may bring some advantages[17]. But while there seems to be some room for cost reductions, these are likely to occur at a lower pace. Therefore, a more modest cost reduction for foundation and cable installation is assumed, compared to the turbine installation. Due to lack of available data, a PR of 95% is used.

Table 2 Overview of relevant factors behind cost reductions of offshore wind farms.

	Specific offshore wind developments	*Exogenous developments*
Wind turbine	Upscaling Improved design Standardization Economies of scale	Further development of onshore turbines Steel price
Grid connection	Standardizing the design of HVDC cables Applicability of XLPE insulation to HVDC cables Advances in valve technology and power electronics	Further development and diffusion of submarine HVDC interconnectors
Foundations	Standardization Economies of scale Design regarding dynamic loads	Steel prices
Installation	Learning-by-doing Development and structural deployment of purpose-built ships Standardization of turbines and equipment	(Oil prices)

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[17] For example, a major producer of hydraulic hammers estimated that day rates of hammer equipment may be reduced 20-30%, when both foundation design is standardized, and high utilization rates of the equipment are realized (Jonker, 2003), as especially the anvil plate (currently custom-made for each individual pile diameter) can then be discounted of a number of projects instead of only one or two.

5. Synthesis of total cost reduction possibilities

As mentioned earlier, investment costs depend on a number of factors, such as distance to shore, water depth, soil properties, grid-connection possibilities etc., and cost distribution of different components can vary strongly (as was shown in Table 1). To illustrate the possible cost reduction opportunities described above, a reference offshore wind farm was defined (see Table 3 for details)[18]. The properties and costs for the different components were taken from public data on existing projects, expert literature and own calculations.

Table 3 Overview of parameters for the base case wind farm.

Wind turbine capacity	5 MW
Hub height	95 m
Rotor diameter	125 m
Number of wind turbines	100
Wind farm capacity	500 MW
Water depth	20 m
Distance to shore	40 km
Foundations	Steel monopiles
Grid-connection	HVDC, using two converter stations of 500 MW
Total initial investment costs	1600 €/kW

Initial distribution of total investment costs

Wind turbine	Foundation	Internal grid	Grid connection	Installation	Other
47%	12%	4%	19%	12%	6%

As a second step, two scenarios were defined to explore possible investment cost developments under different circumstances, as described below (see also Table 4).

Table 4 Summary of quantitative cost reduction trends in the two scenarios.

	Sustained diffusion	*Stagnant growth*
Wind turbine	Annual growth rates of onshore wind and offshore wind capacity declining from 27% in 2003 to 15% in 2020 PR of 81%	Annual growth rates of onshore wind and offshore wind capacity declining from 27% in 203 to 10% in 2020 PR of 85%
Foundations	Cost of steel reduction 2% per year	Cost of steel reduction 1% per year
Grid-connection	High growth rates of HVDC converter stations and submarine cables PRs of 62 & 71%	Moderate growth rates of HVDC converter stations and submarine cables PRs of 62 & 71%
Installation	PRs of 77% (turbine erection) and 95% (other)	PRs of 77% (turbine erection) and 95% (other)

- In the first scenario, *Sustained diffusion,* the current high rates of diffusion of onshore wind energy are assumed to decrease slowly by about 0.5 % annually from 27.5% in 2003 to about 15% per year in 2020. These assumptions match the Wind Force 12 scenario (EWEA and Greenpeace, 2003), in which wind turbines cover 12% of the world's electricity demand in 2020. Accompanying this growth, wind offshore capacity would increase to 50 GW in Europe and a worldwide total of 70 GW. In turn, this would implicate that installation vessels will be able to

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[18] In a previous paper (Junginger and Faaij, 2003), a slightly different cost distribution was used. After consultation with actors in the industry, the share of installation costs was lowered, the shares of turbine and grid connection costs increased, and an additional category 'others' added, including costs such as project preparation and management, soil research etc. No cost reductions were investigated for this category.

operate over extended periods of time, thus allowing their depreciation over multiple projects. Additionally, it is assumed that the exogenous reduction of steel prices proceeds by approximately 2% per year, and that the development and penetration of new HVDC interconnectors continues to growth by about 2.5 GW per year.

- In the second scenario *Stagnant growth* more conservative assumptions are made. Growth rates of onshore wind decrease to 10% in 2020. Also, a less benign PR of 85% for the turbines is assumed, taking into account the uncertainties inherent to the experience curve methodology. Offshore wind also experiences slower growth rates, assuming that its development depends largely on the stimulation programs of individual countries. This results in lower cost reductions for the turbine and for the installation. As the example of Denmark shows, government support may drastically change within short periods of time (WPM, 2002). This leads to less installed capacity in 2020, but also to a high-risk investment market, which in turn keeps the day rates of installation equipment high. To explore the more conservative boundaries of cost reduction potentials, more moderate cost reductions are assumed for the reduction of steel prices, and the diffusion speed of HVDC converter stations and submarine cables.

The outcomes of the two scenarios are depicted in Figure 7. Especially the cost of offshore wind turbines in the year 2020 depend strongly on both the PR assumed, and the amount of cumulative installed capacity until 2020. Overall, costs decrease from initially 1600 €/kW[19] to 980 €/kW in the sustained diffusion scenario, and 1160 €/kW in the stagnating growth scenario (see also Figure 8).

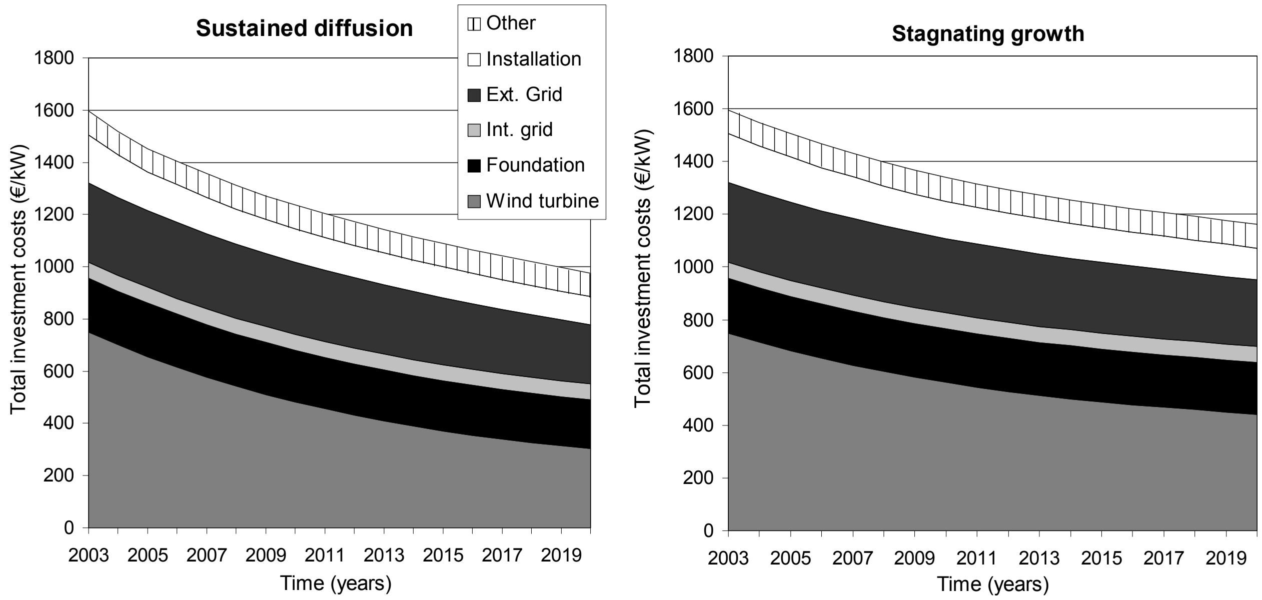

Figure 7 Two investment cost reduction scenarios for the reference wind farm.

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[19] All calculations in this paper were carried out in constant Euros of 2001.

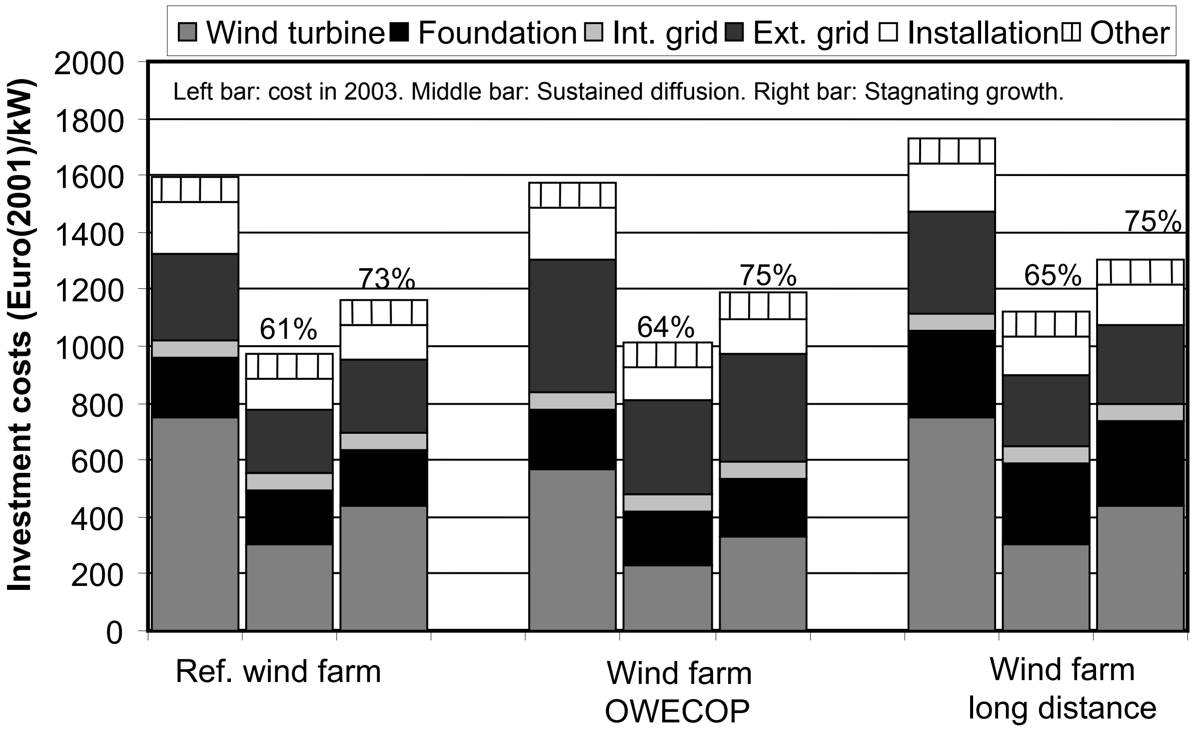

Figure 8 Comparison of specific capital cost of three different offshore wind farms in 2003 and for the two scenarios; the indicated percentages give levels of investment costs compared to 2003. The OWECOP data differs from the reference wind farm by lower turbine and higher grid connection costs. The long distance wind farm utilizes tripod foundations instead of monopiles, and is situated 100 km offshore in 40 m water depth instead of 40 km offshore and 20 m water depth.

5.1. Sensitivity analysis and comparison with other studies

To check the sensitivity of our results on variation in initial investment costs, a comparison is made with data from the OWECOP model of the Energy research Centre of the Netherlands (ECN)[20]. Main differences are the lower turbine costs and higher grid-connection costs (mainly the HVDC converter stations) in the OWECOP model. Other components (e.g. foundation and internal grid connection costs) are almost identical. Total investment costs from ECN[20] and our data are almost equal, and cost reduction potentials do not differ strongly in the two scenarios.

Furthermore, in the longer-term, offshore wind farms will expectedly have to be placed in deeper waters and at a larger distance from shore due to the limited availability of suitable sites close shore. Therefore, the costs of a wind farm in deeper water (40 m, utilizing tripod foundations) and at a larger distance from shore (100 km) are also calculated to estimate the effect on cost reduction possibilities. This results in higher initial investment costs, mainly for foundations and grid-connection (see Figure 8). The relative cost reduction potentials remained approximately the same.

In Figure 8, these three wind farms are compared to get a further insight in the dependency of cost reduction potentials on initial assumptions. The graph shows that under a sustained development of offshore wind energy, 35-39% cost reduction seems possible, while under the stagnant growth

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[20] The Energy research Centre of the Netherlands (ECN) has developed a computer program for the analysis of wind energy exploitation at sea. This program couples a geographic information system (GIS) to a spreadsheet model that calculates the costs of wind farming (ECN, 2003). In this paper, only data from the spreadsheet model was used.

scenario, cost reduction may be 25-27%. The absolute costs range between 980 and 1300 €/kW. Compared to other studies assessing the future cost of offshore wind farms, this range is about average. Milborrow (2003) finds that investment cost of a similar reference wind farm as used in this study may decline by 40% by the year 2012. Compared to this study, our results are less optimistic, potentially caused by more conservative assumptions. Lako (2002a) find investment costs between 970-1140 €/kW, which is also in the same range as our analysis, but Lako expects these cost levels only to be reached in 2030. This is mainly due to assumptions on less optimistic PRs used for all components (between 0.925-0.975 for turbines, construction work and grid connection). Finally, Chabot (2002) finds investment costs of 1230 €/kW for 2020. This relatively high estimate is likely caused by assumptions for harsher conditions and deeper water in the French Atlantic Ocean (Chabot, 2003).

5.2. Determination of levelized electricity costs

The range of 980 and 1300 €/kW can be utilized to calculate the reduction of levelized electricity production costs (LPC). In literature, costs of annual operation and maintenance costs are estimated to lie between 2 and 4.4% of the turnkey investment costs (Bulder et al., 2000; Lichtendonk, 2002). For the calculation of the LPC in this study, annual O&M costs are set as 4% of the investment cost. Further assuming a capacity factor of 38% (based on most existing offshore wind farms), a life time of 20 years[21] and an interest rate of 8%, the reference wind farm in 2003 has LPC of 6.8 €ct/kWh. Under the assumption that O&M costs remain a fixed percentage of the investment costs, the levelized production costs of electricity are identically reduced by 25-39% to 4.2-5.4 €ct/kWh[22].

6. Discussion and conclusions

It is of interest to examine the composition of the calculated cost reductions. For the reference wind farm, in both scenarios about 15% of all cost reductions are caused by direct improvements related to the development of offshore wind farms, mainly the lower installation costs. About 5% reduction is caused by exogenous developments; most important here being the development of steel prices, as these directly affect the cost of foundation structures and towers. The remaining 80% are caused by developments both in the offshore wind sector and in other sectors, for example the assumed mutual learning of onshore and offshore wind turbines with increasing diffusion. As stated before, this is part of the experience curve approach followed, where it is assumed that similar technologies learn mutually.

A number of remarks can be made regarding the methodology followed, data collection and results:

- The experience curve methodology relies on extrapolating trends from the past to the future. As stated in section 3, this is deemed acceptable if both a continuing growth of the specific technology can be expected, and if reasons are known why costs may actually be reduced.

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[21] While some parts of an offshore wind farm (such as the electrical infrastructure and foundations) may possibly be used longer than 20 years, it is uncertain whether this will actually occur. Also, it is deemed unrealistic to stretch the economic operational life of the wind farm beyond 20 years.

[22] In general, with prolonged technological development, O&M costs tend to decline along with investment costs. However, as we do not investigate reasons for possible O&M cost reductions in this chapter, also the worst case was investigated in which O&M costs remain stable at current levels. In this case, lower investment costs alone lead to reductions of the LPC of 18-28% to 4.9-5.9 €ct/kWh in the various scenarios.

- A drawback of the chosen method is the extended amounts of data required and the number of assumptions on the development of each component. Especially obtaining historical data on the development of foundation costs and installation costs proved to be difficult. Also, the players in the field considered some of the information required as confidential.
- Possible cost reductions for the internal grid connection and other costs (i.e. soil investigation, project management) were not investigated. However, if these costs were to be reduced by e.g. 20%, this would have no major impact on the main results.
- In this study, only the cost reduction possibilities of a HVDC connection were investigated. A recommendation for further research is the determination of cost reduction opportunities for HVAC connections.
- The cost reductions presented here are based on the properties of the chosen reference wind farm, and may be different in case of different assumptions. With the chosen methodology, it is not possible to forecast costs of specific projects, as these are strongly affected by specific site conditions, such as distance to shore, soil conditions, water depth, average wave height, et cetera.
- While current offshore wind farms are less than 200 MW in size, wind farms of up to (or even larger than) 1000 MW until 2020 are feasible. For such very large wind farms, the costs of grid connection can be shared over much larger capacity than current wind farms. While we did not take associated cost reductions explicitly into account, they are partially accounted for in the PR for HVDC cables and converter stations. Also, the size of the chosen 500 MW reference wind farm is likely to be representative for medium-sized offshore wind farms within the next 15 years.
- Only costs directly related to the construction of an offshore wind farm were scrutinized. With possible large-scale penetration of this technology within the next decades, additional investments on land may be required such as grid fortifications or storage of electricity.

From our results, it can be concluded that the investment cost and cost of electricity from offshore wind farms may be lowered by up to 39% until 2020. Given the fast technical potential, the additional advantages over onshore wind farms and the EU target of 22.1% renewable electricity in 2010 (and possibly more beyond 2010), it would seem that offshore wind farms may contribute a significant share to this target at declining costs.

The analysis has also shown, that long-term stable offshore prospects may support cost reductions, especially for the installation costs, but also for (offshore) wind turbine manufacturers. No single (European) country has the potential to satisfy this requirement over an extended period of time. Thus, a key policy recommendation is to consider a joint European policy regarding the stimulation of offshore wind farms, as this might be a great benefit both to ensure offshore wind diffusion and cost reductions.

7. Acknowledgements

The authors would like to thank the following persons for helpful advice and supplying data: Lennart Carlsson (ABB), Erwin Coolen (Vestas), Mats Engvall (HHS), Jan Groenendijk (ICE), Wiel Hendrikx (SIF group), Niels Møller Jensen (Techwise A/S), Geert Jonker (IHC Hydrohammers), Henk-Jan Kooijman (ECN), Paul Lako (ECN), Ruud Liem (IRO), Jan Meek (Heerema), Jan van der Tempel (Technical University Delft), Wouter Op den Velde (Mammoet van Oord), Per Vølund (E2) and Michiel Zaaijer (Technical University Delft). Also, Ad Peeters and Gijs Termeer (Utrecht University) are thanked for their extensive work regarding cost reduction opportunities for HVDC technology and offshore foundation structures.

Appendix 1 Determining marginal turbine installation speed

To plot an experience curve, marginal production costs (or here: installation times) are plotted against cumulative production (here: turbine installation). However, in the case of the offshore wind farms, the exact installation date of each turbine was not available, and estimating marginal installation time would therefore be difficult. Using the average installation time can circumvent this problem, as the following discussion will show:

In Figure 6, the number of days past since the start of the installation is plotted against the number of turbine installed. This data can be fitted by using a simple power function of the form:

$$f(t) = at^c \tag{4}$$

with the constraint of

$0 \leq c \leq 1$

where
t : number of turbines installed since start of installation
f(t) : number of days past since the start of installation

In the case of b equaling one, there would be a linear relationship between the number of days and the number of turbines installed (and thus no learning). In case of c being smaller than one, the average installation time decreases. The average installation time for all turbines at turbine t is defined as:

$$g(t) = \frac{at^c}{t} \tag{5}$$

The marginal installation time of each turbine is the derivate of equation (4):

$$f'(t) = act^{c-1} \tag{6}$$

Equation 6 is basically the experience curve formula (see equation 1), with the exponent c-1 being equal to the experience index b. Thus, it follows that the PR can be derived by fitting a power function the number of days past since the start of the installation is plotted against the number of turbine installed:

$$PR = 2^b = 2^{c-1} \tag{2a}$$

As c was defined as lying between zero and one, this would imply of b lying between minus one and zero, which in turn results in PRs between 50% and 100%, a range in which almost all empirically-found PRs fall (McDonald and Schrattenholzer, 2001). Using equation 6 and the data from Figure 6, Figure 5 was devised.

Chapter 5: Technological learning and cost reductions in woodfuel supply chains in Sweden[1]

Abstract

With its increasing use, the production costs of Primary Forest Fuel (PFF) have declined over the last three decades in Sweden. The aims of this study are to quantify cost reductions of PFF production as achieved in Sweden over time, to identify underlying reasons for these reductions, and to determine whether the experience curve concept can be used to describe this cost reduction trend. If applicable, the suitability of this concept for future cost reduction analysis and for use in other countries is explored. The analysis was done using average national PFF price data (as a proxy for production costs), a number of production cost studies and data on annual Swedish production volumes. Results show that main cost reductions were achieved in forwarding and chipping of PFF, largely due to learning-by-doing, improved equipment and changes in organization. The price for wood fuel chips does follow an experience curve from 1975-2003 (over nine cumulative doublings). The progress ratio (PR) is calculated at 87%. However, given the uncertainty in data on PFF price and annual production volumes the PR may range between 85% and 88%. It is concluded that in combination with the available supply potential of PFF and with bottom-up assessment of cost reduction opportunities, experience curves can be valuable tools for assessing future PFF production cost development in Sweden. A methodological issue that needs to be further explored is how learning took place between Sweden and other countries, especially with Finland, and how the development of technology and PFF production in these countries should be combined with the Swedish experiences. This would allow the utilization of the experience curve concept to estimate cost developments also in other countries with a large potential to supply PFF, but with less developed PFF supply systems.

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[1] Accepted for publication in Biomass & Bioenergy. Co-authors: A. Faaij, R. Björheden and W.C. Turkenburg.

1. Introduction and rationale

Biomass is seen as one of the most promising renewable energy sources that could contribute substantially to sustainable energy supply including the reduction of greenhouse gas emissions. However, the present costs of primary biomass fuels are often higher than the costs of competing fossil fuels, especially for energy crops and residues that need to be collected for energy use such as Primary Forest Fuel (PFF). PFF is defined as branches, tops, small trees and unmerchantable wood left in the forest after the cleaning, thinning or final felling of forest stands. It is then used as fuel without any intermittent applications. The production costs of PFF (as delivered to the plant gate) depend on a number of steps within the logistic chain, such as harvesting, comminution and transport.

There are ample indications that factors such as technological progress and upscaling have led to significant reductions in production costs of PFF in the past few decades. For example, Roos et al. (1999) highlight that factors such as learning (e.g. standardization of procedures) and technological development (e.g. innovation in harvesting and processing equipment) contributed to cost reductions and subsequent successful large-scale implementation of biomass district heating in Sweden. Hillring (1999) documents the corresponding reduction of market prices for PFF in Sweden. For Finland, Hakkila (2000) reports decreasing cost due to development of new chip procurement systems, corresponding economies-of-scale effects, decreasing costs of machinery and shift from delimbed stems to whole trees to logging residues as main source of PFF.

However, monitoring the influence of the different advances in biomass fuel supply chain on production costs over a long period of time (e.g. 25 years), including changes in the different steps in fuel supply chains, has not been carried out. Also, little is known on how PFF production costs may develop in the near future or on the longer term. A method to analyze past cost developments of technologies is the experience curve concept. In this concept, the cost development of a product or a technology is investigated as function of cumulative production, and plotted in a figure with double-logarithmic scale, often resulting in a linear curve, the experience curve. Within the field of renewable energy, this tool has been used to analyze e.g. the progress made in reducing the production costs of photovoltaic modules, onshore and offshore wind turbines, solar water heaters, fuel cells and gas turbines (IEA/OECD, 2000; Neij et al., 2003; Junginger et al., 2004c). A particular advantage of this concept is that under a number of conditions (see section 3) it can be used to make future cost projections. Regarding biofuel production, Goldemberg (2004) briefly described an experience curve for the large-scale production of ethanol from sugarcane in Brazil. For biomass-fuelled power plants producing electricity, the total learning system of producing electricity can be split up in three parts (see Figure 1): the investment costs of the plant (including different sub-components), the operation and maintenance (O&M) costs of the plant, and the fuel costs. For each of these parts, a separate learning system can be defined. For the investment costs, it was shown that an experience curve is more difficult to construct due to a low degree of data availability and a large spread in the investment costs caused by variation in individual plant layout (Junginger et al., 2004e). O&M costs are typically high during the start-up phase, and normally decline after the first few years when start-up problems have been resolved, but may increase in later years with the wear of equipment. Overall O&M cost of individual plants also may decline with an increasing number of plants built, but are not further investigated in this paper. The focus in this study lies on the third component: the cost of the biomass fuel as function of the cumulative fuel supply (grey fields in Figure 1).

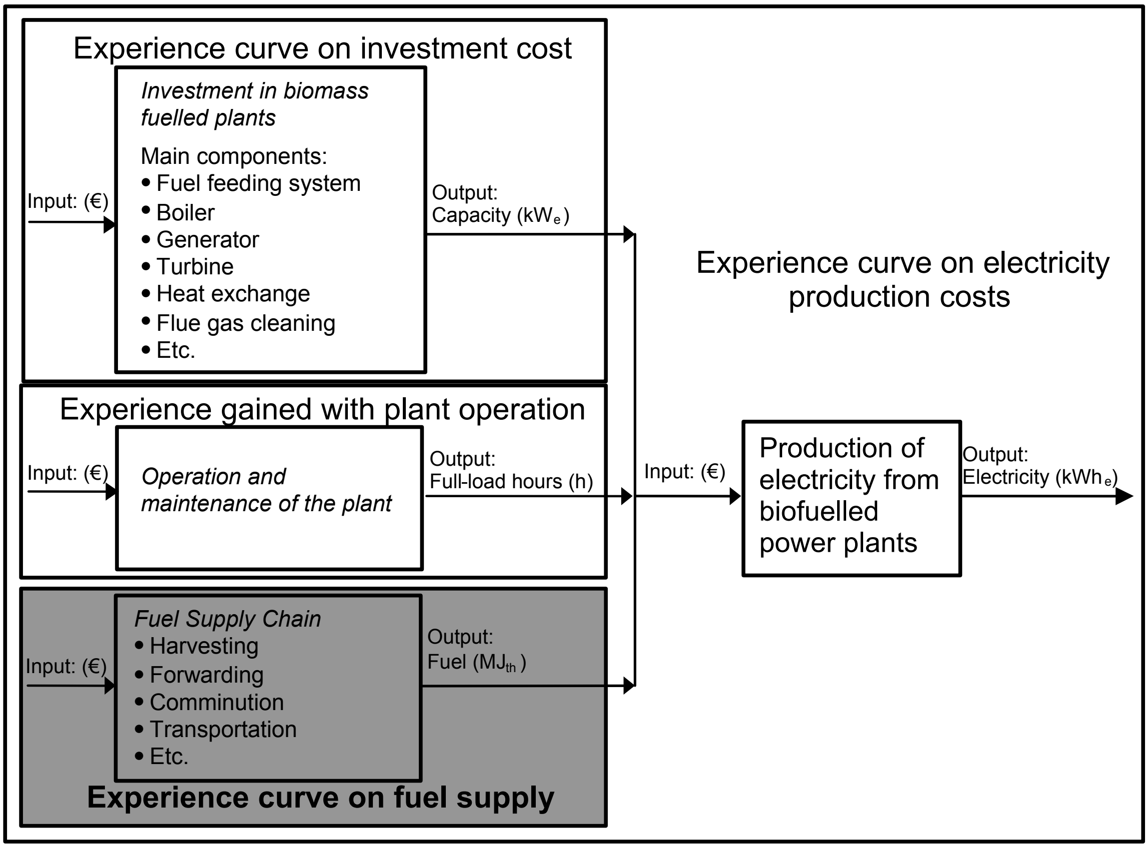

Figure 1 Total learning system for biomass-fuelled power plants producing electricity. The focus in this chapter lies on the fuel supply chain learning system. In chapter 6, a somewhat more elaborate figure is presented, as the other subsystems are discussed in detail in chapter 6 as well.

In regard to solid biomass fuels, three main categories can be distinguished. First, process residues such as sawdust or bark, or waste streams like municipal solid waste are generally available in large quantities at a central location, often for low or even negative costs. Therefore learning and cost reduction potential for these types of biomass is probably minimal. Second, a number of energy crops can be grown for biomass energy, e.g. miscanthus, willow or eucalyptus. While these types of biomass have high costs and likely a large potential for cost reductions, the lack of long-term experience and data complicates the application of the experience curve methodology. Third, many agricultural and forest residues e.g. straw, verge grass or PFF may be utilized. The focus of this study is on PFF production in Sweden due to the long-term use of PFF in Sweden and the availability of good data. So far, for fuel supply chains of primary biomass such as PFF, experience curves have not been published.

The aims of this study are to quantify cost reductions of PFF production as achieved in Sweden and to identify underlying reasons for this reduction. Also it is our aim to determine whether the experience curve concept can be employed to describe this trend. If so, the applicability of this concept to analyze future cost reductions and to investigate the development of primary biomass in other countries will be explored.

In the following section, the experience curve concept is presented. In section 3, the Swedish energy policy regarding PFF production and biomass in general is described briefly. Data collection and data availability are described in section 4. The results are presented in section 5, followed by a sensitivity analysis in section 6. In section 7, the possibilities to use the experience curve concept to analyze future costs of primary biomass in Sweden are sketched. Next, a closer look is taken at the choice of geographical system boundaries in the analysis. While Sweden is clearly one of the most advanced countries regarding the production of PFF, cost reductions may also have been achieved in other countries, and experience may have been exchanged between Sweden and other countries. This issue is explored in section 8. In the same section, it is investigated how insights from the example of Sweden may provide valuable lessons for other countries with large wood-fuel resources and (so far) less developed bio-energy systems, for example in Central and Eastern Europe. Finally, in section 9 some general conclusions are drawn.

2. Methodology – the experience curve concept

Typically, the unit cost of a technology decreases with increasing penetration of the technology. This phenomenon has been frequently described historically (BCG, 1968; Argote and Epple, 1990), starting with serial production of airplanes at the beginning of the last century (Wright, 1936). A special empirical observation is that costs tend to decline almost at a fixed rate with every doubling of the cumulative production. This relationship can be described mathematically by means of the following curve, the experience curve[2]:

$$C_{\mathrm{Cum}} = C_0 \, \mathrm{Cum}^b \tag{1}$$

$$\log C_{\mathrm{Cum}} = \log C_0 + b \log \mathrm{Cum} \tag{2}$$

$$\mathrm{PR} = 2^b \tag{3}$$

C_{Cum}	:	Cost per unit	C_0	:	Cost of the first unit produced
Cum	:	Cumulative (unit) production	b	:	Experience index
PR	:	Progress ratio			

PR denotes the progress ratio, expressing the rate of unit cost decline with each doubling of cumulative shipments. For example, a PR of 0.8 implies that after one doubling of cumulative production, unit costs are reduced to 80% of the original costs, i.e. a 20% cost decrease. The definition of the ‘unit’ may vary: in many cases a unit is a product (for example a car or an airplane). In relation to energy technologies, more often the unit is the capacity of an energy technology (e.g. the capacity of a solar module or a wind turbine) or the amount of electricity produced by a technology. The experience curve concept has been used and applied for many different energy technologies; for an overview see McDonald and Schrattenholzer (2001). Users may vary from individual corporations analyzing the speed with which the costs of their products may decline, to energy modellers and national policy makers (Neij et al., 2003).

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[2] In the remainder of this paper, the term *experience curve* refers to curves which can be described with formula (1). Plotting costs versus cumulative production in a figure with double logarithmic scales shows the experience curve as a straight line (see equation (2)).

It must be stated that there is no natural law requiring production costs to follow an experience curve. However, this phenomenon has been observed empirically numerous times, and a number of factors can be identified causing the development of cost reductions:

- Learning-by-doing and learning-by-using, leading to increased labor efficiency, work specialization and improvements of production methods
- Innovations caused by RD&D (learning-by-searching), leading for example to the use of better materials or the introduction of new, more effective production processes
- Improving the network interactions between research institutes, industry, end-users, policy makers, etc. (learning-by-interacting), allowing for the better diffusion of knowledge
- Standardization of the product, allowing upscaling of the production plant (i.e. mass production)
- Redesigning and upsizing (or downsizing) of the individual product (e.g. upscaling a gas turbine leads to lower specific cost of the turbine)

In many cases a combination of these factors occurs, and in addition the contribution of each may change during the development of a product over time. For example, in the early development phase, RD&D expenditures may have a significant impact on cost reductions, while typically during the market penetration, cost reduction due to mass production dominates learning. Some authors also differentiate between effects of (technological) learning (such as the first three factors) and scale effects (such as the last two factors). However, in practice these factors may overlap and may contribute to cost reductions simultaneously. For a more elaborate discussion, see for example Abell and Hammond (1979), Grübler (1998), or Kamp (2002).

Regarding the use of experience curves, a number of issues should be briefly mentioned.

First, in order to compare costs from the past with current costs, the data have to be corrected for inflation. In case only data from one country are used, normally either the GDP deflator or the consumer price index is used. In this study, all Swedish financial data have been adjusted for inflation to the year 2002 using the Swedish consumer price index (Statistiska Centralbyrån, 2004). Conversion to Euro was carried out using the average exchange rate of 2002 (1 € = 9.16 SEK) (Oanda, 2004).

Second, the experience curve ideally presents the reduction of production cost. However, in general data about production costs are kept confidential, and often only prices are publicly available. Prices can be used as a proxy for production costs under the condition that profit margins are a fairly constant share of total prices (IEA/OECD, 2000). In this case, prices and costs decline with the same speed. However, it also possible that prices are temporarily below actual production cost (forward pricing), remain stable for a prolonged time (a so-called umbrella phase, due to e.g. an oligopolistic market) while actual production costs decline, or vary due to variations in demand or changes in tax or subsidy regimes. Prices can also drop dramatically for a short period of time if there are too many suppliers on the market, causing shakeout effects (IEA/OECD, 2000). In all these cases, prices cannot be used directly as proxy for costs. Thus, the analysis should always cover whether prices have been dominated by production costs or have also been influenced by other factors.

Third, next to the system boundaries shown in Figure 1, the correct geographical boundaries should also be determined for the learning system. Experience curves are often set up for individual countries, especially when the aim is to support and evaluate policy measures. When the focus lies on analyzing the speed with which the costs of a technology are reduced, it is of importance to determine whether experience has been gained from developments within the analyzed system only, or also from developments outside this system. Not including experience gained outside the investigated system may lead to serious distortions in the results, as shown in the case of wind turbine cost developments (Junginger et al., 2004b).

Other issues, such as whether or not the PR is a constant or may change with the diffusion of the technology or to what extent the concept of experience curves can be used for policy making, are not discussed here for sake of brevity. For a detailed discussion of the use of experience curves in energy technology development, see for example (Neij, 1999; IEA/OECD, 2000; McDonald and Schrattenholzer, 2001; Neij et al., 2003; Junginger et al., 2004b).

3. The Swedish background

3.1. Swedish policy concerning biomass 1975-2003

Since the late 70’s, the use of woodfuels has strongly increased in Sweden. Main driving forces for developing biomass use for energy were high oil-prices in the late 70’s and first half of the 80’s, development of alternatives for nuclear power energy supply and (later) growing awareness of the possible negative effects of climate change due to greenhouse gas emissions of fossil fuel use. Swedish policy has stimulated wood fuel use through a number of instruments. First of all, the oil crisis in the early 70’s triggered a number of energy RD&D programs. The aim of these programs varied over time accordingly to the driving forces mentioned above, but basically always included the promotion of biomass use (Hillring, 1998; Silveira, 2001). Second, both in the 80’s and 90’s, investment subsidies of up to 25% on boilers or total investment costs were available for biomass-fuelled district heating and CHP plants (Hillring, 1998; Björklund et al., 2001; de Visser, 2004). Further subsidies for biofuelled heating plants were available from the Local Investment Programme (LIP) between 1998-2002. Since 2003, subsidies are available from the climate investment programme (KLIMP) (Nilsson et al., 2004). Third, the introduction of a CO_2 –tax in 1991 and taxes on NO_x emissions from fossil fuels used for heating strongly improved the competitiveness of the use of biomass fuels for the production of heat and electricity (Hillring, 1998). Finally, a number of other policy measures, e.g. the solid fuel act and the wood fibre act, promoted the increased use of biomass in Sweden to some extent (Hillring, 1998). For the future, the renewable electricity certificate system may also cause increased biomass-based CHP-capacity (Nilsson et al., 2004). Since its introduction in May 2003, 75% of the certificates issued were for biomass-based electricity (Johansson, 2004). Due to beneficial policies, the production of PFF started off in the second half of the 70’s in Sweden. Consequently the development of PFF production volumes and costs in Sweden can be investigated over a period of almost three decades (see Figure 2).

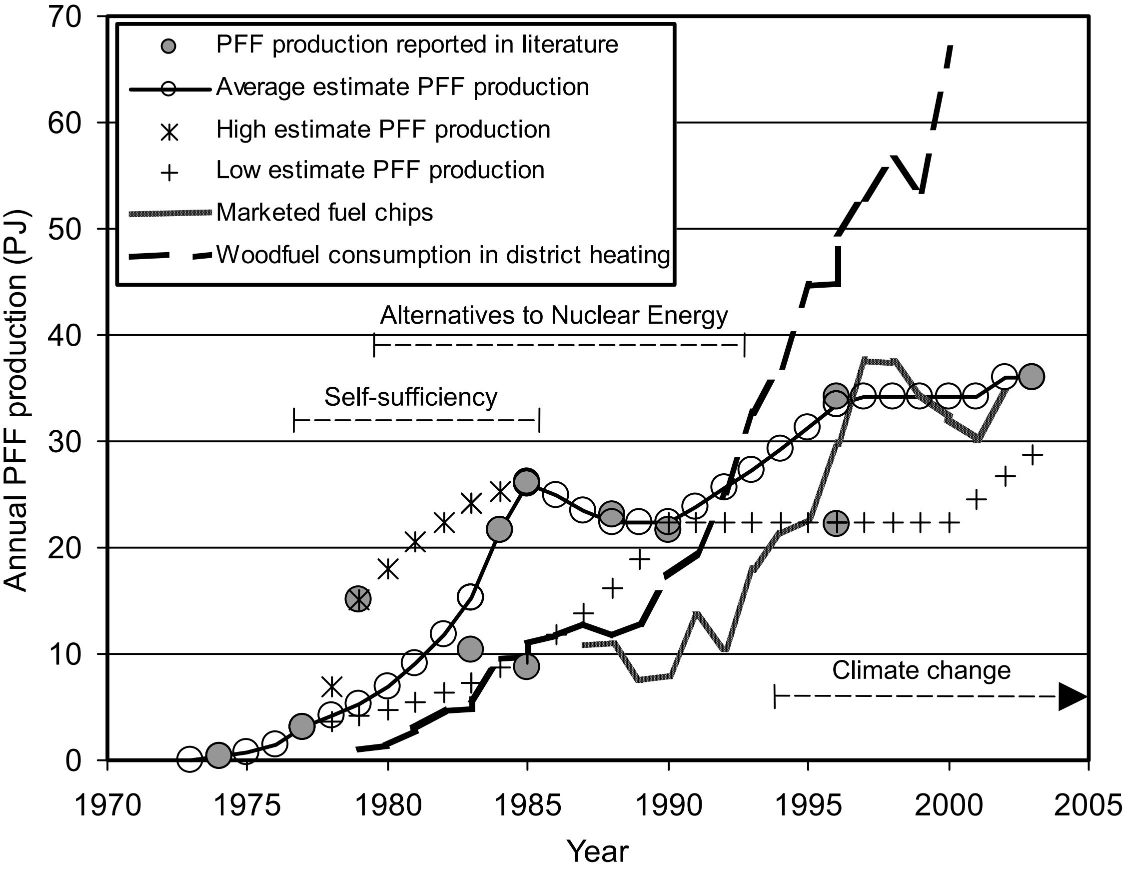

Figure 2 Annual PFF production in Sweden in the period 1970-2003 as reported in or derived from literature (Projekt Helträdsutnyttjande, 1977; Fridh et al., 1993; SPK, 1984; Andersson and Björheden, 1986; Nilsson, 1988; Statens energiverk, 1989; Danielsson et al., 1990; Brunberg, 1991; Hogfors, 1997; Filipsson, 1998b; Filipsson, 1998a; Hogfors, 2004b). Using these data points, an average, low and high estimate of PFF production is presented. Marketed wood fuel chip volumes and consumption of wood fuels in district heating plants are presented for comparison (Anonymous, 1985-1997; Skogstyrelsen, 2003). Main driving forces over time behind the increased use of biomass energy are also shown.

