# Learning curves for renewables and other technologies: an international analysis

MASTER THESIS

For obtaining the academic degree

**Diplom-Ingenieur (Dipl.-Ing.)**

**Vienna University of Technology**

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Vienna, November 2018

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# Abstract

As the avoidance of CO2 emissions in energy production is gaining more and more attention in our time, the focus is on renewable energies is more significant. However, in the past, these enegy supply technologies have proven not to be cost favorable. It is necessary to investigate how and by what the investment costs of the respective energy sources have changed over time.

Therefore, the investment costs of renewable and other technologies were analyzed and compared. For this purpose, the learning curve was used, which allows a qualitative description of the investment costs over time.

It has been found that photovoltaic has a high learning rate compared to the other technologies used for energy production. The learning rate for wind energy approaches zero. There are also technologies such as nuclear energy, for example, which even have "negative" learning.

To get more meaningful analysis, more data is needed. On the basis of the learning curves at least it can be seen that the investment in renewable energy sources is worthwhile.

# Kurzfasssung

Da die Vermeidung von $CO_2$ – Emissionen in der Energieerzeugung in unserer Zeit immer immer mehr an Beachtung gewinnt, wird der Fokus auf erneuerbare Energien gelegt. Diese haben sich aber in der Vergangheit als nicht Kosten günstig bewährt. Es ist zu untersuchen, wie und vor allem wodurch sich die Investitionskosten der jeweiligen Energieträger mit der Zeit geändert haben.

Deshalb wurden die Investitionskosten von erneuerbaren und anderen Technologien verglichen. Dazu wurde die Lernkurve zur Hilfe genommen, die eine qualitative Beschreibung der Investitionskosten über die Zeit erlaubt.

Es hat sich herausgestellt, dass Photovoltaik eine hohe Lernrate hat im Vergleich zu den anderen Technlogien, die zur Energiegewinnung genutzt werden. Die Lernrate für Windenergie nähert sich derm Wert 0. Es gibt auch Technologien wie Atomenergie zum Beispiel, die sogar ein „negatives“ Lernen aufweisen.

Um wirklich aussagekräftigere Analysen zu bekommen, sind mehr Daten notwendig. Anhand der Lernkurven ist zumindest ersichtlich, dass sich die Investition in erneuerbare Energieträgern lohnt.

# 1 Introduction

## 1.1 Motive

To limit growing global energy demand, reduce the emission of greenhouse gases (GHG) and achieve other environmental targets, technological development at low cost is essential. Therefore large number of technologies to supply renewable energy and to save energy are needed. Thus these technologies are at the core of most energy and climate policies worldwide. Due to scenario analyses of world's future energy system and climate change mitigation scenario, one can see that technological progress is key to minimize costs of such development pathways. In order to meet required reductions and supply contributions on time, especially the speed of development is essential. Through strong support for research, development, demonstration and deployment (RDD&D) of renewable energy technologies positive economic and security impacts are achieved.

Research and development (R&D) and market deployment of promising new energy technologies are supported by many (national) policies. Especially market deployment can be accompanied by substantial investment. In order to design and implement effective policies and strategies, a detailed understanding of specific technologies and their factors influencing their performance are essential.

Technological learning has been a driver of economic development. Many of the conventional technologies that are used today to produce electricity have already been continually improved over several decades or even over a century. For example, Coal-fired power plants have been built for nearly a century, whereas nuclear plants and gas fired power plants have been built and developed since the 1960s and 1970s. These well-established technologies are also continually improved. Production cost of established fossil fuel technologies is low because of their long-term development. On the other hand they have disadvantages, especially the greenhouse gas emission.

Compared to fossil fuel technologies, renewable and clean fossil fuel energy technologies and energy-saving technologies have higher production costs, but lower GHG emissions and fuel demands. Such technologies have potential for further technological development and resulting production cost reduction. Therefor policy makers are taken to task to develop strategies for cost-effective implementation of these relatively technologies.

The experience curve is one of the opportunities to analyzing the reduction in production costs. For many different technologies, it has been empirically observed that production costs tend to decrease by a fixed percentage with every doubling of the cumulative production. This cost reduction approximately lies between 10 and 30 percent.

## 1.2 Objective

As part of this work the author is focusing on the following matters:

- Comparison of historical investment costs of wind power, photovoltaics and biomass power generation.
- Are learning effects constant over time?
- Which learning effect is national or international? Cost differences between countries!

## 1.3 Method

This work is based on a literature research and review. Major literature was found on the internet. There are different online sites which provide an extensive source for scientific literature. The analysis was done by the application of *Microsoft Excel*, which is a widespread tool for scientific calculation, graphing, etc. Data unfortunately was not that easy to get. It depends on the technology and its distribution, how easy the data is to be found. Sometimes data is incomplete with regard to the years. Or data even is not available. Data used in this work were available at different online renewable and fossil and national or international (electricity) energy production databases like the *International Renewable Energy Agency (IRENA),* the *International Energy Agency (IEA)* or the *International Energy Agency – Photovoltaic Power Systems (IEA-PVPS).*

## 1.4 The Experience Curve Formula

Figure with double-logarithmic scale where cost development of a product or technology is described as a function of cumulative production is called experience curve. The following equation (1) is used to express this relationship in a mathematical way.

$$C_{Cum} = C_0 * \ Cum^m \qquad (1)$$

In order to estimate the experience curve econometrically, equation (2) is transformed in a logarithmic form, which results in equation (3).

$$\log C_{Cum} = \log C_0 + \mathrm{m} * \log Cum \qquad (2)$$

$$PR = \ 2^m \qquad (3)$$

Where $C_{Cum}$ = Cost per unit; $C_0$ = Cost of the first unit produced; $Cum$ = Cumulative (unit) production; $\mathrm{m}$ = Experience parameter; $PR$ = Progress ratio.

> “The progress ratio (PR), also interpreted as the slope of the experience curve, is a parameter that expresses the rate at which unitary cost declines for every doubling of the cumulative production. For example, a progress ratio of 80 per cent equals a learning rate (LR) of 20 per cent and thus a 20 per cent cost decrease for each doubling of the cumulative capacity. Both terms are used in the literature.”(Junginger et al. 2010)[1]

In the experience curve approach, costs are expressed in real terms. By using, for example, a GDP-deflator, these terms are corrected for inflation. Besides the conventional one factor experience curve, there also exist multi factor experience curve, to include the impact of research and development (R&D) or the R&D-based knowledge stock as an additional explaining factor of the technology cost decrease. However, the experience curves discussed in this work are generally one factor experience curves.

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[1] see page 11

## 1.5 Perils of the Experience Curve

Learning curves or experience curves should be used with caution, because the results can be misleading. William D. Nordhaus dedicated himself to this topic in his work.[2]

He found that learning coefficients are often overestimated. This overestimation of learning coefficients lead to an underestimation of marginal cost of output. Therefore, finally optimization models are biased to tend to technologies, which are falsely assumed to have higher learning coefficients.

In his work Nordhaus presents three important points, which identify learning curves or experience curves in their dangerous nature. First, there is a statistical identification problem in trying to separate learning from exogenous technological change and that learning coefficients are biased upwards. Second, he presents two empirical tests, which show the potential bias in practice and that learning parameters are not robust to alternative specifications. Third, as mentioned before, an overestimation of learning coefficients leads to an underestimation of marginal cost of output and at the end to wrong decision of technology.

In most studies or models of environmental and climate-change policy the issue of induced innovation or technological change was avoided. Until now one assumed that technological change is exogenous and that it is influenced by scientific and technological force but it does not depend on prices or taxes and other incentives.

The Romer model and the learning model were two important approaches to cover induced innovation. In the 1960s, the idea for the Romer model developed to understand why technological change accompanies by labor saving {Citation}. Most studies on induced innovation have been theoretical. Only a few of them lay out a testable hypotheses or ones that can be used to model the innovation development at an industrial level.

Another opportunity to analyze induced innovation is the learning model. It has particularly been popular for policy studies, because it can help to make decision in favor of technologies which are currently uneconomically but have the promise to be competitive in the future according to the learning curve.

For the present study the learning model was used.

In this section, the author analyzes the problem of identifying differences in productivity because of learning from exogenous changes. First he shows "why it is impossible without further identifying assumptions to distinguish learning from exogenous technological change, and why the learning coefficient is generally biased upwards". Output ($Q_t$) assumed to grow exponentially at constant grow rate *g.* Cumulative output (*Yt*) at time t is:

$$Y_t = \int_{v=-\infty}^{t} Q_0\, e^{gv} dv = Q_0 e^{gt}/g \qquad (4)$$

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[2] (Nordhaus 2009)

So we see that the growth rate of *Yt is also g.*

The cost function is:

$$C_t C_t = C_0 e^{-ht} {Y_t}^{-b}, \tag{5}$$

where h is the technological change rate and b is the experience coefficient. Current average and marginal cost are not dependent of current production. “Exogenous technological change” denotes all source of cost declines other than the learning-curve-determined technological change.

Prices are proportional to current instantaneous marginal cost, therefore the rate of decline in cost ($c_t$) is equal to the rate of decline of price ($p_t$).

$$p_t = c_t = h + bg_t \tag{6}$$

Next we assume a constant price elasticity $\varepsilon$ and $z_t$, which describes the population growth and growth of income. So the growth in output (demand) is:

$$g_t = \varepsilon p_t + z_t. \tag{7}$$

By solving the last two equations and suppressing the time subscripts, because the growth rates are constants, we can calculate the deterministic slope of the *behavioral learning curve, β:*

$$\beta = \frac{p}{g}\beta = \frac{p}{g} = \frac{h + bz}{\varepsilon h + z} = b(1 + \phi) \tag{8}$$

*, where*

$$\phi = \frac{h(1 - \varepsilon b)}{b(\varepsilon h + z)} \tag{9}$$

As one can see, to calculate the true learning parameter, reliable estimates of the rate of technological change, the demand elasticity, and the rate of autonomous growth of demand are needed.

The empirical experience parameter will be unbiased only when the rate of technological change is zero, because only then β = b. The expression (1- $\varepsilon$b) determines the size of the bias. The bias is upwards, when demand elasticity for example is less than 4, because then $\varepsilon$b > 1.

"Behavioral learning curves will generally have an upward biased in estimated learning coefficients because of influence of demand, output growth, exogenous technological change and learning. The only general case in which the learning coefficient is unbiased is when exogenous (non-learning) technological change is zero."(Nordhaus 2009)[3]

Due to the experience curve an additional unit of output lowers the all future costs as producers move down the curve. So total marginal costs are lower than current marginal costs. In the following this fact will be explained.

The present value of all current and future production (*$V_0$*) is:

$$V_0 = \int_{t=0}^{\infty} Q_t\, C_t e^{-rt} = \int_{t=0}^{\infty} Q_t\, [k_0 e^{-ht} Y_t{}^{-b}] e^{-rt} dt \tag{10}$$

Next a parameter Θ is considered as an increment of output at time 0. So we get a modified present-value cost:

$$V_0(\Theta) = (Q_0 + \Theta) C_0 + \int_{t=0}^{\infty} Q_t\, [k_0 e^{-ht} (Y_t{}^{-b} + \Theta] e^{-rt} dt \tag{11}$$

By taking the derivative of the last equation we get the total marginal cost:

$$V_0'(\Theta) = C_0 - b \int_{t=0}^{\infty} Q_t\, [k_0 e^{-ht} \big(Y_t{}^{-b-1)}\big] e^{-rt} dt \tag{12}$$

$$= C_0 - b \int_{t=0}^{\infty} Q_t\, C_0 e^{-pt} \left(\frac{Q_t}{g}\right)^{-1} e^{-rt} dt = C_0 [1 - \frac{bg}{r+p}] \tag{13}$$

The growth output (g) and the decline in cost (p) were defined in the last section. The expression with the variables in the bracket is called "learning discount". It is linear in the learning coefficient and the growth rate of output. Discount is positive if there is learning and all other terms are positive. Table 1 shows the total marginal cost as calculated for different growth, different discount rate, and different learning coefficients. The equation for total marginal cost (13) was normalized. Therefore, when learning coefficient (b) is zero

[3] see page 6

total marginal cost ($V_0'(\Theta)$) will always be 1. It is assumed that all productivity improvements are due to learning (*h* = 0).

As one can see, when the assumed learning rate increases there is a sharply decrease in the total marginal cost. For example, when the growth rate of output is 10 percent per year for a new product, the discount rate is 5 percent per year, and learning rate is 0.2, total marginal cost is 71 percent of the current marginal cost ($C_0$). That means, due to an extra unit produced today, future units get a productivity bonus of 0.29 additional units.

When the learning parameters are calculated incorrectly, we are able to see the dangers in using the learning curve. As mentioned above, if the true learning *b* rate is overestimated to a higher estimated learning rate $\beta$ - for example from b = 0.1 to $\beta$ = 0.3 – the learning account is overestimated by a factor of two.

So if one would have the choice between two different technologies, especially by using energy and global warming models which are designed to choose among different emerging technology, then technology A might be preferred due to the biased learning rate. At the end there would be a wrong recommendation for an investment in research and development. Therefore, modelers should be careful about their use of learning curves.

*Tabelle 1: Total marginal cost with learning as function of growth, discount rate, and learning coefficient.*[4]

| | Growth rate = 3 percent per year | | | | Growth rate = 10 percent per year | | | |
|---|---|---|---|---|---|---|---|---|
| | Discount rate | | | | Discount rate | | | |
| Learning coefficient | 0.01 | 0.03 | 0.05 | 0.1 | 0.01 | 0.03 | 0.05 | 0.1 |
| 0 | 1.000 | 1.000 | 1.000 | 1.000 | 1.000 | 1.000 | 1.000 | 1.000 |
| 0.1 | 0.769 | 0.909 | 0.943 | 0.971 | 0.500 | 0.750 | 0.833 | 0.909 |
| 0.2 | 0.625 | 0.833 | 0.893 | 0.943 | 0.333 | 0.600 | 0.714 | 0.833 |
| 0.3 | 0.526 | 0.769 | 0.847 | 0.917 | 0.250 | 0.500 | 0.625 | 0.769 |
| 0.5 | 0.400 | 0.667 | 0.769 | 0.870 | 0.167 | 0.375 | 0.500 | 0.667 |

[4] Data: (Nordhaus 2009)

# 2 History of Technological Learning

In 1936, an aeronautical engineer and educator called Theodore Paul Wright carried out an analysis on production cost in the aircraft industry. In his paper “Factors Affecting the Cost of Airplanes” he described how production cost per unit changed with increasing quantity.

In 1922, he started the study with the factor labor, because data for other factors were yet not available. As more data became available other factors were added to study. The original curve, which is shown in Fig. 1, was updated through the years. The curve also shows ratio of labor to material cost and ratio of total cost to construction cost with increasing quantity.