3.2. The Swedish PFF supply chains

There are three main PFF-sources: slash from final fellings, slash and small trees from thinnings and cleanings, and unmerchantable wood. Slash from final fellings constitutes the largest share: over 71% in 1996 (Filipsson, 1998b). According to most experts interviewed, this share has even increased over the last few years. There are four main supply chains of PFF from final fellings, which basically differ from each other with respect to the comminution step:

1. In the *terrain-chipping method*, the slash is directly chipped in the field, collected in a small container and then brought to the roadside, where the chips are transferred to a truck.
2. When using the *roadside chipping method*, the slash is first forwarded to the roadside, where it is chipped directly into a container truck (load volume up to 100 m^3) either by a mobile chipper or a truck-mounted chipper.
3. *Terminal chipping* is a third option, where the uncomminuted PFF is transported (short distances) to a central terminal, where the slash is comminuted, and loaded onto large bulk

trucks (volume up to 130 m^3). Occasionally, loose slash is transported to the plant directly (especially when the transport distance is short), and chipped at the plant. Terminal chipping also encompasses the tree section method, in which trees are felled, cross-cut forwarded and trucked without first delimbing the stems (Björheden, 2001). This method was popular in the 80's, but has basically not been practiced during the last decade.

4. When a fourth option, the *bundling method*, is applied, the PFF are compressed to composite residue logs (CRLs) using a mobile bundler in the terrain. These CRLs have similar dimensions as round wood, and are forwarded to roadside, and transported by truck to the end-user, where comminution takes place.

A summary of the chains is presented in Table 1. For a more elaborate description of these methods, see for example Andersson et al. (2002) and Hakkila (2004).The first three methods have been practiced in Sweden since the late 70's, while the bundling method is still being tested in Sweden. The most predominant supply chain over the last 20 years in Sweden is roadside chipping, covering approximately 40% in the early 90's (Brunberg, 1991) to about 75-80% nowadays (Brunberg et al., 1998).

Table 1 Overview of the different steps within the four fuel supply chains.

	Location			
Supply chain	*Clear-cutting*	*Roadside*	*Terminal*	*Plant gate*
1 Terrain chipping	Residues are chipped into a small container, and forwarded to the roadside	Chips are transferred from small container to a container truck	-	PFF arrive at plant as chips
2. Roadside chipping	Loose slash is forwarded to the road side	Slash is chipped at the roadside, and blown into a container truck	-	PFF arrive at plant as chips
3. Terminal chipping	Loose slash is forwarded to the road side	Loose residues are loaded on a container truck and transported to a terminal	Residues are chipped by a stationary chipper and loaded on a bulk truck	PFF arrive at plant as chips
4. Bundling	Loose slash is bundled, and forwarded to the roadside	Bundles are loaded on a truck	-	Bundles are chipped at the plant

4. Data collection and availability

Data on production costs, market prices and production volumes of PFF in Sweden were collected by literature review, the use of Swedish energy and forestry statistics and a number of semi-structured interviews with experts in the field.

4.1. PFF production costs and prices

The production costs of PFF in this study are set at the plant gate, i.e. including steps such as the felling, forwarding, comminuting, compacting, transportation, stumpage fee and overhead/administrative costs in relation to these activities, but excluding costs for storage or further fuel preparation at the plant. The availability of data on production costs of PFF in Sweden is reasonable. Due to the extensive amount of research carried out in Sweden on the use of PFF, a number of production cost analyses of PFF supply chains have been published between 1981-2003 (SVEBIO, 1981; SPK, 1984; Nilsson, 1985; Björheden, 1986; Rutegård, 1987; Lönner et al., 1989; Danielsson et al., 1990; Hektor and Parikka, 1992; Brunberg et al., 1994; Brunberg et al., 1998; Andersson, 2000; Björheden, 2000; Liss, 2003). Also, specific studies regarding steps in the chain (such as forwarding or truck transport) are available. These studies are sufficient to gain insights in the development of costs of the individual steps in the fuel supply chains. However, the production cost data from these studies were insufficient for the construction of an experience curve. Therefore PFF prices were used as proxy for production costs. Regarding data on PFF prices, no exact data were found for the period before 1981. Due to the small amounts produced, no well-developed market existed, and so it is difficult to determine average price levels. In this study, estimates given by Hillring (1999), Gustavsson (197) and Nilsson et al. (1999) for the period of 1975-1980 were used. From 1981-1984, prices were recorded by Lönner and Parikka (1985). Since 1984, prices of PFF have been recorded by the Swedish competition authority (SPK, 1984). From 1984, onwards the Swedish Energy Agency STEM (formerly Nutek) monitored the development of PFF prices in Sweden. Since 1993 this monitoring is executed both per season and per region (Statens energimyndighet (STEM), 1993-2004; Nutek, 1994).

4.2. PFF production volumes

Annual production volumes of PFF have been poorly recorded in Sweden. Only the aggregated consumption of all biomass fuels has been monitored continuously since the late 70's (Skogstyrelsen, 2003). However, the sources of the biomass are not specified, and contain also imported biomass. From 1986 onwards, the production of (marketed) woodchips has been monitored by the Swedish Woodfuel Association (Hogfors, 2004a), but it covers production of its members only, thus causing an underestimation. Also, the origin of the wood chips is unknown (Hogfors, 2004a). In the 80's, the source was to a large degree Swedish PFF, but later on also chips from industry byproducts and recycled wood have become more significant, thus causing an overestimation. In addition, the degree to which PFFs were marketed vs. used internally (and thus not recorded in statistics) is unclear. Only for 2003, a detailed survey was recently published, covering 64 producers, and specifying which part of the chips is derived from PFF (Hogfors, 2004b). Other literature only incidentally reports actual production levels of PFF[3]. The most elaborate study was performed by Filipsson (1998b) who conducted an extensive survey covering the 59 producers of PFFs, though only for production in 1996. In order to obtain more insights in the relative changes in production quantities over time, several of the largest PFF manufacturers were contacted to obtain more historical first-hand data. This proved rather laborious, as most producers either did not wish to participate in the survey, or did not possess the required data. In total, four producers supplied (fragmented) production figures under strict conditions.

5. Results

5.1. Production quantities

As described in section 4, time series on PFF in Sweden are not available. Therefore, PFF production levels were estimated based on literature (grey circles in Figure 2) and expert opinions. Overall, a strong increase in annual production during the late 70's and early eighties is observed. In

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[3] See: (Projekt Helträdsutnyttjande, 1977; Sveriges skogsägareföreningars Riksförbund, 1980-1989; Danielsson, 1982; Fridh et al., 1993; SPK, 1984; Andersson and Björheden, 1986; Nilsson, 1988; Statens energiverk, 1989; Danielsson et al., 1990; Brunberg, 1991; Filipsson, 1998b).

the second-half of the eighties, with declining oil prices the annual PFF quantities probably declined somewhat. From 1990 onwards, annual quantities are estimated to have increased by 10-15 % per year (Hogfors, 1997), though very little actual data from this period are available. For 1996, the lower estimate is based on a survey covering all major producers of PFF (Filipsson, 1998b), while the upper estimate covers also additional small-scale production (Hogfors, 1997). Since 2000, amounts have likely increased, as slightly higher prices increased profit margins. The data obtained from the individual producers supports these developments in general, but do not show a coherent picture. Most producers started in the early eighties, but while two have increased their production continuously, two others display (strongly) decreasing rates after 1996. To parry the uncertainty of this data, next to a best estimate, a low- and high production scenario are included, see Figure 2. The low production scenario is based on the lowest production figures available between 1977 and 2003. The high production scenario differs from the average scenario for the period 1978-1985, assuming a stronger annual increase in PFF production volumes, based on the highest available estimates in this time frame.

Regarding consumption, most marketed PFF was consumed in district heating plants, where it constituted the major share of wood fuels in the 80's. In total, the number of district heating plants firing PFF has increased from 1 in 1981 to over 130 in 2002 (Linder, 2004). From 1990 onwards, secondary residues such as bark and sawdust and imported wood fuels gained importance as fuel (see Figure 2), causing a lower growth in annual PFF production. Since 2000, steadily increasing demand for wood fuels has also caused an increase in PFF production.

5.2. Supply chains and production costs

As described in section 3.2, the roadside chipping supply chain is predominant in Sweden. Factors influencing the costs for this chain are illustrated below.

Felling costs are normally allocated to the main products (timber and pulp), and not to the PFF production costs[4]. Due to increased awareness that the slash is going to be harvested, harvester operators have learned to avoid driving over the residues, thereby reducing the contamination of the slash with rocks and earth. Furthermore, while slash used to lie randomly distributed over the clear-cutting, nowadays during processing it is piled next to the timber and pulpwood. These changes in slash treatment have indirectly led to lower costs for the following steps.

Forwarding costs have been lowered mainly due to the experience gained by learning-by-doing and improved equipment. Forwarders have adopted the method to only 'cream off the top', while in the early days they were often instructed to collect as much slash as possible (Björheden, 2004). Regarding equipment, often forwarders nowadays are used with an extended slash-carrying capacity. These factors have increased PFF quality and forwarder productivity, thereby reducing costs / GJ (see Figure 3). Another important factor is increased operator experience. This is basically important for all steps involving complex human tasks (mainly felling & forwarding). A well-documented example of learning-by-doing in PFF harvest is described by Björheden (2001) for tree-section hauling in central Sweden. In this study, a clear increase in productivity (measured in payload/truck) was found of approximately 10% within two years under constant circumstances

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[1] So far the revenues of PFF are marginal compared to revenues from roundwood and pulp production. With the continuing growth of PFF production and potentially increasing revenues, in the future possibly a part of felling costs may also be attributed to PFF.

of technology (same machinery used), work object properties (e.g. same tree types harvested) and conditions of work (e.g. weather or legislation).

Furthermore, *chipping costs* at the roadside have been reduced significantly (see Figure 3). This can be attributed to a large extent to the advantages of less contaminated slash at the roadside and technical development of chippers. Since 1980, the average roadside chipper has increased in production capacity, and technical availability has increased from approximately 50% in 1980 to an estimated 90% nowadays (Galfvensjö, 2004).

In comparison, net *transportation costs* seem to have remained stable. The predominant transportation mode is wood chips in containers trucks. A comparison of transportation costs of chips in containers from the roadside described in seven Swedish studies between 1977-2000 revealed that neither fixed nor variable costs have changed significantly in real terms (see Figure 4). This is likely due to the fact that container transportation on trucks has been carried out for many decades, and the potential for cost reductions is probably minimal. However, the variation shown in Figure 4 ranges from approximately 0.28 Euro/GJ at short distances to 0.39 Euro/GJ at long distances. Also, as the supply potential is much larger than current demand and the number of plants utilizing PFF has increased (e.g. district heating plants from 1 in 1981 to over 130 in 2002), the average transportation distance (50-80 km (Håkansson and Westerberg, 2004)) has not changed much over the last 20 years.

Another cost factor is a *stumpage fee* for the forest owner. The height has varied over the last 25 years, mainly depending on the market prices. In addition, *administrative / overhead costs* have been between 10-15% of total production costs both in early and recent years (Lönner et al., 1989; Brunberg, 1994; Liss, 2003).

Since the early 80's, the developments described above have led to a significant reduction of production costs. In Table 2, two studies from 1983 and 2003 are compared directly. It is concluded that forwarding cost have been reduced most (about 58%), followed by chipping costs (about 33%), corresponding well to the general cost development trends shown in Figure 3. The transportation costs seem also somewhat reduced (15%). However, the transportation distance used in the SPK study (SPK, 1984) was not given. The reduction may be due to variations in transportation costs due to local factors. Overall the share in total costs has increased from 22% to 27%. This is also illustrated by Figure 5 in which a number of cost breakdowns are shown of different supply chains for PFF production from final fellings, described in literature between 1981-2003. The different studies and costs cannot simply be compared one-on-one, due to differing assumptions and settings, e.g. average forwarding and transportation distances, harvesting of green (fresh) or brown (seasoned) PFF, assumed harvesting area size, etc. Yet, the overall picture shows a clear reduction in production costs.

Table 2 Comparison of the cost structure of road-side shipping fuel supply chains in 1983 and 2003 (SPK, 1984; Liss, 2003). These numbers can vary according to size of the clear-cutting, forwarding distances to the road, optional roadside storage, transportaton distance, possible stumpage fee, etc.

	PFF Production cost (Euro(2002)/GJ)		Cost reduction (%)
Year	1983	2003	2003 vs. 1983
Forwarding	1.61 (28.3%)	0.68 (17.7%)	58%
Chipping	1.89 (33.3%)	1.27 (33.0%)	33%
Transportation	1.23 (21.6%)	1.04 (27.2%)	15%
Stumpage fee and other cost	0.95 (16.7%)	0.85 (22.1%)	10%
Total	**5.68 (100%)**	**3.84 (100%)**	**32%**

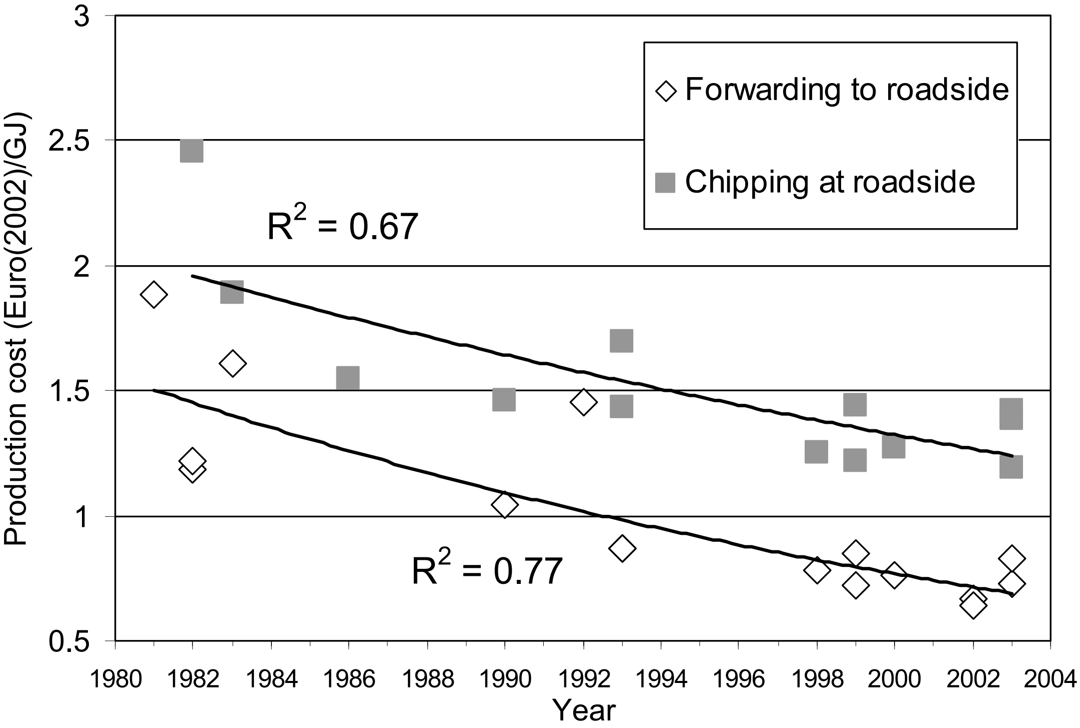

Figure 3 Forwarding and chipping cost 1981-2003. Data from literature studies and interviews (SVEBIO, 1981; Larsson, 1982; SPK, 1984; Nilsson, 1985; Brunberg, 1991; Hektor and Parikka, 1992; Brunberg, 1994; Brunberg et al., 1998; Andersson, 2000; Björheden, 2000; Liss, 2003; Gustén, 2004; Håkansson and Westerberg, 2004; Harrysson, 2004).

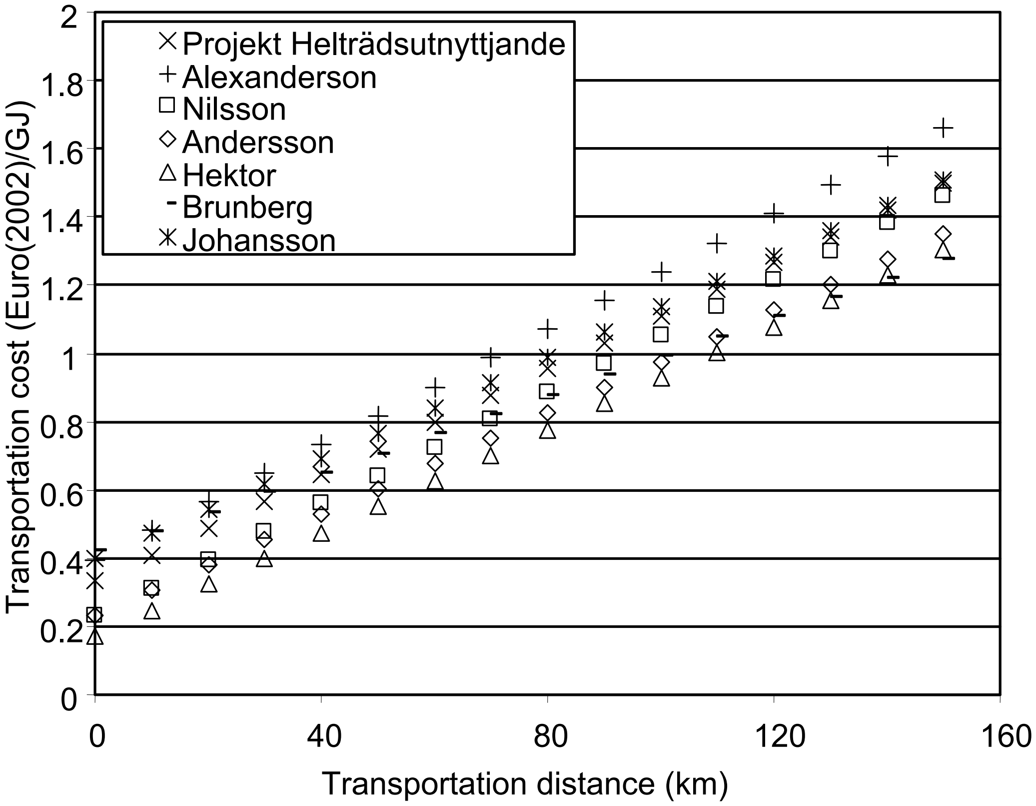

Figure 4 Comparison of chip transportation costs using containers in Sweden 1977-2000 from 7 studies (Projekt Helträdsutnyttjande, 1977; Alexandersson et al., 1984; Nilsson and (main author), 1985; Andersson and Björheden, 1986; Hektor and Parikka, 1992; Brunberg et al., 1998; Johansson, 2000).

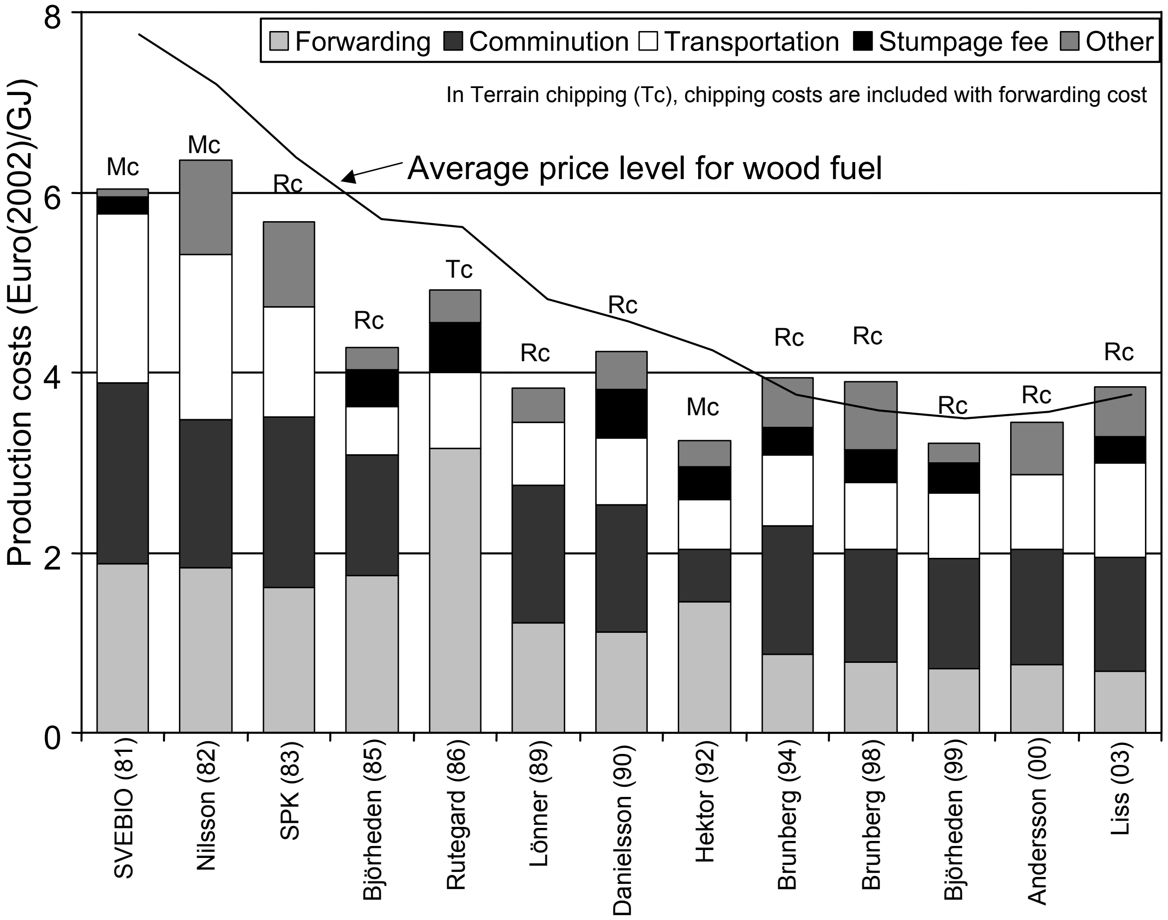

Figure 5 Examples for the cost development and composition of Terrain (Tc), Roadside (Rc) and terMinal (Mc) fuel supply chains in Sweden from various literature studies (SVEBIO, 1981; SPK, 1984; Nilsson and (main author), 1985; Björheden, 1986; Rutegård, 1987; Lönner et al., 1989; Danielsson et al., 1990; Hektor and Parikka, 1992; Brunberg et al., 1994; Brunberg et al., 1998; Andersson, 2000; Björheden, 2000; Liss, 2003) between 1981-2003. Not for all years studies were available. Note that these studies were not carried out under the same conditions, e.g. average forwarding and transport distances may differ. National average price levels for fuel chips are also presented for comparison.

5.3. Prices, market situation and relation to production costs

Average national data on prices can be regarded as relatively reliable, as they have been monitored consistently since the mid-eighties. Before 1984, price information is likely to be more uncertain, as also the traded PFF volumes were very small. It should be noted that local prices may deviate due to specific demand and supply conditions. Also, prices may generally be higher during wintertime due to higher demand by district heating plants. In this study, prices averaged over the whole of Sweden and the whole year are used.

As can be seen in Figure 5, the production cost level has not been much lower than market prices, especially during the nineties. In the early nineties, regulations regarding the use of sawdust pulp chips for energy use were abandoned (Hillring, 1997). This caused a strong increase in the use of bark, sawdust and refined wood fuels. In addition, since the beginning of the nineties and especially from 1995 onwards, large-scale imports of various forms of biomass (e.g. refined wood fuels, wood chips, tall oil and waste wood) occurred, mainly from the Baltic States, but also from Russia, Canada, Finland and other countries (Ericsson and Nilsson, 2004). During this period, incidentally prices were even lower than production costs and some PFF suppliers went bankrupt. Only since 2001, prices and profit margins have been going up again, due to increasing demand and limited supply of secondary residues.

Thus it is concluded, that since prices in general reflect production costs rather well (i.e. no strongly varying profit margins) in the past, prices can be used for devising the experience curve of PFF in Sweden. However, as average prices are not determined by PFF production alone, in the future they may deviate more from production costs, as demand for PPF is expected to rise further in the near future.

5.4. Experience curves for Swedish PFF production

Using the annual average production volumes of PFF and the market prices for wood fuel chips, an experience curve for PFF in Sweden was devised (Figure 6). The PR of this curve is about 87%[5], measured over more than ten cumulative doublings of PFF production in Sweden. The correlation of $R^2 = 0.93$ is quite satisfactory for this type of analysis (McDonald and Schrattenholzer, 2001). In the time period from 1975 until 2003 prices were reduced by 65 –70%, from approximately 11 to 3.3-3.8 €(2002)/GJ at the plant gate.

6. Sensitivity analysis

There are two main uncertainties in the data used: the annual PFF production volumes are partially based on estimates, and the price data before 1980 is not well recorded. To analyze the effect of uncertainties in the production volumes, experience curves were devised using the low and high production scenario described in section 5.2. The corresponding PRs are 86% and 88% respectively (see Figure 6). As described previously, the price data before 1981 are based on estimates. As data situated at the beginning of an experience curve can influence the PR relatively strongly (Snik, 2002), another experience curve was devised, in which the price data from 1981 onwards was weighed by a factor of 10 compared to the data before 1981. As no indication was available on how good these estimates are, this factor is chosen relatively arbitrarily. The resulting PR of the corresponding experience curve is 85%. When leaving out the data before 1981 altogether, the PR even drops to 81%. However, such a strong cost reduction is not deemed realistic, as the data before 1980 are expert estimates, and should not be completely dismissed.

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[5] In an earlier publication (Junginger et al., 2004d), a slighlty lower PR of 86% was presented, due to the use of a different fitting algorithm.

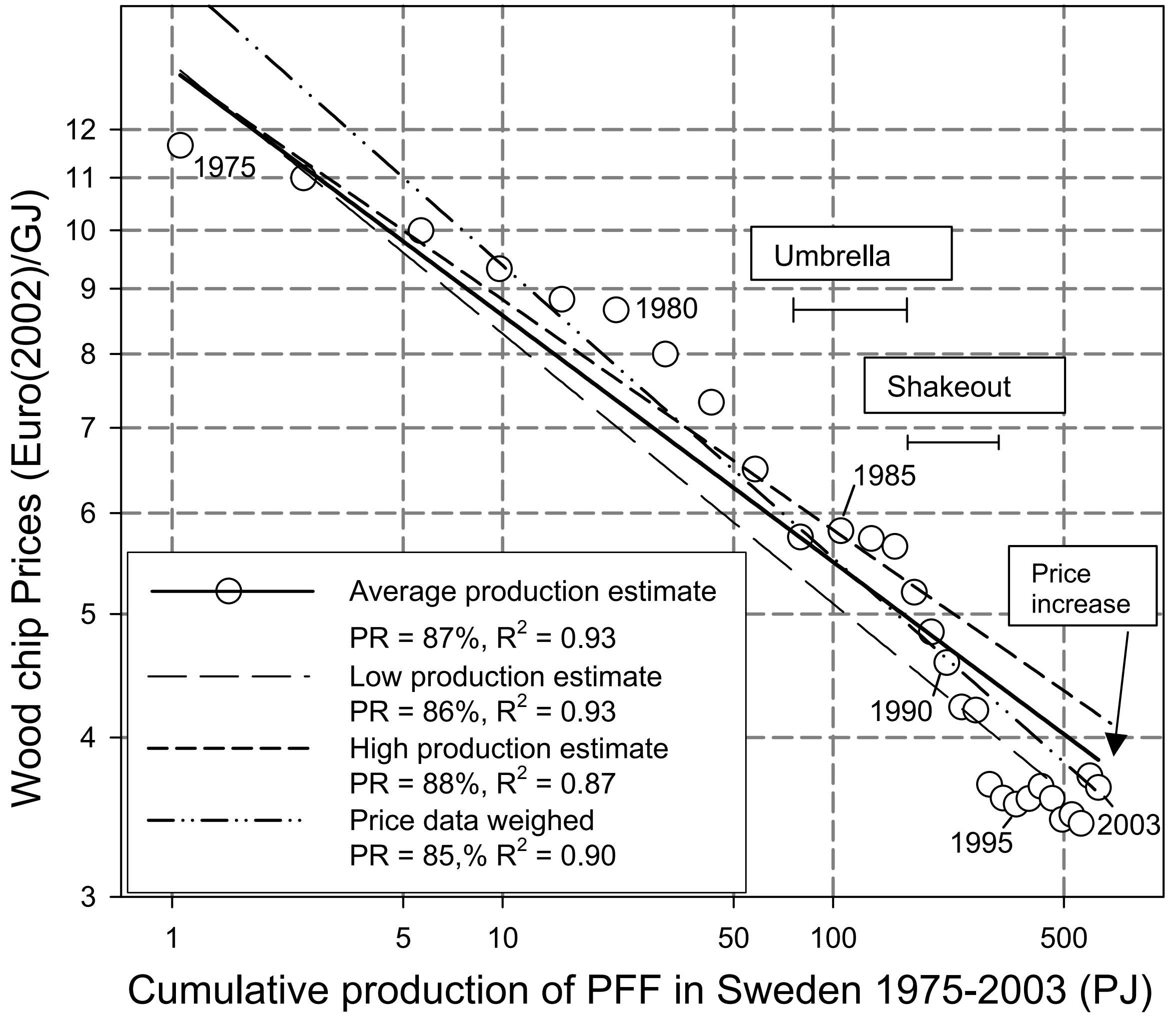

Figure 6 Experience Curve for Swedish PFF production from 1975-2003. For clarity, only for the best PFF production estimate, actual data points are given. For the low/high PFF production scenarios (see Figure 2) and the weighed price data scenario (see section 6), only the resulting trend lines are presented. From 1983-1987, PFF prices are almost constant, likely due to high oil prices. From 1987-1992, prices decline rapidly, probably due to increased competition from low oil prices and other wood fuels. Since 2002, prices appear to increase, possibly caused by increasing demand for PFF.

Furthermore, as mentioned in section 3 the rate at which production cost and market prices decline is not necessarily identical. From the historical background and from Figure 6, it can be seen that PFF prices temporarily remained stable due to the high oil prices, while actual production cost most likely kept declining. With rapidly declining oil prices from the mid-eighties onwards, PFF prices producers were forced to lower prices as well, which led to a number of bankruptcies. These two phases can also be described as ‘umbrella’ and ‘shakeout’ phase (see section 2). From the early 90’s onwards, prices have been very close to costs due to competition from secondary wood fuels and imported wood (see section 5.3), and thus the data are most likely suitable to be used in experience curve analyses. Since 2001, prices show a tendency to increase again, due to an increased demand. When the average production scenario is used and the prices are left out from 2001 onward (which show an increasing trend), the change in PR is statistically insignificant. Given the relative uncertainty in both production volumes and prices, a 85-88% range will be used in the remainder of this paper.

7. Application for future cost reduction analysis in Sweden

When using experience curves to assess potential future cost reductions, a number of steps are recommended. First of all, developments should be identified that may bring costs down further in the future (Junginger et al., 2004c). As was shown in the previous sections, the largest cost reductions have been achieved in chipping and forwarding, and little further cost reductions are expected here. From literature and interviews with experts in the field, two main potential developments were identified, that could lead to further cost reductions in Sweden:

Increased utilization of pulp wood. The first main option may be an increase of production levels of PFF by using so-called long-tops (i.e. more stem wood) for PFF production (Danielsson and Liss, 2004). This means, that the fraction currently used as pulp wood is used as PFF. There are several advantages to this: the yield per hectare is higher, causing a higher productivity. Compared to the conventional road-side chipping, production costs have been estimated to be 16% lower. Second, the relative bark content is lower (due to a higher fraction of ‘white’ stemwood), for which heating plants are willing to pay up to 17% more than for ordinary wood ships from slash (Danielsson and Liss, 2004). The economic viability of this option is mainly depending on the price of pulp chips and PFF. In addition, the fiber industry is likely to perceive such a development as a threat to their raw material supply.

Application of bundling technology. The second main option may be a reduction of transportation cost which so far have shown little cost reductions. One way may be the use of bundling technology. Composite residue logs (CRLs) have a higher density than wood chips, thus decreasing the transportation costs per tonne PFF. These may outweigh the additional bundling costs, especially for large transportation distances (Andersson et al., 2000; Ranta, 2002; Johansson et al., 2004). The possibility to introduce this technology on a large scale in Sweden is discussed in section 8. Another option could be further optimization of the logistics of supply and demand. As one PFF producer stated, the coordination between production and demand is often complex, and incidentally transportation distances above one hundred kilometers occur (Westerberg, 2004). Better planning may result in lower average transportation distances, and thus lower costs.

To assess future cost reductions, the experience curve can be combined with a Swedish fuel supply curve, taking into account the availability of PFF. For example, taking into account ecological and technical restrictions, Lönner et al. (1998) found that about 340 PJ of PFF may come available in Sweden per year at production cost levels between 3.2-5.8 Euro(2002)/GJ. At a utilization of 36 PJ in 2003 and an annual 10% increase of PFF production from 2004 until 2020, PFF production would amount to ca. 180 PJ in 2020. This corresponds to 1600 PJ cumulative production, another 1.8 doublings compared to current cumulative production of PFF. As a *rough indication*, assuming a PR of 87% and average production costs at plant gate of 3.7 €(02)/GJ at present, a reduction of average production costs of 24% to ca. 2.8 €(02)/GJ could be achieved. Using the PR range of 85-88%, the cost reduction estimate lies between 21% and 26%. These cost reductions may possibly be achieved by two developments described above, but should be investigated further.

However, such an analysis must also take into account that with increased production levels also transport distances will likely increase, and it may be necessary to use PFF increasingly from thinnings or from smaller average lot size, as the available PFF volumes from final fellings are limited (Lönner et al., 1998). These factors may increase average PFF production costs, and thus the suggested cost reduction is probably too optimistic[6].

Furthermore, it must be pointed out again that production cost and market prices are not identical. So far, supply in most parts of Sweden has been abundant, keeping prices low. If however demand continues to increase in the future, prices might increase as well. This would mean that prices may no longer be a proxy for costs. However it would imply also that with continuing decrease of production costs, a larger amount of PFF would be economically accessible (e.g. more PFF fuel from thinnings and cleanings).

8. Geographical system boundaries and applicability for other countries – methodological considerations

As stated in section 3, when analyzing the speed with which technological learning and cost reductions occur, it is of importance whether significant learning has also taken place outside the geographical system investigated, and whether there was any interaction between the system investigated and other learning systems. In case an international learning system exists, an analysis of only a part of the learning system may lead to distorted results.

In the case of PFF production, only a handful of countries have had similar production increases of PFF fuels in the last 30 years, the most important ones being Finland and Austria, so the number of potential candidates to exchange knowledge with is limited. Furthermore, as was shown in previous sections, a large amount of the cost reduction achieved is due to learning-by-doing. This experience (e.g. operator skills) is often dependent on local conditions, and is probably not easily ‘exported’ compared to exporting machinery. In terms of technology development (such as harvesters, forwarders and chippers), Sweden and Finland were the most dominant countries in the last decades (Johansson, 2004). Also due to the geographical vicinity, Finland and Sweden have had close links. Therefore, Finland seems to be the most likely country with which knowledge may have been exchanged, and a comparison between the two countries is discussed below.

Finland had a similar rise in PFF production levels in the early 80’s, though not to the same level as Sweden (see Figure 7 and compare to Figure 2). Also, production levels declined more strongly in the second half of the 80’s. Starting in 1992, Finland has shown renewed interest in PFF production, and two five year R&D programs have been carried out since. Since 1992, annual production volumes sharply increased annually, and it is likely that annual PFF production in Finland will surpass Sweden in 2004. However, when adding up all PFF production over the last decades until 2001, it is estimated that Finland produced an approximate cumulative 80 PJ only, compared to over 600 PJ of cumulative PFF production in Sweden.

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[6] However, longer transportation distances and higher fuel costs do not necessarily have to lead to higher cost of heat or electricity. Larger amounts of available wood fuels may allow the use of larger plants, which generally have higher conversion efficiencies than small plants, thereby lowering the total production costs.

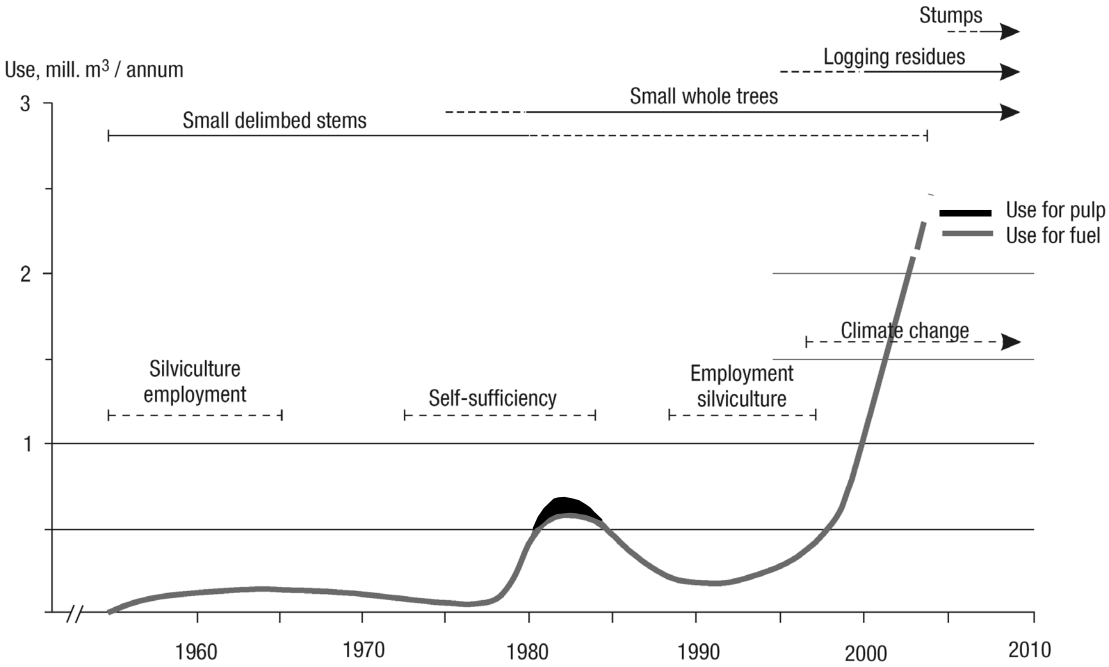

Figure 7 Use of forest chips since the mid-1950s in Finland (Source: Hakkila (2004)). For comparison with the Swedish production (see figure 1): 1 mill. m^3 corresponds to approximately 7.2 PJ.

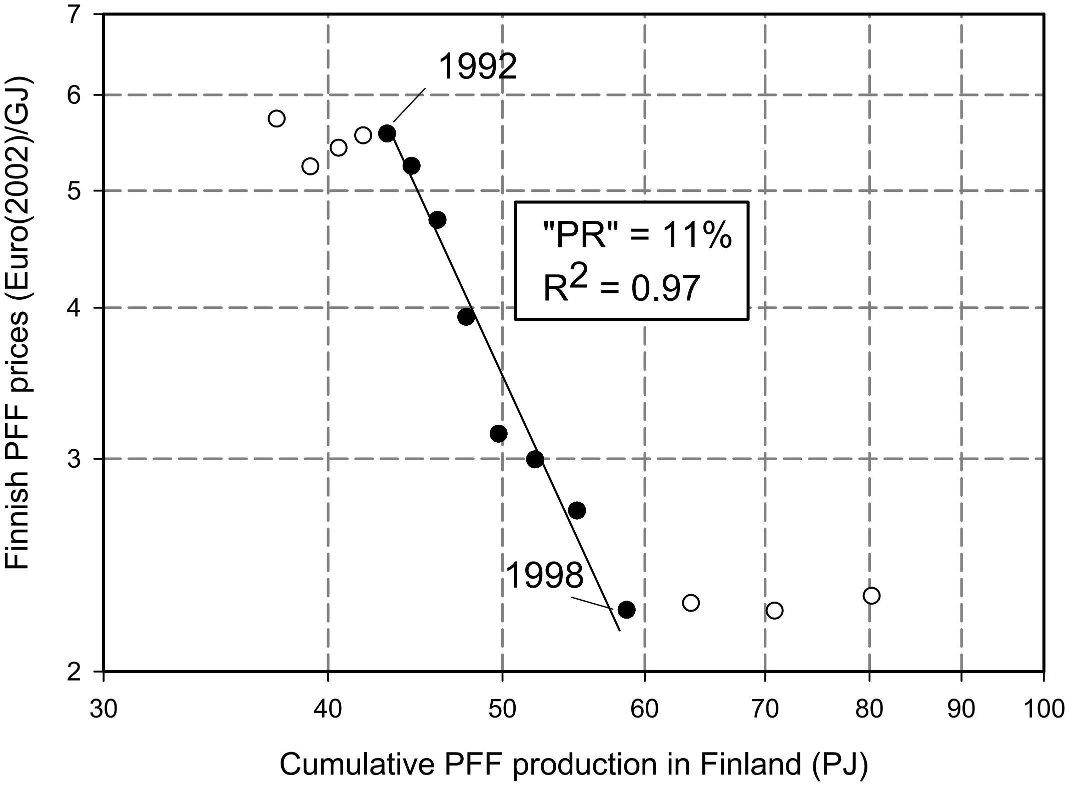

Figure 8 Finnish wood chip production and price levels (all dots) from 1988-2001, and a Finnish ‘experience curve’ from 1992-1998 (black dots). Production levels were estimated from Figure 7, prices are taken from the Finnish energy statistics (Statistics Finland, 2003). All prices were deflated using the Finnish consumer price index.