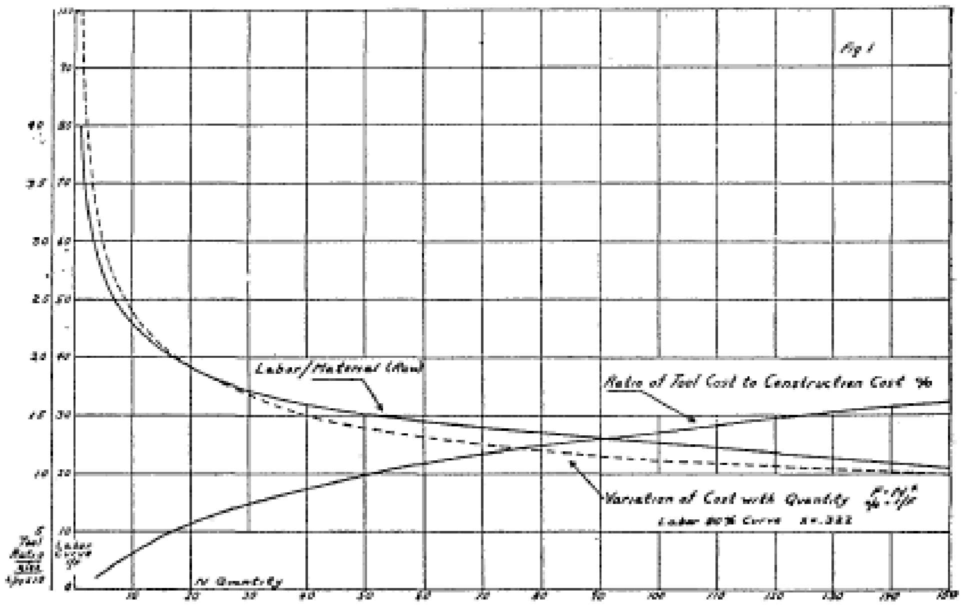


Figure 1: Variation of cost with increasing quantity in the Aircraft industry. Source: (Wright 1936)

Also a Figure was constructed to show the cost of each machine of a series in percent of the total cost of the series with increasing quantity (Fig. 2). Due difficulties in securing reliable empirical information on the cost of each machine of a series, the Figure must be considered as more approximate. But the curves are believed to show the general shape of curves and trend of data of this kind.

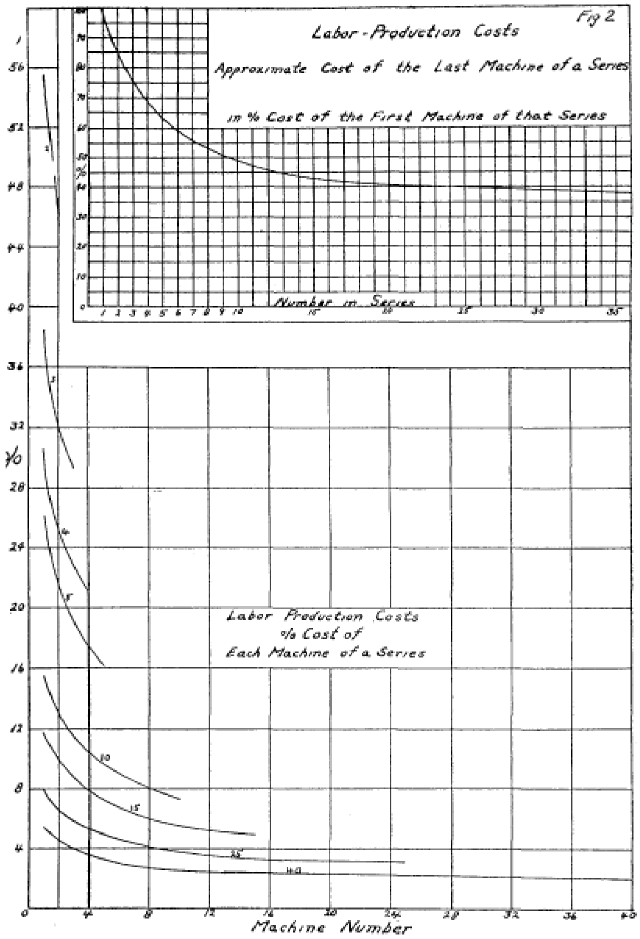

*Figure 2: Cost of each machine of a series in percent of the total cost of the series with increasing quantity. Source: (Wright 1936).*

The so-called stick-and-wire-and-fabric construction was leading in the early years. It enabled a quick and cheap construction of a prototype machine.

After the stick-and-wire construction type the usage of welded steel was prevalent. Wooden beams were the rule. Cheap construction at reasonable quantity was achieved by use of jigs and fixtures. On the other hand welding could not progress in time saving beyond a certain quantity. Therefore, better tools and fixtures were used to reduce the production cost.

The third and last construction type the author mentioned in his work is the monocoque construction type, which is characterized by forming thin materials and attaching them together by rivets. To achieve cheap quantity production, the monocoque construction type to an even greater extent requires the use of proper tools and fixtures. It is not suitable to constructing small quantities or prottypes. On the other hand monocoque construction type has its advantage by reducing the labor cost in very large quantities.

The author mentioned the following factors for the reason of production cost variation:

- **Tooling:**
  At the time parts are drawn the sight frequently has been lost of the need for considering future tooling. For example it is frequently necessary to design an amount of parts in order substitute forgings for built-up construction, when production orders are received. To make a forging die pie, the quantity of parts is small. In an order of twenty-five ships it is usually possible to use forgings for a great many parts. In the case of one hundred ships, there are very few small parts, which cannot economically be so made.
- **Changes:**
  Due to constantly changing in airplane technology it was obvious that changes take a significant part of cost because of shop delays and in the engineering expense of re-designing. Nevertheless, as standardization of type construction becomes more general, less changes should be there. The curve in this work was constructed assuming that no major changes will happen during construction of the airplane.

- **Size:**
  The following factors are necessary for the effect of size:
  1. The number of parts does not increase proportionally to size increase.
  2. Ease of Handling through less parts of minimum size in large airplane.
  3. Expectation to maintain a slightly smaller unit weight as size increases.

  It is believed that there will be decreasing in cost for machines up to about twenty-five thousand pounds with a gradual increase above that Figure, when measured in dollar per pound of structural weight.

- **Labor:**
  With practice a workman improves in proficiency. Assembly operations are examples for that. To disconcert the workman, it may also be anticipated that there will be less changes as the quantity increases. Another factor is that as more and more tooling and standardization of procedure is introduced there is the ability to use less skilled labor.
  The curve which shows variation of labor cost with production quantity was of the type depicted by the formula F = $N^X$. So the expression for X is:

$$X = \frac{Log\ F}{Log\ N}$$

  Where F is a factor of cost variation, which is proportional to the quantity N. To show directly the relationship between this two variables, the curve was plotted on log-log paper. Through the logarithm nature of the diagram we get a straight line, shown in Fig. 3.

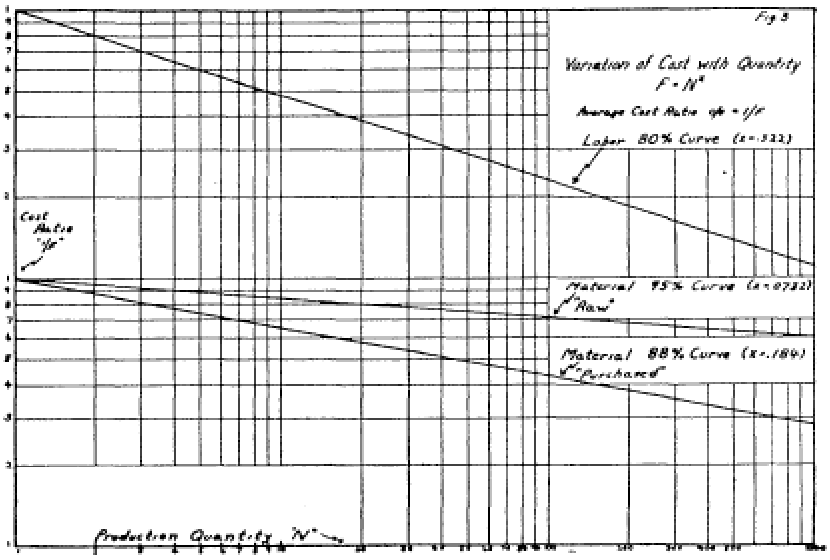


*Figure 3: Variation of cost with quantity. Source: (Wright 1936)*

For the 80% curve the X becomes 0.322. “80%” represents “the factor by which the average labor cost in any quantity shall be multiplied in order to determine the average labor cost for a quantity of twice that number of airplanes" (Wright 1936). In Fig. 3 it is assumed that quantities likely maintain for some time to come, whereas Fig. 4 was constructed for large quantities. So it is more suitable for future cost analysis of airplanes.

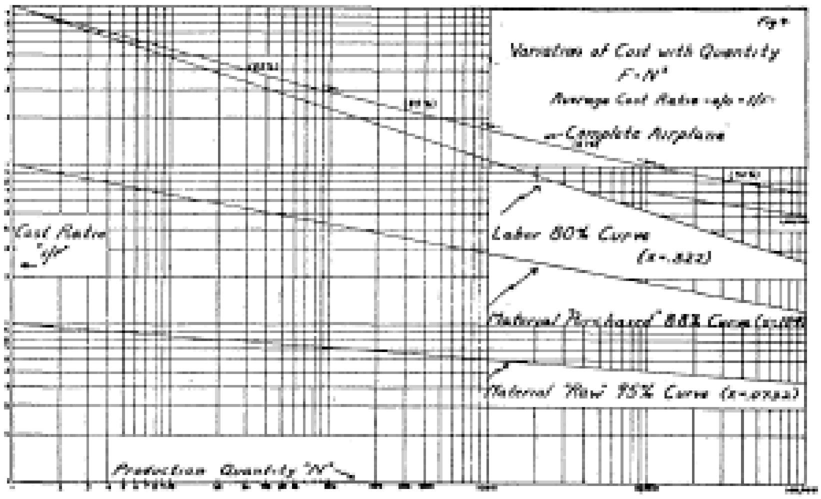


*Figure 4: Variation of cost with quantity for larger quantities. Source: (Wright 1936)*

- **Material:**
  Due to the following reasons there is a decrease in cost of material:

  1. As quantity increases waste reduces rapidly.
  2. Reduction in material cost through discounts when purchasing in large quantities.

  In Fig. X and Fig. X the curve for material reduction applying to raw materials is given as a 95% curve ( X = 0.0732), whereas for purchased material this factor is 88% ( X = 0.184). The change in factor from 95% to 88% is brought about by the greater expense on labor.

- **Overhead:**
  The overhead varies within limits, with quantity. It fluctuates depending on whether a factory is engaged in the manufacture of one type of machine or of many types.
  The effect of overhead was described by mentioning an example. A factory was employing five hundred workmen. Overhead ran one hundred percent. At one thousand workmen, overhead was reduced to seventy-five percent, and at fifteen hundred workmen to sixty percent. The curve would flatten out above that amount, in very large quantities it would increase in amount.

- **Complete Airplane:**
  The curve which describes the cost of a complete airplane in different quantities was created by implying the factors labor, raw material, purchased material and overhead. By this method it is indicated that the curve will in parts have slopes at eighty-three percent, then change to eighty-five percent, then change to eighty-seven, an finally reach ninety percent. Therefore, the relatively greater importance of material to labor is visible.

- **Non-Consecutive Orders:**
  New set ups; re-establishment of tools; labor turnover between orders, necessity for making new purchases; all mean a higher costs for the second order than would maintain if it were combined at one time with an earlier one.

- **Market:**
  As Design will be simple and cheap as time goes by prices will reduce. So sale will be driven to greater quantities. At the end we have the usual circle of relationship wherein price can be reduced most effectively by increasing quantity. In Fig. 5 one can see the price variation of airplanes at this time.

CHART OF PRICE VARIATION

*Assumed Airplane—Specifications*

| | | | |
|---|---|---|---|
| Capacity | 4–5 Place. | Engine | 300–400 h.p. |
| Useful Load | 1,400 lbs. | High Speed | 175–200 m.p.h. |
| Light Weight | 2,200 lbs. | Speed Range | 3. |
| Gross Weight | 3,600 lbs. | Construction | All-Metal. |
| Structural Weight | 1,600 lbs. | | |

*Unit Airplane Prices*

| | | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| Quantity | 25 | 100 | 500 | 1,000 | 10,000 | 100,000 | 250,000 | 1,000,000 |
| Factor (%) | .43 | .29 | .20 | .168 | .10 | .07 | .061 | .05 |
| Price ($) | 18,000 | 12,140 | 8360 | 7040 | 4180 | 2930 | 2550 | 2090 |
| Unit Price ($/lb.) | 8.18 | 5.52 | 3.80 | 3.20 | 1.90 | 1.33 | 1.16 | .95 |

*Rough Automobile Data*

| | | | | | |
|---|---|---|---|---|---|
| Weight (lbs.) | 6,000 | 3,700 | 3,400 | 3,250 | 2,900 |
| Price ($) | 4,700 | 1,200 | 1,000 | 750 | 650 |
| Unit Price ($/lbs.) | .783 | .324 | .294 | .231 | .224 |
| Ratio of Unit Prices Plane to Auto | 4.1 | 5.86 | 4.53 | 5.02 | 4.28 |

*Figure 5: Price variation of airplanes in 1936. Source: (Wright 1936)*

# 3 A Survey on Learning Curves

## 3.1 Photovoltaic solar power

### 3.1.1 Photovoltaic Technology

The history of the photovoltaic technology began with the finding of Alexandre Edmond Becquerel in 1839. He observed the conversion of solar radiation into electricity due to the photovoltaic effect. The materials in which this effect occurs are known as semiconductors. Semiconductors consist of two energy bands. In the valence band electrons are allowed, but the conduction band is free of them. Silicon, the second most abundant element on earth, is the material of which semiconductors are made from. The atoms of silicon form a crystalline structure with their neighboring atoms through 4 external electrons.

Sunlight powers the outermost electron with energy, which moves from the valence band to the conduction band. So the electron generates electricity. To exceed the gap, especially in case of silicon, it is needed 1.12 eV (electron Volt) for electrons (Peng and Lee 2011). Nearly all photovoltaic cells include a pn junction in a semiconductor, developed through a photo voltage. A typical photovoltaic cell or solar cell is shown in Fig.6[5].