In Finland, between 1987-1992, prices seem to remain stable, but during the period 1992-1998 a very strong decline in prices occurred, after which prices stabilized again (see Figure 8). If the prices between 1992-98 were plotted against the cumulative produced PFF volume (starting in 1970), the resulting experience curve would have a PR of 11% (i.e. 89% cost reduction with every cumulative doubling). Clearly this rate cannot be sustained, and also cannot be attributed to the Finnish learning and R&D efforts alone. More likely, this rapid decline can be attributed to two reasons: first of all, the source of PPF changed from small delimbed stems via small whole trees (both from thinning operations) to logging residues (from final fellings) (Hakkila, 2000). Using the latter is more economical, because of the far higher quantities of PFF available per hectare. Second, it is likely that Finland was able to import a large amount of technology and experience previously developed and gained in Sweden (Björheden, 2004). For example, the bundling concept had been mainly developed in Sweden, and was successfully adopted in Finland. Only when they reached the Swedish price levels, the prices stabilize again[7], and have been slightly increasing over the last few years, most likely due to increasing transportation distances.

As a methodological exercise, an additional experience curve is devised, in which the cumulative production of PFF in Sweden and Finland is combined. The resulting curve displays a high correlation coefficient ($R^2 = 0.97$), and a PR of 85% (see Figure 9), which is within the range found for Sweden alone (85-88%). So, it would seem that experience was exported from Sweden to Finland, effectively enlarging the learning system. Due to the relatively small cumulative amount produced in Finland, the impact on the PR is small in the case of Sweden but very strong in the case of Finland. It is emphasized, that before any final conclusions can be drawn from these results, a more detailed investigation should be carried out, about when and to what extent knowledge and technology was exchanged between the different countries. With the strong ambitions of Finland for future production levels, and their current leading role in technology development, Finland may obtain the leading position in the future. Therefore it seems evident, that for future cost estimates, the Finish PFF production volumes and production cost developments should be taken into account.

For future developments, also another aspect is of importance: Finland increasingly follows a different supply chain strategy than Sweden. In Sweden, PFF consumers are mainly small-to-medium scale heating plants, often situated close to or in residential areas. As quite a large number of these plants exist, transportation distances of wood chips are relatively small. These plants often have limited storage capacities, and restrictions regarding noise and odor emissions. Finland, however, has built recently some very large (CHP) biomass energy plants, including the Alhomens Kraft plant of 550 MW_{th}/ 240 MW_e in Pietarsaari. These plants require large amounts of biomass, and thus larger transportation distances, which makes CRL transportation favorable to chip transportation. In addition, large transportation distances increasingly allow transportation by train or boat, increasing transportation efficiency. The large scale also enables these plants to operate large crushers, which is often not possible in existing Swedish plants.

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[7] Actually, price levels are lower than in Sweden. This may be attributed to several factors: the absence of stumpage fees and taxes on diesel fuels in Finland, and the predominant harvesting of green residues in Finland. In Sweden, mainly brown residues are harvested, which may lead to an increased dry matter loss and thus higher prices per GJ. In addition, the data given in Figure 8 is based on Finnish energy statistics data, in which the transportation distance is not specified (Statistics Finland, 2003).

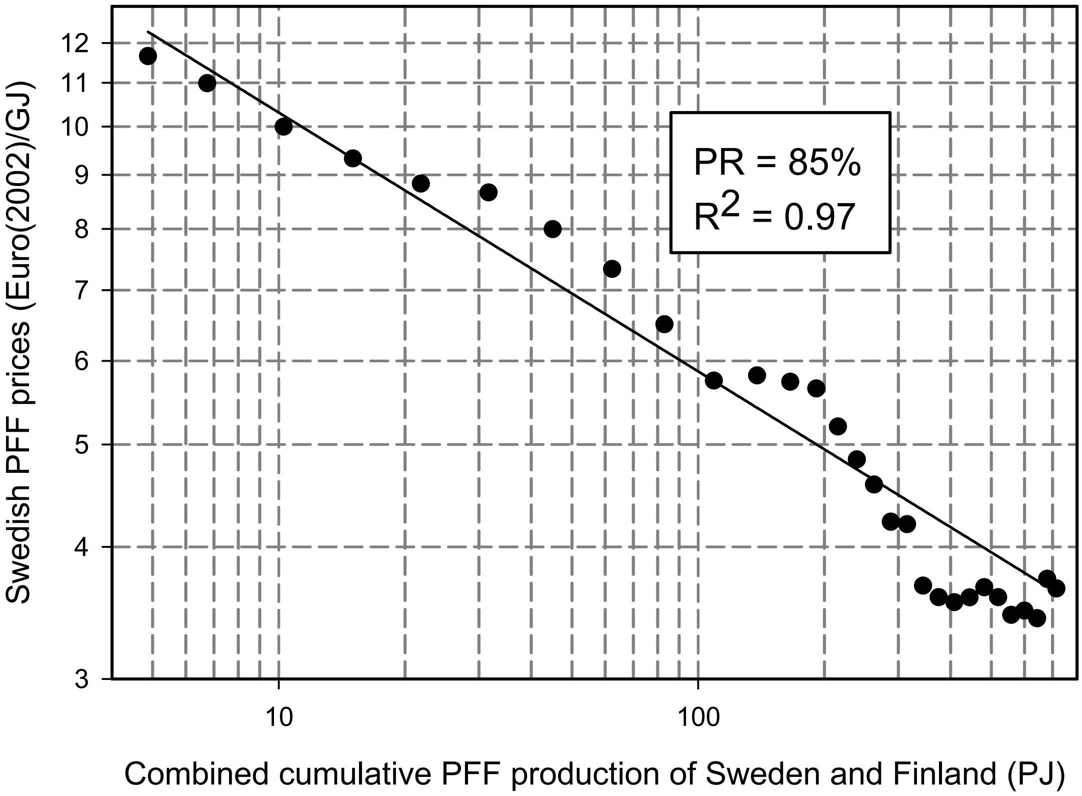

Figure 9 Experience curve for Sweden and Finland combined, using the Swedish PFF prices and the combined cumulative PFF production of Finland and Sweden between 1975 and 2003. Compared to the 'average production' experience curve of Sweden alone, the PR is lower (85% vs. 87%) and the correlation improves (R^2 of 0.97 vs. 0.93).

This leaves the question, whether and how the PR- range of 85-88% might be used for estimating future production costs in other countries, starting to produce PFF, such as many eastern-European countries. One obvious pitfall would be to apply these PR values directly to the (starting) PFF production of another country. This would certainly lead to overoptimistic cost reduction projections. Probably a more sensible approach would be to analyze the extent to which technology and experience is exported to these countries, and possibly use the combined PFF production of these countries and the production in Scandinavia as shown in Figure 9. Factors which would also have to be taken into account is whether the same fuel supply chain will be used (e.g. roadside chipping), whether the same technology is used (chippers, forwarders, trucks etc.) how local circumstances differ from the situation in Scandinavia (e.g. average transportation distances or wage differences between Scandinavia and Eastern Europe), and how the tacit knowledge of Scandinavian operators and entrepreneurs can be transferred.

9. Conclusions

The analysis has shown that the costs of PFF have decreased with cumulative production and that the experience curve concept is suitable to describe this trend. In Sweden, cost reductions follow an experience curve from 1975-2003 over nine cumulative doublings of PFF production. The PR was determined to be between 85% - 88%. This analysis is based on PFF prices, which were found to reflect PFF production costs rather well. For the short to medium term, the experience curve may be a tool to assess further production cost development in Sweden, taking into account the available potential. This may allow policy makers to estimate cost developments of PFF production and to determine policy support measures that may be required for PFF production accordingly.

In regard to the methodology, it was shown that the experience curve can be applied to PFF supply chains. A methodological issue that needs further exploration is how learning took place between Sweden and other countries, especially Finland, and how the development of technologies used in PFF production in these countries should be combined with the Swedish experiences. It may then be possible to use the experience curve concept to estimate PFF cost developments in countries with a large potential of PFF supply but less developed PFF supply systems. Within the frame of the growing Eastern European market and the emerging international trade in wood fuels, it is recommended that the production cost developments in these new PFF producing countries is monitored. Transferring knowledge and technology to these countries may be crucial to low PFF costs, which (through imports of biomass) may also be beneficial to implementation of biomass energy in countries with less abundant biomass resources.

10. Acknowledgements

The authors would like to thank the following persons for their time and help: Anders Westerberg, Bengt Hillring, Bengt-Olof Danielsson, Berndt Nordén, Göran Hedman, Jan-Erik Liss, Lars-Göran Harrysson, Lotta Tranvik, Magnus Thor, Mats Håkansson, Minna Niininen, Ola Galfvensjö, Sven Hogfors, Tomas Gullberg, Tomas Gustén and Ulf Johnsson. We are grateful to Lena Neij for valuable comments on an earlier draft of this paper. The main author would like to express his gratitude to Växjö University for logistic support.

Chapter 6: Technological learning in bioenergy systems[1]

Abstract

The main goal of this chapter is to determine whether cost reductions in different bioenergy systems can be quantified using the experience curve approach, and how specific issues (arising from the complexity of biomass energy systems) can be addressed. This is pursued by case studies on biofuelled combined heat and power (CHP) plants in Sweden, global development of fluidized bed boilers and Danish biogas plants. As secondary goal, the aim is to identify learning mechanisms behind technology development and cost reduction for the biomass energy systems investigated. The case studies reveal large difficulties to devise empirical experience curves for investment costs of biomass fuelled power plants. To some extent, this is due to lack of (detailed) data. The main reason, however are varying plant costs due to differences in scale, fuel type, plant layout, region etc. For fluidized bed boiler plants built on a global level, PRs for the price of entire plants lies approximately between 90-93% (which is typical for large plant-like technologies). The costs for the boiler section alone was found to decline much faster. The experience curve approach delivers better results, when the production costs of the final energy carrier are analyzed. Electricity from biofuelled CHP-plants yields progress ratios (PRs) of 91-92%, i.e. a 8-9% reduction of electricity production costs with each cumulative doubling of electricity production. The experience curve for biogas production displays a PR of 85% from 1984 to the beginning of the 1990, and then levels to approximately 100% until 2002. For technologies developed on a local level (e.g. biogas plants), learning-by-using and learning-by-interacting are important learning mechanism, while for CHP plants utilizing fluidized bed boilers, upscaling is probably one of the main mechanisms behind cost reductions.

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[1] Submitted to Energy Policy. Co-authors are E. de Visser, K. Hjort-Gregersen, J. Koornneef, R. Raven, A. Faaij and W.C. Turkenburg.

1. Introduction and goal definition

Modern biomass is seen as one of the most promising renewable energy sources in the near future. Using biomass to generate energy carriers like heat, electricity and gaseous and liquid fuels can contribute significantly to the reduction of greenhouse gas emissions, as shown in many studies (e.g. Goldemberg and Johansson, 2004; Hoogwijk, 2004) and projected in most scenarios about potential development of energy and economic systems (Nakicenovic et al., 2000; Shell, 2001; OECD/IEA, 2002; European Commission, 2003; Uyterlinde et al., 2003). It can also decrease dependency on fossil fuels. The utilization of biomass within the European Union (EU) has strongly increased over the last decades, and the ambitions of the EU for the use of biomass are high. Up to 6000 PJ in 2010 are targeted (tripling the use compared to 1999 levels), and possibly even more beyond 2010 (Faaij, 2005 (Forthcoming)).

There are several reasons to investigate the techno-economic development of biomass energy systems in detail. First, most biomass energy technologies have difficulties to compete with fossil fuels on direct costs, especially if fuelled by energy crops. However, as experience with modern biomass technologies has been gained over several decades, production costs have been reduced. Several biomass options (e.g. large-scale combustion of organic waste and residues) are already providing renewable electricity competitively. This chapter focuses on how production costs were reduced in the past few decades and whether the development of cost reductions can be quantified. Second, most global models (to assess developments in the economic and energy system and impacts on climate change) use endogenous technological learning in which the rate of cost reduction depends on the diffusion rate of the technology (and in turn, a lower cost allows for a faster diffusion of the technology). These models often use the experience curve concept to model endogenous technological change. Most bottom-up (systems engineering) models, such as ERIS (Kypreos and Barreto, 1998), Genie (Mattsson and Wene, 1997), MESSAGE (Messner, 1997; Messner and Schrattenholzer, 1998), MARKAL (Seebregts et al., 1998) and TIMER (Hoogwijk, 2004), model the development of different energy technologies separately. For renewable energy options such as wind energy and photovoltaics, an abundance of empirical data on cost development related to cumulative shipments of the energy technology is available as empirical basis for these models, see e.g. Neij et al. (2003) and Schaeffer et al. (2004). In contrast, for most biomass options, little or no empirical data has been gathered. Also, biomass energy systems are often more complex than modular technologies such as wind turbines or solar cells, as they require fuel (which can constitute a large part of the final cost of electricity), and their costs are often dependent on local conditions. Thus, more insights are desired in the actual technological development of biomass energy technologies and the extent to which the experience curve approach may be suitable to describe cost reductions .

The main goal of this chapter is to determine experience curves of several (parts of) biomass energy systems. It is investigated whether reduction of investment costs, fuel costs and electricity/biogas costs can be quantified using the experience curve concept, and how specific issues arising from the complexity of biomass energy systems can be addressed to fit the experience curve concept. This is pursued by case studies on biomass CHP plants, fluidized bed boilers and biogas plants. These are all developed markets with a well-documented history. As secondary goal, the aim is to identify learning mechanisms behind techno-economic development of the investigated biomass energy systems.

In section 2, a number of methodological issues in regard to the use of the experience curve approach to analyze the cost development of biomass energy systems are described. In order to explore different methodological issues, three case studies are presented. In section 3, biomass fuelled combined heat and power plants in Sweden are investigated. In section 4, the global development and cost reductions of (partially) biomass fuelled fluidized bed boilers and plants are scrutinized, while section 5 analyses the cost development of Danish centralized biogas plants. In section 6, the main findings are discussed and general conclusions are drawn.

2. General experience curve methodology and use with biomass energy systems

2.1 Mechanisms of technological learning and experience curves

Typically, the unit cost of a technology decreases with increasing diffusion of the technology into the market. This phenomenon has been frequently described in various case studies (BCG, 1968; Argote and Epple, 1990), starting with serial production of airplanes in the first half of the last century (Wright, 1936). A special empirical observation is that costs tend to decline almost at a fixed rate with every doubling of the cumulative production. This relationship can be described mathematically by means of the following curve, the so-called experience curve[2]:

$$C_{Cum} = C_0 \, Cum^b \tag{1}$$

$$\log C_{Cum} = \log C_0 + b \log Cum \tag{2}$$

$$PR = 2^b \tag{3}$$

C_{Cum}	:	Cost per unit	C_0	:	Cost of the first unit produced
Cum	:	Cumulative (unit) production	b	:	Experience index
PR	:	Progress ratio			

PR denotes the progress ratio, expressing the rate of unit cost decline with each doubling of cumulative production. For example, a PR of 0.8 implies that after one doubling of cumulative production, unit costs are reduced to 80% of the original costs, i.e. a 20% cost decrease. The definition of the ‘unit’ may vary: in many cases a unit is a product (for example a car or an airplane). In relation to energy technologies, more often the unit is the unit of capacity (Watt) of the energy technology produced or the unit of electricity produced (kWh). The experience curve concept has been used and applied for many different energy technologies; for an overview see (McDonald and Schrattenholzer, 2001). Experience curves describe historic trends that may be extrapolated to forecast future cost reductions. This possibility is frequently used by individual corporations, energy modelers and policy makers (Neij et al., 2003).

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[2] In the remainder of this paper, the term *experience curve* refers to curves which can be described with formula (1). Plotting costs versus cumulative production in a figure with double logarithmic scales shows the experience curve as a straight line, see equation (2).

There is no natural law requiring production costs to follow an experience curve. However, this phenomenon has been observed empirically numerous times (McDonald and Schrattenholzer, 2001). Different learning mechanisms have been identified that may cause the observed development of cost reductions, amongst others by Kamp (2002), Grübler (1998; 1999), Garud (1997), Dannemand Andersen (2004) and Utterback (1994). These mechanisms may influence both the production process and the product itself (Neij et al., 2003). The following mechanisms can be identified:

- *Learning-by-searching,* i.e. improvements due to *RD&D (Research, Development and Demonstration)*, is the most dominant mechanism in the stages of invention and RD&D, and to some extent also during niche market deployment. Often also during the stages of pervasive diffusion and saturation, RD&D may contribute to technology enhancements.
- L*earning-by-doing* (Arrow, 1962) takes place in the production stage after the product has been designed. Typically, the repetitious manufacturing of a product leads or improvements in the production process (e.g. increased labor efficiency, work specialization and production method improvements).
- *Learning-by-using* (Rosenberg, 1986) can occur as soon as soon as a technology is introduced to (niche) markets. A technology cannot be fully developed inside laboratories and factories, and technological development and improvement continues afterwards. Feedback from user experiences into the innovation process may lead to improvements of the product design.
- *Learning-by-interacting* is related to the increasing diffusion of the technology. During this process, the network interactions between actors such as research institutes, industry, end-users and policy makers generally improve, and the above-mentioned mechanisms are reinforced (Lundvall, 1988). In other words, the diffusion of knowledge itself supports the diffusion of the technology[3].
- *Upsizing* (or downsizing) a technology (e.g. upscaling a gas turbine) may lead to lower specific unit costs (e.g. the costs per unit of capacity).
- *Economies of scale* (i.e. mass production) can be exploited once the stage of large-scale production and diffusion is reached. Standardization of the product allows upscaling of production plants, and producing the same product in large numbers.

Often, combinations of these factors occur in each stage of the market diffusion process, and the contribution of each may change over time. Some authors also differentiate between effects of (technological) learning (such as the first three factors) and scale effects (such as the last two factors) (Abell and Hammond, 1979). However, in practice these factors may overlap and are difficult to separate (Neij, 1999a). Also it is stressed, that both upscaling and mass production of a technology or production process in most cases require separate steps[4]. During each step, experience is gained based on learning-by-doing and learning-by-using, which is then incorporated in the next generation of the technology[5].

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[3] Somewhat related to this mechanism, Rotmans and Kemp (2003) also mention 'learning by learning', indicating that the primary learning processes themselves can improve over time. In addition, Schaeffer et al. (2004) distinguish 'Learning by expanding', recognizing the fact that more actors, organizational structures and industrial sectors become involved in, focused on, dependent on and adapted to the new technology. Arthur (1988) calls this mechanism 'increasing returns on adoption'.

[4] For example, it took over twenty years and one hundred plants to scale up steel plants from 0.3 to 8 million tons of steel output capacity (Grübler, 1998). A similar trend and time span was found for fluidized bed boilers (Koornneef, 2004).

[5] This process is documented in great detail for the development and upscaling of Danish wind turbines by Neij et al. (2003).

Regarding the construction of experience curves, a number of general points should be briefly mentioned. First, in order to compare costs from the past with current costs, the data should be corrected for inflation. In case only data from one country are applied, normally either the GDP deflator or the consumer price index is used to achieve that. Second, the experience curve ideally presents the reduction of production costs. In general, however, data about production costs are kept confidential, and often only prices are publicly available. Prices can be used as a proxy for production costs under the condition that profit margins are a fairly constant share of total prices (IEA/OECD, 2000). In this case, prices and costs decline with the same speed. Third, the correct geographical boundaries should be determined for the learning system. Experience curves are often set up for individual countries, especially when the aim is to support and evaluate policy measures. However, it is important to determine whether experience has been gained from developments within the analyzed national system of innovation only, or also from developments outside this system, as shown by Junginger et al. (2004b).

2.2 The experience curve approach, technological learning and bio-energy systems

In the energy field, the experience curve concept is so far used mostly to describe learning for modular products, such as wind turbines, fuel cells and solar photovoltaic (PV) modules. Learning effects have been also investigated for e.g. coal-fired power plants (Joskow and Rose, 1985) and light water reactor nuclear power plants (Lester and McCabe, 1993). Many integrated energy assessment models, however, only use estimated PRs for various plant type technologies using fuels (Kouvaritakis et al., 2000). Only few empirical studies have been carried out to actually determine the PR values of such technologies. Examples are the development of natural-gas-fired combined cycle gas turbine power plant (Claeson Colpier and Cornland, 2002) and the large-scale production of ethanol from sugarcane in Brazil (Goldemberg, 2004b).

Biomass energy systems differ from most other renewable energy technologies, as they require fuel. This adds another cost component to the total production costs. It can also influence investment costs and O&M costs[6]. Thus, for biomass-fuelled power plants, the total learning system can be split up in three parts (see Figure 1). For each of these parts, a separate learning system can be defined. This approach of investigating compound learning systems has been described by Wene (IEA/OECD, 2000), and is recommended especially when the production costs development of electricity is investigated. Splitting the entire learning system in several subsystems may provide insights in the various learning mechanisms. The compound learning system approach has recently been used also to investigate (potential) cost reductions of solar PV systems (Schaeffer et al., 2004) and offshore wind farms (Junginger et al., 2004c).

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[6] For example, meeting emission levels may require additional investment and O&M costs, and difficult fuels may affect reliability and maintenance cost.

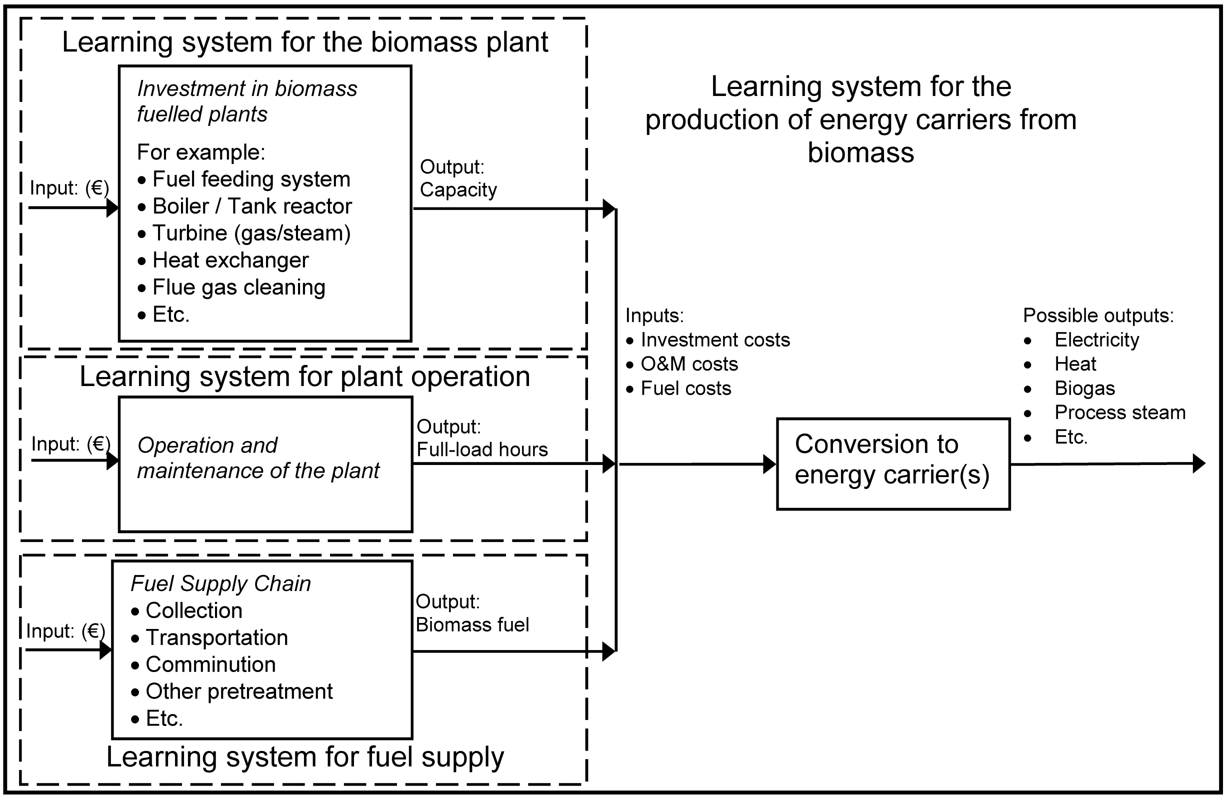

Figure 1 General structure of biomass energy learning systems.

When analyzing the investment costs of biomass power plants, there are several issues that complicate the application of the experience curve concept compared to other (modular) renewable energy technologies. First, as plants are normally large-scale technologies, in general far **less 'plants'** are produced compared to modular technology such as solar PV or wind to generate a certain amount of electricity. To give an indication of differences in volumes compared on basis of annual electricity production, a single biomass plant of 30 MW_e will annually produce approximately as much electricity as 50 wind turbines of 1.5 MW_e or 1.5 million solar panels of 100 W_p. To devise experience curves, large amounts of data are required to be able to calculate average investment costs in a statistically significant way for biomass plant technologies. These data are generally available in small amounts only.

Second, (biomass) power plant investment costs generally depend on **local conditions**. In many cases, plants are custom-designed to meet specific conditions and circumstances requirements in terms of heat and electricity demand and load, available building space, biomass storage space, existing infrastructure etc. The fuel type also has an important influence on investment costs. A wide variety of biomass fuels exist, with often very different properties such as moisture content, ash content, alkali content and size. In addition, biomass may be co-fired with other fuels such as coal and municipal solid waste. If a plant is designed to handle a multitude of different fuels instead of a single one, investment costs are generally higher. Furthermore, the investment costs are determined by local factors such as environmental regulations and the cost of labor. The impact of these factors on the analysis of PRs may possibly be circumvented by focusing on one fuel, one geographical region, a minimum emission standard and one, narrowly defined, type of power plant.

Third, **scale effects** strongly influence costs per unit of capacity (specific costs). It has often been shown that in general the specific costs decrease with upscaling the capacity of the plant or component (such as the boilers or turbines). This difference can be adjusted by using scaling functions (Remer and Chai, 1990), as shown in equation (4)[7]:

$$\frac{\mathrm{Cost}_{\mathrm{Plant\ x}}}{\mathrm{Cost}_{\mathrm{Reference\ size}}} = \left(\frac{\mathrm{Capacity}_{\mathrm{Plant\ x}}}{\mathrm{Capacity}_{\mathrm{Reference\ plant}}} \right)^{R} \tag{4}$$

R: Scaling factor

For power plants, R-values around 0.7 are quite commonly used (Joskow and Rose, 1985; Faaij et al., 1998). By setting the reference size equal to unity, equation (4) can be transformed to equation (5).

$$\frac{\mathrm{Cost}_{\mathrm{Plant\ x}}}{\mathrm{Capacity}_{\mathrm{Plant\ x}}^{\ R}} = \text{Standardized plant cost} \tag{5}$$

With equation (5), it can be estimated how much a plant (or individual component) would have cost if it would have been built at the reference size. Applying a scaling function and converting all plants to a reference size may make the data more suitable for use in an experience curve. However, as upscaling is one of the underlying mechanisms of cost reductions, this will probably also flatten the experience curve (assuming that average plant size increases with the development of the technology).

Fourth, biomass energy systems often have **more than one output**. Most common is the production of electricity and heat using combined heat and power (CHP) plants, but also poly-generating systems with biomass transportation fuels (Hamelinck, 2004) or biomass-based polymers (Dornburg, 2004) as additional outputs can be an option. In these cases, allocation of the production costs is required, based e.g. on the market or exergy value of the products.

Fifth, in most experience curves for renewable energy technologies, data about **marginal[8] production costs** are used, especially for modular technologies such as wind turbines and PV modules[9]. For these technologies, the investment cost largely determine the overall electricity production costs. Also, once installed, the electricity production costs for these technologies tend to remain constant (or even rise with increasing O&M costs at the end of the economical lifetime). However, for plants producing a certain commodity (such as biomass plants producing electricity), there is also significant learning-by-using occurring during the operation of the plant. Typically, a plant achieves a rather low load factor in its first year of operation, and only achieves the design load factor after several years, when all start-up problems have been solved. In addition, electricity costs are also more influenced by fuel and O&M costs; these costs may change over the entire

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[7] Equation (4) suggests that there are no limits to the cost reductions that can be achieved by upscaling. In reality, other economic and technical limits also determine the optimal scale of a plant.

[8] The term marginal is used here in the sense that only the newest state-of-the-art technology is used, to calculate the production costs of e.g. electricity by a new plant at a certain point in time. The term average implies that also the production costs of plants built in previous years is taken into account, so that the average (electricity) production costs of all existing plants at the same point in time are calculated.

[9] Also in general, most experience curves use marginal production costs, i.e. the marginal unit costs as a function of total cumulative unit production.

lifetime of a plant. For example, fuel costs may decline as an effect of more efficient supply chains. O&M costs may decline because of automation and efficiency gains on one hand, but increase due to aging on the other hand. Therefore, it is also interesting to analyze the development of the **average[8] production costs**. Empirically, it was shown that the experience curve approach can also be applied to describe average costs developments b. For example, average costs data have been used in experience curves describing the development different of different chemical commodities, the American electricity sector (BCG, 1968) or the carbon intensity of the global economy (IEA/OECD, 2000).

In the following sections, several case studies are presented. In each of them, possible approaches to a number of the issues described above are investigated. The first case (biomass fuelled CHP energy system in Sweden) applies the compound learning system approach, and scrutinizes the allocation of heat and electricity and the scale issue. In the second case (global development of fluidized bed boilers) special attention is given to data availability and the possibility to correct for scale, plant type and fuel type are discussed. The third case investigates another conversion technology (digestion instead of combustion), which uses a different type of fuel (liquid manure and organic waste). Also the size of the plants is smaller than in the first two cases.

3. Electricity from biomass fuelled CHP plants in Sweden

3.1 Case setting

The first case study is limited to biofuelled CHP systems for district heating in Sweden installed between 1980 and 2002[10]. The choice for Sweden was made on basis of both its long-term experience with biomass combustion CHP plants and with collecting forest residues as biomass fuel (see also Junginger et al., 2004d and 2004e). Biomass has been an important source of energy for centuries in Sweden. The main application is for heat production, both for process heat and steam needs in industry and district heating. Production of heat and electricity using biomass has been introduced during the last two decades. There are two sectors in Sweden where CHP plants are used a large scale: in the forest product industry (industrial CHP) and in district-heating networks (municipal CHP). Both sectors together produced 4.4 TWh electricity in 2001 (STEM, 2002), about 1% of total Swedish electricity production in that year. While this is only a minor share, especially electricity production from district heating plants strongly increased over the past decade due to the installation of 18 new CHP plants and the conversion of 5 CHP plants from firing fossil fuels to biomass (see Table 1). Most of these plants use wood residues, either from the wood processing industry (e.g. bark and sawdust), or from the forest industry (such as tree tops and branches).

To investigate the development of the electricity production costs of the biomass CHP plants in Sweden, the sub-learning systems for the development of the investment costs, O&M costs and biomass fuels costs were analyzed. In this study, all Swedish financial data have been adjusted for inflation to the year 2002 using the Swedish consumer price index (Statistiska Centralbyrån, 2004). Conversion to Euros was carried out using the average exchange rate of 2002 (1 € = 9.16 SEK) (Oanda, 2004).

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[10] Industrial CHP systems are not investigated, as they generally deliver high-pressure steam instead of hot water, have a rather constant load (unlike district heating plants with a high load in wintertime), and are generally integrated in the industrial process, while district heating CHP plants are generally stand-alone plants. These actors all influence investment costs, and make a combined analysis of the two unsuitable.

3.2 The learning system for investment costs

Of the 24 plants presented in Table 1, five are converted plants, built for fossil fuel use and later adapted to utilization of biomass as fuel, mainly during the 1980s. These plants mainly had to install new boilers, and to adjust their fuel feeding system and flue gas cleaning. Consequently, the costs involved are much lower than the costs of building a biomass-fuelled CHP plant from scratch. Thus, the costs of converted plants cannot be compared directly with those of new plants. In this study, we therefore refrained from using the investment cost for these retrofitted plants. But as these plants gained experience with biomass specific components such as the boiler and fuel feeding system, their total installed capacity of 102.5 MW_e, was included as initial capacity.

An experience curve was plotted, using the initial capacity and the investment costs, and the capacity development presented in Table 1, yielding a PR of 77% (see Figure 2). For comparison, when assuming zero initial capacity, the PR would be less benign (91%). However, for both curves it is found that the R^2 values of 0.17 and 0.18 respectively, which is far too low to indicate any meaningful correlation.

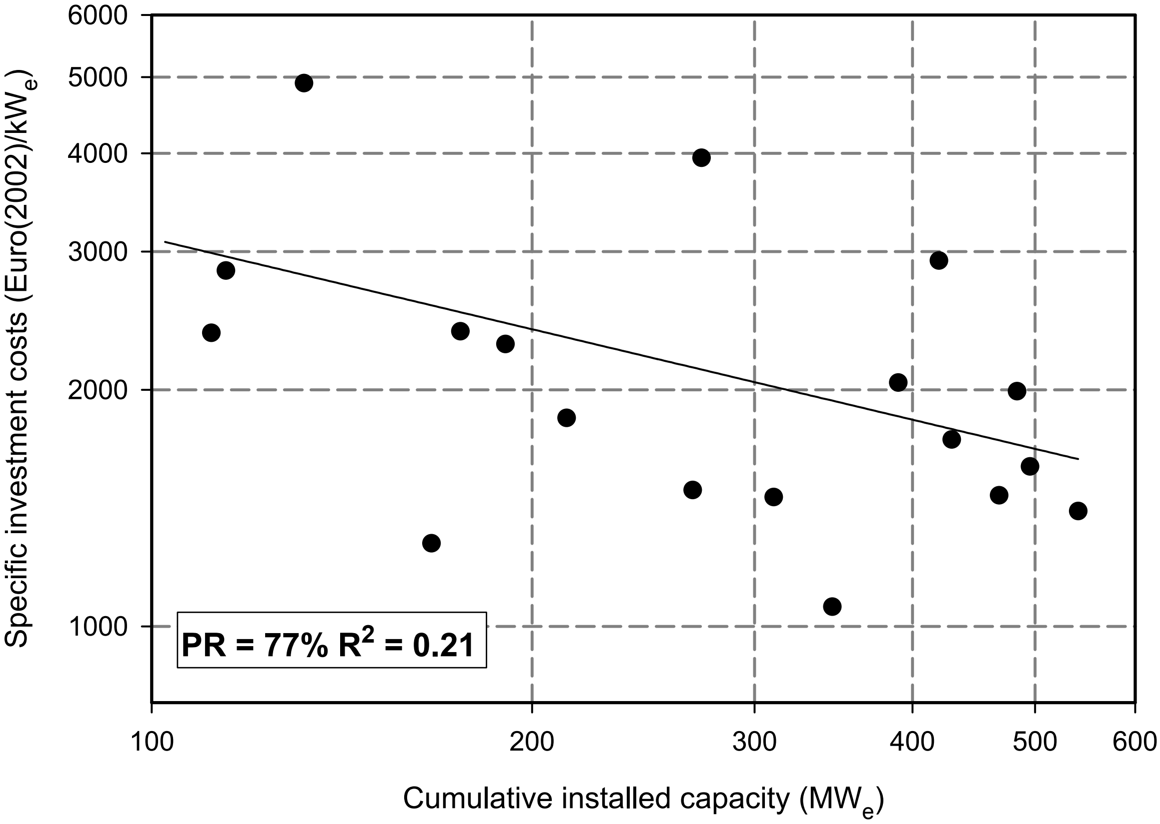

Figure 2 Experience curve for specific investment costs of Swedish biomass fuelled CHP plants built between 1991- 2002. The initial cumulative capacity of 102.5 MW_e is related to CHP plants, were converted from coal to biomass fuels.

Table 1 Data on Swedish biomass fuelled CHP plants (characteristics; investment costs). A detailed overview including a qualitative description of each plant is provided by de Visser (2004).

Company/name	Year	El. Cap.	Heat Cap.	P/H ratio	El eff.	Fuel input	Av. load hours	Inv. Cost[a]	Boiler type	Sub-sidy	Fuel
Converted plants		MW_e	MW_{th}		%	$MW_{th\text{-}in}$	hours	MSEK		MSEK	
Växjö Energi AB (VEAB)/ Sandvik 1	1983	18	47	0.4	---	---	---	44	---	18	---
Borås Energi AB / Ryaverket	1984	19	---	---	---	---	---	18.5	Mov.gr.	---	forest res.
Tekn. Verk. I Linköping / Kraftvärmev.	1985	0/23[b]	55	0.4	0.3	75	6000	18	Mov.gr.	---	bark, recycled wood, tires, oil & coal
Örebro Energi AB	1990	26	---	---	---	---	---	75	CFB	---	---
Norrköping Energi AB / Händelöverket	1994	40	85	0.5	0.3	140	---		CFB	0	90% wood chips & 10% bitum. coal
New plants											
Nässjö Affärsverk / Nässjö	1990	9	20	0.5	0.3	33	5500	160	CFB	0	wet wood chips
Skellefteå Kraft AB / Malå	1991	3	12	0.3	0.2	16.3	8000	60	BFB	4	---
Karlstad Kommun / Heden 2	1993	18	60	0.3	0.2	88	5000	650	CFB	26	wood res.
Nyköping Energi / Idbäcksverket	1994	35	58	0.6	0.3	105	5760	340	BFB	137	---
Falu Elverk / Västermalmsverket	1994	9	22	0.3	0.3	35	6500	165	BFB	33	---
C4 Energi / Allö	1994	15	35	0.4	0.3	55.5	6500	265	BFB	57	---
Ena Kraft AB / Ena Kraft	1994	23	46	0.5	0.3	80	5600	320	Vibr.gr.	90	wood pellets, logging res., bark, sawd., willow
Linköping Tekn. Verken / Gärstadsv.	1994	50	85	0.6	---	---	---	---	FB	26	household & industrial waste
Gustav Kähr AB	1995	5	17	0.3	---	---	4000	59	Vibr.gr	5	sawd., hard wood res.
Lomma Energiverk / Återbruket	1996	4	12	0.4	0.2	18.3	6500	135	CFB	20	wood waste, paper waste
Växjö Energi AB (VEAB) / Sandvik2	1996	38	66	0.6	0.4	111	5700	445	CFB	104	wood res., peat, bark, sawd.
Skellefteå Kraft, Hedensbyn	1996	35	63	0.6	0.3	106	6000	295	CFB	86	wood chips, bark
Brista Kraft AB / Bristaverket	1997	44	75	0.6	0.3	132	5500	720	CFB	113	bark, tree tops, branches
Sävenäs GRAAB / Renova	1998	30	150	0.2	0.2	194	---	700	CFB	63	household waste
Sala-Heby Energi AB / Silververket	2000	9	30	0.3	---	---	5000	140	BFB	30	peat, bark, sawd., wood res.
Eskiltuna Energi & Miljö AB	2000	39	71	0.6	0.3	121.8	6200	460	BFB	112	sawmill by-prod., forest res.
Lycksele Energi AB	2000	16	31	0.5	0.3	49	4000	250	BFB	43	forest res., sawd., peat (max. 30%)
Härnösand Energi & Miljö AB	2002	12	26	0.5	0.3	43	5500	155	CFB	35	peat, unref. wood fuels
Jämtkraft AB / Lugnviksverket	2002	45	80	0.6	0.3	137	5000	538	CFB	130	forest res., peat, bark, sawd., recycled wood

a For converted plants, these are retrofitting costs. All costs are presented in nominal terms, i.e. not corrected for inflation.

b The Linköping does use biomass as fuel, but in contrast to all other plants, biomass only constitutes a minor share in the fuel mix. Therefore, it was decided to exclude this plant for the inital capacity calculation.

--- Data not available.

In order to improve the correlation, several attempt were made. In table 2, vale two an overview is presented of the different approaches, with resulting PR and R^2-values. First, plants with a power to heat ratio below 0.3 were excluded[11]. As an alternative approach, all data were converted to exergy values, thus taking into account both heat and electricity production capacity. However, both approaches only resulted in a worse correlation of the data (see Table 2). Another attempt to reduce the large variation in data was to apply scaling factors between 0.65 - 0.8 to the data (see formulas (4) and (5)). Again, the data correlation was not improved. Also combinations of these different approaches did not result in any better correlation.. Thus, the attempts to adjust for the variation of investment cost data did not succeed. The main reason is probably the varying plant layout (due to presence of existing infrastructure and additional components such as flue gas condensation or hot water accumulators). As no detailed cost breakdown for these additional components is available, it was not possible to correct for their costs.

Table 2 Overview of results of different approaches to set up experience curves for biomass fuelled CHP plants in Sweden.

Approach	PR (%)	R^2
1. Basic data	91	0.18
2. Initial capacity at 102.5 MW_e	75	0.17
3. 2. + removal of plants with PHR < 0.3	86	0.09
4. 2. + calculation on exergy basis	92	0.17
5. 2. + applying scale factor of R= 0.8	84	0.07
6. 2. + applying scale factor of R= 0.65	97	0.02

In spite of the large variation in investment cost data, Figure 2 shows that average investment costs declined from 2500-5000 €/kW_e in 1990 to 1500-2000 €/kW_e in 2002. Almost all of these plants are using fluidized bed combustion boilers. The costs of this technology partially depend on the global market. The development, cost reductions and learning mechanisms for this type of plant are described in section 4. In several cases, new biofuelled plants were built on sites where biofuelled plants already existed (e.g. in Enköping or Växjö). In these cases, knowledge on constructing and operating biofuelled CHP plants was available in-house (de Visser 2004). Thus, in these cases, learning-by-using was also involved in the cost developments found .

3.3. The learning system for biomass fuel costs and O&M costs

As shown in Table 1, most plants use wood processing residues (such as sawdust and bark) and forest residues (such as chips from treetops and small branches) as main fuel. The production costs of process residues are basically zero (or sometimes even negative) as they are a waste product from the wood industries. Forestry residues, however, have to be collected, and different fuel supply chains of harvesting, forwarding, comminution and transportation have been developed over the last three decades. This learning system has been described in detail elsewhere (Junginger et al., 2004d; Junginger et al., forthcoming). Results show that main cost reductions were achieved in forwarding and chipping these primary forest residues (PFF), largely due to learning-by-doing, improved equipment and changes in organization. Figure 3 displays that the price for wood fuel chips follows an experience curve from 1975-2003 (over nine cumulative doublings), based on a best guess scenario for PFF production. The PR is calculated at 87%. However, given the uncertainty in data

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[11] The power to heat ratio (PHR) is the installed electrical capacity divided by the heat capacity. Most Swedish plants have a PHR between 0.3-0.6. Plants with a small PHR have little electric capacity installed, and, therefore, relatively high costs per kW_e.

on PFF price and annual production volumes the PR may range between 85% and 88% (see also chapter 5 / Junginger et al. (forthcoming)).

Unfortunately, no detailed data on operation and maintenance costs were available. Thus, the average O&M costs were based on data from literature and on expert opinions resulting in fixed annual O&M costs of 2% of the investment costs (including costs for personnel, insurance, reparation and maintenance) and variable O&M costs of 0.2 €ct per kWh produced (for chemicals, water and treatment costs for waste products) (Bärring et al., 2003). No specific information on learning mechanisms could be found.

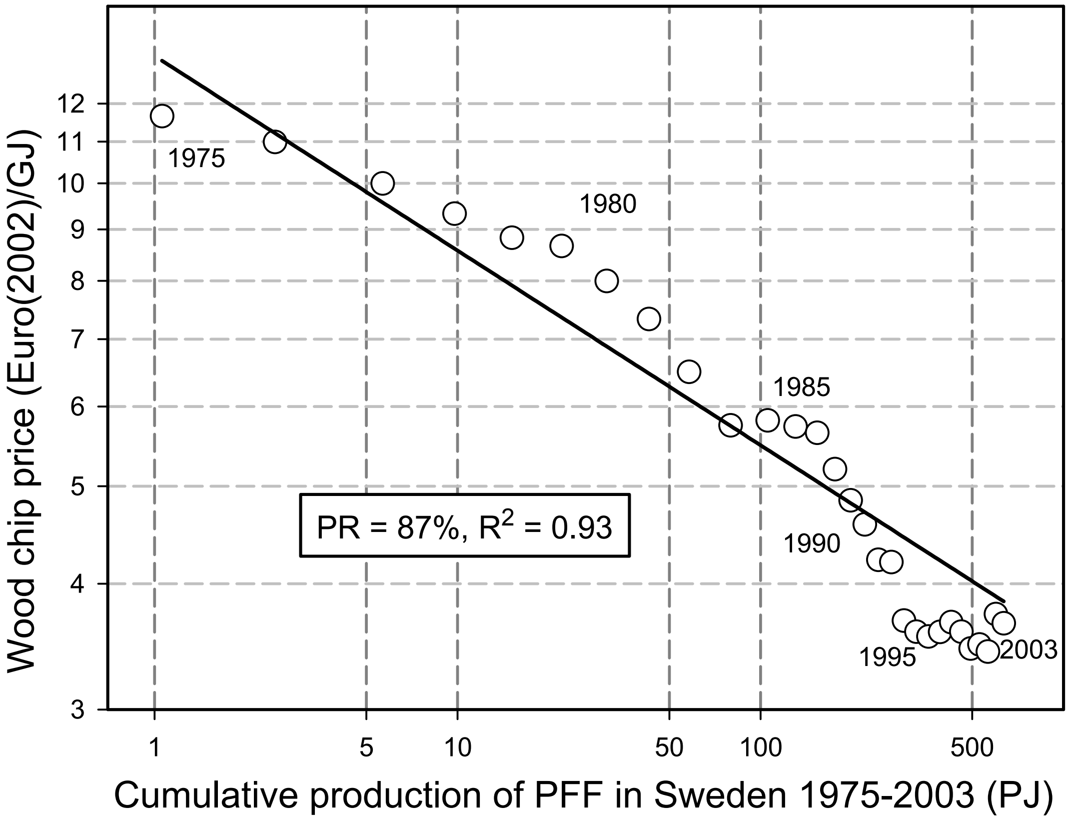

Figure 3 Experience curve for the price of wood chips from forest residues in Sweden 1975-2003 and a best guess scenario for PFF production volumes (slightly adapted from chapter 5 / Junginger et al. (forthcoming)).

3.4. The learning system for electricity from Swedish CHP plants

For this learning system, the production of electricity from biofuelled CHP systems, the individual costs of electricity per plant can be calculated by annualizing capital cost and using equation (6).

$$\mathrm{CoE} = \frac{\mathrm{All}(\mathrm{AC} + \mathrm{O\,M} + \mathrm{F})}{\mathrm{E}} \tag{6}$$

CoE	Cost of electricity (€/kWh)
All	Allocation factor ($0 \leq \mathrm{All} \leq 1$) to allocate the production costs of heat and electricity
AC	Annualized capital cost (€/year)
OM	Annual operating and maintenance cost (€/year)
F	Annual fuel cost for the plant (€/year)
E	number of kWh produced annually (€/year)

For the experience curves on electricity production, the annual electricity production costs of all plants for each plant are calculated. Data on the annual electricity production of each plant were obtained from the individual plants. Data on the investment costs and fuel costs were already presented in the sections above. To annualize the investment costs, an interest rate of 10% and an economical lifetime of 20 years were assumed, which are typical values for Swedish CHP plants (Steinwall et al., 2002; Bärring et al., 2003). The allocation of production costs to heat and electricity was done on basis of the annual economic value of both products[12].

For the calculation of *average* electricity production cost, the annual production costs of all plants were averaged, using the annual amount of electricity produced by each plant as weighing factor. The average production costs were plotted against the cumulative electricity production from the Swedish CHP plants (see Figure 4). The resulting experience curve yields a PR of 91%, and displays a reasonably high correlation of $R^2 = 0.85$. For the calculation of *marginal* electricity costs, the average production costs of the second, third and fourth year of operation of newly built CHP plants were calculated[13]. They were also plotted in Figure 4, at their third year of operation. If several data points were available for one year, they were averaged, parallel to the procedure of the average production costs. The resulting experience curve yields a PR of 92%. The curve lies slightly lower than the experience curve for average production costs, as one would expect. The correlation coefficient is also relatively high ($R^2 = 0.88$). Due to the correlation values found, the difference in PR-value of the two curves is not significant.

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[12] In previous publications, the value of electricity included the grid transportation tariffs. In the present publication, grid transportation tariffs were not included, as this was deemed more appropriate from the plant operators' point of view. The previous analysis yielded a PR of 91% at a lower correlation ($R^2 = 0.75$). For further details, see de Visser (2004) and Junginger et al. (2004e).

[13] As electricity production in the first year of operation is normally low due to start-up problems, the first year electricity costs were not deemed representative as the typical electricity costs of a new plant. The average costs of the 2nd-4th year of production were taken instead.

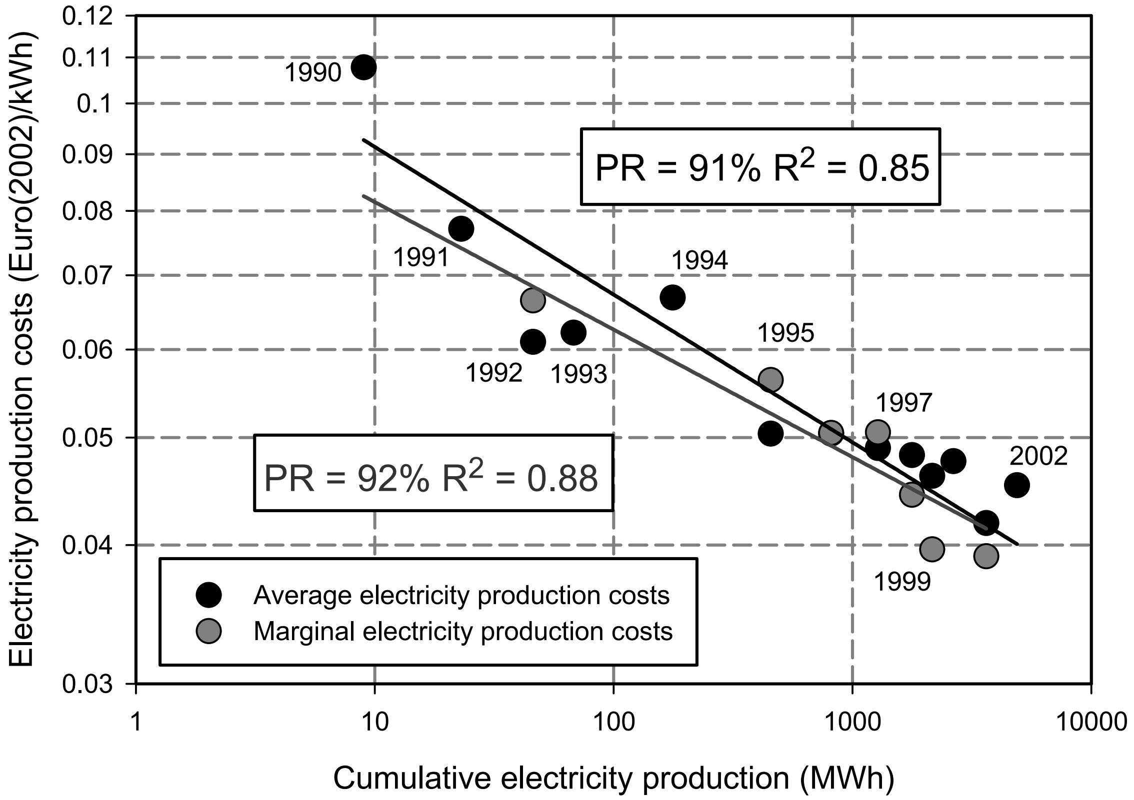

Figure 4 Experience curve for the average and marginal production cost of electricity from Swedish biofuelled CHP plants from 1990-2002. Data on investment costs, annual production and O&M figures from de Visser (2004). The allocation of production costs to electricity and heat was done based on market value.

Given the fact that the experience curve for investment costs showed such a low correlation, it is remarkable that both experience curves for electricity show a much higher correlation coefficient. This can be explained by several reasons. First of all, as the investment costs decline over time, their share in the total electricity production costs declines from about 65% in 1990 to 30% in 2002. Another reason is that the fuel costs were relatively constant over the time period investigated. In addition, there is a general trend for all plants showing a continuous increase in electricity production over the lifetime, resulting in an average load factor of 18% in the first year to 40% in the 10th year of operation.

Some remarks should be made about the results. First, the prices of forest residues declined strongly until 1993, and have since then remained relatively stable. The study period of newly-built biomass CHP-plants however is from 1990-2002. Thus, the wood fuel prices have been decreasing mainly before 1990, and remained more or less stable in the investigated time frame. Second, forest residues are not the sole fuel for the CHP plants investigated. The other main fuel (wood process residues) is somewhat cheaper, but follows forest residue prices (STEM, 1993-2004). The costs of other fuels (e.g. MSW or coal, which are used in minor quantities at a few plants, see Table 1) were not taken into account in this study. Finally it is interesting to see that both experience curves have similar slopes. This suggests that the average production costs decline at the same speed as the marginal production costs.

4. Global development of fluidized bed boilers

4.1 Case setting

Most biomass CHP plants built after 1990 (mainly in Scandinavia) are utilizing fluidized bed combustion (FBC) boilers. While other major power plant components (such as the entire steam cycle or the civil works) have been developed for almost a century, this boiler type is relatively new. The FBC boiler has been developed at a global scale. Therefore, an attempt was made to analyze the production cost decline of FBC boilers since 1975.

FBC is known for its ability to burn low-grade fuels with low calorific value, and high ash and moisture content. Other advantages of FBC are fuel flexibility, emission performance, ability to re-use non-hazardous by-products and the possibility of the technology to be retrofitted in an existing (non-FBC) plant. Since the introduction three decades ago, many improvements have been made to the FBC technology and its derivates, the Circulating Fluidized Bed (CFB), the Bubbling Fluidized Bed (BFB) and the Hybrid of both forms[14]. The technology has mainly been developed by companies in the USA, Scandinavia and Germany, but plants have been built all over the world. For further details: the history of fluidized bed boiler development has been described extensively by Watson (1997). The main technological development over the last few decades have been: scale-up, environmental compliance and fuel flexibility in design and use. Much research has been done in these areas. However little efforts have been made to study and chart the development of the economic performance of the technology.

4.2 The learning system for investment costs

To make this analysis possible, a database has been constructed comprising technological and economic data on 491 FBC projects (of which CFB represents 311, BFB 146 and Hybrid 34 projects), by extracting data from trade journals, conference proceedings, information from manufacturers, public databases and governmental monitoring programs. The coverage of the database is approximately 70 % of worldwide installed capacity.

From the almost 500 projects in the database, for about 140 only some information on project prices could be obtained. These data were converted into US (2003) dollars. the data were deflated using the average GDP inflation of the OECD countries (IMF, 2004). The year of publishing the price data was used to determine the deflation factor. When price data were given in other currencies, the currency was converted into dollars of the same year; the result was then deflated to 2003 US dollars.

As mentioned in section 3.2, prices of plants may vary strongly due to a number of factors, such as the scale, fuel used, technology variant (i.e. BFB or CFB), application and region. Furthermore, also the scope of a contract[15] and the manufacturer involved may influence prices. To cope with the variations, the collected data was categorized according to these factors. The primary categorization differentiate between:

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[14] The hybrid type is not discussed in detail in this chapter as only few plants of this type have been built.

[15] Orders recorded in literature vary from replacing a single boiler without the steam system to entire new turnkey plants. Unfortunately, often the exact scope of a contract is not given.

1. Projects encompassing the boiler price only.
2. Engineering Procurement and Construction (EPC) projects, also including all other plant components such as steam cycle, emission control, instrumentation and control technology and other equipment.
3. Projects encompassing the total price, also including e.g. financing costs.

A secondary differentiation was done on basis of technology type (BFB or CFB), region[16], manufacturer[17], fuel type[18] and order type[19] The deflated price data were used to calculate the specific investment price in $/kWe of the boiler, EPC and total project. As a next step, the 140 plants were divided in data sets based on the primary category and one to three secondary categories, yielding individual data sets of 5-56 data points.

Table 3 Overview of PRs and R^2 for experiences curves based different CFB and BFB order type, fuel type and geographical location.

	Selection method	PR	$R^{2\,a}$	Sample size
Project price	BFB	0.90	0.77	6
	CFB	1.02	0.00	15
	BFB, new plant (pilot plant excluded)	0.91	0.77	5
	CFB, new plant	0.91	0.06	11
	CFB, new plant, standard design	0.94	0.09	8
	CFB, new plant, standard design + no challenge	0.90	0.19	10
	CFB, new plant, standard design, power	*0.93*	0.61	7
EPC price	BFB	1.40	0.23	23
	CFB	0.93	0.09	56
	BFB, new plant	0.90	0.10	16
	CFB, repower	0.89	0.25	14
	CFB, add-on	0.90	0.31	9
	CFB new plant	0.62	0.17	29
	BFB, new plant, some challenges	0.78	0.26	14
	BFB, new plant, some challenges, Scandinavia, Cogeneration	*0.79*	0.48	7
	CFB, new plant, standard design	0.70	0.18	16
	CFB, new plant, some challenges	*0.47*	**0.82**	11
	CFB, new plant, no challenges + standard design, North-America	0.82	**0.96**	5
	CFB, repower, standard design	0.93	0.29	11
	CFB, repower, no challenges + standard design, North-America	0.90	**0.95**	5
Boiler price	BFB	0.91	0.04	14
	CFB	0.86	0.07	29
	BFB, new plant	0.71	0.16	7
	CFB, new plant	0.98	0.01	16
	BFB, new plant, some challenges	0.71	0.16	7
	BFB, new plant, some challenges, Scandinavia	*0.52*	0.42	5
	CFB, new plant, standard design	0.42	**0.85**	10

a R^2 of 0.8 and above are printed **bold**.

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[16] Seven regions were defined: Asia, Australia, Eastern Europe, Western Europe, North America, Latin America and Scandinavia.

[17] Alstom, Foster-Wheeler, Lurgi, Kvaerner and others.

[18] Standard design, no challenges, some challenges, multiple challenges (classification adopted from (Hamalainen, 2004)).

[19] New plant, repower, retrofit, add-on or conversion.

The analysis indicated that when only one primary and one secondary differentiation variable is selected, the resulting experience curves show a very low correlation coefficient (see Table 3 for an overview). Only when more variables are included, in some cases correlation coefficients (R^2) of 0.8 and above were achieved. An example is given in figure 5, presenting two experience curves differentiated by project type (EPC), technology type (CFB), order type (new plant) and fuel type (standard and some challenges). The figure shows clearly, that plants handling more difficult fuels generally have higher investment costs than plants with a single, easy fuel. Investment costs of both plant types seem to decline, but those of the latter category display such a variation that no statistically significant trend can be determined.

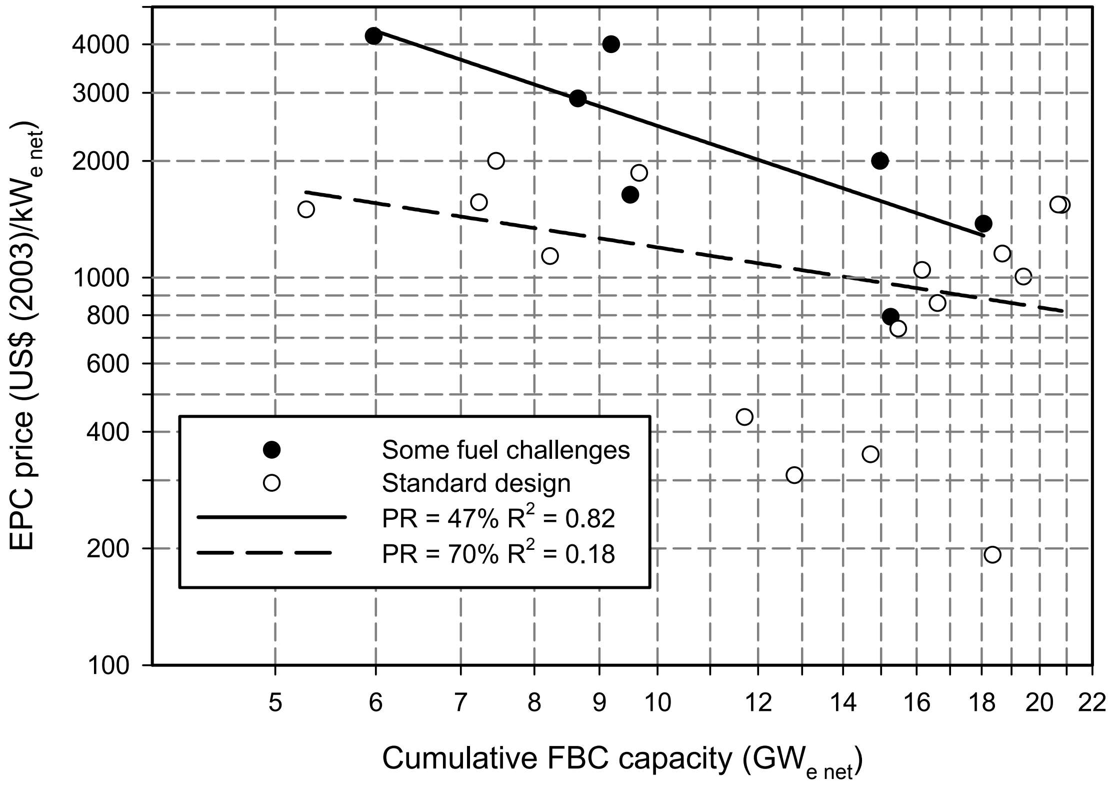

Figure 5 Experience curves for new CFB plants, differentiated by fuel type. "Standard design" fuel types include petroleum coke, bituminous coals, lignite and peat. "Some fuel challenges" include fuels such as woody biomass and clean plastics (Hamalainen, 2004).

In addition, it was attempted to separate upscaling from other learning mechanisms (see section 2.1). An analysis was made of the price reduction that is achieved when the size of the plant is doubled by investigating the scale-up factor (R) for FBC technology. Only newly built plants were taken into account. Also, only data was used of plants built in the same year, to prevent interference with other learning effects, which may have occurred over time. The results are presented in Table 4, showing that the scale factor for boilers is lower (0.62-0.74) than for EPC projects (0.81).

Table 4 Summary of ranges for PRs and scale factors of fluidized bed combustion boiler plants.

Component in breakdown	Share in total price	PRs	R^2	Scale factor R
Project price	100 %	90 - 93 %	0.61-0.77	-[a]
EPC price	~80 %	49 - 90 %	0.67-0.96	0.81
Boiler	~50 %	42 %	0.85	0.62 - 0.74

a No scale factor for project price could be determined due to data limitations.

Furthermore, as shown in Table 3, the experience curve for the boiler section alone is (much) steeper than for the entire project costs. This suggests that a large part of the price reduction is due to price reduction in the boiler section. However, the lowest PR found (42%, $R^2 = 0.85$) is far lower than the range of PRs observed in literature (Argote and Epple, 1990), which is generally 60-100%, with an average of 80%. This very low PR can partially be explained by the lower scale factor for boilers. When the data from this experience curve is corrected by a boiler scale factor (R=0.74), a PR of 60% remains, which is still very low. Other explanations for the steep price decline can be that in the investigated period new product innovations were commercially introduced[20]. A third possibility is that standardized boiler design has led to a limited amount of mass production. Finally, an explanation could be that in the period involved a shake-out of manufacturers occurred. In the period of 1989-2000, a number of mergers, joint ventures and takeovers of FBC boiler producers took place (Koornneef, 2004). Typically, during such a shake-out period, prices can decline much faster than actual production costs (BCG, 1968).

The importance of scale-up and other learning mechanisms is further described by Koornneef (2004) and Watson (1997). Summarizing, learning-by searching was also of importance for the development of FBC technology. Especially during the 1970s and 1980s, a number of fluidized bed pilot plants in the USA were constructed, which enabled manufacturers to correct design errors, and led to the introduction of the first commercial FBC plants in the 1980s. In addition, learning-by-using was a vital process. The experiences with various fuels in the demonstration plants clearly allowed designers to minimize problems with the first generation of fluidized bed plants. Learning-by-using also played a role during the process of gradually upscaling CFB plants from pilot size to 500 MW_e. On the other hand, as the technology was mainly developed by a number of private companies, there was little learning-by-interacting. Also, as the market size for FBC plants is still rather small (compared to other technologies such as gas turbines, or pulverized coal plants), mass production of boilers has (so far) not been of importance.

5. Centralized biogas plants in Denmark

5.1 Case setting

Digestion of manure and organic waste is a well-established technological practice in Denmark. In 2002, twenty centralized biogas plants were in operation and over 35 farmscale plants were installed. These plants produce biogas by digesting biomass under anaerobic (oxygen-free) conditions. Biogas is the name of the mix of CO_2 and the inflammable gas CH_4, which can be used to generate heat and electricity. The sources for biogas production are principally a wide range of organic material. The continuously stirred tank reactor (CSTR) applied in Denmark is well suited for treatment of liquid animal manure and organic industrial wastes. In Denmark, the first centralized plant was built in 1984. Since 1988, the number of plants has been steadily increasing, reaching twenty in 1998. No new plants have been built between 1998 and 2002. In 2002, the plants produced about 350 GWh electricity and 1.29 PJ heat, and processed about 3% of all manure in Denmark (Holm-Nielsen and Al Seadi, 2001). The plants have been monitored continuously from 1989 onwards, as part of an extensive public research and development programme. This programme also included high investment grants (up to 40% in the late 1980s and early 1990s). The

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[20] For example the Compact CFB in 1992 built by Foster Wheeler and the IR-CFB by B&W in 1994. The manufacturers claim that the new boilers are less expensive and perform better than their predecessors (Koornneef, 2004).

programme was focused on bringing together the experiences and insights from scientists, producers of biogas plants, and farmers. Both biogas plant design concepts and functionality[21] of the plants have varied over time, and there were both successes and setbacks. Especially in the years 1984-1991, most of the early built plants were functioning unsatisfactorily, and some had to undergo major changes. The underlying qualitative developments have been described in detail by Raven and Gregersen (2004).

While digestion of manure and organic waste has also been developed in other countries (e.g. Germany and The Netherlands), only very limited exchange of knowledge and experiences took place. Also, all centralized Danish plants have been built by Danish contractors. Thus, the amount of experience gained outside Denmark and used in the Danish learning system is deemed to be marginal.

5.2 Investment cost reductions

The plant layouts of the twenty biogas plants differ somewhat. About two thirds of all plants operate under thermophilic conditions, while the remainder operates at mesophilic temperatures[22]. Some plants use the biogas directly in a gas-fired boiler, but at most plants, the biogas produced is transported some distances and used in decentralized CHP plants for local heat and power production. At several plants, the biogas is co-fired with oil or natural gas. In addition, some plants also have straw or wood-burning facilities (Al Seadi, 2000). The biomass digester capacity of the plants varies between 750 and 8500 m^3.

To be able to compare the investment costs of the plants, all other CHP components were excluded (were possible) from the investment costs. Also other non-relevant investments (e.g. for small wind turbines or straw burning facilities) were excluded. Furthermore, unlike power plants (which have a clearly defined capacity in MW_e), the maximum capacity of biogas plants depends on many factors, such as the digester capacity, thermophilic or mesophilic operation, the quality of the manure and organic waste. The following approach was used in this study. It was assumed that the capacity of the digester and the average retention time determine the maximum amount of biomass that can be treated per day[23]. Next, the investment costs for each plant were divided by the daily maximum digester capacity to process biomass. In Figure 6, these investment costs are plotted against the cumulative biogas digester capacity. While there is a trend of declining investment costs, the correlation is mediocre (R^2=0.69). Again, different local conditions, varying plant layouts (some plants include sanitation equipment, gas storage systems, etc.) as well as differences in scale are most likely reasons for the variation.

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[21] I.e. the ability to produce heat and electricity, and process manure and organic waste. The importance of these different functions has varied over time.

[22] Mesophilic plants operate at about 35 °C with 25 days retention time, thermophilic plants at about 55 °C and an average of 15 days retention time.

[23] For example, a thermophilic plant (15 days retention time) with a digester capacity of 3000 m^3 has a theoretical maximum daily processing capacity of untreated biomass of 200 m^3 (3000/15).

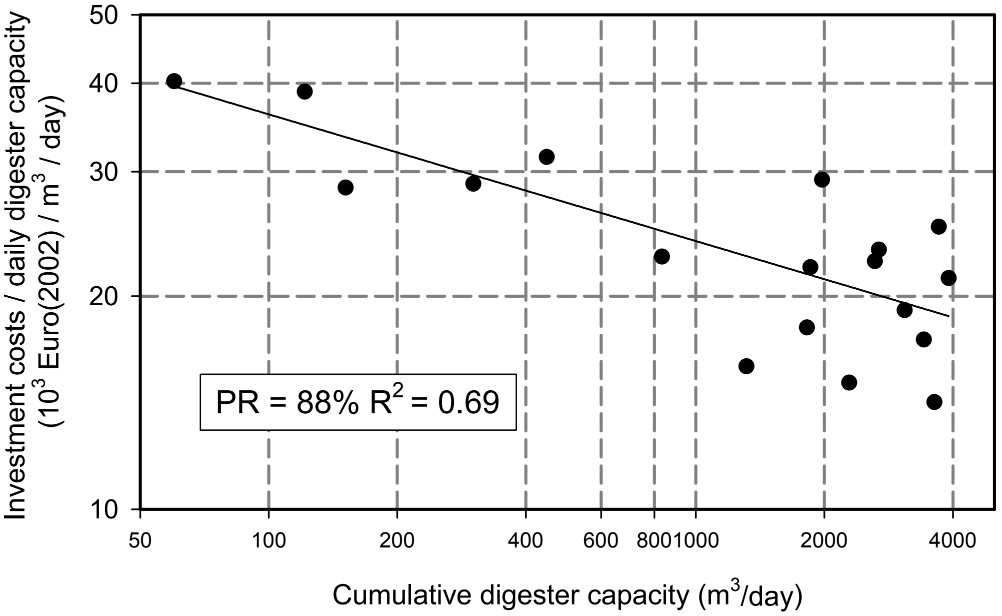

Figure 6 Experience curve for Danish centralized biogas plants. The daily digester capacity data is based on Al Seadi (2000). Investments for CHP components, wood and heat burning facilities etc. have been excluded.

5.3 Biogas cost reductions

The biogas plant investment costs are not likely to be a good measure for technological learning, for two reasons. First, as discussed in section 2, the number of plants is small compared to the number that is generally required for constructing a reliable experience curve. Second, technological performance did not only increase when new plants were constructed, but also when existing plants were redesigned and because plant operators learned to improve plant operation. Thus, the number of units produced does not necessarily reflect all technological learning in the case of biogas plants. Therefore, also an experience curve on the basis of final biogas production costs was devised. The final biogas production costs are better suited, as they also reflect the higher yield of biogas (due to adding organic waste), the increase of plant availability and lowering of operation and maintenance costs. Therefore, an experience curve for the average production costs of biogas was plotted (see Figure 7). The biogas production costs for each plant and each year were determined by the cumulative biogas production and O&M costs of all plants.[24] Unfortunately, for the years 1984-1986, only data from one plant were available (the Vester Hjermitslev plant). During the period of 1984-1988, this first centralized plant experienced serious operating problems, leading to extensive reconstruction (Al Seadi, 2000). Thus, the data from this period is rather uncertain. From 1988 onwards, the averages are based on data from 3-19 plants. For each year, the annual average biogas costs were estimated by weighing the production costs of each plant with the share in total biogas production. The data were then compared with the biogas production costs published by Mæng et al. (1999). Both the data from our study and from Mæng display a strong decline in biogas production costs until 1991. The production costs decline stronger when using the data from

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[24] An interest rate of 6% and a lifetime of 20 years were assumed to annualize the capital costs. These numbers are typical for the local situation (Mæng et al., 1999). In the O&M costs, also the negative costs (gate fees) for the fuel (manure and organic waste) were included.

Mæng[25] resulting in a PR of 76%, compared to 85% based on our data. In both cases, the trend line displays a high degree of correlation (R^2 of 0.97 and 0.98). After 1991, biogas production costs remain more or less constant, i.e. a PR of about 100%.

Similar to the Swedish CHP plant case, also the marginal biogas production costs were determined, again using the average of the second, third and fourth year of production, and plotted at the third year of operation. Due to this procedure, only three data points were available between 1987-1991. Therefore, no attempt was made to construct an experience curve for this period. However, the general pattern from 1987-2001 suggests that marginal production costs were slightly lower than the average costs, and follow the same trend.

Another performance indicator is the cost per cubic meter of treated biomass, i.e. all production costs divided by the total amount of manure and organic wastes digested per plant and year. This is an indicator for how well the production capacity of each plant is utilized. In Figure 7, these costs are also shown. They basically display the same trend as biogas production costs: first a strong decline between 1989-1991, but a stabilization at 10-12 €/m^3 treated biomass between 1991-2001. Unfortunately, no data about production volumes of treated biomass were available before 1989.

There are several explanations for the flattening of the biogas experience curves from 1991 onwards. First, the period from 1984-1991 was a more or less experimental period, in which different plant layouts were tested and evaluated. For example, until 1990, only submerged, high-speed propellers were used, while later top-mounted, slow-rotating stirrers proved to be more appropriate (Danish Energy Agency, 1995). Faulty design (e.g. the use of heat pumps) caused low production volumes and thus high biogas costs, errors that were avoided during the design and construction of later plants. From 1991 onwards, the basic optimal designs were clear, and the learning process shifted from improving the construction of plants to a more efficient operation of the plants. For example, in 1993 the need for chemicals to purify the biogas from hydrogen sulfide (H_2S) was strongly reduced by adding 5% air to the biogas. This innovation spread within two years from one plant to almost all other plants. Such small additions to the operational process and overall gain in operating experience reduced operational costs and increased availability of the plants. However, these reductions were less dramatic compared to the reductions achieved in investment cost.

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[25] This is likely due to the fact that in that study, investment costs are discounted for 50% in the first year, while in our calculations, investments are annualized over the entire lifetime of the project. With few plants built between 1984-1990, the high costs in the first year have a large impact on the average. In later years, with more plants built, this effect is less severe.

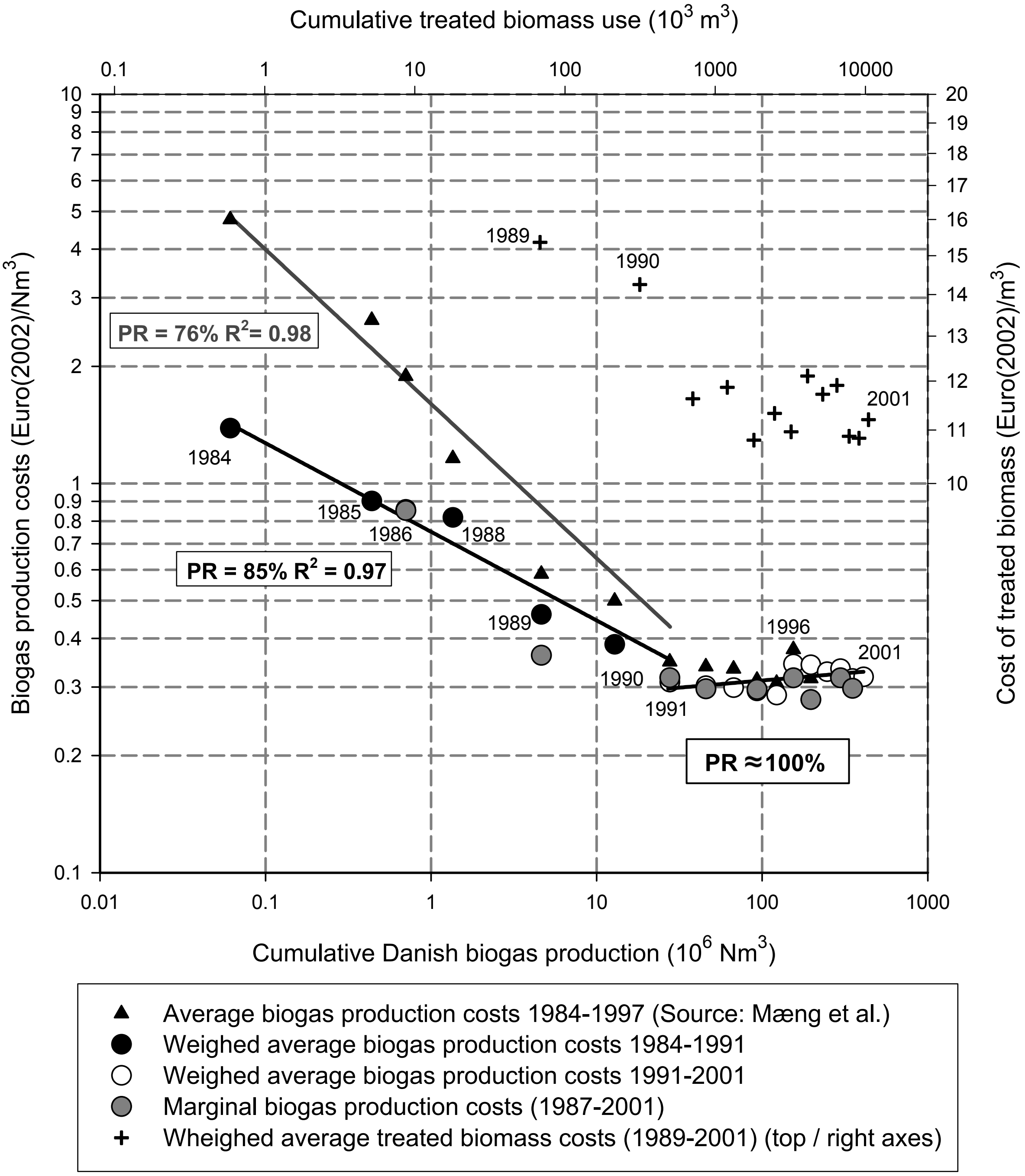

Figure 7 Experience curves for Danish biogas production costs from 1984-2001. Data from (Danish Energy Agency, 1995, Hjort-Gregersen, 2003, Mæng et al. 1999). 1 m^3 biogas equals approximately 22 MJ. For comparison, the corresponding cost development per m^3 of treated biomass is also shown (1989-2001). The biogas production costs quoted by Mæng et al. are declining faster between 1984-1991, as 50% of the investment costs are discounted in the first year of operation.

Second, the production of biogas is highly dependent on the addition of organic waste. Production of biogas from solely manure results in very poor biogas yields. The production can be strongly increased by adding up to 20% of organic waste. This was the main reason that average biogas yields increased from less than 30 to over 45 cubic meters biogas per cubic meter of treated biomass from 1989 to 1991 (see Figure 8). However, the amount of suitable industrial waste was limited, and most of the desired waste for biogas production had been contractually claimed by the first biogas plants. As a result of the competition, industrial waste was not as economically advantageous as it used to be (Mæng et al., 1999). As competition on waste increased throughout the 1990ies, it became increasingly difficult to maintain high gate fees, especially for attractive wastes, which were easily relocated to other plants if profitable. On the other hand, the tariffs for heat and electricity increased over time, leading to a gradual overall increase in plant income (see Figure 8).