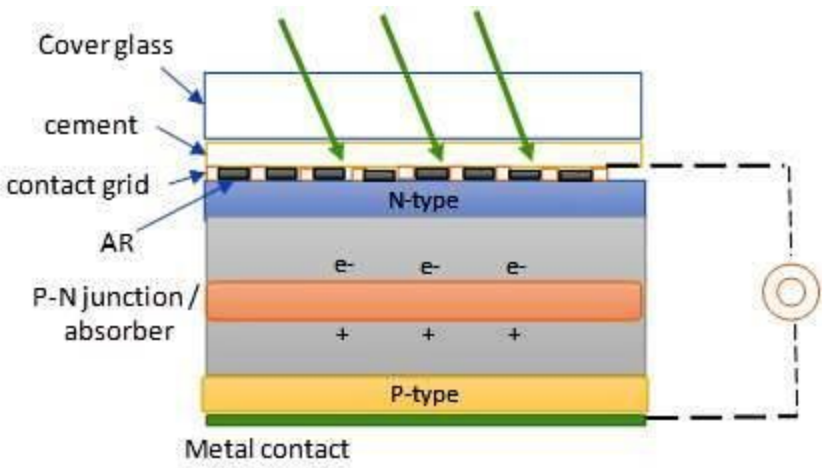


*Figure 6: Fundamental functionality of a solar cell. Source: materion.com*

On the top and the bottom are the electrical contacts. The main part is the pn-junction which is between n-type and p-type layer. To provide a better functionality the n- and p-type layer are doped with other elements, such as phosphorus (for n) and boron (for p).

[5] (Samuel Pellicori 2018)

PV systems are comprised of PV modules in which many cells are interconnected and convert sunlight in DC electricity. To provide the DC electricity to the grid inverters are used to conversion to AC. There are also additional components like electrical connection and the mounting structure. The set of components excluding the module is usually referred to as Balance of System (BOS) components. The classification of PV modules is made through their rated power. Which is the power they deliver at standard test conditions (STC) of 1000 W/m$^2$ irradiance while the module is at 25°C. For example a 13 per cent efficient, 1 m$^2$ PV module is rated at 130 Wp. p denotes in this case peak performance.

The total global PV module production from 1997 to 2016 by region is shown in Fig. 7[6], and again in Fig. 8[7] in percentage. One can see that until 2005 and 2007 total module production in Europe respectively Japan increases. From then on, a huge increase in production took place in China and Taiwan, replacing Europe and Japan. US produced less and less over time. Only in the recent years there has been a slight increase in production.

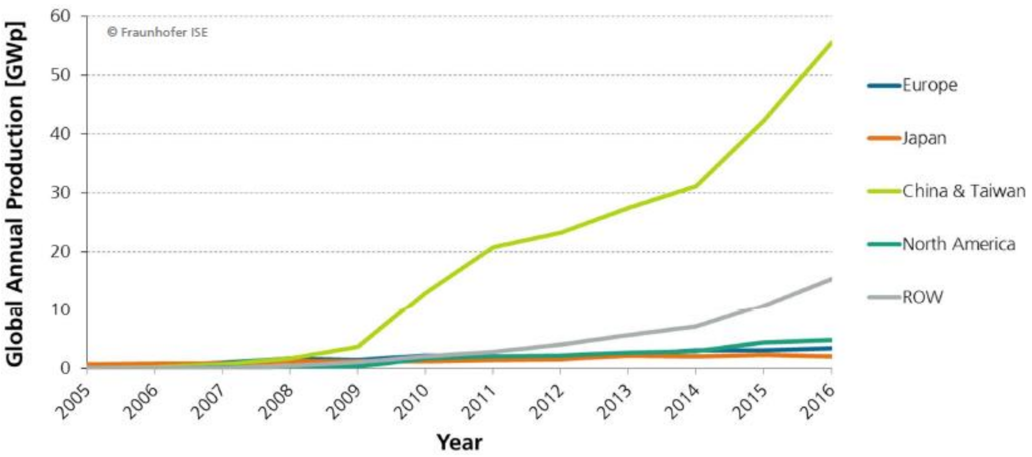


*Figure 7: Total Global Annual Production of PV Industry. Source: Fraunhofer ISE . Data: Up to 2009: Navigant Consulting; since 2010: IHS. Graph: PSE AG 2017.*

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[6](Dr Simon Philipps and Warmuth 2017)
[7] (Dr Simon Philipps and Warmuth 2017)

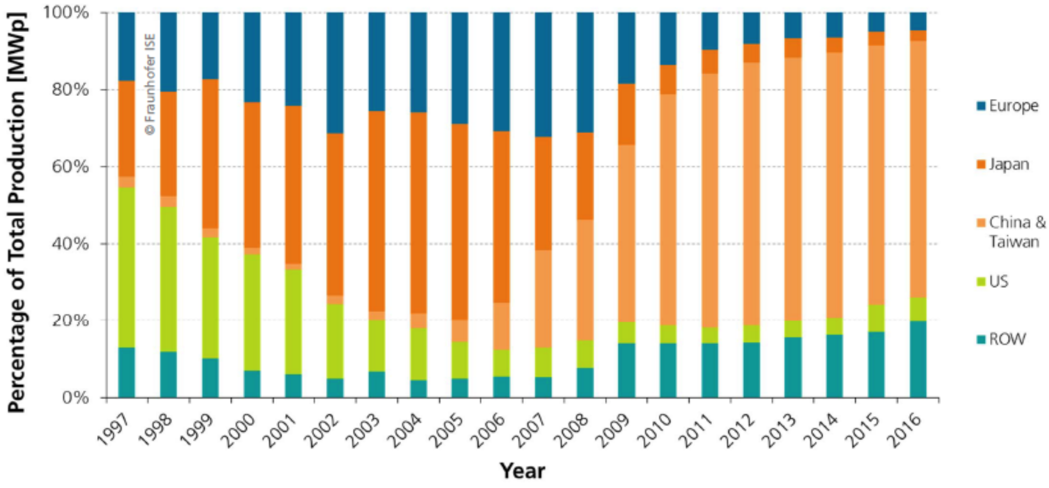


*Figure 8: PV Module Production by Region 1997-2016. Source: Fraunhofer ISE. Data: Up to 2009: Navigant Consulting; since 2010: HIS. Graph: PSE AG 2017)*

There exist different types of solar cells. The materials they are based on are mono- and multicrystalline, and amorphous or microcrystalline thin films.

*Crystalline silicon (c-Si)*

Are known as first generation PV module material. Is made of crystalline structures which use silicon to produce the solar cells. C –Si modules are usually guaranteed for a lifetime of 25 years at a minimum 80% of their rated output and sometimes for 30 years at 70% (IEA 2014). Some manufacturers also provide double power warranty for their products. This typically includes 90% of the initial maximal power after 10 years and 80% of the original maximum power after 25 years (Skoczek et al. 2009).

C-Si is the oldest PV technology type. Its commercial production began 1963 (IRENA 2012). It is divided into two subtypes: mono- crystalline or single-crystalline cells (sc-Si). Sc-Si cells use crystalline Si p-n junction, and poly-crystalline or multi-crystalline cells (mc-Si). Compared to sc-Si the efficiency of mc-Si is lower, because its grain boundaries impede the flow of electrons and reduce its power output. To produce the same power output mc-Si modules therefore require a larger surface than sc-Si modules. Si crystals of mc-Si cells are grown and cut in square wafers rather than the rounder shape of sc-Si cells. Hence mc-Si can cover more solar module area and achieve less waste of space (Wong et al. 2016). In Fig.9[8] an example of a c-SI PV solar module is shown.

Since the cost of c-Si is high, one is continuously working on new technologies to offer a cheaper solution. Therefore the development of thin film technology began.

[8] (Pilkington 2018)

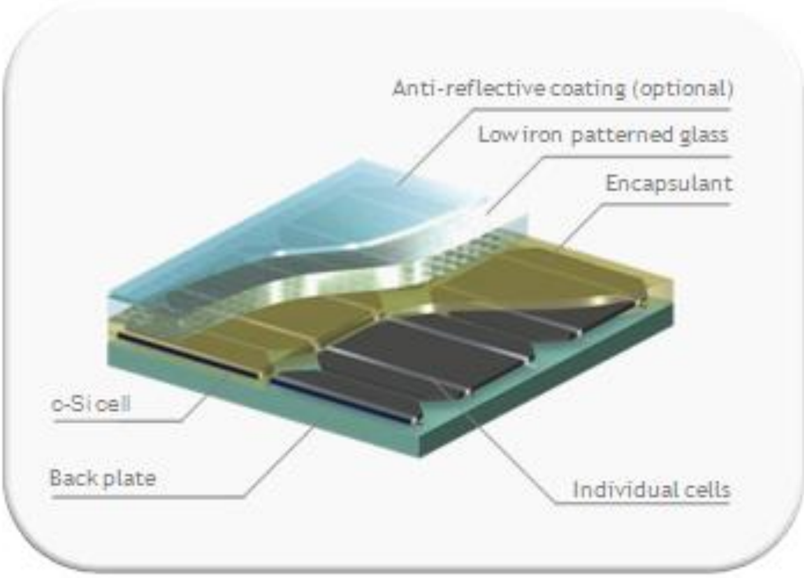


*Figure 9: Example of a c-Si PV solar module. Source: www.pilkington.com.*

*Thin film*

Thin film cell types, also known as second generation PV, are created by depositing thin layers of semiconductor material on glass or stainless steel substrates. Compared to crystalline wafers which usually have a thickness of several hundred µm, thin film layers are less than 10 µm thick (Hosenuzzaman et al. 2015). Because of their thinner construction thin film cells cost less, but in the same time they have a lower capability to absorb the incoming solar radiation, which leads to low efficiency. In sunny hot locations CdTe outperforms c-Si by 5-6% (Hegedus Steven 2013).

There are four important types of thin film solar cells:

- Amorphous silicon (a-Si)
- Thin poly-crystalline silicon on a low cost substrate
- Copper indium diseleride (CuInSe2 or CIS)
- Cadmium telluride (CdTe)

CdTe has the easiest and fastest material deposition process and has proven to be a promising PV material for thin film solar cells (El Chaar et al. 2011). A-Si was first developed. Several years ago it was the most popular thin film technology, but it has an initial light induced degradation (Parida et al. 2011). Once stabilized a-Si technology has a degradation rate of about 1.3%, whereas CdTe and CIS increase to 1.7% and 1.8%, respectively. C-Si has a considerable lower degradation rate. Fig. 10[9] shows an example of a thin film PV solar cell.

[9] (Vysakh 2011)

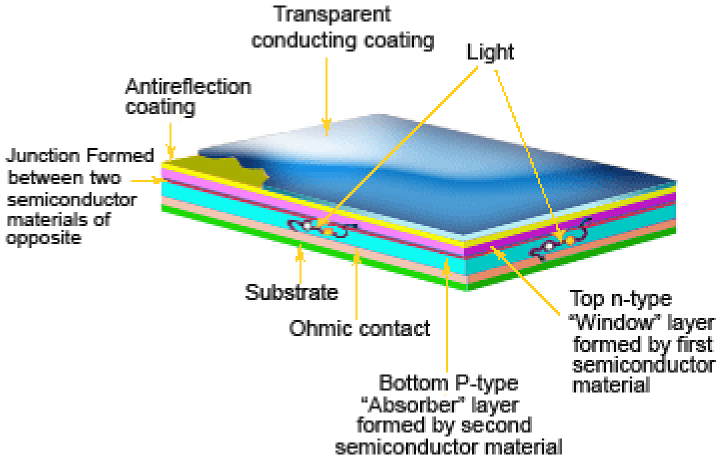


*Figure 10: Thin film PV solar cell. Source: www.circuitstoday.com*

*Compound semiconductor*

In order to absorb most of the solar radiation compound semiconductors are made of stack of crystalline layers. Examples of this technology are Gallium arsenide (GaAs) and Indium gallium phosphide (InGaP) multi-junction devices. This technology has its use in powering satellites (Grau et al. 2012). The substrates are expensive, therefor the cost of compound semiconductors are much higher than c-Si cells (IRENA 2012). To reduce cost, a large lens is installed above the solar cell in order to concentrate the solar radiation on the small cell, which is called concentrating PV (CPV). Unlike other PV solar cells CPV use direct normal irradiation (DNI). An example of compound semiconductor PV solar cell is shown in Fig. 11[10].

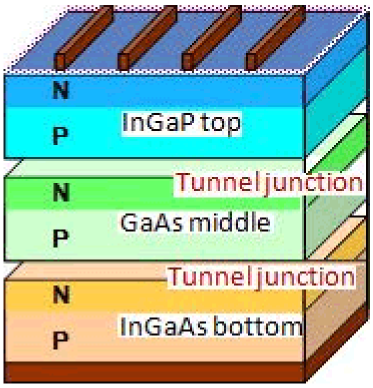


*Figure 11: Compound Semiconductor PV Solar cell. Source: www.sharp-world.com*

[10] (Sharp 2011)

*Nanotechnology*

Nanotechnology PV solar cells are made of different structures from nanotechnology products. By managing the band-gap they absorb more sunlight in order to improve the PV conversion efficiency. There are commonly 3 types of devices used in nanotechnology-based PV cells: quantum dots (QDs), carbon nanotubes (CNT) and hot carrier solar cells (HC). They are cost-effective, lightweight, flexible and offer good electrical performance (Akinyele_2015). The efficiency compared to other PV technologies is low, because nanotechnology PV cells are still at research stage (V. Benda 2015). The efficiency of nanotechnology PV cells is nowadays is around 12%. Fig. 12[11] shows different layers of a carbon nanotube cell.

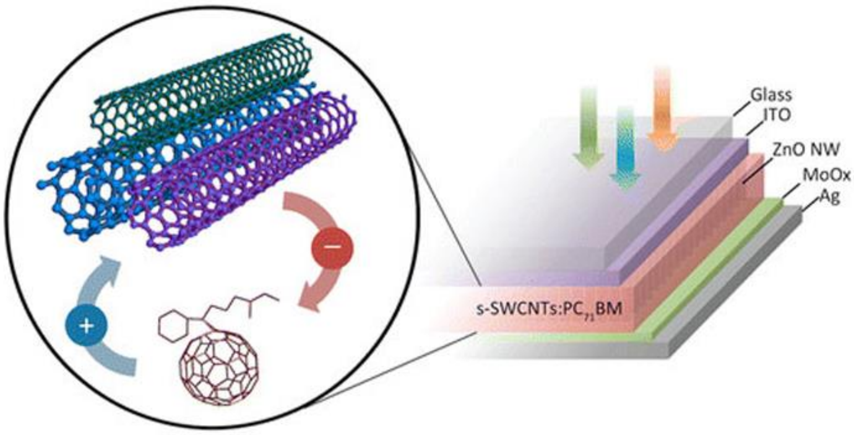


*Figure 12: Carbon nanotube cell. Source: www.physicsworld.com*

[11] (Belle Dume 2014)

Fig.13[12][13] shows the efficiency of the mentioned PV solar technologies.