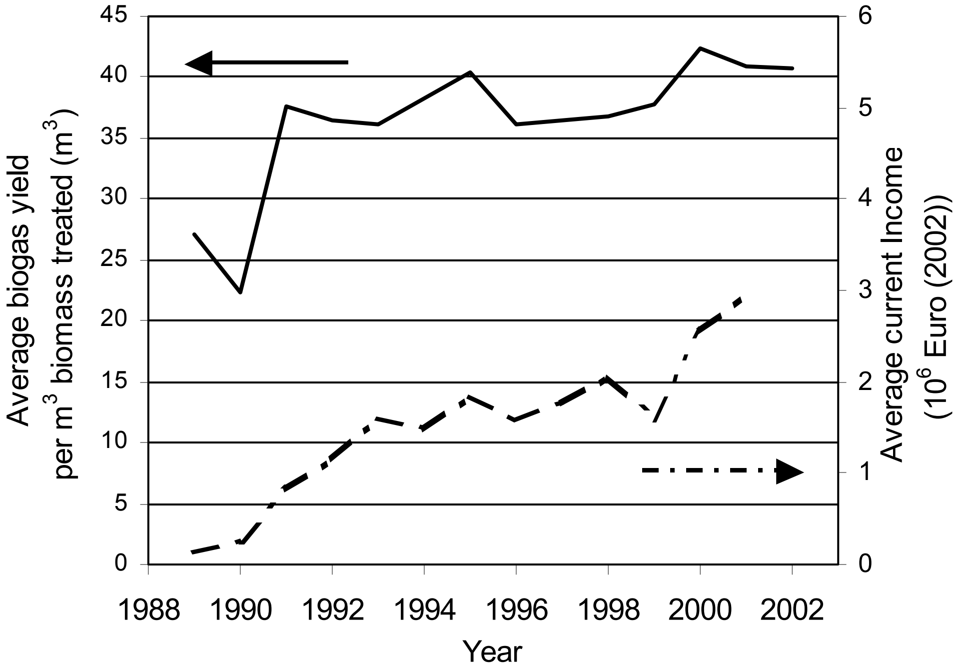

Figure 8 Development of the average biogas yield per m3 of treated biomass, and of the average income, defined as difference between operation cost and income from energy sales and gate fees for processing waste. The operation costs do not include the repayment of loans (Raven and Gregersen, 2004).

Third, another possible reason for the lack of continuing biogas cost reduction is that the further development of centralized biogas plants has come to halt in Denmark. The liberalization of the energy market (and resulting uncertainties for the prices of electricity from biogas) has stopped new investments in biogas plants since 1998 (Christensen, 2000). Without new investments in the technology, it is unlikely that further technological development will occur. Studies have shown that it may be possible to lower biogas cost further by scaling up biogas plants (Hjort-Gregersen, 2003; ter Steege, 2004), but this would require even higher investments, which are less likely to be made in a liberalized market. Also public resistance to lorry traffic may result in the installation of two or three small plants rather than one large plant.

In summary, while some examples of learning-by-doing and learning-by-interacting have been shown, and the actual yield has gradually improved from 1991-2001, this has not lead to lower biogas costs, due to the scarcity of organic waste and the stagnating installation of further plants[26]. The performance increase of Danish biogas plants has been counteracted by conditions that had no direct link to technological improvements. The success of biogas plants not only depends on technological learning, but also on changes in the selection environment in which biogas plants

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[26] It should however be noted, that the actual exploitation of biogas plants has become more profitable during the last years (see Figure 8). This is due to increased prices for electricity since 2000.

need to survive. Limited availability of waste, changes in agro-environmental regulations, and an ongoing liberalization process are examples of external factors that can limit (or expand) the possibilities for a new technology to compete. By increasing technological performance, the Danes were able to keep the production costs at a stable level, which otherwise would have increased due to increased fuel costs. They were able to do so by applying a bottom-up and bricolage strategy, similar to the one observed by Garud and Karnøe for the development of the Danish wind turbine industry (Garud and Karnøe, 2003). This approach is characterized by taking small steps rather than forcing radical breakthroughs and focuses on learning and social network building through experimentation. Elsewhere this approach is conceptualized in terms of Strategic Niche Management (e.g. Raven, forthcoming).

6. Discussion and Conclusions

6.1 Methodological discussion and conclusions

The main aim of this chapter was to evaluate the suitability of the experience curve approach for biomass energy systems. In Table 5, an overview is given of the case studies described above. From these case studies, it can be concluded that it is very difficult to devise empirical experience curves for the investment costs of biomass fuelled power plants. To some extent, this is due to lack of (detailed) data. Mainly, it is caused by varying plant costs due to scale, fuel type, plant layout, region etc. For both the Swedish CHP plants and the fluidized bed boilers, nearly all attempts to compensate or correct for these issues have not been successful. While in almost all graphs costs appear to decline, most of these trends cannot be proven statistically. Two major reasons can be given. First, the amount of data is limited, and often of poor quality. Second, specific plant properties have proven to vary too strongly to adjust for with the methods proposed in section 2. Only for the Danish biogas plants and few fluidized bed boiler sub-categories, some reasonable correlations could be found, see also Table 5 for an overview. For fluidized bed boiler plants built on a global level, PRs for the price of entire plants lies approximately between 90-93%. The costs for the boiler section alone were found to decline much faster. In the case of fluidized bed boilers, it was also possible to separate the upscaling effect from other learning mechanisms. Still, given the general quality of the data, these results should be interpreted with care. Summarizing, while there are many qualitative indications for technological learning and associated cost reductions, it has proven difficult to plot experience curves with reasonable fits. Still, as the PR's found for biogas plants (88%), (entire) fluidized bed boiler plants (90-93%) are similar, and also in the literature PRs of around 90% are reported (see e.g. Claeson Colpier and Cornland, 2002; Neij 1999), an average PR of 90% for (energy producing) plants seems a reasonable average estimate for this kind of technology.

The experience curve approach seems to deliver better results, when the production costs of the final energy carrier (e.g. electricity or biogas) are analyzed. PRs of 91-92% for electricity from biofuelled CHP plants and 85-100% for biogas production costs were found with satisfactory correlation values (R^2). One simple explanation is the larger amounts of principally available data, and thus the possibility of averaging plant data. Other explanations are that investment costs only contribute a minor share to the cost of the final energy carrier. In both the Swedish CHP case and the Danish biogas case, the other cost components (fuel costs and O&M costs) and also the annual load change in a gradual, structural fashion, which makes the data more suitable for use in experience curves. Unfortunately, calculating total production costs is even more data intensive. Therefore, this was only possible in the case of CHP plants in Sweden and biogas plants in

Denmark. The experience curve approach also seems to be suitable for measuring the cost development of complex fuel supply chains. Further research is however recommended to investigate, whether this holds also for other (biomass) supply chains.

An interesting methodological issue is the difference between the use of marginal and average production cost data. In both the Swedish and Danish case studies, the experience curves for marginal and average production cost data follow the same slope. This allows for speculation, whether average (price) data (which may be more widely available) can be used to determine the PR of a technology, and whether this PR is then also suitable to analyze the development of marginal costs, which seems realistic.

Table 5 Overview of case study parameters and results.

	Swedish CHP plants	Global FB boilers	Danish biogas plants
Case parameters			
Geographical limitation	Sweden	Global	Denmark
Timeframe	1990-2002	1975-2002	1984-2002
Number of plants	18	150 / 491[a]	20
Fuel type	Mainly woody biomass	Various biomass and fossil fuels	Manure and organic waste
Scale	3-50 MW_e	10-520 MW_e	22-500 m^3 untreated biomass/day[b]
Overview of experience curves	Type	PR	R^2
Swedish CHP plants	Investment cost	75 - 97 %	0.02 - 0.21
	Fuel Cost	85 - 88 %	0.87 - 0.93
	Cost of electricity	91 - 92 %	0.85 - 0.88
Fluidized bed combustion plants	Project price	90 - 93 %	0.61 - 0.77
	EPC price	49 - 90 %	0.67 - 0.96
	Boiler	42 %	0.85
Danish biogas plants	Investment cost	88 %	0.69
	Biogas cost	85 - 100 %	0.97

a For 150 out of 491 plants, financial data was available.

b Maximum theoretical daily capacity. Most plants deliver the biogas to CHP plants with capacities between 0.7-2 MW_e.

6.2 Learning mechanisms compared in the different case studies

The role of different learning mechanisms was highlighted briefly for the different case studies. The chosen approach of investigating subsystems of the overall biomass energy systems allows for a closer analysis of the achieved cost reductions, and may yield valuable insights for policy makers.

When comparing the development of the investment costs, it is found that in all three case studies, the investment costs (and in the Swedish and Danish cases also the cost of the final energy carrier) are declining, but different learning mechanisms are responsible for the cost reductions. In the case of fluidized bed boiler plants, the main RD&D phase was in the 1970's, and commercial market diffusion occurred since 1980 on a global scale. For the case of Swedish CHP plants, while there was certainly some local knowledge present and used for the design and operation of new plants, the main reason for cost reduction in the time frame was probably the continuing upscaling of the technology and the introduction of the compact CFB technology, processes that occurred mainly outside the Swedish learning system. On the other hand, the biomass digestion technology was largely developed locally. Public RD&D funding and the construction of the pilot plants in the second half of the 1980s were vital for the initial learning process, mainly to improve the plant layout and to reduce investment costs. With the starting market penetration during the 1990's, learning-by-using and learning-by-interacting played a major role in the reduction of investment and biogas production costs. In this context, it should be noted that reduction of (investment) costs does not occur automatically. For example, Rakos et al. (1995) investigated biomass-fuelled district heating plants in Austria. Like biomass digestion plants, this a small-scale technology, was developed to a large extent on a local level. Rakos et al. report that in Austria the average investment costs of these plants continuously increased (corrected for inflation) from 1984-1992. They find a diseconomy of scale (i.e. rising costs with rising scale) and increasing costs with technological sophistication. Two main reasons for these findings are that no technical monitoring of the overall performance of the plants was performed, and most plant operators did not properly identify problems. Thus, no feedback reached the responsible technical planners, slowing down technological learning considerably (Rakos et al., 1995). In these aspects, the Austrian case is the opposite of the Danish biogas case.

These examples indicate, that for relatively new technologies, developed on a local or regional scale, successful learning-by-using and learning-by-interacting may be of major importance of the successful development. With technologies developed on a global scale, it is mainly fruitful to focus on the local dissemination of knowledge about the operation of plants, and setting up successful fuel supply strategies. The latter was one of the weaker points in the Danish learning system, but was developed successfully for the case of Swedish forest residues. These may be important insights for policy makers and deserve further investigation.

Chapter 7: The implications of technological learning on the prospects of specific renewable energy technologies in Europe[1]

Glossary

ADMIRE REBUS	Assessment and dissemination on major investment opportunities for renewable electricity in Europe using the REBUS tool
BIG/CC	Biomass Integrated Gasification / Combined Cycle
EC	Experience curve
EU-25	The European Union as of May 1st 2004, including 25 member states
MS	Member States of the EU
NMS	The 10 New Member States of the EU
OTLS / PTLS	Optimistic / Pessimistic Technological Learning Scenario
PR	Progress Ratio
REBUS	Renewable Energy Burden Sharing
RES-E	Electricity from renewable energy sources
ROW	Rest Of the World (all countries outside the EU-25)
TRECs	Tradable Renewable Energy Certificates
WEO	World Energy Outlook 2002 (IEA/OECD, 2002)
WETO	World Energy, Technology and climate policy Outlook (European Commission, 2003)

Abstract

The objective of this chapter is to examine the impact of technological learning on the diffusion of specific renewable energy technologies into the electricity market of the EU-25 until 2020, using a market simulation model (ADMIRE REBUS). It is assumed that from 2012 a harmonized trading system for renewable energy certificates will be implemented. Also it is assumed that a target of 24% renewable electricity (RES-E) in 2020 is set and met. By comparing optimistic and pessimistic endogenous technological learning scenarios, it is found that the diffusion of onshore wind energy into the market is relatively robust, regardless of technological development. However the diffusion rates of offshore wind energy and biomass gasification greatly depend on their technological development. Competition between these two options and already existing biomass combustion options largely determines the overall costs of electricity from renewables and the choice of technologies for the individual member countries. In the optimistic learning scenario, in 2020 the market price for RES-E is 1 €ct/kWh lower than in the pessimistic scenario (about 7 vs. 8 €ct/kWh). As a result, the total expenditures for RES-E market stimulation are 30% lower in the optimistic scenario. For comparison, instead of introducing a harmonized trading system, also continuation of present policies to support renewables was evaluated, assuming that the member states of the EU can fulfil their ambition levels only by exploiting their domestic renewable energy potentials (i.e. exclusion of international trade). This would require many member states to use their offshore wind potential, making the diffusion of offshore wind much less dependent on both the rate of technological learning and competition from biomass options, compared to the harmonization policy scenario.

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[1] Submitted in slighltly different form to the International Journal of Energy Technology and Policy. Authors: M. Uyterlinde, M. Junginger, H. de Vries, A. Faaij, W.C. Turkenburg.

Chapter 7: The implications of technological learning on the prospects of specific renewable energy technologies in Europe

1. Introduction

In the last few decades, renewable energy technologies have progressed in terms of market introduction, reduction of investment costs and reliability. Renewable energy technologies are regarded as an option to contribute to the reduction of greenhouse gas emissions. They can also reduce dependency on imported oil and gas. In some countries, renewable technology manufacturing industries have experienced large growth, leading to an increase in employment in the sectors involved. In line with these developments, the ambition level of policies and targets increased over time. An important milestone in this respect in Europe was the adoption of the Renewables Directive (European Parliament, 2001) setting a target of achieving 22% electricity production from renewable energy sources (RES-E) in the year 2010, compared to 14.5% in 1999. Jansen and Uyterlinde (2004) have given an overview of the process that led to the adoption of this Directive; they also present an assessment of its implementation.

Given the fact that most grid-connected RES-E technologies need financial support to penetrate the market, the design and ambition level of support policies determines to a great extent the diffusion of different RES-E technologies. Presently, there is a large variety of support schemes across Europe. Roughly, two main types of support schemes have emerged, apart from investment support which is given by nearly all EU countries. Feed-in tariffs, which offer a fixed, technology specific, revenue for each kWh produced by RES-E, are generally favoured by investors because they provide security for a number of years in advance. The other major type of support scheme is based on a quota obligation, usually imposed on the suppliers of electricity. Apart from producing RES-E, the obliged actors can meet a possible shortage of their quota by purchasing Tradable Renewable Energy Certificates (TRECs). This system, based on a market for RES-E production, introduces competition between different technologies and is thereby expected to function in a cost-efficient way. However, in the short run when a liquid market is yet to develop, many investors regard it as a more uncertain support scheme[2].

For most RES-E technologies, such as onshore wind turbines, biomass combustion and photovoltaics, technological learning has resulted in both declining investment costs and electricity production costs over the last few decades (Goldemberg and Johansson, 2004). For example, the cost of electricity produced by onshore wind turbines have roughly been reduced by a factor five over the last twenty years, due to the technological development (BTM, 2000). Also for the coming decades, production costs are expected to decline, especially for advanced technologies which only recently have been commercialized (e.g. offshore wind energy), or are still in the research, development and demonstration phase (e.g. biomass integrated gasification combined cycle (BIG/CC) for electricity production).

A wide variety of energy models have been constructed to provide policy makers with a better insight into the complexities of energy system development under various policy objectives. Many of these describe the complete energy system either with a technical 'bottom-up' (systems engineering) approach or with a macro-economic 'top-down' approach. Examples of bottom-up models are MESSAGE, MARKAL and ERIS; see Seebregts et al. (1999) for an overview. Top-down models are for example CETA, DICE and DEMETER (Peck and Teisberg, 1992; Nordhaus,

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[2] De Vries et al. (2003) and Reiche et al. (2003) provide overviews of the current state of the art in the EU-15 and the NMS respectively. Feed-in tariffs are being used in many countries, notably Germany, Spain, The Netherlands and in many new Member States (NMS). TRECs are currently used in the United Kingdom, Sweden, parts of Belgium, Italy and Poland.

1993; van der Zwaan et al., 2002). Most of the energy models that cover complete energy systems have analysed the impact of varying assumptions on technological development, and find that it may have a strong impact on total energy system costs and the shares of individual technologies in the overall energy system, see e.g. Gerlagh and van der Zwaan (2004).

Next to the general energy models, energy sector models exist that concentrate particularly on the prospects for one fuel or market. ADMIRE REBUS is one of these sector models, developed with the purpose of modelling the fragmented and changing market of RES-E in Europe (Daniëls and Uyterlinde, 2005). Other models that pay specific attention to the role of RES-E are SAFIRE (Whiteley et al., 2003) and GREEN-X (Huber, 2004). These sector-specific models so far have not reported on variations in market penetration of specific RES-E options under different scenarios for technological learning.

Against the background of a changing market for RES-E in Europe, induced by the Renewables Directive of the EU, and the potential impact of varying development of RES-E technologies, the objectives of this chapter are to examine:

- Which consequences differing technological developments may have on the diffusion of specific RES-E technologies in the EU-25 until 2020.
- Which technologies seem most attractive for individual countries, and what are the resulting production costs and total expenditures to stimulate RES-E development (in the frame of a chosen policy scenario).
- Which market diffusion trends are relatively robust and which ones are most sensitive to learning effects.

The main aim of this chapter is to explore the effects of varying technological developments on the market diffusion of different renewable electricity technologies in the EU-25 until 2020. It is emphasized, that this exercise is not an attempt to forecast the diffusion of RES-E in the EU-25, as this also strongly depends on policy developments, price development of fossil fuels and other exogenous factors. The effects of different policy scenarios on the diffusion rate of RES-E technologies have already extensively been described by Daniëls and Uyterlinde (2005) and Uyterlinde et al. (2003). These studies show that policies with a high ambition level and with a harmonized approach within Europe can achieve higher diffusion levels of RES-E, but are also more costly than continuation of the present policies (CPP) of the EU member states. This study focuses mainly on the impact of different technological developments under a harmonization scenario. For comparison, also a brief analysis of the effects of different technological development under a CPP scenario is carried out.

Section 2 starts with describing the methodology applied, explaining first the ADMIRE-REBUS simulation model and next the concept of experience curves to describe technical learning. Section 3 provides an overview of the input data and assumptions made for the analysis, while Section 4 presents results and a discussion of the outcomes. In addition, in Section 5 several methodological issues are discussed. Finally, in Section 6 conclusions are drawn.

2. Methodology

2.1. The ADMIRE REBUS model

Offering a vintage approach[3] for new and existing capacity, ADMIRE REBUS is a dynamic simulation tool. The model is capable of providing insight not only into the functioning of a mature market for renewable energy, but also into the transition to such a market, because it can deal with unstable planning horizons and high risk investments. The simulation approach deals with investment decisions under different support schemes from the point of view of the investor. It therefore allows for a representation of the barriers involved in the development of electricity markets for renewables, such as investment risks, lead times, failure rates in permission procedures and transaction costs. Results of the ADMIRE REBUS model include equilibrium prices, trade flows, technology implementation, governmental and end-user expenditures and other parameters in the national and European markets under different scenarios.

2.1.1. Model database

The model database contains detailed information on present costs and application potentials of twelve RES-E technologies in the EU-25 Member States. A brief overview of all technologies is given in Table 1. Details can be found in two background reports (de Noord et al., 2004; de Vries, 2004). Specifications about renewables support policies in individual MS can be found in Uyterlinde et al. (2003).

For all renewable technologies within a country, 'realistic' exploitation potentials have been assessed. These potentials present the maximum amount of energy that can be produced by a specific technology in a specific country at a specific point in time, taking into account both technical and non-technological constraints. The realistic potentials have been constructed in a systematic way, relating each potential to its main constraining factor (see also Table 1). For example, wind potentials for each country have been determined based on the available (mainly agricultural) area with different average wind speeds. The factors that translate these areas into electricity production include the maximum installed capacity (MW) per area and load factors. For all biomass technologies, the available current and future potentials and costs for various biomass streams (see Table 1) have been estimated for all 25 EU MS. It is assumed that biomass is not traded between MS member countries, and no biomass is imported from outside the EU-25.

Developments in both the primarily constraining factor and the technology lead to changes of the maximum potential over time. Within the simulation process, various dynamic limitations on the deployment growth are taken into account, related to e.g. the success rate of planning procedures and the speed of opening up (biomass) resources. An endogenous cost calculation module determines the operational costs of renewable technologies, expressed in terms of the Required Green Price, i.e. the initial investment deficit faced by an investor in renewable generation capacity[4]. This means that the Required Green Price incorporates the production costs minus the revenues the producer expects to obtain apart from support policies.

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[3] The model keeps track of renewable capacity by year of installation, e.g. by vintage.

[4] An annual average green price to be received from the RES-E market in order to achieve a zero net present value.

Table 1 Overview of technological input data in ADMIRE-REBUS. More details are given by de Noord et al. (2004) and de Vries (2004). The reference year for all data is 2001.

	Main constraining factor (technology bands)	Load factor (%)	Inv. Costs (€/kW_e)	Annual O&M (% of Inv.)	Life-time (years)
Wind onshore	Wind speed (<5 to >9 m/s)	10-28	860-1240	2-4	20
Wind offshore	Wind speed (<7 to >9 m/s) & water depth	18-36	1690-2080	3-4	20
Biomass co-firing[a]	Suitable biomass types: (1), (2) and available co-firing potential	80	190-220	6	15
Biomass combustion	Suitable biomass types: (1), (2)	70-90	1590-6000	4-5	15
Biomass CHP[b]	Suitable biomass types: (1)	74-90	2500	4	15
Biomass gasification[c]	Suitable biomass types: (1), (2), (3)	63	3400	5-6.5	15
Biomass digestion	Suitable biomass types: (3), (4)	75-80	5000	6	15
Solar PV[d] electricity	Solar radiation (<1000 to >1800 $kWh/m^2/year$)	9-18	5400	1	25
Geothermal	Available current and future sites	65	1700-2500	2	20
Tidal	Available current and future sites	26	1750	0.8	30
Large hydro (>10 MW)	Available current and future sites	16-70	1660-8270	0.7-1.3	30
Small & medium hydro	Available current and future sites	28-57	1410-6050	3.1-6.3	25

	Biomass types	Cost range (€/PJ)	Total potential in EU-25 (PJ)[e]
(1)	Energy crops, forest residues, agricultural residues (barley, maize, oil crop, rapeseed, wheat)	1.8-6.4	2070 (energy crops) 1080 (forest residues) 1280 (agricult. residues)
(2)	Solid manure	0	125
(3)	Biodegradable part of MSW	0	213
(4)	Liquid manure, landfill gas and sewage sludge	0	112 (+ 6.54 TWh_e)[f]

a The classification 'co-firing' implies the direct co-firing of solid biomass in coal power plants. Current and estimated future coal plant capacities for al MS are included in the model. The model assumes a maximum co-firing share, increasing from 10% in 2010 to 20% in 2020.
b Combined heat and power.
c In this chapter, the classification 'biomass gasification' implies the use of biomass integrated gasification/ combined cycle (BIG/CC) plants.
d Photovoltaic.
e These potentials are based on several literature studies based on available agricultural and forest area, expected MSW production etc., see de Noord et al. (2004) for details. The potentials can be considered conservative estimates.
f The potential for energy from liquid manure and sewage is calculated from a yield in kWh_e/ton.

Data on technological cost components are documented by de Noord et al. (2004) while assumptions on future cost developments are discussed in Section 3.2. Finally, the Required Green Price calculation includes a required return on equity of 12% with a variable, country- and technology-dependent risk adder that takes into account the effect of risks and uncertainties on various cost and revenue components.

The database on support policies is based on a detailed inventory of the different instruments for operational and investment support applied in the EU-25 Member States. It takes into account the level of support, and terms and conditions such as the number of years for which the support is granted. RD&D (Research, Development and Demonstration) support for RES-E technologies is not explicitly accounted for, because the effect of RD&D spending on technology costs is not a priori clear (see also Section 3.2). The database also does not include the effect of generic policies designed for instance for CO_2 emission reductions, unless these policies have been translated into specific financial incentives for RES-E technologies.

2.1.2. The general simulation approach

Figure 1 gives an overview of the overall functionality of the model, with the relevant factors. The basic building blocks of the model are supply curves, based on the potential of individual renewable technology options, and demand curves, consisting of demand segments, influenced by policies measures.

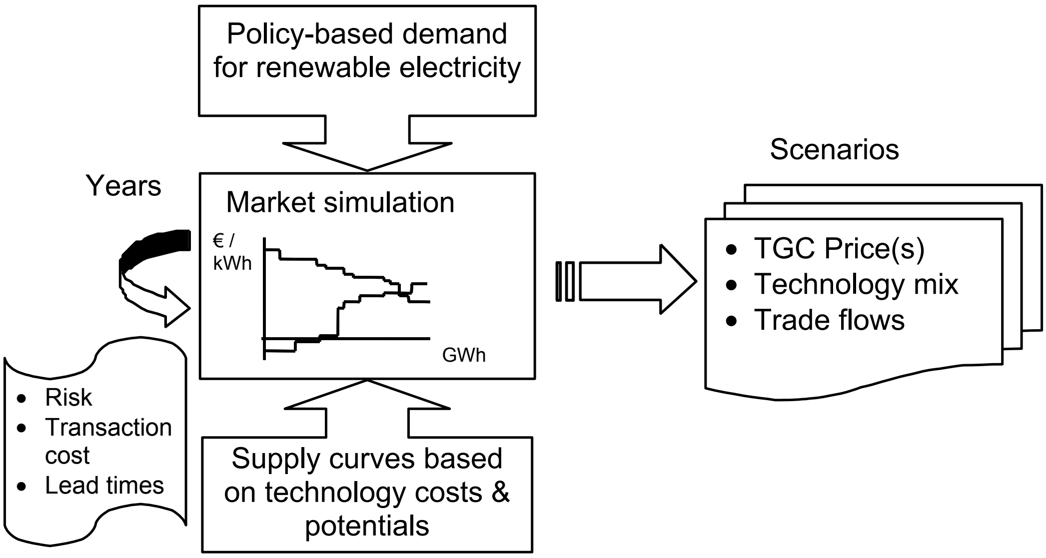

Figure 1 Schematic overview of the ADMIRE REBUS model.

The RES-E supply curve consists of technology options, characterised by their potentials (in GWh) and costs (in €ct/kWh). From year to year, the model constructs a new supply curve based on installed capacities and the realisable potentials that become available for each technology and country. In parallel, a stepwise demand curve is constructed. For this purpose, the model translates each Member State's RES-E support policy into a separate demand segment with a demand size (in GWh) and a bid price (in €ct/kWh)[5]. This translation is directly related to the type of policy. For instance, a feed-in premium tariff for wind onshore is translated into a demand segment characterised by the level of the tariff (bid price) while the demand size is determined by the amount of wind onshore potential that is available in that specific MS. On the other hand, a quota obligation will be characterised by a demand size based on the size of the quota, and a bid price based on the level of the penalty, and will accept production from several renewable technologies. This implies that the demand segments may be specific for a technology, depending on the terms of the support policy. Similarly, the demand segments may discriminate on whether production from

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[5] The demand curve includes segments for all past policies, which support production that is still operational, such as feed-in tariffs that are guaranteed for a specific number of years.

other MS is eligible for support. This way, trade flows between MS may emerge. Finally, the model applies a matching algorithm in which all demand segments are matched with eligible supply options. Consequently, the model accounts both for the discriminative characteristics of policies and for the ability of producers to choose whether they produce for the domestic market or wish to trade their production.

The simulation is done on a year-to-year basis, up to 2020[6]. Although the modelled actors make investment decisions based on their expectations, there is no overall foresight mechanism. Therefore the model results may demonstrate lock-in effects for individual technologies, or path dependency. This feature is useful when analysing different scenarios for technological learning.

2.1.3. Cost calculations

In this section, the cost calculations are explained for a single quota-system, as this will be the main policy regime used in this study[7]. The supply and demand curves of an individual country or a trading region are exemplified in Figure 2. The figure consists of two parts. On the left hand side, the 'green market' is displayed, i.e. the amount of RES-E produced that receives additional support. The cost supply curve consists of technology options, characterised by their potentials (in GWh) and their costs (in €ct/kWh). For intermittent electricity sources (e.g. wind and PV), an additional cost factor may be included. The demand curve is set by a penalty level and a quota obligation, for which all production except large hydro is eligible. Unless the market is short of TRECs, an *equilibrium price* will be established below the penalty level. The right-hand side of the graph represents the production that can compete on the grey market, but still counts for achieving the target, such as existing large hydro. The *additional production costs (striped area)* represent the costs of the options additional to the electricity commodity price, assuming no separate investment support is given. This cost measure represents a lower bound to the actual costs incurred, because it does not include any profit margins for either producers or traders. The model also calculates *total expenditures* (grey area), representing the amount of money spent in order to stimulate renewables deployment[8]. For a trading scheme these expenditures are calculated based on the assumption that the equilibrium price is assumed to be the price paid for all supply in the green market[9]. The difference between *total expenditures* and *additional production costs* is the *producers' surplus*. Each year, a new quota is set, and a new supply curve is calculated, resulting in a new equilibrium price. Also, the electricity commodity price level may change over time.

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[6] The timeframe for this paper is 2020. The model is however capable to perform simulations until 2040.

[7] ADMIRE REBUS is also capable of dealing with other (more complex) policy support systems, e.g. a mixture of feed-in tariffs and quota systems in different countries. For a more detailed description, see Daniëls et al. (2003).

[8] Note that the total expenditures are only the expenditures on top of the electricity commodity price. No further distinction is made in this paper who is covering these expenditures (e.g. electricity utilities, national governments or the end consumer).

[9] The assumption that the market clearing equilibrium price will be set at the cost level of the marginal option holds for a perfect, transparent market, see for instance Morthorst (2000). In practice, however, price setting may be less straightforward, involving long-term contracts. As is clear from Figure 2, a disadvantage of the quota-based system is that there may be a group of producers that gain large profits, because their operational costs are relatively low, see also Verbruggen (2004).

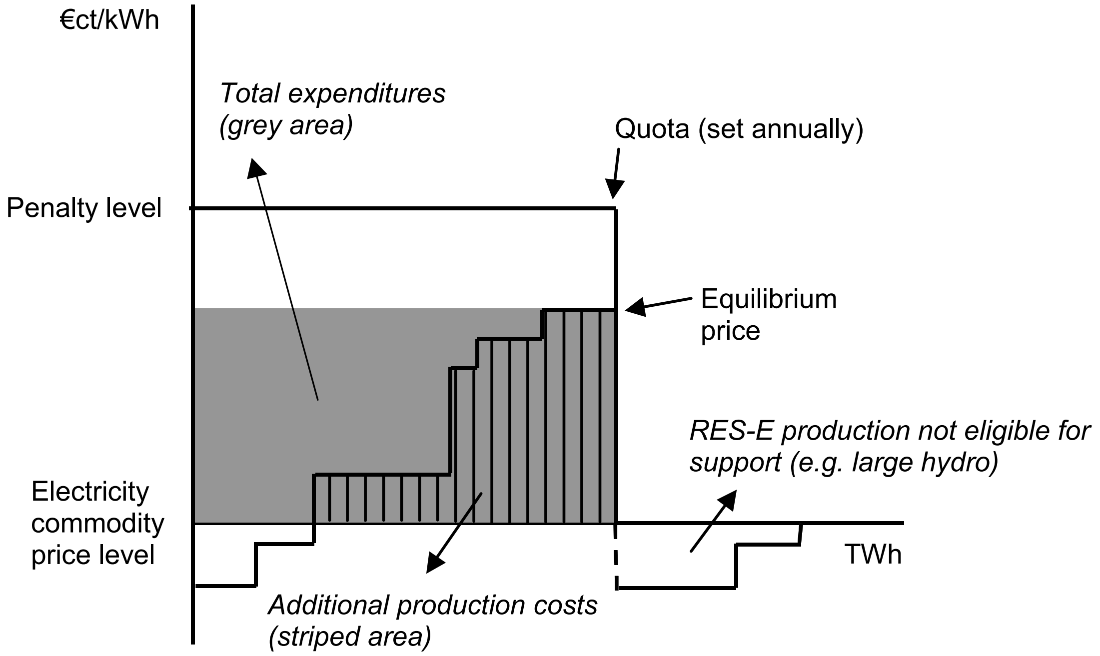

Figure 2 Example of cost calculations, performed annually in the model. The baseline is equal to the electricity commodity price, which may change over time. The quota is set annually (depending on the chosen target).

2.2. Technological learning and experience curves

When making scenarios or models for future development and penetration of new (energy) technologies, one has to take into account the technological development and the associated cost reductions. Typically, this can be modelled in two ways. Either the cost reductions are exogenous, i.e. they are determined in advance as a constant cost reduction over time (based on bottom-up cost estimates), independent of the actual diffusion rate of the technology. The second possibility is to model change endogenously, assuming that the costs of a technology depend to a large extent on the actual diffusion rate of the technology. This is based on the assumption, that with increasing use of the technology, mechanisms such as learning-by-doing, learning-by-using, upscaling and mass production yield lower production costs. This relationship was quantified by the Boston Consultancy Group (BCG), which in 1968 formulated the experience curve (EC) concept (BCG, 1968). An EC (as defined by the BCG) describes the change in production costs (a total of labor, capital, RD&D, marketing, overhead etc.) as a fixed percentage with every cumulative doubling of production. The basic EC can be expressed as:

$$C_{Cum} = C_0 \, Cum^b \tag{1}$$

$$\log C_{Cum} = \log C_0 + b \log Cum \tag{2}$$

$$PR = 2^b \tag{3}$$

C_{Cum}	:	Cost per unit	C_0	:	Cost of the first unit produced
Cum	:	Cumulative (unit) production	b	:	Experience index
PR	:	Progress ratio			

The definition of the ‘unit’ may vary: in many cases a unit is a product (for example a car or an airplane). In relation to energy technologies, often the unit is the unit of capacity of an energy technology (e.g. the capacity of a gas turbine). The progress ratio (PR) is a parameter that expresses the rate at which costs (per unit of capacity) decline each time the cumulative produced capacity doubles. For example, a progress ratio of 0.8 (80%) equals a 20% cost decrease for each doubling of the cumulative produced capacity.

While there is no natural law that production costs have to decline in this fashion, empirically this trend has been observed many times (see for an overview of various studies Argote and Epple (1990). Also for many (renewable) energy technologies, ECs have been devised, such as photovoltaic modules, wind turbines, gas turbines and fuel cells. An overview is presented by McDonald and Schrattenholzer (2001).

Since the mid-90's, the EC concept has been applied in several energy and climate models, both in top-down models such as DEMETER (van der Zwaan and Seebregts, 2004) and bottom-up models such as MESSAGE, MARKAL, ERIS (Seebregts et al., 1999) and IMAGE/TIMER (Hoogwijk, 2004). In the bottom-up models, the investment costs of specific renewable energy technologies are modeled using ECs. This allows to demonstrate and quantify the benefits of early investments in emerging technologies that are not competitive at the moment of their deployment (Seebregts et al., 1999). Therefore this approach was also included in the ADMIRE REBUS model.

3. Policy and technology assumptions and input data

3.1. Policy scenarios to 2020

For the current study, one reference policy scenario was designed to serve as a common background to the different technology development scenarios. The main characteristics of this policy scenario are: the **EU-25 wide introduction of a quota system**, including the **trade of TRECs from 2012 onwards,** and a **fixed target for RES-E production in the EU-25 in 2020 of 24%**. This scenario is meant to provide a plausible background to the analysis of the impact of technological learning, rather than giving a forecast of how support policies in Europe might develop. Therefore, the analysis assumes a generic support policy instead of a technology-specific support. If different technologies would benefit from different subsidies, differentiated by country, as is the present situation, it would be difficult to assess the effect of the assumptions regarding technological learning.

In detail, the Reference scenario is characterised as follows. Until 2008, all EU Member States are expected to continue their current national support policies. Reflecting the uncertainty in policy developments, we assume that from 2008 until 2012 all MS replace these with generic support. This implies that they still use their preferred type of instrument, but they harmonize the support level to 5 €ct/kWh[10], not differentiated by technology. This level has been chosen to reflect a moderate ambition level, and is comparable to the current buy-out price (penalty level) of the Renewables Obligation in the UK. Many countries in Western Europe that use feed-in tariffs currently pay slightly higher levels (de Vries et al. 2003). At the time of writing, it does not seem likely that national governments opt for a joint approach towards achieving their renewables targets in 2010[11]. Therefore, the scenario does not expect international trade in RES-E to take off before 2012. After

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[10] Producers receive this on top of the electricity commodity price.

[11] For instance, the diversity of implementations of the Guarantees of Origin (GO) requirement in the Renewables Directive by different MS is not expected to facilitate a harmonised market in GO or other certificates in the short term (Linden et al., 2004).

2012, it is assumed that the quota system is used, in which TRECs are traded in a harmonized European market. Capacity installed before 2012 has still the right to make use of domestic schemes[12].

All MS are assumed to regard the 2010 targets conform the Renewables Directive as leading in the sense that the target provides an upper bound to what will be installed each year. Several studies have shown, that the 22% target for 2010 is very ambitious, and is unlikely to be met. In 2002, the RES-E production in the EU-15 was 14.8% (EREF, 2004), indicating a marginal increase compared to the figure of 14.5% in 1997. Roughly three quarters of this production is covered by large-scale hydropower, a source with almost no potential to increase for further increases. With the continuation of the present policies in the MS, it is likely that only 17-19% RES-E will be achieved by 2010 (European Commission, 2004; Uyterlinde et al., 2003). Targets for 2020 are yet to be negotiated, presumably in 2007. In this study, it is assumed that countries slow down their ambition level compared to the target of 22% in 2010, and settle for a moderately ambitious increase, yielding an overall share of 24% RES-E in 2020[13]. Table 2 presents the targets used for each country in the reference policy scenario.

Due to the chosen method of constructing MS targets by extrapolation, the implicit assumption is made that countries that were ambitious in their 2010 targets remain so, while less ambitious countries are not required to 'compensate' beyond 2010. Obviously, more advanced methods of determining a distribution of targets over countries are possible, see e.g. Voogt et al (2001) for a discussion on burden sharing options based on different equity principles but these are beyond the scope of this study. It should be noted, however, that the impact of this assumption on our assessment is limited, because in a harmonized, open TREC market in Europe beyond 2012, the 24% target is leading for the amount and the composition of additional renewable capacity installed. The targets of individual Member States in fact only determine the trade flows, but not the European technology mix, as technologies will be deployed on the cheapest locations. Note that the use of these common policy assumptions implies that, independent of the different technological learning scenarios (described in the next section), approximately the same amount of RES-E production, i.e. 961 TWh in the year 2020, is achieved, as a consequence of the exogenous quota[14].

It is also of interest to evaluate the impact of varying technological development under a different policy scenario and to compare the results with the outcomes obtained in the harmonization scenario. Therefore, also the OTLS and PTLS were combined with the CPP policy scenario variant, in which present and planned support policies are continued until 2020. The CPP variant represents a mixture of feed-in tariffs, national quota-based TREC systems, investment and fiscal support schemes, with no international trade[15]. As most MS currently have currently lower RES-E ambition levels than assumed in the harmonization scenario, and no RES-E trading occurs, the CPP scenario is basically the opposite of the harmonization scenario.

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[12] In those cases where currently available policy data indicates a longer operational period, e.g. feed-in tariffs that are guaranteed for 10 years.

[13] The targets for individual MS have been constructed by extrapolating their average growth rates conform their commitment for 1997-2010 in the Renewables Directive, while assuming that the resulting target for 2016 is actually agreed for 2020. This implies also, that in this scenario the original targets of 22% in 2010 are not (likely to be) met.

[14] It is possible that the quota is not met, in case the costs of the renewable options exceed the level of the penalty. This is however not likely to occur in this scenario due to the relative moderate quota level.

[15] A more comprehensive description of this scenario is presented in Uyterlinde et al. (2003), though the policy assumptions have been updated to the level of end of 2004.

A general background to both policy scenarios is provided by the baseline projection for the energy consumption until 2030 made for the European Commission by Mantzos et al.(2003). This projection is the source for the assumed development of the electricity demand in the member states of the EU. Electricity commodity prices (based on industrial prices minus transport cost, see Uyterlinde et al. (2003) are expected to increase from a EU-wide average of 3 €ct/kWh in 2003 to 5 €ct/kWh in 2020 due to an expected reduction in generating overcapacity and a carbon premium. Furthermore it is assumed that intermittent sources face an additional cost factor of 0.5 €ct/kWh on top of their production costs in a number of countries[16]. This is a simplification, as the height of the intermittency costs is in principal dependent on the share of intermittent electricity fed into the grid. The chosen value of the intermittency costs in 2020 is probably on the high side, as high additional costs are generally only expected at overall penetration levels of intermittent sources of over 20% (see e.g. Hoogwijk (2004)).

Table 2 RES-E targets for 2010 and 2020 in the reference policy scenario[17].

	Actual production 1997 (1999 for NMS) (%)[a]	Present target 2010 (%)[a]	Assumed target 2020 (%)[a]	Projected total electricity consumption 2020 (TWh)[b]	Assumed target 2020 (TWh)
Austria	72.7	78.1	80.6	82.1	66.2
Belgium	1.1	6	8.3	107.6	8.9
Cyprus	0.05	6	9.2	5.7	0.5
Czech Republic	3.8	8	10.3	88.8	9.1
Denmark	8.7	29	38.4	45.7	17.6
Estonia	0.2	5.1	7.8	9.8	0.8
Finland	24.7	31.5	34.6	99.4	34.4
France	15	21	23.8	654.1	155.7
Germany	4.5	12.5	16.2	656.7	106.4
Greece	8.6	20.1	25.4	88.0	22.3
Hungary	0.7	3.6	5.2	64.4	3.4
Ireland	3.6	13.2	17.6	39.7	7.0
Italy	16	25	29.2	393.0	114.7
Latvia	42.4	49.3	53.1	12.2	6.5
Lithuania	3.3	7	9	16.8	1.5
Luxemburg	2.1	5.7	7.4	9.1	0.7
Malta	0	5	7.7	4.2	0.3
Netherlands	3.5	9	11.5	161.9	18.6
Poland	1.6	7.5	10.7	255.6	27.3
Portugal	38.5	39	39.2	72.6	28.5
Slovak Republic[c]	17.9	24.6	28.3	47.0	13.3
Slovenia	29.9	33.6	35.6	15.8	5.6
Spain	19.9	29.4	33.8	365.4	123.5
Sweden	49.1	60	65	175.3	113.9
United Kingdom	1.7	10	13.8	538.1	74.3
EU-25	14.5	22	24	4008.9	961.0

a As percentage of total electricity consumption. Source: Renewables Directive (European Parliament, 2001).

b Source: EU Outlook until 2030 (Mantzos et al., 2003).

c The target for the Slovak Republic in 2010 has been adjusted to the fact that the Slovakian government intends to renegotiate the target, which was originally set at 31% (Anonymous, 2004).

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[16] Finland, France, the Netherlands, Sweden and the United Kingdom, in line with current policies for intermittent electricity sources.

[17] The targets for 2020 have been constructed by extrapolation. Targets already formulated by individual MS for 2020 were not taken into account, because only a few countries have set such targets, and for reasons of consistency in ambition levels.

3.2. Assumptions on technology development

This chapter investigates the impact of technological learning and associated cost reductions of RES-E technologies on the penetration, total cost and distribution over the various MS. Technological learning can be modelled endogenously by using the EC approach. However, given the empirical nature of ECs, the PR of a technology is always somewhat uncertain. Most studies rather present ranges in which the PR may vary, and recommend using these ranges in scenario-analysis[18] (Neij et al., 2003; Schaeffer et al., 2004; Junginger et al., 2004b; Junginger et al., 2004c). Therefore, an optimistic and a pessimistic technological learning scenario (OTLS and PTLS) were formulated. In the OTLS, the lower (i.e. more optimistic) boundaries of these ranges are utilized. The main underlying assumption in the OTLS is, that technological development of RES-E options is actively pursued and supported by policy measures. As recently suggested by Schaeffer et al. (2004), 'investing in learning'[19] may lead to lower (i.e. better) PRs, at least in the case of photovoltaic modules. Such a scenario would for example include financing of long-term RD&D research including financial support for pilot plants, building and supporting user networks etc. In contrast, in the PTLS the effects of slower technology development are explored. This would correspond to fewer efforts from both the public and the private sector to further develop RES-E technologies.

In these scenarios, the reduction of the investment costs of four technologies have been modelled using the EC approach: solar electricity (PV), onshore wind, offshore wind and biomass gasification[20]. These renewable energy technologies both have a significant geographical potential within the EU-25 and substantial cost reduction opportunities (Faaij et al., 1998; IEA/OECD, 2003; de Noord et al., 2004; Schaeffer et al., 2004; Junginger et al., 2004b; Junginger et al., 2004c). The remaining technologies were either deemed to have no significant cost reduction potential (such as different forms of biomass combustion and large-scale and small-scale hydropower) or to have too high costs and limited potential until 2020 (e.g. wave energy) to have any significant impact on the European electricity market (IEA/OECD, 2003; de Noord et al., 2004).

Technological learning of RES-E technologies like solar PV, wind turbines and BIG/CC occurs on a global level, i.e. improvements of a technology (e.g. a wind turbine) are rapidly adopted all over the world. As the EC concept uses cumulative installed capacity as a proxy for accumulated experience, worldwide (and not only European) development of capacities should be used to measure cumulative experience. However, the ADMIRE-REBUS model currently models the development in the EU-25 MS only. To take technological developments and capacity additions achieved in the rest of the world (ROW) into account, also assumptions had to be made on the development of the installed capacity of each technology until 2020 in the ROW. These assumptions were deliberately chosen to be identical in both the OTLS and PTLS, allowing for a better comparison and interpretation of the differing results of the scenarios. In general, the capacity growth expectations in the ROW were mainly based on the World Energy Outlook 2002

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[18] These ranges may appear small at first glance (e.g. 77-80% for photovoltaics). However, with an increasing number of cumulative doublings of capacity, even such a small difference may cause huge differences in the outcome of the scenarios, as the PR is one of the most sensitive parameters in energy models (van der Zwaan and Seebregts, 2004).

[19] The total amount of support spent on technology development up to the point of market break-even. This happens not only through RD&D actions, but also through support of learning-by-using and learning-by-interacting processes (Schaeffer et al., 2004). However, it is not easy to quantify or predict the effect of such policy measures beforehand.

[20] Other performance indicators, like the availability or the conversion efficiency of technologies were modelled exogenously (see de Noord et al. (2004)).

(WEO)(IEA/OECD, 2002)[21] and the reference scenario of the World Energy, Technology and climate policy Outlook (WETO) (European Commission, 2003)[22].

Below, the *assumptions for the PRs* and *capacity growth outside the EU-25* are presented for each of the four technologies scrutinized. An overview is presented in Table 3.

Table 3 Overview of assumptions on technological development in the OTLS and PTLS.

	PR OTLS	PR PTLS	Assumed initial investment costs in 2001 (€/kW)	Assumed capacity ROW 2001/2020 (GW)
PV	77%	80%	5400	1.5 / 22
Wind onshore	81%	85%	860-1240[a]	6.1 / 93
Wind offshore	[b]	[b]	1690-2080	0 / 2.1
Turbine	81%[c]	85%[c]		
Foundation	[d]	[d]		
Conv. stations	71%[c]	71%[c]		
Cables	62%[c]	62%[c]		
Installation	77%	77%		
BIG/CC	91%[e]	93%[e]	3400 (in 2001)	See methodological discussion (section 5)
Pretreatment	87%	87%	OTLS: 1600 (in 2014)[g]	
Gasif. system & gas cleaning	80%	82%	PTLS: 2035 (in 2014)[h]	
Comb. Cycle & compressor	89%[f]	90%[f]		
Other components	100%	100%		

a Depending on the technology band. For a definition and detailed description of all technology bands, see de Noord et al. (2004).

b No PR is given, as the cost developments depend on an aggregate of several underlying ECs for the different components of an offshore wind farm, and the development of onshore wind capacity. For further details see Junginger et al. (2004c).

c For these components, also the speed of diffusion of onshore wind turbine and HVDC technologies influences the cost reduction (Junginger et al., 2004c).

d Based on trend analysis, an annual cost reduction of steel (the main component of monopile and tripod foundations) of 2% and 1% was assumed in the OTLS and PTLS respectively.

e This is an aggregated PR, based on the development of several underlying PRs for the different components listed below. For further details see Faaij et al. (1998).

f These values correspond well to the value given by Claeson Colpier (2002) for natural gas turbine combined cycles (90%).

g Assuming realization of 10 pilot plants until 2014.

h Assuming realization of 3 pilot plants until 2014.

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[21] The WEO 2002 include the IEAs projections of the global energy system until 2030, based on the IEAs World energy model. In their reference scenario, the overall share of non-hydro renewables is expected to grow 3.3% annually on a global level, but most growth is expected to occur in OECD countries, especially in those with strong measures to promote renewable energy.

[22] The WETO reference scenario provides a description of the future world energy system, under a continuation of the on-going trends and structural changes in the world economy, and is based on the POLES model. The share of RES-E is expected to increase from 2% in 2000 to 4% in 2030.

For *photovoltaics*, PRs of 77% and 80% were chosen for the OTLS and PTLS respectively, based on recent findings of Schaeffer et al. (2004). The assumed capacity growth in the ROW was mainly based on the WEO and WETO expectations (15 and 30 GW respectively in 2020). For the OTLS and PTLS scenarios, in the ROW a further growth to 22 GW in 2020 of installed PV capacity was assumed.

Regarding *onshore wind*, PRs of 81% and 85% are based on the approach that wind energy technology learns on a global level (Junginger et al., 2004b). For the ROW capacity growth until 2020, next to the WEO and WETO results, also other forecasts about market development (Molly and Ender, 2004; Westwood, 2004) were taken into account. Again, a moderate exponential growth was assumed, in between the WETO and the WEO scenario. This leads to 93 GW installed onshore wind capacity in the ROW in 2020.

For *offshore wind*, the EC approach is not directly applicable, as not sufficient offshore wind farms exist so far. A possible method to overcome this issue is to analyze the cost reduction potential for each of the main components of offshore wind farms. These are wind turbines, foundations, electrical infrastructure and installation costs. For each of these components, it is possible to analyze the cost reduction potential. For example, the cost reductions achieved for onshore turbines also benefit the costs of offshore turbines. Foundations like monopiles, gravity based structures and tripod structures have been utilized for several decades in the offshore oil and gas industry. For each of these components, the cost reduction trends and underlying mechanisms were analysed, and (where possible) separate ECs were set up. More detailed information is given by Junginger et al. (2004c). Regarding the developments of offshore wind energy in the ROW, few forecasts were found in the literature. An installed capacity of 680 MW in 2008 was assumed based on expectations for North America (Westwood, 2004). In absence of any further estimates, from 2008 onward a moderate 10% annual increase of this capacity was assumed, resulting in 2.1 GW offshore wind capacity in 2020 for the ROW.

Similarly to offshore wind farms, ECs for large-scale *biomass gasification* plants (BIG/CC) cannot be devised directly. However, as with offshore wind farms, estimates can be made for each component of gasification plants using the EC concept. Based on Faaij et al. (1998), assumptions were made for the cost reduction potential of specific plant components. These included standard components such as fuel storage and preparation, and the entire steam cycle (including steam turbine and condenser) for which practically no cost reduction potential was assumed. Also standard costs for civil works, engineering piping, site preparation etc. were kept constant. For the biomass gasification specific components, such as the fuel feeding system, gasifier, tar cracker, cyclones, gas cooling and gas cleaning, estimates were made how upscaling a 30 MW plant to 100 MW and learning by building several plants may contribute to cost reductions for these components. Combining the estimates for all components, an overall PR varying between 91-93% was determined. Recent empirical research for plants utilizing fluidized bed boilers has shown that the new components show lower (i.e. better) PRs than the overall plant investment costs (Koornneef, 2004). The PR of fluidized bed combustion power plants (which are somewhat similar in size and technology to gasification plants) was found to lie between 90-93%, which is in agreement with our assumptions. Regarding the market introduction of biomass gasification, no suitable forecasts were found in literature. For that reason, assumptions were made based mainly on expert opinions. So far, biomass gasification for electricity production has been applied in two ways. First, the product gas is (co-)fired, which was successfully demonstrated at plants in Lathi, Finland, and Geertruidenberg, the Netherlands. The second options is to clean the product gas extensively and to use it in a combined cycle (BIG/CC) plant. In the past decade, two main BIG/CC pilot plants have been built: the Värnamo plant in Sweden and the ARBRE plant in the UK (Morris et al., Forthcoming, 2005). Currently, the major technical problems of gasification for BIG/CC power production include gas cleaning, advanced fuel feeding and NOx control technology (Nieminen, 2004). The costs of gas cleaning can be significantly reduced if the scale of operation is maximized (Babu and Hofbauer, 2004). In conclusion, several more pilot plants (with increasing scale) are required to successfully develop commercial BIG/CC power plants. In the OTLS it was assumed that until 2014, ten demonstration BIG/CC plants are built. With these plants substantial experience can be gained, both to lower investment costs and to demonstrate technical reliability and commercial viability. BIG/CC plants are then introduced in the market from 2014 onwards. In the PTLS, only three such pilot plants were assumed to be built. In combination with different PRs for gasification technology, the investment costs (and thus the cost of electricity) differ significantly in the OTLS and PTLS scenario.

4. Results and discussion

4.1. Technology-specific developments

An overview of the development of RES-E electricity production from 2001 until 2020 and the contribution of different technologies is shown in Figure 3. In Figure 4, the development of electricity production volumes of the major biomass options and offshore wind energy are also displayed over time.

The net installed *PV* capacity varies slightly from 1.2 GW in the PTLS to 1.5 GW in the OTLS, which lies in between WEO (4 GW) and WETO (1 GW) expectations for Europe. Until the year of harmonization (2012) PV is supported by national incentives, and installed capacity grows in both scenarios. After international trade starts in 2012, in the PTLS, no further capacity is added. In the OTLS, capacity continues to grow slightly[23], but the total electricity contribution (less than 3 TWh) to the overall RES-E target for 2020 is marginal (about 0.3%).

For *onshore wind*, the growth in annual added capacity varies little between the OTLS and PTLS (see Figure 3 and 5). In both cases, the annual added capacity is mainly limited by the available geographical potential for low-cost wind electricity in the EU-25 countries. The total installed capacity increases to about 107 GW in 2020, corresponding to an annual production of about 247 TWh in 2020. This capacity falls well within the range of the WETO/WEO scenarios and is also similar to the results of scenarios without endogenous technological change. Thus, onshore wind can be regarded as a relatively robust option. Its application does not greatly depend on further cost reductions.

In both the OTLS and the PTLS, *offshore wind* capacity increases continuously until 2020 (see also Figure 4). From 2014 onwards, the annual additions start to slow down in the optimistic learning scenario, and the total diffusion in 2020 in the OTLS (7.3 GW, 22 TWh) is lower than in the PTLS (11 GW, 36 TWh), as a result of the advantageous development of other technologies, especially biomass gasification.

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[23] The growth occurs in Italy. This has two reasons. First, investment costs are reduced over 60% until 2020 (see Table 4). Consequently, the total production costs of PV are 7.5 €ct/kWh in 2020. Second, Italy has a relatively high electricity commodity price (6.2 €ct/kWh) compared to other countries. Therefore, PV can compete with other RES-E options in Italy. This is not the case in other countries, at least not until 2020.

Biomass gasification displays by far the two most differing trends in the two scenarios. In the OTLS, the annually installed capacity increases rapidly from 2014 onwards and reaches about 24 GW in 2020, corresponding to an annual electricity production of 133 TWh. Contrary, in the PTLS, biomass gasification capacity remains marginal until 2018, and only starts to increase in capacity in the last two years of the chosen time frame (see also Figure 4), reaching 5 GW by 2020. This is clearly due to the different investment costs assumed in both scenarios. With 1600 €/kW, gasification can compete with the more expensive forms of biomass combustion, leading to a rapid increase in capacity, which in turn leads to further cost reductions. In the PTLS, where investment costs are 25% higher, gasification remains a niche option for five more years. This indicates, that the outcomes of the scenarios are highly sensitive to (assumptions about) technological development for biomass gasification.

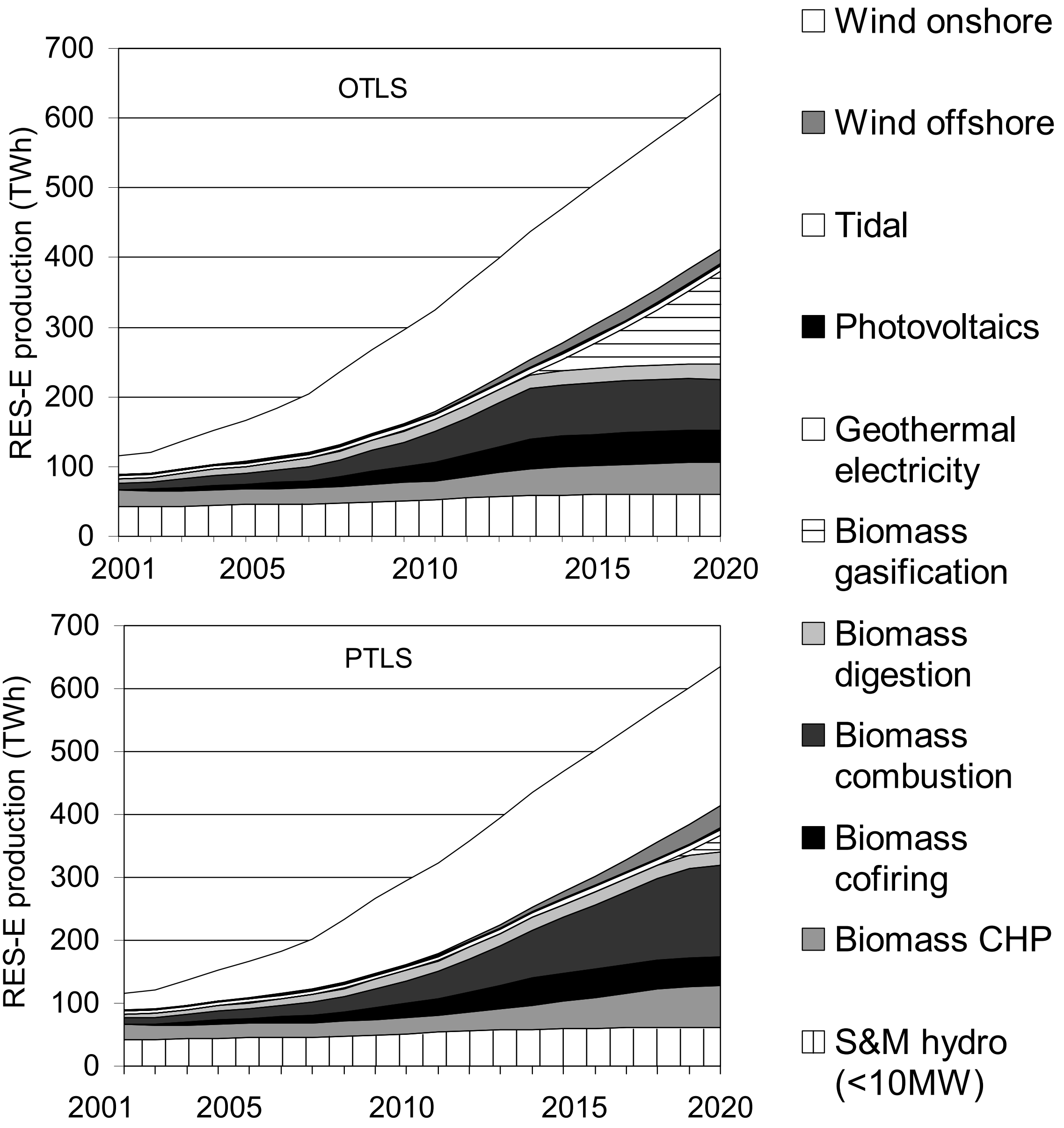

Figure 3 RES-production of all technologies in the OTLS and PTLS. Large scale hydro has been excluded, as the annual production is almost constant (2001: 312 TWh, 2020: 326 TWh in both scenarios). The contributions of tidal and PV electricity are marginal and barely visible.

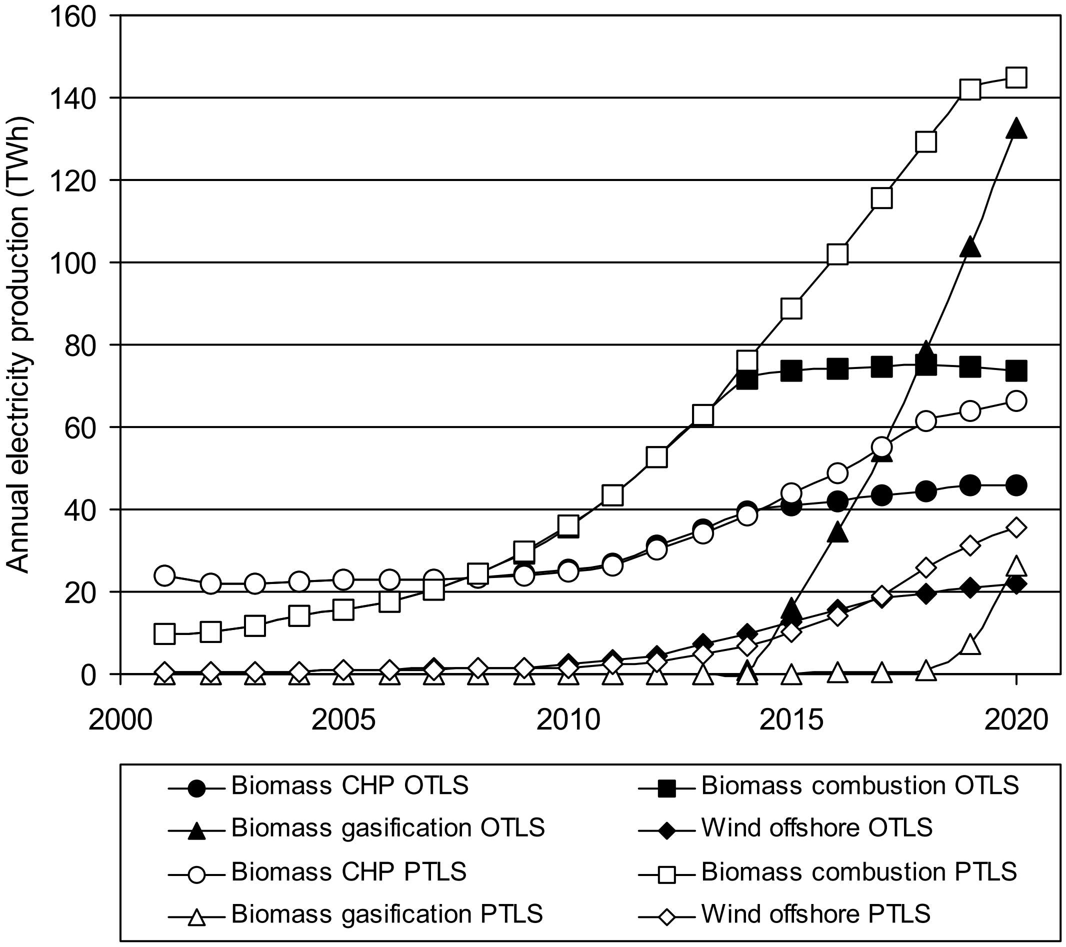

Figure 4 Annual electricity production for the major biomass technologies and offshore wind energy in the OTLS (black symbols) and PTLS (white symbols) from 2001-2020.

Finally, Table 4 gives an overview of the reduction of investment costs in 2020, compared to 2001 in the OTLS and PTLS. The impact of different assumptions about learning is clearly visible in the resulting investment cost level. For some technologies, such as biomass gasification, the faster cost decrease leads to higher installed capacities, thereby lowering costs further. The lower investment costs in the OTLS are reflected in lower overall production costs for all technologies concerned, as further described in Section 4.4.

Table 4 Investment costs level in 2020, in €/kW and relative to the level in 2001, in the different technological learning scenarios.

	OTLS €/kW (% of 2001)	PTLS €/kW (% of 2001)
PV	1840 (34 %)	2160 (40 %)
Wind Onshore	390-560 (45 %)	460-660 (53 %)
Wind Offshore	1100-1350 (65 %)	1230-1520 (73%)
Biomass gasification	1120 (33 %)	1770 (52 %)

4.2. Competition among renewable technologies

The strong cost reduction of biomass gasification technology in the OTLS does have an effect on the competitiveness between a number of RES-E options. Biomass gasification will mainly compete with other biomass options for the biomass supply. This is clearly shown in Figure 5. Biomass combustion and biomass CHP both lose significant shares compared to the PTLS. However, the ultimate competition is based on the price of electricity, and thus biomass gasification also competes with offshore wind energy. As biomass gasification strongly determines the outcome of the OTLS, another scenario was evaluated: OTLS-LG (late gasification). In this scenario the rate of technological learning and cost reductions for wind onshore, wind offshore and PV are the same as in the OTLS, but for biomass gasification, the pessimistic assumption from the PTLS was used. The aim was mainly to analyse whether offshore wind would gain substantially more market share against the biomass combustion options. The results show, that this is only partially the case: in OTLS-LG, RES-E production is 25% higher than in the PTLS, but this is still substantially less than the RES-E production from biomass gasification in the OTLS. The outcome of this exercise is also depicted in Figure 5.

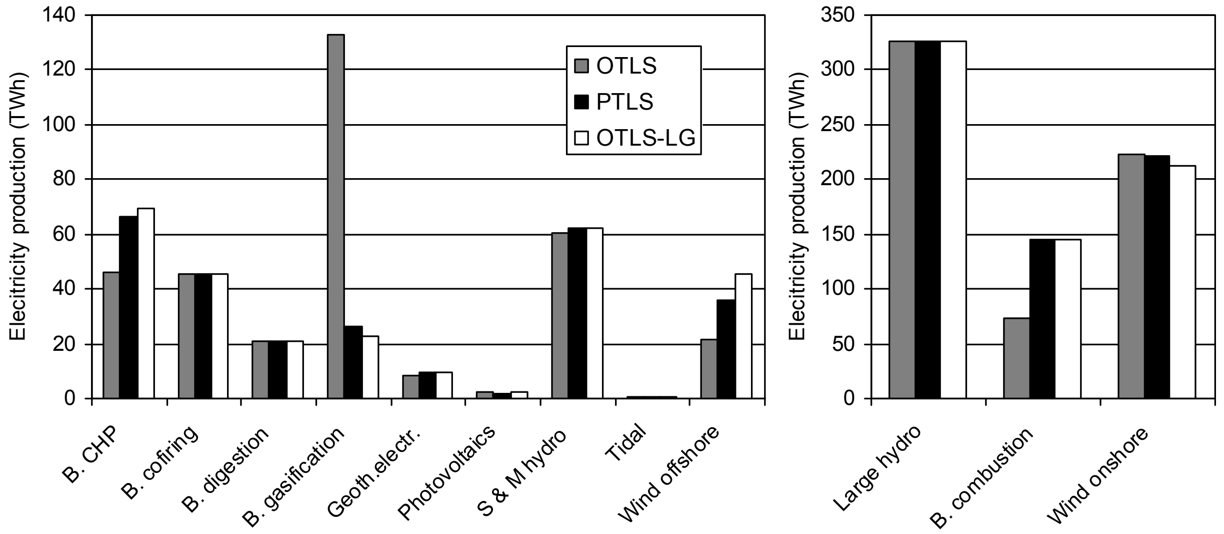

Figure 5 Overview of electricity production levels in the OTLS and PTLS. The OTLS-LG scenario analyses the case with optimistic learning assumptions for offshore wind but pessimistic assumptions for biomass gasification.

4.3. Options for individual countries

Depending on the application potential of specific renewable energy sources and the RES-E targets set for 2020, individual MS have different possibilities for achieving their target domestically. Moreover, the different technological learning scenarios have an impact on the costs of these technologies relative to each other and therefore may impact the costs and composition of the preferred technology mix of a Member State.

For Germany these effects are clearly visible. The development of offshore wind and biomass gasification both start around 2012. Figure 6 shows the production of RES-E in Germany in 2020 by source. In the OTLS, biomass gasification plays a significant role, whereas in the PTLS, production from gasification is zero, while biomass combustion, CHP and offshore wind have a larger contribution. So when gasification becomes cheap enough, it takes over production from combustion and from offshore wind. When the learning effects of gasification are limited, as in the PTLS, biomass combustion will develop to a large-scale source of RES-E, and wind offshore gain importance, but must compete with biomass CHP.

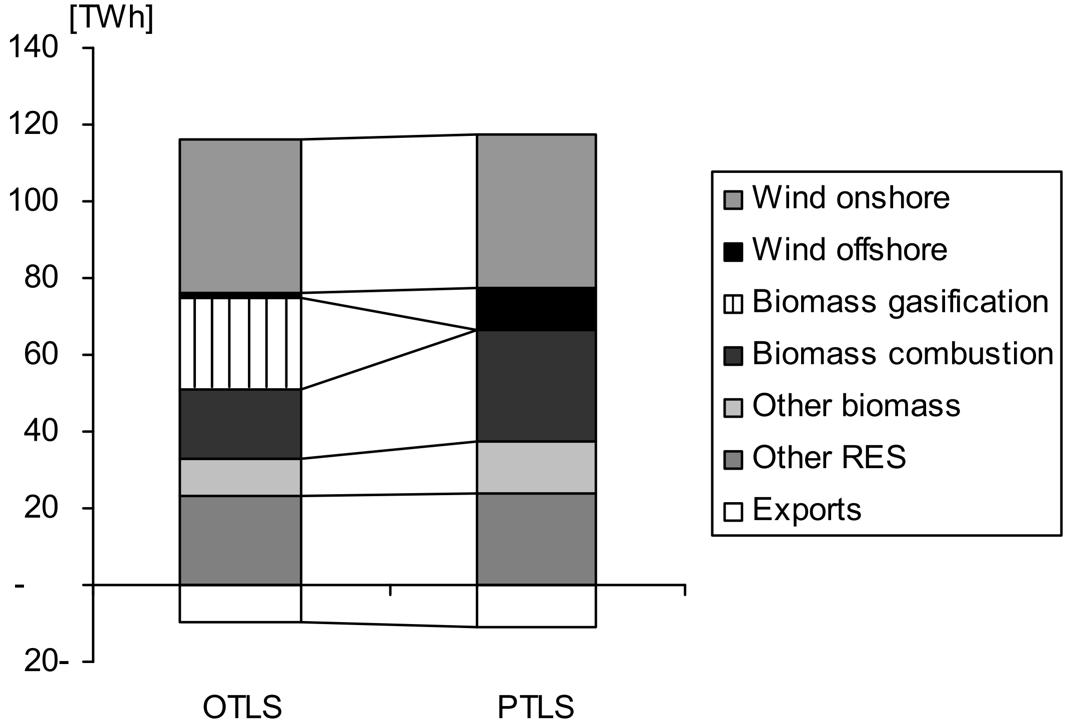

Figure 6 RES-E production in Germany in the OTLS and PTLS in 2020.

While the German situation seems to lead to a rather straightforward choice between biomass gasification and wind offshore, a different outcome is observed for the Netherlands. Comparable to the trend in the EU, the contribution of offshore wind is larger in the PTLS than in the OTLS. Apparently, in the PTLS, wind offshore can compete better to the other renewable energy options than in the OTLS, although wind offshore has a substantial contribution in this scenario as well. However, in the OTLS the contribution of biomass-based electricity, particularly from gasification, is only slightly higher than in the PTLS. The remainder of the difference between OTLS and PTLS is compensated by imports. This indicates that for the Netherlands, due to limited indigenous supply of biomass, it is cheaper in the OTLS to import RES-E than to produce it domestically. Moreover, for the Netherlands, offshore wind appears to be a strategic option when it comes to extending RES-E supply.

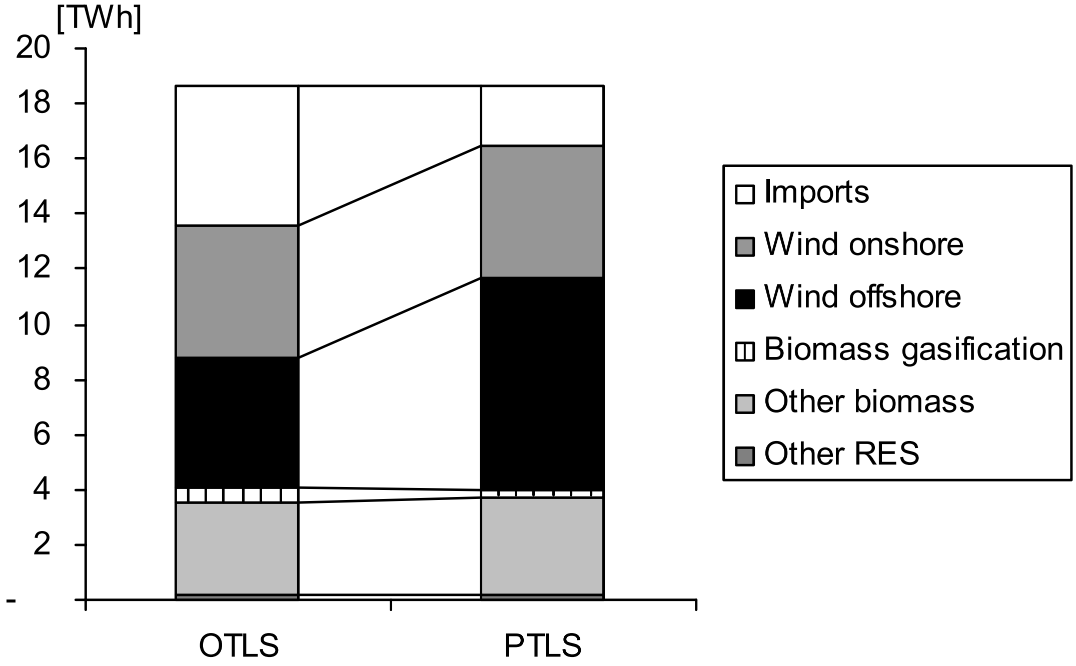

Figure 7 RES-E production (and imports of RES-E certificates) in the Netherlands in the OTLS and PTLS in 2020.

For other EU Member States, roughly three patterns are observed. First, a number of countries have significant wind offshore potentials but limited cheap domestic biomass resources (such as Denmark and the UK). For these countries, the model results indicate that in the OTLS and PTLS similar amounts of offshore wind capacity are installed. Second, in countries in Central and Eastern Europe, where biomass is one of the major renewables resources, the main competition is among biomass combustion, biomass CHP and biomass gasification, depending on the technology-learning scenario. Finally, some countries do not greatly rely on either of these options, and do not show large differences in technology choices. Nevertheless, these countries are also facing higher costs if technological learning progresses at a lower pace, as in the PTLS.

4.4. The costs of achieving the targets and learning investments

The costs of achieving the 24% target in both scenarios differ due to differences in technology costs and technology choices. In Table 5, the costs in both scenarios in 2020 are compared.

Table 5 Overview of costs for the EU-25 in 2020.

	Total additional production costs [a] (bln euro)	Total expenditures [a,b] (bln euro)	Equilibrium price [a, c] (€ct/kWh)	Green market size [d] (TWh)	Average additional cost [c, e] (€ct/kWh)
OTLS	9.0	14.2	2.1	661	1.4
PTLS	11.1	20.3	3.1	648	1.7

a For definitions, see section 2.1.3.
b This is the green market size multiplied by the equilibrium price.
c On top of an electricity commodity price of 5 €ct/kWh.
d Note that roughly one-third of the total RES-E production does not participate in the TREC market and does not receive any additional financial support. This 'grey' part of the market consists mainly of large hydropower and waste-to-energy production.
e The average additional cost level of all RES-E technologies, of which certificates are traded in 2020.

The additional production costs represent the costs of the options additional to the electricity commodity price, assuming no separate investment support is given (see section 2.1.3). The 24% difference between total additional production costs in the OTLS and PTLS reflects the fact that in the PTLS, the production mix of RES-E consists of more expensive technologies. The total expenditures represent the amount of money spent in order to stimulate renewables deployment. It is evident that the higher cost level in the PTLS, which results in a one-cent higher equilibrium price, causes total expenditures in 2020 to be significantly higher with 43%.

The difference between total expenditures and total additional production costs is the producers' surplus. In the PTLS, the producers' surplus is much larger than in the OTLS, indicating that the cost level of the majority of the supply options in the PTLS is comparable to the OTLS, but that the costs of the marginal option (which determine the equilibrium price) appear to be substantially higher. Indeed, the marginal option in the PTLS appears to be biomass gasification, which is needed for achieving the targets, but assumed to be still relatively expensive in 2020 in this scenario. This shows that in a market based system, where total expenditures are determined by the price of the marginal option, the quota and penalty level should be determined with great care, because a high equilibrium price can cause large windfall profits for the majority of RES-E producers.

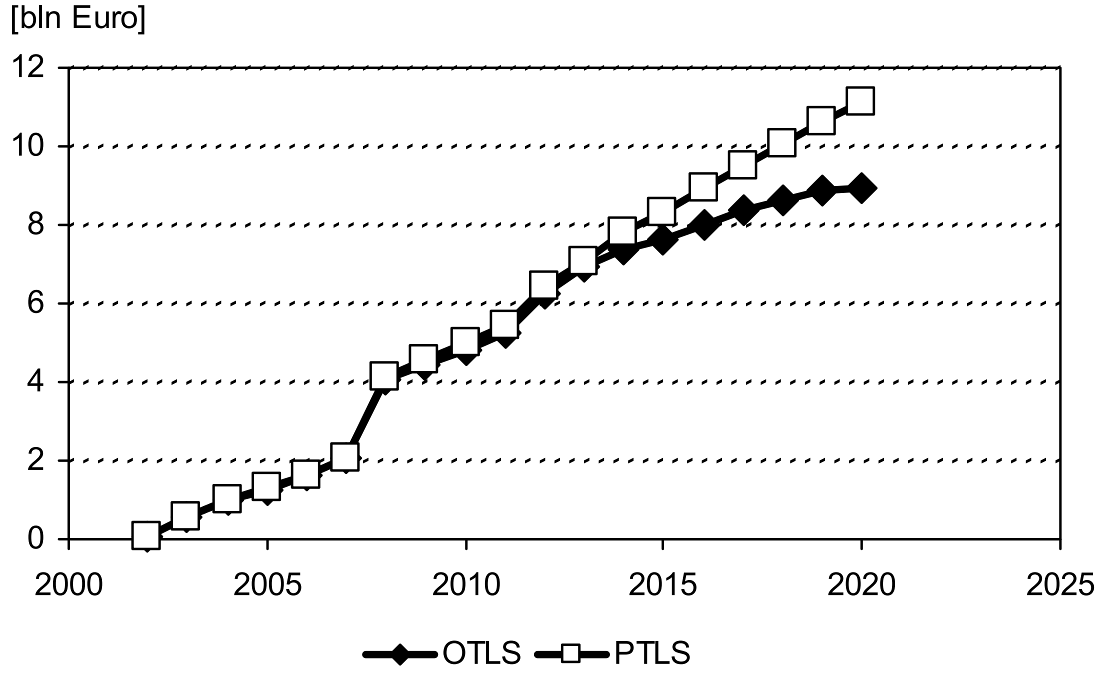

Figure 8 Total additional production costs in the two scenarios on technological learning.

From Figure 8 some additional insights in the development of the production costs over time can be gained. Obviously, the increase of total costs corresponds to the increase in production levels. Also the difference in costs levels between OTLS and PTLS increases over time, especially in the period after 2012, when the competition between technologies is enhanced. Furthermore, there is a significant cost increase visible in 2008 in both scenarios. This is due to the transition from the national support policies to the generic EU policy to promote RES-E. For MS with previously low ambitions (i.e. minimal policy support instruments), this implicitly leads to an increase in ambition level and therefore a peak in the costs. Indeed, transitions from one support scheme to another always encompass some risks and a change should therefore be implemented in a gradual fashion.

The overall goal of all RES-E support – be it RD&D or operational support – is to establish a cost reduction for these technologies that allows them to approach the break-even point where they can compete with fossil fuel based electricity generation. The sooner this is reached, the better, because it saves the expenditures related to additional support. This is particularly important given the increasing difference between the costs in OTLS compared to PTLS. Therefore, the main question would be how much RD&D efforts are required to achieve the PRs assumed in the OTLS instead of those in the PTLS. For this purpose Kouvaritakis et al. (2000) propose to quantify the concept of 'investing in learning'[19] further by extending the EC described in Section 2.2 with a factor reflecting cumulative RD&D expenditures[24].

Within the scope of this paper, it is not possible to determine directly the amount of RD&D spending necessary to achieve the progress ratios in the OTLS instead of those in the PTLS. Nevertheless, given the increasing difference between the total additional production costs in OTLS and PTLS (Figure 8), there is a clear trade-off between investing in learning by searching – reflected in RD&D expenditures – and learning by doing – reflected in direct support expenditures. For technologies that are approaching the point of large scale market introduction, such as offshore wind and biomass gasification, it seems particularly worthwhile to invest in pilot plants and demonstration projects in order to reduce their costs. For illustration, the difference in total additional production costs in the period 2001-2020 between the OTLS and PTLS is 9600 million Euro, i.e. about 480 million Euro per year on average. For comparison, in 1998, the individual EU-15 MS and the EU spent in total (as a rough estimate) about 400 million Euro on public RD&D[25] on renewables. In other words, given the assumptions on a harmonization policy scenario and technology development, the model illustrates that higher technological progress and associated cost reductions may result in savings for market introduction measures in the same order of magnitude as current public RD&D expenditures[26].