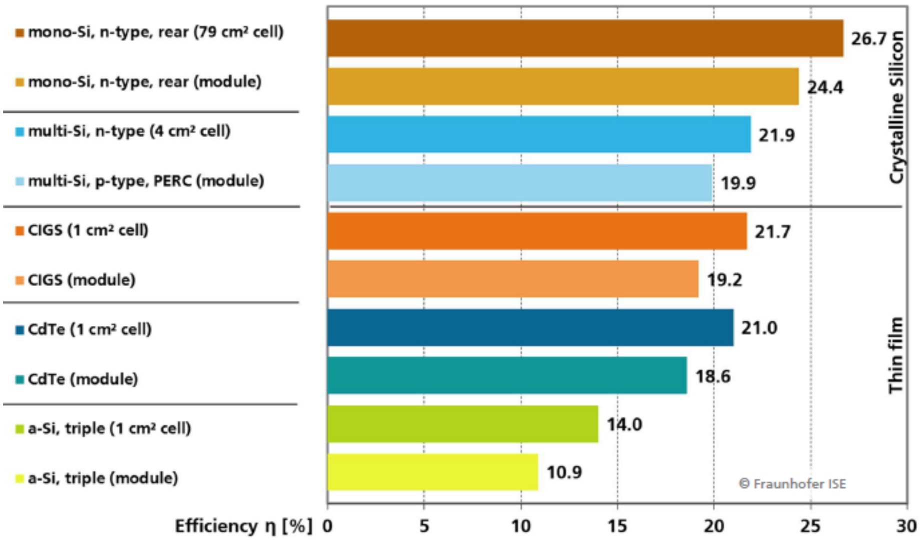


*Figure 13: Efficiency Comparison of PV module Technologies. Source: Fraunhofer ISE. Data: Green et al. Graph: PSE AG 2017.*

Like with other renewable energy sources electricity generation with PV solar has a very low greenhouse gas emission (GHG) rate. To determine significant GHG rates several life cycle assessments (LCA) were conducted in different regions. The summarized table (Table 2) shows a review of them for multi-Si PV systems.

[12] (Dr Simon Philipps and Warmuth 2017)
[13] (Green et al. 2017)

*Table 2: LCA result review of GHG emission rates of different multi-Si PV Systems. Source : (Wu et al. 2017)*

| Author | Location/irradiation ($kWh/m^2/yr$) | Module efficiency | Life Time (yr) | Performance ratio | GHG emission rate (g CO2-eq./kWh) |
|---|---|---|---|---|---|
| Kato an Murata | Japan/1427 | 11.6% | 20 | 0.81 | 20 |
| Alsema | South-European/1700 | 13% | 30 | 0.75 | 60 |
| Ito an Kato | Gobi (China)/1675 | 12.8% | 30 | 0.78 | 12 |
| Alsema and Wild-Scholten | South-European/1700 | 13.2% | 30 | 0.75 | 32 |
| Ito an Komoto | China/1702 | N/A | N/A | 0.78 | 43 |

For an example of avoidance of GHG emission in Fig. 14[14] the CO2 emission avoidance and the generation of electrical energy by PV in Germany is shown. In 2016 approximately 22 Mio.t of CO2 emissions were avoided due to 38.2 TWh PV electricity consumption.

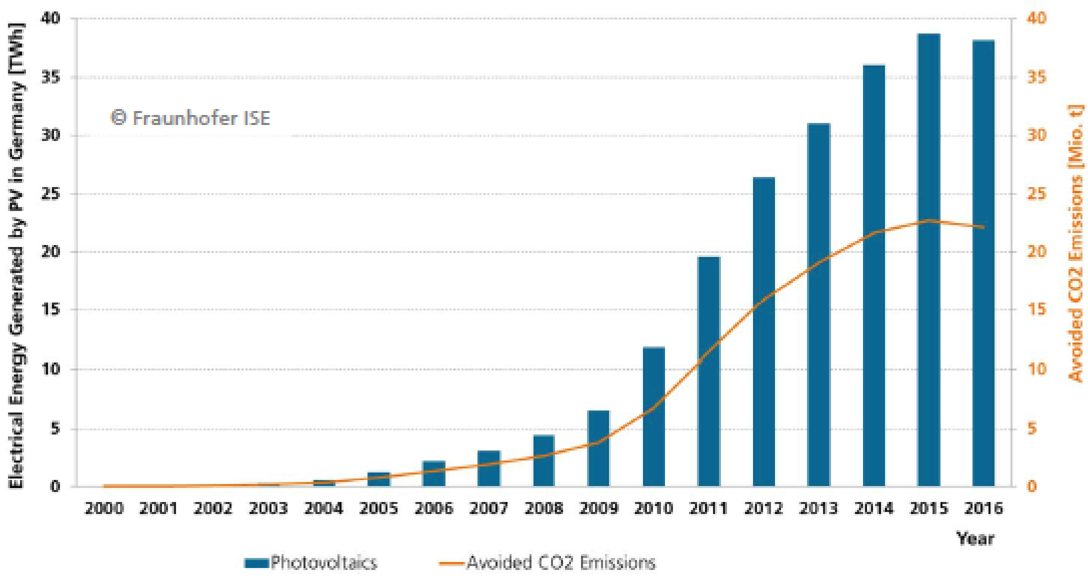


*Figure 14: CO2 Emission Avoided and Electricity Energy Generated by PV in Germany. Source: Fraunhofer ISE PV report (2018).Data: BMU, BDEW, BMWi, Federal Environmental Agency (UBA) 2017. Graph: PSE AG 2017*

[14] (Dr Simon Philipps and Warmuth 2017)

In Table 3 some advantages and disadvantages are described.

*Table 3: Overview of Advantages and Disadvantages of PV solar (Sampaio and González 2017)*

| **Advantages** | **Disadvantages** |
|---|---|
| Reliable System | High initial cost |
| Low cost O&M | Limitations in availability of systems on market |
| Free energy source | Relatively large area of installation needed |
| Clean Energy | High dependence on technology development |
| High Availability | Depends on geographical conditions (solar irradiation |
| Generation can be made closer to consumer | |
| Environmental friendly | |
| Noiseless | |
| Potential to mitigate emissions of GHG | |

There are 4 categories of PV systems:

- Centralized and grid-connected systems as analogue to conventional power plants.
- Grid-connected distributed generation systems installed on buildings and feeding only their excess electricity into the utility grid.
- Off-grid domestic systems (home systems) providing power to local households and villages.
- Off-grid remote systems to power applications such as water pumping, telecommunication appliance, buoys.

As one can see in Fig. 15[15], in 2000 there was almost no share of Grid-connected centralized PV systems. Grid-connected decentralized systems made up approximately 85%, rest were Off-grid systems. Since 2004, percentage of Grid-connected centralized systems has increased. So in 2016 its share was about 72%. Almost no share of Off-grid systems and about 27% of Grid-connected decentralized Systems.