4.5. Effects of technological learning under the continuation of present policies

The OTLS and PTLS were combined with the CPP scenario variant, in which present and planned support policies are continued till 2020. The CPP variant represents a mixture of feed-in tariffs, national quota-based TREC systems, investment and fiscal support schemes and no international trade in TRECs. Due to the lower ambition level in most member states, in the CPP scenario total RES-E production levels are much lower: 743 TWh in the OTLS-CCP variant, and 739 TWh in the PTLS-CCP, compared to 961 TWh in the harmonization scenarios. This difference is mainly the result of less RES-E production from biomass combustion, biomass gasification and about 20% less RES-E production from wind onshore.

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[24] Work on parameter estimates and applications of this two-factor learning curve is in progress, see for instance Klaassen et al. (2003) and Miketa and Schrattenholzer (2004).

[25] This estimate is based on two main figures. First, the spending of individual MS was approximately 265 million Euro in 1998 ((IEA, 2005), based on 254 million US$ of 2002). Second, in the 5th framework programme of the EU (1998-2002), 1042 million Euro were spent on RD&D for all energy technologies except nuclear energy (EU CORDIS, 2005). Based on the program content, it was assumed that roughly half of this amount was spent on renewables, resulting in annual expenditures of about 130 million Euros on RD&D for renewables.

[26] However, an unknown (but probably substantial) amount of private RD&D was not included in this comparison.

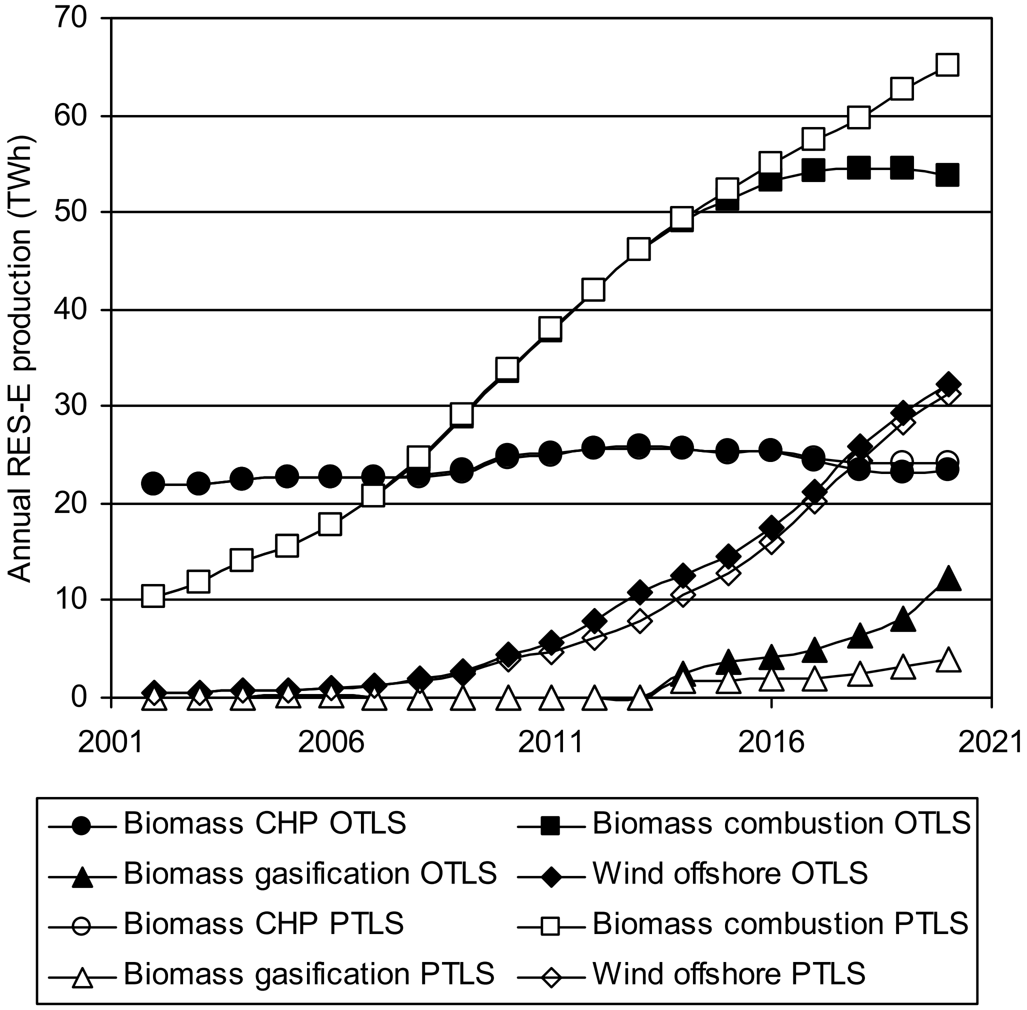

Figure 9 Annual electricity production for the major biomass technologies and offshore wind energy in the OTLS (black symbols) and PTLS (white symbols) from 2001-2020 under CPP assumptions.

For most technologies, the total RES-E production trends within the EU-25 do not differ greatly between the OTLS and PTLS (see Figure 9). As can be seen, Biomass CHP and wind offshore display almost identical trends. This also holds for the other biomass options, onshore wind and large hydropower (not shown in Figure 9). This can be explained by several factors. First, as the element of trade is missing in this scenario, there is also less competition between the RES-E options. Second, the cost of electricity is not the main limiting factor for the implementation of some technologies. For onshore wind, the availability of suitable land area is a more important barrier. In the case of biomass conversion technologies, the supply of biomass is a key parameter. However, as can be seen in Figure 9, there is competition (per MS) for the biomass resource between biomass combustion and biomass gasification. While in the PTLS biomass combustion reaches 65 TWh, in the OTLS production is less than 55 TWh, as the remaining biomass potential is claimed by biomass gasification. Furthermore, the RES-E production in the OTLS does actually increase, as a result of technologies that are not limited by resource or land requirement constraints, such as PV. Over the entire EU-25, RES-E production from PV is about 28% higher in the OTLS than in the PTLS. In MS with a feed-in tariff system, this difference can be much higher. For example, in the Netherlands, where a feed-in tariff for PV is given, the electricity production from

PV is 114% higher in the OTLS than in the PTLS (231 vs. 108 GWh). This is an important difference with the harmonization scenarios. In this example, PV does not have to compete with other RES-E technologies, and may also penetrate when its costs are higher than the penalty price of 5 €ct/kWh of the harmonization scenario. Thus, it appears that less competition may result in higher technological learning and an increase of PV deployment.

When comparing the OTLS and PTLS and the two policy scenarios, the Netherlands display also a peculiarity. Under the CPP scenario, the indigenous production of RES-E is higher in the OTLS than in the PTLS (see Figure 10), due to additional production from biomass gasification, wind onshore and wind offshore. Under the harmonization scenario, this is vice versa: under the OTLS less electricity is produced indigenously, as cheaper RES-E is available abroad (see also Figure 7).

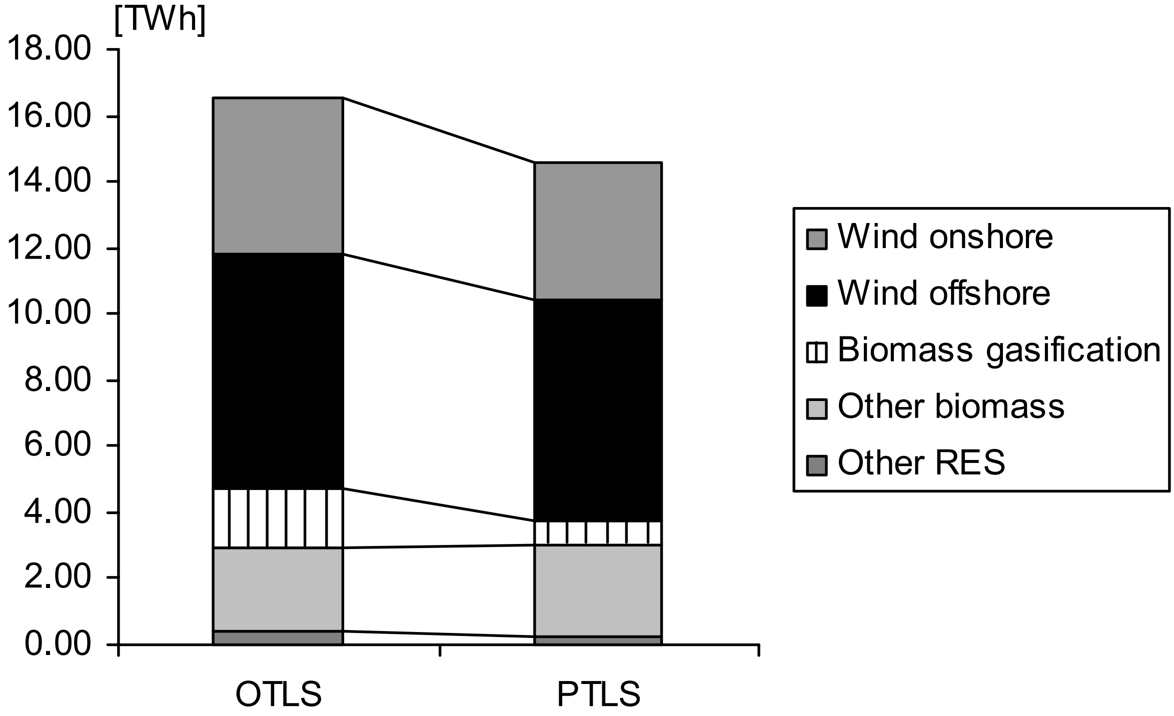

Figure 10 RES-E production in the Netherlands in the OTLS and PTLS in 2020 under CPP assumptions.

5. Methodological Discussion

Regarding the methodology followed on implementing endogenous learning, a number of limitations of the present study have to be highlighted. First of all, assumptions had to be made for the capacity growth in the ROW, mainly influencing the development and cost of solar PV electricity, as in 2001, about 88% of all PV capacity was installed outside the EU25, and this share may increase to 93-95% in 2020. Therefore, the cost reductions for PV are only to a limited extent modelled endogenously. For onshore wind this share is both less high (22% in 2001 and 46% in 2020), and less relevant, as the results show that it is already a relatively low-cost option, and does diffuse strongly in both scenarios. For offshore wind the technological change and cost reductions will depend to an even larger extent on the developments in Europe. It is expected that only about 2 GW of offshore wind capacity is placed outside the EU-25 until 2020, compared to 7-22 GW in Europe. Therefore the influence of this ROW-capacity on the cost reductions is relatively small.

A similar methodological issue is the modelling of cost reductions of large-scale biomass gasification plants. The year 2014 was chosen as introduction year in the OTLS, as starting in 2004 a ten-year time period was deemed the minimum required time span to develop such large-scale plants. However, the choice of how many pilot plants are built until 2014 (and thus to what level investment costs may decline) is somewhat arbitrary. From 2014, biomass gasification technology is implemented extremely fast: about 24 GW of capacity in only six years in the case of OTLS. This growth is equivalent to 40 plants (of 100 MW each) per year. While such a growth rate may seem unrealistic at first glance, it has to be placed in a larger frame. First, the total thermal capacity in the EU-25 in 2001 was about 380 GW (EIA, 2003). Assuming an average life span of 30 years, more than 12 GW of thermal capacity have to be replaced each year, apart from adding capacity to fulfil the increasing electricity needs until 2020. Thus, capacity additions of 4 GW per annum within the EU-25 are quite feasible. Second, the gasification capacity in the OTLS is basically replaced by other biomass combustion options (and offshore wind) in the PTLS scenario. The total biomass capacity growth is mainly limited by the available biomass supply. Third, such a rapid diffusion of a new technology as modelled in the OTLS is not common, but also not impossible. For example, the combined cycle gas turbine capacity in only 6 EU countries (UK, the Netherlands, Germany, Italy, Belgium and Finland) increased from 1.9 GW in 1990 to over 30 GW in 1997 (Watson, 1997). Thus, it is concluded, that the strong diffusion is optimistic, but certainly not unrealistic.

In addition, no assumptions were made in the OTLS on further growth of biomass gasification in the ROW after 2014. Given the low investment costs, it is plausible that also outside the EU-25, gasification capacity would drastically increase, as especially the global pulp and paper industry and the sugar industry are likely to embrace biomass gasification technology. Additional learning and cost reductions would probably occur, further lowering the electricity production costs. Thus, the overall costs to reach the target of 24% RES-E in 2020 may be even lower than modelled. On the other hand, this does have little influence on the OTLS scenario outcome in terms of capacity and electricity production volumes, as these quantities are already limited by the available biomass supply.

The biomass supply is another issue deserving explicit attention. Especially for the ten NMS of the EU, relatively modest assumptions on the availability of biomass (such as energy crops and forest residues) have been made in ADMIRE REBUS. Recent results from the EU-funded Viewls study (van Dam and Faaij, 2004) show that especially the potential of energy crops such as willow may be over a factor of 10 higher for countries like Poland (also at relatively low costs) than assumed in the ADMIRE-REBUS database. This would have a profound influence on the competitiveness of all biomass options. Also, no trade of biomass (e.g. in the form of pellets) between MS was modelled. If this would have been implemented, the TREC import / export balances of individual MS may develop differently. Furthermore, import of biomass from outside the EU-25 was not included in the model, which leads to an underestimation of RES-E production from biomass, as biomass imports from e.g. Canada, Brazil and White Russia are increasing rapidly in recent years (IEA Task 40, 2004). A larger diffusion of biomass technologies may in turn also result in stronger learning effects. On the other hand, an increased demand for biomass for biofuel production for transport may limit the available biomass potential for RES-E production. All these issues should be further investigated.

Furthermore, a promising technology that has not been evaluated in the current analysis, but which might contribute significantly to future renewable energy supply, is solar thermal power production.

With costs presently around 10-13 USD cent/kWh and these costs are expected to decrease in the coming years, it is an option to be considered for densely populated areas with high direct solar irradiation areas in e.g. Southern Europe (NREL, 2003).

Another issue are the additional costs caused by high penetration levels of intermittent electricity sources. In the ADMIRE REBUS model, no modelling is performed concerning the physical consequences on the power system. With high penetration degrees of intermittent electricity sources, additional costs are made due to the increased need for back-up capacity and/or electricity storage, spinning reserve, and potentially an increasing amount of discarded electricity. To compensate for these costs, an intermittency penalty of 0.5 €ct/kWh is currently used in ADMIRE REBUS. The actual share of intermittent energy sources (onshore wind, offshore wind and PV) in 2020 is about 7% of the predicted demand of 4 PWh in the EU-25 in both the OTLS and PTLS scenarios. According to a recent study for the European OECD countries, at 7% penetration level, the overall additional costs are likely far lower than 0.5 €ct/kWh (Hoogwijk, 2004). However, as large amounts of (especially offshore wind) power may be fed into the grid at a single connection point, the costs of grid fortification may be locally high for areas like northern Germany, Denmark, the Netherlands and the UK.

6. Conclusions

This chapter has presented results of a model simulation, focusing on the prospects for RES-E technologies under different technological learning scenarios. The results provide a basis for further understanding the role of technological learning for technologies that are rather close to market penetration. The analysis has assumed a moderately ambitious policy scenario, where technologies have to compete on the market in the period beyond 2012. Competition will not only involve economic aspects, but also potentials for renewables deployment, as taken into account in the model evaluation.

Against this background, the consequences of technological learning on the market success of technologies may be largest for offshore wind and biomass gasification. For biomass gasification, the direct impact of optimistic technological learning assumptions can be strong. However, the large difference between the OTLS and PTLS indicates a large uncertainty on future prospects for this technology. On the other hand, for offshore wind, the realised cost reduction in the OTLS does not lead to a higher penetration than in the PTLS, due to the stronger position of biomass gasification on the European market. It illustrates the importance of investigating the diffusion of individual technologies in a system approach.

More robust trends are observed for onshore wind and photovoltaic electricity production. If policies are directed at the application of renewable energy sources, the diffusion of wind onshore does not only depend on further cost reductions, but rather on the remaining wind energy potential that is available on attractive sites. For PV, the progress ratio assumed in the OTLS allows the technology to become competitive in Mediterranean countries. However, the impact of endogenous learning is limited because over 90% of all PV capacity is expected to be installed outside the EU-25.

For individual countries, the technology diffusion trends may be different from the overall picture, due to the domestic resource base, and the possibility to trade the RES-E certificates in view of achieving the EU targets. For some countries, there is a choice between wind offshore and biomass gasification, depending on their costs, while other countries shift between different biomass technologies. Trade flows also differ between the scenarios, due to the different geographical distribution of the potentials for wind and biomass. Still, in the PTLS, all countries are facing higher costs for achieving their RES-E targets.

When a less ambitious policy scenario is chosen with continuation of present policies (CPP) and no international trade, it becomes clear that the robustness of technology trends also depends on the amount of competition allowed. In the much more fragmented CPP scenario, MS have to realize their ambitions based on their own domestic potentials only, which for a number of MS implies that they have to use their offshore wind potential, making the diffusion of offshore wind in the CPP scenario rather robust. On the other hand, for a relatively costly technology such as PV the trends in OTLS and PTLS do diverge, as now the faster technological learning allows for higher profits. Biomass combustion and gasification technologies are showing diverging trends too, due to competition (in each MS) for the biomass resource.

Given the finding that the diffusion trends for offshore wind and biomass gasification are most sensitive to learning effects (under a harmonization policy scenario), early investments in the form of pilot plants or demonstration projects are particularly expected to pay off for these technologies. These technologies seem to be on the edge of competitiveness with more established RES-E options such as onshore wind and biomass combustion, and have significant potentials for contributing to an increased share of RES-E in the European Union, providing that this remains a policy objective.

In a market based system, total expenditures are to a great extent determined by the price of the marginal option. Therefore, in order to avoid large windfall profits for RES-E producers, the ambition level of the target and the height of the penalty level are important design variables (Verbruggen, 2004). Alternative ways to keep the equilibrium price on the TREC market within acceptable ranges include the provision of investment support for the more expensive options, or, in a sufficiently large market, the introduction of separate quota for groups of technologies depending on their level of maturity.

Chapter 8: Summary and Conclusions

1. Introduction

Renewable energy sources are not limited by finite fuel reserves. They have a large technical potential to contribute to global energy needs and this potential is geographically more evenly distributed than fossil fuel reserves are. In general, their application also has lower external (e.g. environmental) costs than the present use of fossil fuels. These characteristics have been key drivers for the Dutch government to set ambitious targets for the production of electricity from renewable sources in 2010 and 2020: a contribution of respectively 9% and 17% to the gross domestic electricity consumption. Yet, the current contribution is only 3.3% and it is uncertain whether these targets will be reached. The efforts to accelerate the implementation of renewable electricity can be hindered by several barriers, such as technical, economic, social and institutional barriers. A major barrier to a large-scale diffusion of renewable energy technologies are the electricity production costs. These costs have been reduced in the past few decades for a number of renewables and are expected to decline in the future too due to technological learning. A frequently used approach to quantify and evaluate past cost reductions and to project potential future cost reductions is the experience curve approach. The experience curve describes the cost development of a product or technology as a function of cumulative production. The approach has been applied to the development of renewable electricity technologies frequently, especially onshore wind turbines and solar photovoltaic energy modules and systems. However, many methodological questions when using this approach have not been answered yet, such as the appropriate geographical boundaries of learning systems, the use of a so-called compound learning system approach (in which the main learning system is disaggregated, and the cost development of components is investigated), and the question whether the slope of these curves is, or remains constant or not. A question is also whether the experience curve approach is suitable to describe the cost development of biomass fuelled plants. Given the range of application of experience curves, especially for policy advice and in energy models, further insights are required on how to deal with these issues.

2. Thesis objectives and research questions

The main objectives of this thesis are:

To investigate technological change and cost reduction for a number of renewable electricity technologies by means of the experience curve approach,

To address related methodological issues in the experience curve approach,

and, based on these insights,

To analyze the implications for achieving the Dutch renewable electricity targets for the year 2020 within a European context.

In order to meet these objectives, a number of research questions have been formulated:

I. What are the most promising renewable electricity technologies for the Netherlands until 2020 under different technological, economic and environmental conditions?

II. To what extent is the current use of the experience curve approach to investigate renewable energy technology development sound, what are differences in the utilization of this approach and what are possible pitfalls?
III. How can the experience curve approach be used to describe the potential development of partially new energy technologies, such as offshore wind energy? Is it possible to describe biomass fuel supply chains with experience curves? What are the possibilities and limits of the experience curve approach when describing non-modular technologies such as large (biomass) energy plants?
IV. What are the main learning mechanisms behind the cost reduction of the investigated technologies?
V. How can differences in the technological progress of renewable electricity options influence the market diffusion of renewable electricity technologies, and what implications can varying technological development and policy have on the implementation of renewable electricity technologies in the Netherlands?

The development of different renewable energy technologies is investigated by means of some case studies. The possible effects of varying technological development in combination with different policy backgrounds are illustrated for the Netherlands. The thesis focuses mainly on the development of investment costs and electricity production costs. Possible additional costs of intermittent renewable electricity sources (such as storage, backup-capacity or grid fortification) with advanced penetration are not investigated, although these issues may be important on the longer term (after 2020).

3. Summary of the findings

It is uncertain whether and under which conditions the Dutch policy goal of realizing a contribution of 17% from renewable sources to the domestic electricity demand in 2020 (i.e. 18-24 TWh) can be achieved. *Chapter 2* explores the feasible deployment of renewable electricity production in the Netherlands until 2020 by evaluating different images representing policies and societal preferences. First Dutch policy goals, governmental policy measures and definitions of renewable electricity are discussed. Second, a comparison is made of four studies that analyze the possible development of renewable electricity production in the coming decades. Finally, three images are set up. In each image, the impact of a key factor that influences the maximum realizable potential (economical performance, ecological sustainability and technological progress) is evaluated. Results show that for the onshore wind potential, environmental criteria and available space are the main limiting parameters. With a realization of 5-7.5 TWh electricity production a year in all images, it is a relatively robust option in all three images. Wind offshore also obtains a significant share in all three images. The largest uncertainties of this yet unproven technology are the successful technological development, the possibility to build plants within the 12 mile zone (which is economically attractive, but less desirable from an environmental point of view), and the maximum installation rate that can be achieved until 2020. With regard to biomass, two different technologies are evident: different forms of co-firing biomass as the most economical option, or large-scale (stand-alone) gasification plants as the most efficient technology. In all images, either large-scale co-firing in coal plants and natural gas combined cycle (NGCC) plants or biomass integrated gasification / combined cycle (BIG/CC) plants contribute substantially to the total renewable electricity production. In the image with high technological progress and implementation rates, an annual production of 42 TWh may be achieved in 2020, mainly due to the large penetration of offshore wind farms and BIG/CC plants. Under stringent economical or ecological criteria, about 25 TWh may be reached. The three scenarios are not 'best guess' scenarios, and no integration of them was carried out. When only the robust options (i.e. options present in all three scenarios) are considered, 9-22 TWh can be realized. The analysis illustrates the importance of taking the different key factors mentioned influencing implementation into account. Doing so allows for identification of robust and less robust technological options.

Chapter 2 revealed that the technological development of various renewable electricity options and the associated reduction in production costs can have a major influence on their market diffusion. Therefore, in the following chapters, the past and potential future technological development of onshore wind farms (chapter 3), offshore wind farms (chapter 4) and different biomass energy systems (chapter 5 and 6) are investigated. As the development of these technologies has occurred on in many different countries, several international case studies are carried out.

In *chapter 3,* technological development and cost of wind farms and the production costs of wind electricity are investigated, using the experience curve approach. Experience curves of wind turbines are generally based on data describing the development of national markets, which cause a number of problems when applied for global assessments. To analyze global wind energy price developments more adequately, a global experience curve is composed. First, underlying factors for past and potential future price reductions of wind turbines are analyzed. Also possible implications and pitfalls when applying the experience curve approach are assessed. An explicitly investigated issue are the geographical boundaries of learning systems. Within this frame, the price development of wind turbines and wind farms and the effects of support policy in Germany are evaluated. It is concluded, that the German support policy has caused prices to remain stable since 1995, making the German data unsuitable to determine the general speed of technological learning of wind turbines. Based on these insights, an approach is presented to establish a global experience curve and thus to determine a global progress ratio (PR) for the investment costs of wind farms, based on wind farm price data from the UK and Spain, which are deemed to follow production costs more closely. Results show that global PRs for wind farms may lie between 77-85% (with an average of 81%), which is significantly more optimistic than PRs applied in most current scenario studies (based on the construction of national experience curves) and integrated assessment models. While the findings are based on a limited amount of data, they may indicate faster price reduction opportunities than so far assumed.

Chapter 4 investigates the potential cost reduction prospects of offshore wind farms. The economics of wind farms offshore are presently less favorable than for onshore wind farms. Consequently there is a strong need for significant cost reductions in order to become competitive. About 70% of the electricity cost of offshore wind farms is determined by the initial investment costs, which mainly consist of the wind turbines, foundations, internal and external grid-connections and installation. Possible cost reductions until 2020 are explored for each of these components. Technological developments and cost reduction trends in both the offshore and onshore wind sector are analyzed. Information is also taken from offshore oil and gas sector and from the experience with high-voltage submarine transmission of electricity. Where possible, cost reduction trends are quantified using the experience curve concept, or otherwise based on expert judgments. Main drivers for cost reduction appear to be (a) design improvements and upscaling of wind turbines, (b) the continuing growth of onshore wind capacity, and (c) the development and high utilization rates of purpose-built installation vessels. Other factors are: reduction of steel prices, technological development of HVDC converter stations and cables, standardization of turbine and foundation design, and economies of scale for the wind turbine production. It is concluded that it is possible to use the experience curve approach for offshore wind farms, by using data from related industry sectors. Under different growth scenarios, investment costs of offshore wind farms may decline from 1600-1700 €/kW in 2001 to 980-1300 €/kW in 2020. Assuming an identical relative decline of annual O&M costs, the levelized electricity production costs may be reduced by 25-39% compared to current costs. The analysis also reveals, that under the presumptions of mutual learning and cost reductions with other technologies, only 15% of all cost reductions are related directly to the installation of offshore wind farms alone, while 80% are partially depending on the further development of involved technologies (onshore wind turbines, HVDC converter stations and submarine cables, and offshore steel and concrete foundations).

In *chapter 5*, the focus switches to the development of biomass energy systems. An important part of bioenergy systems is the fuel supply. With its increasing use for heat and electricity production, the production costs of Primary Forest Fuel (PFF)[1] have declined over the last three decades in Sweden. The aims of chapter 5 are to quantify cost reductions of PFF production as achieved in Sweden over time, to identify underlying reasons for these reductions, and to determine whether the experience curve concept can be used to describe this cost reduction trend. Also the suitability of this concept to project future PFF cost reductions in Sweden and in other countries is explored. The analysis was done using average national PFF price data (as a proxy for production costs), a number of production cost studies and data on annual Swedish production volumes. Results show that main cost reductions were achieved in forwarding and chipping of PFF, largely due to learning-by-doing, improved equipment and changes in organization. The price for wood fuel chips does follow an experience curve from 1975-2003 (with over nine cumulative doublings). The PR is calculated at 87%. However, given the uncertainty in data on PFF price and annual production volumes, the PR may range between 85% and 88%. It is concluded that in combination with the available supply potential of PFF and taking into account the results of a bottom-up assessment of cost reduction opportunities, the experience curve can be a valuable tool for assessing future PFF production cost development in Sweden. A methodological issue that needs to be further explored is how learning took place between Sweden and other countries, especially with Finland, and how the development of technology and PFF production in these countries should be combined with the Swedish experiences. This would allow the utilization of the experience curve concept to estimate cost developments also in other countries with a large potential to supply PFF, but with less developed PFF supply systems. It should also be investigated, how local knowledge and technology can be transferred to these countries, which is likely to be crucial to achieve low PFF costs.

The main goal of *chapter 6* is to determine whether cost reductions in different bioenergy systems can be quantified using the experience curve approach, and how specific issues (arising from the complexity of biomass energy systems) can be addressed. This is pursued by case studies on biomass-fuelled combined heat and power (CHP) plants in Sweden, global development of fluidized bed boilers, the results from chapter five, and the development of biogas plants in Denmark. As secondary goal, the aim is to identify learning mechanisms behind technology development and cost reduction for the biomass energy systems investigated. The case studies reveal large difficulties to devise empirical experience curves for investment costs of biomass fuelled power plants. To some extent, this is due to general lack of (detailed) data, but mainly because of varying plant costs due to differences in scale, fuel type, plant layout, region, etc. Only in a few cases, some meaningful trends were found. For plants utilizing fluidized bed boilers, PRs

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[1] Branches, tops, small trees and un-merchantable wood left in the forest after the cleaning, thinning or final felling of forest stands.

for the entire plant lie between 90-93% (a range which has also been found for other large plants using a number of fuels), but the costs for the boiler section alone may decline much faster. The experience curve approach delivers better results, when the production costs of the final energy carrier are analyzed. Electricity costs from biomass-fuelled CHP-plants yield PRs of 91-92%. The experience curve for biogas production costs displays a PR of 85% from 1984 to the beginning of the 1990s, and levels afterwards to approximately 100% until the year 2002. For technologies developed on a local level (e.g. biogas plants), learning-by-using and learning-by-interacting are important learning mechanism, while for CHP plants utilizing fluidized bed boilers, upscaling is probably one of the main mechanisms behind cost reductions.

The objective of *chapter 7* is to examine the consequences of differences in technological developments on the market diffusion of specific renewable electricity technologies in the EU-25 until 2020, using a market simulation model (ADMIRE REBUS) developed by the Energy research Centre of the Netherlands (ECN). For the main analysis, it is assumed that from 2012 a harmonized trading system will be implemented, and a target of 24% renewable electricity (RES-E) in 2020 is set and met. The results from the previous chapters were used to set up an optimistic and a pessimistic endogenous technological learning scenario. It was found that the diffusion of onshore wind energy is relatively robust, i.e. independent of technological development, but the diffusion rates of offshore wind energy and biomass gasification greatly depend on assumptions about their technological development. Competition between these two options and (conventional) biomass combustion options largely determines the overall costs of electricity from renewables and the choice of technologies for the individual member countries. In the optimistic scenario, in 2020 the market price for RES-E is 1 €ct/kWh lower than in the pessimistic scenario (7 vs. 8 €ct/kWh). As a result, total expenditures for RES-E market stimulation are 30% lower in the optimistic scenario. For comparison, also the impact of continuing present support policies until 2020 was evaluated assuming no international trade of RES-E certificates. As Member states then have to achieve their target by exploiting their own potentials only, a number of member states have to utilize their offshore wind potential, making the diffusion of offshore wind electricity production much less dependent on both the rate of technological development and the competition from biomass options, compared to the harmonization scenario.

When the results of chapter 2 and chapter 7 are compared, chapter 2 shows 9-22 TWh as robust potentials under different assumptions. In chapter 7, the analysis shows that under the *continuation of present policies,* likely 14-16 TWh is realized, depending on the rate of technological development. Clearly, if the Netherlands are going to pursue ambitious renewable energy targets, offshore wind energy use offers the largest potential if only domestic sources are considered and no biomass is imported. However, even under the continuation of the current policy measures, and the optimistic technological learning scenario, in 2020 only the production of 7 TWh is realized. This corresponds to an installed wind turbine capacity of approximately 2200 MW, which is far less than the current governmental target of 6000 MW for 2020. Overall, even under conditions of optimistic technological learning, the target of 17% contribution from renewable sources in 2020 (i.e. 17-24 TWh, depending on growth in electricity demand and other factors) is unlikely to be met. Under the *harmonization scenario*, a similar domestic production of electricity from onshore wind, offshore wind and biomass occurs, but an additional 2-4 TWh are imported (in the form of certificates), leading to an overall realization of about 19 TWh. Thus, under the harmonization scenario, the Dutch 17% target is more likely to be achieved, as elsewhere in the European Union sufficient other renewable energy can be realized. Remarkably, under the optimistic learning scenario, the

Netherlands import more certificates, as more low-cost potential can be exploited in other countries of the European Union.
It is emphasized that the numbers presented here are no forecast, but merely possible developments under the conditions assumed in chapters 2 and 7. For example, as pointed out in chapter 2 and 7, the availability of cheap and sustainable biomass from abroad may play an important role for the overall biomass generated electricity potential, and could increase the overall potential of biomass use in the Netherlands.

4. Methodological lessons

The investigations on the selection of **geographical boundaries** for learning systems shows that for technologies deployed all over the world (such as onshore wind farms or PV modules), the most appropriate system boundaries are on a global level. However, for technologies, which have been developed on a more local level (such as small scale biogas plants), and no significant exchange of experiences with other learning systems, an analysis on a local or national level may be most appropriate. A major conclusion is that sufficient attention has to be given to determine the appropriate boundaries of the learning system in order to determine the correct PR of a learning curve, as the examples of national onshore wind farms in chapter 3 and fuel supply chains in Finland in chapter 6 illustrate. In addition, sometimes also mixtures occur, as parts of a technology may learn on a local level whereas other parts may learn on a global level, as was shown for onshore wind farms and for biomass fuel chains.

The approach of **compound learning systems** was used both for offshore wind farms and for biomass energy systems, though with different aims. First, for offshore wind farms, the possible technological development of turbines, foundations, grid-connection and installation was determined by analyzing the PRs of related technologies such as onshore wind turbines, offshore foundations and submarine electricity cables. This was necessary, because only a handful of offshore wind farms have been built so far. The analysis shows, that this approach is feasible, even though only time will tell whether the presented cost reduction potentials will actually be realized. Second, for biomass energy systems, the question was mainly whether or not the experience curve approach was suitable at all to describe the cost development of (different parts of) biomass energy systems. Therefore, a differentiation between the investment costs, the fuel costs and the O&M costs was performed in order to investigate the different cost reduction trends and to determine the suitability of the experience curve approach for the different sub-learning systems. As was shown in chapters 5 and 6, the experience curve approach can be applied to fuel supply chains and to the cost of the final energy carrier (i.e. electricity and biogas) yielding trend lines with quite satisfactory correlations. However, the experience curve approach appears to be less suitable for measuring the decline of biomass plant investment cost. Further studies regarding the applicability of the experience curve approach to evaluated the progress made in biomass fuel supply chains are recommended. This may result in an appropriate method to analyze cost developments of new biomass energy chains, for example chains based on dedicated crop plantations.

Furthermore, the question remains, **whether the PR value may change** (and, more specifically, may approach towards 100%) with increasing market diffusion. In two cases (German onshore wind farms and Danish biogas plants), experience curves were found to flatten, the PR value becoming approximately 100%. However, in both cases, it was shown that this was due to changes in the market (i.e. subsidies and fuel shortages), but not as a result of structural changes in technology development. Overall, no indications were found that PRs based on production costs should become less benign, at least as long as the market share of the technology continues to increase.

The difference in use of **marginal and average cost** was explored for different biomass energy systems. As expected, the marginal cost experience curve lies below the average cost experience curve. However, it also displays the same slope. This may allow for using PRs from experience curves based on historical data of average costs (which may be more readily available) to determine potential further cost reductions of the best available technology.

Related to the issue of geographical learning system boundaries is the matter of **correcting for inflation** in complex international innovation systems. When data from several countries are involved, the choice of reference currency and the method of using exchange rates can influence the PR significantly, as was shown in chapter 3. While no ideal solution was found for this problem, evaluating the use of several reference currencies may provide insights in the uncertainty of the results.

In addition, the **learning mechanisms** behind the cost reductions of renewable energy technologies were investigated. Naturally, they differ per technology, but some parallels can be drawn on basis of scale and geographical diffusion. For onshore wind turbines, upscaling has been the most important factor behind cost reductions on a global level in the past. However, learning effects such as the improved siting of wind farms and lower grid connection costs typically occur on a more local level. The development of offshore wind farm has only been possible by the continuous upscaling of onshore wind turbines. Both onshore and offshore wind farms are expected to benefit from the effects of economies of scale with the increasing wind farm size in the future. With regard to biomass technologies, the fluidized bed boiler combustion plants, currently deployed on a global level, has also benefited from gradual upscaling over the past few decades. On the other hand, cost components such as the fuel supply and the operation and maintenance of plants largely depend on local knowledge, as the examples of Swedish CHP plants and Danish biogas plants illustrated. In these cases, local learning-by-doing, learning-by-using and learning-by-interacting have been vital mechanisms for the successful development of these technologies. In addition, by determining learning mechanism that may occur in the future (e.g. the mass production of wind turbines), the extrapolation of experience curves for prospective cost development analysis can be supported qualitatively.

5. Implications for the development and market diffusion of renewable energy technologies

In general, the two policy scenarios demonstrate, that the influence of technological learning on the diffusion and cost of renewable energy technologies largely depends on the possibility of competition. A European-wide trade in renewable energy certificates enables the optimal utilization of the cheapest available sources and technologies, and therefore favors technologies with rapidly declining electricity production costs. If trading possibilities are absent, technological learning my have a much lower impact on overall diffusion rates, as shown for offshore wind energy and various biomass energy technologies in chapter 7 of this thesis. Furthermore, as was pointed out in chapter 4 and 7, the development of pilot plants for offshore wind farms and BIG/CC plants requires international cooperation and knowledge exchange, as no single country on its own can build the required number of plants needed to reduce investment costs over a long period of time. On the other hand, as already pointed out, the dissemination of knowledge acquired by the use of technologies is much more limited to the local level, especially for smaller-scale technologies. Therefore, this should achieve specific attention when national policy supports are increased.

The research has shown that in many cases the quantity and quality of data are not sufficient to carry out experience curve based analyses. This is partially due to the confidentiality of data, e.g. on production costs, but also to lack of structured data collection on renewable energy technologies. While this database is available for PV and wind turbines, there is very little data available on most biomass technologies. It is recommended, that this data is collected in a more structured way to enable further analyses. Also in regard to the development of new renewable energy technologies (e.g. offshore wind farms) the data availability of related technologies (such as submarine high voltage electricity cables and steel or concrete foundations) is not optimal.

In the case studies scrutinized in this thesis it was observed that most large-scale technologies are deployed on a global scale, and that therefore also technological learning occurs worldwide. While national research programs to develop new technologies may be very useful in the very first stages of diffusion, in later stages it may prove more fruitful to focus on knowledge exchange and dissemination of local experiences. Within this frame, a EU wide approach to stimulate offshore wind farms and BIG/CC plants may be required, also to achieve the necessary volumes.

Policy makers always have to make a trade off between funding RD&D, funding early market introduction and funding large-scale market diffusion (VROM-raad and AER, 2004). While the optimal funding ratio between these categories is difficult to determine and may depend on the local geographical situation and the technology involved, chapter 7 has shown, that early investments in pilot plants may save large amounts of subsidies later, in the market diffusion phase. However, as this relation is not easily determined beforehand, further research is recommended in this direction.

Samenvatting en conclusies

1. Inleiding

Hernieuwbare energiebronnen zijn niet begrensd door eindige brandstofreserves. Ze hebben een groot potentieel om aan de mondiale energiebehoefte te voorzien, en ze zijn vergeleken met fossiele brandstofvoorraden geografisch gelijkmatiger verspreid over de wereld. In het algemeen hebben zij ook lagere externe kosten (bij voorbeeld milieukosten) dan het huidige gebruik van fossiele brandstoffen. Deze kenmerken waren de hoofddrijfveren voor de Nederlandse overheid om hoge doelstellingen te formuleren voor de productie van elektriciteit uit hernieuwbare bronnen in 2010 en 2020, met bijdrages van 9% en 17% aan de bruto elektriciteitsconsumptie in Nederland. Echter, de huidige bijdrage is slechts 3.3%, en het is onzeker of deze doelstellingen gehaald kunnen worden. De inspanningen om de implementatie van hernieuwbare elektriciteit te versnellen, worden belemmerd door meerdere barrières, zoals technische, economische, sociale en institutionele barrières. Een grote barrière voor de grootschalige toepassing van hernieuwbare energietechnologieën zijn de elektriciteitsproductiekosten. Deze kosten zijn de afgelopen tientallen jaren voor een aantal hernieuwbare energietechnologieën belangrijk gedaald, en zullen naar verwachting ook in de toekomst door technologisch leren verder afnemen. Een vaak gebruikte benadering om zowel de in het verleden bereikte kostenreducties te kwantificeren als mogelijk toekomstige kostenreducties in kaart te brengen, is de leercurvebenadering[1]. De leercurve beschrijft de kostenontwikkeling van een product of een technologie als functie van de cumulatieve productie van dit product of deze technologie. Op een dubbel logaritmische schaal vertoont de leercurve nogal een rechte lijn, waarbij de helling van de lijn iets zegt over de snelheid waarmee in de ontwikkeling van de technologie wordt geleerd. Het in kaart brengen van leercurves is al gedaan voor technologieën om elektriciteit op te wekken uit energiebronnen, met name voor windparken op land en voor fotovoltaïsche zonne-energiepanelen en -systemen. Echter, een aantal methodologische vraagstukken met betrekking tot het construeren, toepassen en interpreteren van leercurves dient verder onderzocht te worden, zoals de toe te passen geografische grenzen van het leersysteem, en de bruikbaarheid van zogenaamde samengestelde leersystemen, waarbij het hoofdsysteem in meerdere componenten verdeeld wordt en de kostenontwikkeling per component wordt onderzocht. Verder is het de vraag of de helling van leercurves constant is en voor het beleid een voorspellende waarde heeft. Ook is een vraag, of de leercurvebenadering toegepast kan worden om de kostenontwikkeling van biomassacentrales te beschrijven. Mede gezien het scala van toepassingen van de leercurvebenadering, met name bij het maken van beleidsadviezen en het ontwikkelen van modellen voor het maken van energiescenarios, is het relevant via onderzoek een antwoord op deze vragen te geven.

2. Doelstellingen en onderzoeksvragen van dit proefschrift

De hoofddoelstellingen van dit proefschrift zijn:

Om de technologische verandering en de reductie van de kostprijs te onderzoeken voor een aantal technologieën om elektriciteit op te wekken uit hernieuwbare energiebronnen, door gebruik te maken van de leercurvebenadering,

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[1] In de Engelstalige literatuur wordt thans de uitdrukking *experience curve* gebruikt in plaats van *learning curve*. In de Nederlandse literatuur wordt echter steeds over de *leercurve* gesproken, ook als *ervaringscurve* wordt bedoeld.

Om methodologische vraagstukken van de leercurvebenadering aan de orde te stellen,

en, gebaseerd op deze inzichten,

Om een aantal implicaties te analyseren voor het behalen van de Nederlandse doelstelling voor opwekking van elektriciteit uit hernieuwbare bronnen in het jaar 2020 in een Europese context.

Afgeleid van deze doelstellingen zijn een aantal onderzoeksvragen geformuleerd:

I. Wat zijn de meest belovende technologieën voor elektriciteitsopwekking uit hernieuwbare bronnen in Nederland tot 2020 onder verschillende technologische, economische en milieu-randvoorwaarden?
II. In hoeverre is het huidige gebruik van de leercurvebenadering om hernieuwbare energietechnologieën te onderzoeken correct, wat zijn verschillen in benaderingen die worden toegepast, en wat zijn mogelijke valkuilen?
III. Hoe kan de leercurvebenadering gebruikt worden om de mogelijke ontwikkeling van gedeeltelijk nieuwe energietechnologieën te beschrijven, zoals windparken op zee? Is het mogelijk om biomassa-aanvoerketens te beschrijven met de leercurvebenadering? En wat zijn de mogelijkheden en de grenzen om de leercurvebenadering toe te passen op niet modulaire technologieën zoals grootschalige (biomassa-) energiecentrales?
IV. Wat zijn meest belangrijke leermechanismen achter de kostenreducties van de onderzochte technologieën?
V. Hoe kunnen verschillen in de technologische vooruitgang van hernieuwbare elektriciteitstechnologieën de marktdiffusie beïnvloeden? En wat zijn de implicaties van verschillen in technologische voortgang en in beleid voor de implementatie van hernieuwbare elektriciteitstechnologieën in Nederland?

De ontwikkeling van verschillende elektriciteitstechnologieën is onderzocht door middel van internationale case studies. De mogelijke effecten van verschillende technologische ontwikkelingen in combinatie met verschillende beleidsachtergronden worden geïllustreerd voor Nederland.

Dit proefschrift richt zich voornamelijk op de ontwikkeling van investeringskosten en elektriciteitsproductiekosten. Mogelijke additionele kosten van de toepassing van intermitterende hernieuwbare energietechnieken (zoals noodzaak van opslag, bouw van back-up vermogen of versterking van het net) met een toenemend marktaandeel van deze technieken zijn niet onderzocht vanwege de beperkte (verwachte) bijdrage van intermitterende bronnen aan de elektriciteitsproductie tot 2020.

3. Samenvatting van de resultaten

Het is onzeker of en onder welke omstandigheden de Nederlandse doelstelling van 17% hernieuwbare elektriciteit (naar schatting 18-24 TWh) als bijdrage aan de elektriciteitsvraag in 2020 behaald kan worden. In *hoofdstuk 2* wordt de mogelijke inzet van hernieuwbare elektriciteit in Nederland tot 2020 onderzocht door verschillende toekomstbeelden te evalueren. Eerst wordt de Nederlandse beleidsdoelen, overheidsinstrumenten en verschillende definities van hernieuwbare elektriciteit besproken. Vervolgens worden vier bestaande studies vergeleken, die allen de mogelijke ontwikkeling van hernieuwbare elektriciteitsproductie voor de komende decennia analyseren. Onder andere worden daarbij economische prestaties, milieuvriendelijkheid en mogelijke technologische vooruitgang als sleutelfactoren geïdentificeerd. Tenslotte worden drie verschillende toekomstbeelden geconstrueerd. In elk beeld staat één van de drie sleutelfactoren centraal. De resultaten tonen aan dat het potentieel voor windenergie op land de milieucriteria en de beschikbare ruimte de belangrijkste beperkende factoren zijn. In alle beelden wordt een elektriciteitsproductie uit wind van 5 – 7.5 TWh per jaar gerealiseerd, waarmee wind op land een relatief robuuste optie is. Wind op zee heeft ook een significant aandeel in de drie beelden. De grootste onzekerheden van deze tot nu toe niet bewezen technologie zijn de technologische ontwikkeling, de mogelijkheid om al dan niet binnen de twaalf-mijl zone windparken te bouwen (wat vanuit een economisch standpunt aantrekkelijk is, maar minder wenselijk vanuit een milieustandpunt), en de maximale installatiesnelheid die behaald kan worden tot 2020. Met betrekking tot biomassa staan twee verschillende technologieën centraal: diverse vormen van co-verbranding van biomassa zijn de meest economische optie, terwijl grootschalige (stand-alone) vergassing van biomassa geïntegreerd met opwekking van elektriciteit de meest energieefficiënte technologie lijkt te zijn. In alle beelden dragen óf grootschalige co-verbranding in kolencentrales en aardgascentrales óf geïntegreerde Biomassa Vergasser/STEG (BV/STEG) installaties substantieel bij aan de totale elektriciteitsproductie uit hernieuwbare bronnen. In het beeld met hoge technologische vooruitgang en hoge implementatiesnelheden zou er in 2020 jaarlijks 42 TWh geproduceerd kunnen worden, voornamelijk door de grootschalige inzet van windparken op zee en van BV/STEG centrales. Onder strikte economische of milieu-voorwaarden wordt ongeveer 25 TWh behaald. De drie scenario’s zijn geen ‘best guess’ scenarios. Ook is er en er is geen integratie van de drie beelden uitgevoerd. De analyse illustreert het belang om verschillende sleutelfactoren in een analyse mee te nemen. Hierdoor wordt de identificatie van robuuste en minder robuuste opties onder verschillende randvoorwaarden mogelijk.

Hoofdstuk 2 heeft laten zien dat de technologische ontwikkeling van diverse hernieuwbare elektriciteitsopties en de hiermee gepaard gaande reductie van productiekosten een grote invloed kan hebben op de marktdiffusie van deze opties. Daarom worden in de volgende hoofdstukken technologische ontwikkelingen die tot op heden hebben plaatsgevonden onderzocht, evenals mogelijke ontwikkeling van de technologie in de toekomst. Dit is gedaan voor windparken op land (hoofdstuk 3), voor windparken op zee (hoofdstuk 4) en voor verschillende biomassaenergiesystemen (hoofdstuk 5 en 6). Omdat de ontwikkeling van deze opties in verschillende landen heeft plaatsgevonden, worden case studies niet tot Nederland beperkt.

In *hoofdstuk 3* worden de technologische ontwikkeling en de kosten van windparken en de productiekosten van elektriciteit uit windenergie onderzocht met behulp van de leercurvebenadering. Leercurves voor windturbines zijn meestal gebaseerd op data die de ontwikkeling van nationale markten beschrijven. Dit veroorzaakt een aantal methodische problemen, als de resultaten voor mondiale analyses gebruikt worden. Om de mondiale prijsontwikkeling van windenergie beter in kaart te brengen, wordt in dit hoofdstuk een mondiale leercurve geconstrueerd. Eerst worden factoren achter de kostprijsontwikkeling van windturbines in het verleden en mogelijke ontwikkelingen in de toekomst geanalyseerd. Op basis hiervan worden er ook mogelijke implicaties en valkuilen geïdentificeerd voor het gebruik van de leercurvebenadering. Expliciet komt daarbij het vraagstuk geografische grenzen van leersystemen aan bod. In dit kader worden de ontwikkeling van prijzen van windturbines en windparken in Duitsland onderzocht, en het effect van Duitse beleidsinstrumenten ter stimulering van windenergie geëvalueerd. Geconcludeerd kan worden dat de Duitse beleidsinstrumenten ertoe geleid hebben dat de prijzen vanaf 1995 stabiel gebleven zijn, waardoor de Duitse data onbruikbaar zijn, om de daadwerkelijke snelheid te bepalen van de technologische vooruitgang van windturbines. Gebaseerd op deze inzichten wordt een benadering gepresenteerd om een mondiale leercurve op te stellen waarmee een mondiale ‘progress ratio’ (PR) voor de investeringskosten van windparken kan worden bepaald. Deze curve is gebaseerd op prijsdata uit Spanje en het Verenigd Koninkrijk die waarschijnlijk de productiekosten beter volgen. De resultaten laten zien dat de mondiale PR voor windparken tussen 77-85% kan liggen, met een gemiddelde waarde van 81%. Dit is een veel optimistischere waarde dan de PRs die op dit moment in de meeste modellen voor het doen van scenario studies gebruikt worden. Deze bevindingen zijn gebaseerd op een beperkte hoeveelheid data, maar kunnen duiden op snellere prijsreductiemogelijkheden dan dusverre aangenomen is.

In *hoofdstuk 4* wordt het potentieel voor kostenreductie van windparken op zee onderzocht. De economische rentabiliteit van windparken op zee is op dit moment minder gunstig dan voor windparken op land. Derhalve is er een noodzaak om de kosten van windparken op zee te reduceren wil deze optie voldoende aantrekkelijk worden. Ongeveer 70% van de elektriciteitsproductiekosten worden bepaald door de initiële investeringskosten. Deze bestaan voornamelijk uit de kosten voor de windturbines, de funderingen, de interne en externe elektrische aansluiting aan het net en de installatiekosten. De mogelijke kostenreductie voor elk van deze componenten tot 2020 wordt in dit hoofdstuk onderzocht, gebruik makend van (trends in) data van zowel windparken op land als op zee. Ook zijn data gebruikt uit de offshore olie- en gaswinning, en van bestaande hoogspanningskabels onder water. Waar mogelijk, zijn de kostenreductietrends gekwantificeerd met behulp van de leercurvebenadering, of anders gebaseerd op schattingen van experts. De volgende factoren lijken het meest veelbelovend voor toekomstige kostenreducties: (a) verbeteringen in het design van wind turbines en het opschalen van wind turbines, (b) de verdere groei van windcapaciteit op land, en (c) de ontwikkeling en het frequent gebruik van specifiek ontworpen installatieschepen. Andere factoren zijn: de mogelijke reductie van staalprijzen, de technologische ontwikkeling van HVDC converter stations en hoogspanningskabels, de standaardisatie van turbine- en funderingsontwerp, en de kostenreducties die optreden bij de massaproductie van wind turbines. Het kan geconcludeerd worden dat het mogelijk is om de leercurvebenadering toe te passen voor windparken op zee door gebruik te maken van data van gelijksoortige industrieën. Onder twee verschillende groeiscenario’s kunnen de totale investeringskosten van 1600-1700 €/kW in 2001 tot 980-1300 €/kW in 2020 dalen. Indien aangenomen wordt dat de lopende bediening- en onderhoudskosten evenredig afnemen, dan zouden de elektriciteitsproductiekosten kunnen dalen met 25-39% vergeleken met de huidige kosten. De analyse laat ook zien, dat onder de veronderstelling van gezamenlijke kostenreducties met andere technologieën (bij voorbeeld windturbines op land), slechts 15% van alle kostenreducties direct door de ontwikkeling van windparken bepaald worden, terwijl 80% (gedeeltelijk) van de kostenreducties afhangen van de verdere ontwikkeling van andere technologieën.

In *hoofdstuk 5* verandert de focus naar biomassa-energiesystemen. Een belangrijk onderdeel van biomassa-energiesystemen zijn de brandstof aanvoerketens. In Zweden zijn, met het toenemende gebruik van biomassa voor de productie van warmte en elektriciteit, de productiekosten van primaire bosbouw residuen (PFF) over de afgelopen drie decennia gedaald. De doelen van hoofdstuk 5 zijn om deze kostenreducties te kwantificeren, om de factoren achter de kostenreducties te identificeren, en te bepalen of de leercurvebenadering geschikt is om de kostenreducties te beschrijven. Ook is de toepasbaarheid van de leercurvebenadering voor de analyse van mogelijke toekomstige kostenreducties in Zweden en andere landen onderzocht. De analyse is uitgevoerd door gebruik te maken van gemiddelde, nationale prijsdata voor bosbouwresiduen (als een schatting voor de winningskosten), een aantal studies van deze winningskosten, en de data betreffende de jaarlijkse Zweedse productievolumes van bosbouwresiduen. De resultaten tonen aan dat de grootste kostenreducties behaald werden in het (efficiënt) transporteren van de residuen van de tra naar de straat en het hakselen van de residuen. Dit gebeurde voornamelijk door learning-by-doing (leren-door-te-produceren), verbetering van de oogstapparatuur en veranderingen in de organisatie van de oogst. De prijs van bosbouwresiduen volgt een leercurve van 1975-2003 (met meer dan negen cumulatieve verdubbelingen). De gevonden PR is 87%, maar kan tussen 85 en 88% variëren door onzekerheid in de prijsdata en de jaarlijkse volumes van residuproductie. In combinatie met de beschikbare potentiëlen van bosbouw residuen en een bottom-up beoordeling van mogelijkheden tot kostenreducties, kan geconcludeerd worden dat de leercurvebenadering een waardevol instrument kan zijn om de toekomstige kostenontwikkeling van bosbouwresiduen in Zweden te beoordelen. Een vraagstuk, dat verdere aandacht behoeft, is hoe Zweden samen met andere landen (met name Finland) geleerd heeft. Tevens is het de vraag, of en hoe de ontwikkeling van de technologie en van residuvolumes van deze en andere landen gecombineerd kan worden. Dit zou de mogelijkheid bieden, om de leercurvebenadering ook voor andere landen toe te passen, die een groot potentieel voor de winning van bosbouwresiduen hebben, maar over minder ontwikkelde aanvoerketens beschikken. Ook zou verder onderzocht kunnen worden, hoe lokaal aanwezige kennis en technologie naar deze landen optimaal overgedragen kan worden, omdat dit waarschijnlijk cruciaal is voor het realiseren van lage winningskosten.

Het primaire doel van *hoofdstuk 6* is om te bepalen of de kostenreducties in verschillende biomassa energiesystemen met behulp van de leercurvebenadering gekwantificeerd kunnen worden, en hoe specifieke vraagstukken (gerelateerd aan de complexiteit van biomassa-energiesystemen) benaderd kunnen worden. Hiervoor zijn verschillende case studies uitgevoerd voor biomassa warmte-krachtkoppeling (WKK) centrales in Zweden, de mondiale ontwikkeling van wervelbedketels en de ontwikkeling van biomassa-vergistingscentrales in Denemarken. Ook de resultaten van hoofdstuk 5 zijn in dit onderzoek meegenomen. Een secundair doel is om de verschillende leermechanismen achter de technologische ontwikkeling en kostenreducties van de onderzochte biomassa-energiesystemen in kaart te brengen. De case studies laten zien dat het maken van leercurves op basis van empirische gegevens over investeringskosten vaak grote problemen oplevert. Dit is enigszins te wijten aan de algemene schaarsheid van (gedetailleerde) data, maar vooral aan de verschillen in het ontwerp van de centrales, de schaalverschillen, de gebruikte brandstoffen en de geografische regio. Slechts in een beperkt aantal gevallen zijn betekenisvolle trends gevonden. Voor centrales met wervelbedketels is een PR gevonden van 90-93%, een resultaat dat ook voor andere energiecentrales gevonden is. Indien alleen de kosten van de wervelbedketels (zonder de overige onderdelen van een centrale) worden gebruikt, dalen de kosten met een hogere snelheid. De leercurvebenadering levert de beste resultaten op indien de productiekosten van de finale energiedrager geanalyseerd worden. De productie van elektriciteit met biomassa WKK centrales levert een PR-waarde van 91-92% op. De leercurve voor de productie van biogas toont een PR van 85% in de periode van 1984-1990, en vlakt daarna af tot circa 100% in de periode van 1990-2002. Voor technologieën, die op lokaal niveau ontwikkeld zijn (bijvoorbeeld biomassa vergistingscentrales), zijn learning-by-using (leren door te gebruiken) en learning-by-interacting (leren door te interacteren) belangrijke leermechanismen, terwijl voor centrales met wervelbedketels waarschijnlijk het opschalen een van de meest belangrijke mechanismen achter de behaalde kostenreductie is.

De doelstelling van *hoofdstuk 7* is om tot 2020 de impact van mogelijke verschillen in technologisch leren op de marktdiffusie van hernieuwbare energietechnologieën te evalueren binnen de Europese Unie met 25 lidstaten (EU-25). Hiervoor is gebruik gemaakt van het door het Energieonderzoek Centrum Nederland (ECN) ontwikkelde marktsimulatie model ADMIRE

REBUS. Voor de hoofdanalyse is een beleidsscenario geformuleerd, waarin aangenomen wordt dat vanaf 2012 een internationaal geharmoniseerd handelssysteem met certificaten voor hernieuwbare elektriciteit ingevoerd zal worden. Daarnaast wordt een doelstelling van 24% hernieuwbare elektriciteit in Europa voor 2020 bepaald en gehaald. De resultaten van de vorige hoofdstukken zijn gebruikt om één optimistisch en één pessimistisch scenario te ontwikkelen voor endogeen technologisch leren. De resultaten van de scenariostudies geven aan, dat de diffusietrend van windparken op land relatief stabiel is, dat wil zeggen onafhankelijk van de veronderstelde technologische ontwikkeling. De diffusiesnelheden van windparken op zee en BV/STEG centrales hangen daarentegen sterk af van aannamen omtrent hun technologische ontwikkeling. De competitie tussen deze twee technologieën en andere (conventionele) biomassa-verbrandingstechnologieën bepaalt grotendeels de totale hernieuwbare elektriciteitsproductiekosten, en de technologiekeuze van individuele lidstaten. In het optimistische scenario is in 2020 de marktprijs van hernieuwbare elektriciteit 1 €ct/kWh lager dan in het pessimistische scenario (7 vs. 8 €ct/kWh). De totale uitgaven om de productie van hernieuwbare elektriciteit te stimuleren zijn hierdoor 30% lager in het optimistische scenario. Ter vergelijking is ook de impact van een scenario geëvalueerd, waarin het huidige stimuleringsbeleid van alle lidstaten tot 2020 wordt voortgezet, waardoor geen internationale handel in certificaten mogelijk is. Omdat de lidstaten in dat geval slechts hun eigen hernieuwbare energiepotentiëlen kunnen gebruiken, moeten diverse lidstaten hun potentieel voor windparken op zee benutten. Hierdoor wordt de diffusie trend voor offshore windparken (vergeleken met het harmonisatie scenario) veel minder afhankelijk van zowel technologisch leren als ook van de competitie met diverse biomassa opties.

Als de resultaten van hoofdstuk 2 en hoofdstuk 7 met elkaar vergeleken worden, dan wordt in hoofdstuk 2 voor Nederland een robuust potentieel gevonden van 9-22 TWh voor 2020, terwijl in hoofdstuk 7 onder voortzetting van het huidige beleid een mogelijke realisatie van 14-16 TWh wordt gevonden, afhankelijk van de snelheid waarvan de technologieën ontwikkeld worden. Indien Nederland zijn ambitieuze doelstellingen voor 2020, te weten 18-24 TWh elektriciteit uit hernieuwbare bronnen, wil gaan realiseren, dan is het duidelijk dat het potentieel voor windparken op zee de grootste groeimogelijkheden biedt als slechts de inheemse bronnen gebruikt mogen worden en geen biomassa wordt geïmporteerd. Toch blijkt uit het onderzoek dat, bij handhaving van de huidige beleidsmaatregelen (die van een relatief hoog ambitieniveau uitgaan), en onder de aanname van een optimistische technologische leerscenario, door windparken op de Noordzee 7 TWh wordt geproduceerd tot 2020, hetgeen overeenkomt met een geïnstalleerd vermogen van circa 2200 MW. Dit is veel minder dan de huidige overheidsdoelstelling van 6000 MW windvermogen in Nederland in 2020. Ook blijkt uit het onderzoek dat zelfs onder optimistische aannames voor technologieontwikkeling de doelstelling van 17% hernieuwbare elektriciteit in 2020 (een bijdrage van 18-24 TWh) waarschijnlijk niet wordt gehaald. In het harmonisatiescenario worden vergelijkbare landelijke productieniveaus bereikt van windparken op land, windparken op zee en uit biomassacentrales. Daarnaast worden 2-4 TWh geïmporteerd in de vorm van certificaten, waardoor in zowel het pessimistische als optimistische scenario voor technologisch leren de totale realisatie op 19 TWh uitkomt. Derhalve is het waarschijnlijker dat de Nederlandse doelstelling van 17% onder een Europees harmonisatiebeleid bereikt wordt dan onder een beleid waarbij harmonisatie niet plaatsvindt, omdat er elders in Europa makkelijker hernieuwbare elektriciteit geproduceerd kan worden. Daarbij is opvallend, dat Nederland onder het optimistische leerscenario meer certificaten importeert dan onder het pessimistische scenario, omdat er dan in andere Europese landen meer potentieel beschikbaar komt dat tegen lage kosten gewonnen kan worden.

Benadrukt moet worden dat deze getallen geen voorspellingen zijn, maar slechts mogelijke ontwikkelingen onder de aannames zoals beschreven in hoofdstuk 2 en 7. Zoals al aangegeven, kan bijvoorbeeld de beschikbaarheid van goedkope biomassa uit het buitenland voor Nederland een belangrijke rol spelen. Dit zou het totale potentieel van elektriciteitsproductie uit hernieuwbare bronnen in Nederland kunnen verhogen.

4. Methodologische lessen

De analyse van de invloed van de keuze van de precieze **geografische grenzen** van het leersysteem heeft aangetoond dat voor technologieën die over de hele wereld gebruikt worden (zoals windparken op land en PV modules), ook de systeemgrenzen het beste mondiaal gekozen kunnen worden. Echter, indien technologieën op lokale schaal worden ontwikkeld, (zoals kleinschalige biomassa vergistingsinstallaties) en er geen significante uitwisseling is van ervaringen met andere leersystemen, dan is een analyse op lokaal of nationaal niveau het meest zinnig. Een hoofdconclusie is daarom dat bij de constructie van leercurves voldoende aandacht gegeven moet worden aan de correcte grenzen van het leersysteem, om de daadwerkelijke waarde van de PR te kunnen achterhalen. Dit sluit niet uit dat met betrekking tot delen van een technologie ook leren op lokaal niveau kan plaatsvinden, zoals we hebben aangetoond voor windparken op land (voor de elektrische infrastructuur) en voor biomassa aanvoerketens.

De benadering van **samengestelde leersystemen** is zowel gebruikt voor windparken op zee als voor biomassa energiesystemen, echter met verschillende doelen. Voor windparken op zee zijn de techno-economische ontwikkeling van turbines, funderingen, netaansluiting en installatie bepaald door de PR-waarde van gerelateerde technologieën te gebruiken zoals van windturbines op land offshore funderingen en hoogspanningskabels onder water. Dit is gedaan omdat er tot op heden slechts een handvol windparken op zee gebouwd zijn. De analyse toont aan dat een dergelijke aanpak uitvoerbaar is, maar dat pas over enige jaren zal duidelijk worden of de gepresenteerde kostenreducties ook daadwerkelijk gerealiseerd zullen worden. Voor biomassasystemen is het de vraag of de leercurvebenadering bruikbaar is om het verloop van de verschillende kostenposten van (verschillende onderdelen van) biomassa energiesystemen te evalueren. Daarom is in het onderzoek een differentiatie gemaakt tussen investeringskosten, brandstofkosten, en de bediening- en onderhoudskosten. Hierdoor kunnen de verschillende trends in de kostenontwikkeling apart onderzocht worden, en kan de leercurvebenadering voor elk sub-leersysteem getest worden. Zoals in hoofdstukken 5 en 6 aangetoond is, kan de leercurvebenadering gebruikt worden voor brandstofaanvoerketens en voor de kosten van finale energiedragers (elektriciteit en biogas). Voor deze systemen levert de leercurvebenadering trendlijnen op met goede correlatie coëfficiënten. Echter, de leercurvebenadering blijkt minder goed toepasbaar om de reductie van investeringskosten van biomassacentrales te beschrijven. Aanbevolen wordt met de leercurvebenadering verdere analyses van bestaande biomassa aanvoerketens uit te voeren. Dit zou een geschikte methode kunnen opleveren om de techno-economische ontwikkeling van nieuwe biomassa brandstofketens te beschrijven (bijvoorbeeld gerelateerd aan de teelt van energiegewassen).

Verder resteert de vraag **of,** in de tijd of met toenemende penetratiegraad**, de waarde van de PR verandert,** en specifieker of deze de 100% benadert. In twee gevallen (Duitse windparken op land en Deense biomassa vergistingcentrales) is geconstateerd dat de gevonden leercurves afvlakken, en de PR een waarde van circa 100% bereikt. Echter, in beide gevallen is aangetoond dat deze waarneming veroorzaakt werd door veranderingen in de markt (dat wil zeggen door subsidies en het ontstaan van brandstoftekorten) maar niet als gevolg van structurele veranderingen in de ontwikkeling van de technologie. Al met al zijn er geen indicaties gevonden dat PR-waarden gebaseerd op productiekosten gaandeweg veranderen, tenminste zolang als het marktaandeel van de technologie groeit.

Het verschil in gebruik van **marginale en gemiddelde kosten** bij het construeren van leercurves is onderzocht voor diverse biomassa energiesystemen. Zoals verwacht ligt de leercurve uitgaande van marginale kosten lager dan de leercurve met gemiddelde kosten, maar beiden vertonen dezelfde helling. Dit maakt het wellicht mogelijk om bij het bepalen van het kostenreductiepotentieel van de best beschikbare technologie de PR-waarde te gebruiken dis is af te leiden uit historische gemiddelde kostendata (die meestal makkelijker beschikbaar zijn).

Gerelateerd aan het vraagstuk van geografische grenzen van leersystemen is de kwestie van **inflatiecorrectie** in complexe internationale innovatiesystemen. Indien er voor een reeks van jaren data uit verschillende landen worden gebruikt, kan de keuze van de referentiemunteenheid en de gebruikte methode om de verandering in wisselkoersen tot uitdrukking te brengen de PR significant beïnvloeden. Terwijl er geen ideale oplossing voor dit probleem is gevonden, wordt aanbevolen om verschillende referentiemunteenheden te gebruiken om inzicht te verkrijgen in de onzekerheden van de resultaten.

In het onderzoek zijn ook de **leermechanismen** achter de kostenreductie van hernieuwbare energietechnologieën onderzocht. Uiteraard verschillen deze per technologie, maar een aantal conclusies kunnen worden getrokken op basis van schaal en geografische diffusie. Voor windturbines op land was opschalen in het verleden de meest belangrijke factor achter mondiale kostenreducties. Echter, leereffecten zoals de verbeterde plaatsing van windturbines en lagere netaansluitingskosten komen typisch op een lokaal niveau voor. De ontwikkeling van offshore windparken was slechts mogelijk door het continu opschalen van windturbines op land. Voor zowel windparken op land als op zee wordt verwacht dat zij zullen profiteren van de effecten van massaproductie die mogelijk wordt door de toenemende gemiddelde grootte van windparken. Met betrekking tot de techno-economische ontwikkeling van biomassatechnologieën hebben verbrandingscentrales met wervelbedketels (momenteel op mondiale schaal in gebruik) eveneens geprofiteerd van het geleidelijk opschalen van de technologie in de laatste decennia. Aan de andere kant hangen de lokale kostencomponenten (de brandstof aanvoerketen en de bedienings- en onderhoudskosten) van centrales voor een groot gedeelte af van lokale kennis, zoals de voorbeelden van Zweedse WKK centrales en Deense biomassa vergistingcentrales illustreren. In deze gevallen zijn learning-by-doing, learning-by-using en learning-by-interacting belangrijke mechanismen voor het succesvol ontwikkelen van deze technologieën.

5. Implicaties voor de ontwikkeling en marktdiffusie van hernieuwbare energietechnolgieën

Zoals onder meer in hoofdstuk 7 aangetoond hangt de invloed van technologisch leren op de diffusie en kosten van hernieuwbare elektriciteitstechnologieën in belangrijke mate af van de mogelijkheid tot competitie. Een Europees handelssysteem voor hernieuwbare elektriciteitscertificaten maakt een optimaal gebruik van de goedkoopste potentiëlen en technologieën mogelijk. Hierdoor worden technologieën met snel afnemende productiekosten bevoordeeld. Als de mogelijkheid tot handel niet aanwezig is, heeft technologische vooruitgang minder invloed op de diffusie van hernieuwbare energietechnologieën. Voor een snelle ontwikkeling van windparken op zee en BV/STEG centrales is internationale samenwerking en kennisuitwisseling (en meer algemeen meer multinationale ontwikkeling van de technologie) noodzakelijk, omdat geen enkel land de mogelijkheid heeft of biedt om op de thuismarkt voldoende centrales af te zetten en zo de kosten te reduceren tot marktconforme waarden. Aan de andere kant geldt voor diverse kleinschalige technologieën dat de kennis hiervan vaak slechts heel lokaal aanwezig is. De verspreiding hiervan behoeft aandacht als de toepassing van deze technologie beleidsmatig wordt bevorderd.

Het onderzoek toont aan dat in veel gevallen dat de kwaliteit en de kwantiteit van data niet voldoende is om leercurves te construeren. Dit heeft gedeeltelijk te maken met het vertrouwelijke karakter van bijvoorbeeld de productiekosten, maar het is soms ook te wijten aan een gebrek aan gestructureerde dataverzameling over de toepassing van hernieuwbare energietechnologieën. Terwijl er betrekkelijk veel data beschikbaar is over de toepassing van zonnepanelen en windturbines, is er maar weinig data beschikbaar over toepassing van veel biomassatechnologieën. Het wordt daarom aanbevolen om dit soort data gestructureerd te verzamelen voor toekomstige analyses. Ook voor de ontwikkeling van hernieuwbare energietechnologieën, die zich momenteel in een vroege fase van het marktdiffusieproces bevinden (bijvoorbeeld windparken op zee) is de beschikbaarheid van data over gerelateerde technologie (zoals hoogspanningskabels onder water en funderingen van staal of beton) niet optimaal.

In de case studies is geconstateerd dat de ontwikkeling en toepassing van de meeste grootschalige technologieën op een mondiale schaal plaats vindt en daarom leereffecten ook wereldwijd optreden. Ondanks dat nationale programma's zeer nuttig kunnen zijn om tot de ontwikkeling en diffusie van deze technologieën te komen, kan het in latere stadia van het diffusieproces lonender zijn om ook op een internationale aanpak en op verspreiding van lokale kennis te focussen. In dit kader zou een multinationale en/of Europese aanpak om windparken op zee en BV/STEG centrales te stimuleren aan te raden zijn, ook om de vereiste volumes te realiseren die voor significant leren noodzakelijk zijn.

Beleidsmakers moeten altijd een afweging maken voor de financiering van onderzoek; ontwikkeling en demonstratie (RD&D), van niche-markt ontwikkeling en van markttoepassing op grote schaal (VROM-raad and AER, 2004). Ondanks dat het moeilijk is om de ideale financiële verhoudingen tussen deze aandachtsgebieden te bepalen, en dit ook af kan hangen van de lokale situatie, de technologie en de marktomstandigheden, is in hoofdstuk 7 aangetoond dat vroege investeringen in pilot plants grote hoeveelheden subsidies in een later stadium van het marktdiffusieproces kunnen besparen. Het is echter niet eenvoudig om hierover a-priori uitspraken te doen. Verder onderzoek in deze richting wordt daarom aanbevolen.

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Curriculum vitae

Martin Junginger was born on the 7 February 1976 in Braunschweig, Germany. In 1995, he obtained his secondary school degree (Abitur) at the Deutsche Schule Den Haag in The Hague, the Netherlands. He studied chemistry at the Utrecht University from 1995 to 2000. During his study, he was board member of the chemistry student association Proton, and for two years student member of the faculty council. During the work for his Master thesis, he developed a methodology to set up fuel supply chains for large-scale biomass energy plants from agricultural and forest residues in developing countries. In the frame of his Master research, he stayed four months at the Regional Wood Energy Development Programme (RWEDP) of the Food and Agricultural Organization (FAO) in Bangkok, Thailand, and presented his findings at the 1st World biomass Conference in Seville, Spain.

After his chemistry study, he started his PhD research in January 2001 at the department of Science, Technology and Society, part of the Copernicus Institute for Sustainable Development and Innovation of Utrecht University. In the frame of his work, he has given presentations amongst others at conferences in Laxenburg, Rome and Rotterdam. He also stayed three months as a guest researcher at the department of Technology and Design, Växjö University, Sweden. Since January 2005, he is the chair of the Young Energy Specialists and Development Co-operation (YES-DC). From 1 April 2005 onward, Martin works as a post-doctoral researcher on sustainable international bio-energy trade at the Copernicus Institute.

Dankwoord

Een proefschrift schrijven is als een zeilboot besturen. Je weet ongeveer de bestemming, maar zonder mensen die je leren om gunstige stromingen te gebruiken, om ondieptes te omzeilen en met je meeroeien als er een keer geen wind is, was het een barre tocht geweest. Deze mensen wil ik graag danken.

Ten eerste mijn promotor en co-promotor. Wim, mijn dank voor je grondig commentaar waarmee je feilloos zwaktes in tekst en logica aanvoelde. Ook een proefschrift schrijven is ‘learning-by-doing’, en je gaf tot aan het eind steeds weer de stimulans en inzicht om een beter product af te leveren. André, jou wil ik met name danken voor alle motivatie, vertrouwen en steun. Zag ik het even niet zitten, of bleef ik hangen in een detail, binnen een kwartier wist je mij iedere keer weer te motiveren en op de grote lijnen te wijzen. Onze geschiedenis gaat al verder terug dan de afgelopen vier jaar, en ik kijk met veel plezier naar onze toekomstige verdere samenwerking!

Daarnaast hebben aan dit proefschrift nog veel meer mensen een belangrijke bijdrage geleverd zoals de co-auteurs van de diverse artikelen. Susanne Agterbosch, onze paden begonnen gezamenlijk, en het eerste artikel is daar een mooi resultaat van. Rolf Björheden, thank you for having me in Växjö, taking time for all my questions, sharing my enthusiasm and opening so many doors for me. As I’m staying in the biomass field, I really hope we will be working together more often in the future. Rob Raven, je idee om de Deense vergistingsinstallaties erbij te halen was goud waard, en nu zijn we ook nog eens gelijktijdig klaar. Kurt Hjort-Gregersen, thanks for answering all the detailed questions on biogas installations. Erika de Visser en Joris Koornneef, ik heb met veel plezier jullie begeleid tijdens het afstuderen, mijn dank voor jullie waardevolle bijdragen aan dit proefschrift. Martine Uyterlinde en Hage de Vries, het laatste hoofdstuk was een mooi stuk samenwerking! Ik hoop dat we in de toekomst de banden tussen NW&S en ECN verder kunnen aanhalen.

Gedurende de laatste vier jaar heb ik ook veel ondersteuning van andere ECNers gehad: Bob van der Zwaan, hartelijk dank voor je waardevol commentaar op de inleiding. Henk-Jan Kooijman, Paul Lako en Manuel de Noord, mijn dank voor de hulp en kennisuitwisseling op het gebied van leercurves en offshore wind.

Verder wil ik de andere leden van het AIRE team danken: Erik Lysen met name voor de ondersteuning bij het ‘contacten leggen’ aan het begin, Susanne Agterbosch, Han Slootweg en alle andere projectdeelnemers voor hun waardevolle inhoudelijke bijdrages en inzichten in andere vakdisciplines tijdens onze bijeenkomsten. Ook mijn andere studenten Ad, Anouk, Gijs en Diederik, wil ik danken voor de diverse bijdrages, ook jullie heb ik met veel plezier begeleid.

En dan NW&S – wat een geweldige groep. Zelden liggen serieuze discussies en hilarische momenten zo dicht op elkaar. Juist de mogelijkheid om met veel mensen vakinhoudelijk te filosoferen en tegelijkertijd het eigen werk te relativeren maakt het werken (en de koffiepauzes!) erg prettig. Om er een paar te noemen: Monique en Jethro, het geklets en gelach van B213 mis ik nu nog. Roni, in het van Unnikgebouw was je kamergenoot ‘door de gipsmuur’ heen, mijn dank voor alle tips voor het afronden van een proefschrift. Ook de NeWS-redactieavonden zal ik niet vergeten. Andrea, jij bent de volgende die promoveert; ik kijk naar je proefschrift uit. Evert, met jou heb ik vijf jaar lang de LCA-practica begeleid, en was zo in staat om ook onderwijs *geven* met veel plezier uit te oefenen. En dan die dagelijkse serieuze en hilarische discussies in de koffiehoek met Ad, Bas, Barbara, Carlo, Corry, Dirk-Jan, Edward, Esther, Günther, Heleen, Jinke, Kay, Maarten, Manuela, Marc, Martin P, Martin W, Martijn, Nils, Penny, Sander, Tao, Thomas, Vlasis en zoveel anderen ook. Cosy, Mirjam, Siham en Silvia wil ik graag danken voor alle ondersteuning, met name de hulp tijdens de laatste weken was geweldig. And as Växjö was my 'home' for three months: Åsa, Jan-Olof, Johan, Karin, Peter, Per, Tobias and all the others, tack så mycket for showing me Swedish hospitality and making my stay in Växjö a great time!

Vrienden, de laatste zes maanden van een aio-periode zie je elkaar niet zo heel veel, dat gaan we de volgende tijd weer inhalen. Coen en Arjen, paranimfen en vrienden vanaf het allereerste uur in 1995 aan de UU, ik verwacht natuurlijk dat jullie mij met raad en daad zullen bijstaan op de dertiende. Aglaia, mentor-zusje, wanneer gaan we weer eens stappen? Andreas, Tim und Steffi, was kann zusammen segeln herrlich sein! Und Tim, danke für das Layout!

Und dann die Basis, meine Familie. Meinen Eltern möchte ich sagen, dass man sein Leben (und eine Dissertation) nur auf ein solides Fundament bauen kann, und ein Besseres hättet Ihr mir nicht geben können. Als Dank möchte ich Euch gerne dieses Buch widmen. Georg and Siobhan, thanks for all the hospitality during the London mini-breaks and fun over the last years! Ook mijn schoonfamilie wil ik danken voor alle steun gedurende de jaren, en natuurlijk het foto-uitje tegen het eind.

Tenslotte, de belangrijkste: My-Phung. Het is fantastisch om op alle belangrijke momenten een steun en toeverlaat te hebben, met liefde en begrip, die er altijd voor je is - je bent geweldig!