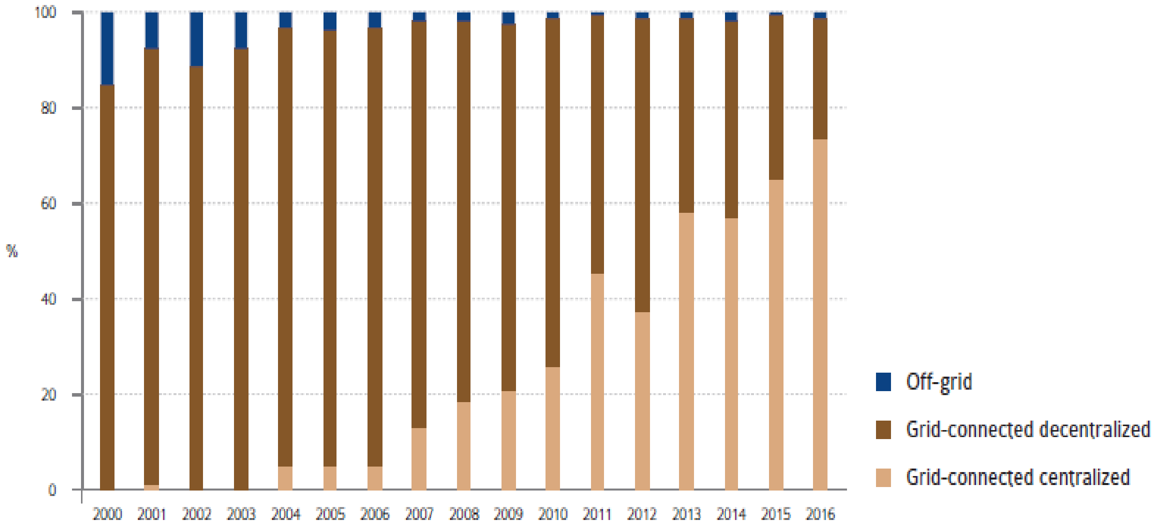


*Figure 15: Share of Grid-Connected and Off-Grid Installations 2000-2016. Source: IEA-PVPS.*

[15] (IEA-PVPS 2017)

### 3.1.2 FIT System in German PV market

*Until 2000*

Before the year 2000, the real driver of development and deployment of PV technologies in Germany were a mix of direct R&D funding, smaller local initiatives and two large demonstrations program called the 1000 and the 100000 roofs program. At this time the national feed-in tariffs had not a sufficient impact. In the year 1991, the governing coalition consisting of the Christian Democratic (CDU) and the Liberal Democratic Party (FDP) established the first Feed-in Law (“Stromeinspeisungsgesetz”). In 1989, the CDU/FDP leadership in the Bundestag initially stopped a member’s bill to create a market for renewable energies. However, in 1990, the law was passed with strong parliament support. Since the remuneration at a level of 90% of the average customer purchasing price was much too low to cover costs of PV power producers. Arguing that subsidizing the technology was uneconomic and further market interventions should be avoided, the CDU/FDP government opposed any increase in the FIT for PV. Instead they were of the opinion that due to the early stage of development, support for R&D and demonstration was best suited to support PV. Other countries, such as Japan and the US, had already established more comprehensive market support schemes, raising concerns that Germany might lose the international race for PV industry development. So politicians of the Social Democratic Party (SPD) and the Greens, on the contrary, emphasized the importance of a mass market for lowering the costs of PV.

In 1998, a coalition consisting of the SPD and the Green Party replaced the CDU/FDP government. A completely new Feed-in Law, the Renewable Energy Sources Act (“Erneuerbare Energie Gesetz [EEG]) was set up. Like the first Feed-in Law, the EEG was established to grant independent producers of PV access to the electricity grid if a grid connection was necessary and economically feasible. The law included a PV-specific remuneration of 51 EUR cents/kWh at which grid operators had to purchase the generated electricity over a guaranteed period of 20 years. The grid operators paid the remuneration to the electricity utility, which apportioned the extra costs (“EEG apportionment”) to the electricity price of the end user. The only utilities which were excluded from having to collect the EEG apportionment were those whose total sales included more than 50% of FIT-eligible electricity. Due to this measure an extra incentive was created for utilities to increase their share of renewables in their electricity portfolio. To account for the expected decreases in the cost of PV resulting from technological learning and economies of scale, the law included an annual degression of 5% in the FIT for newly installed plants as of 2002. The law included an annual degression of 5% in the FIT for newly installed plants as of 2002 because of the expected decreases in the cost of PV, which resulted from technological learning and economies of scale.

The significant increase in the remuneration for PV in combination with low-interest loans provided under the 100000 roofs program led to a surge in the market for PV technologies. In 1999, the annual installed capacity made up 13 MW, whereas the annual installed capacity in 2003 account for 175 MW, which means a 10-fold increase. The annual installed photovoltaic capacity and cumulative installed capacity from 1998 to 2016 in Germany is shown in Fig. 16[16] In June 2002, the German Bundestag commissioned the first experience report on the EEG, in which was noted that PV showed the smallest contribution to the electricity generation (0.05% in 2001) but the highest growth rates.

[16] (IRENA 2018)

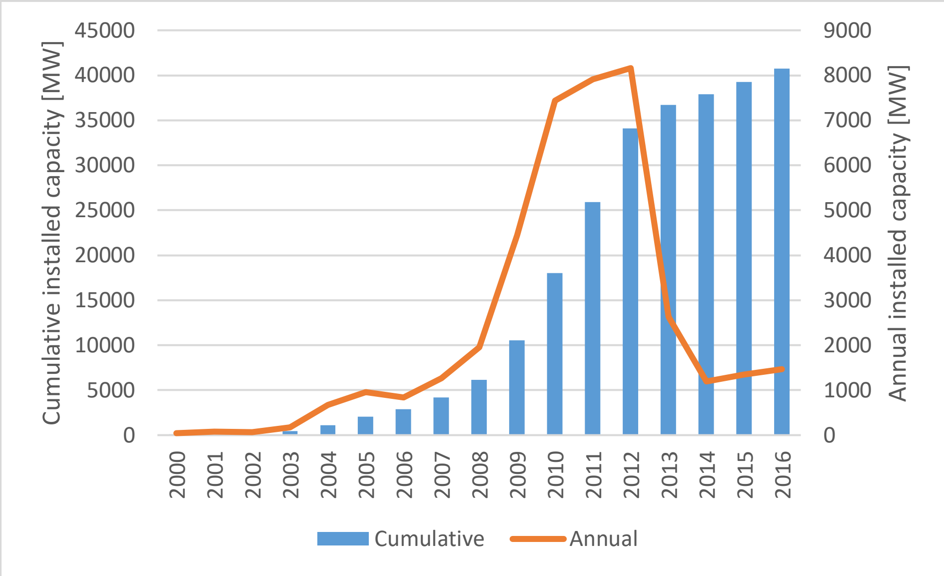


*Figure 16: Annual and cumulative installed solar PV capacity of Germany from 1998-2016. Data: IRENA.*

*2000 - 2004*

Two issues emerged that the 2000 version of the EEG did not take into account. First, the EEG 2000 included a cap of 350 MW for the maximum cumulative installed capacity to be covered by feed-in tariff, because they wanted to alloy concerns among opposition parties and consumer association that the EEG would lead to steep increases in electricity prices. At the same time, the plants which were eligible for the remuneration were limited to a maximum size of 5 MW for roof-mounted PV and 100 kWp for other facilities. These measures were considered potentially harmful barriers to the opportunity of establishing a leading market position and exporting domestic PV technology. Second, the share of the EEG apportionment in the end consumer electricity price increased from 0.2EUR cents/kWh in 2000 to 0.4EUR cents/kWh in 2004 with increasing deployment which led to concerns about potential competitive disadvantages for energy-intensive sectors.

To handle these issues, in 2002 an addition to the EEG was adopted. So the ceiling raised to 1000 MW. Furthermore, in 2003 an article was added that limited EEG apportionment for large electricity consumers that faced international competition and also that ones who had an electricity consumption of more than 100 GWh and a share of electricity costs in gross value added of more than 20% to 0.05 EUR cents/kWh. In December 2003, the ceiling and the limit to suitable plant sizes were completely removed. Because with the end of the 100000 roofs program private households could no longer apply for complementary low-interest loans, for roof mounted PV the remuneration was increased up to 57.4EUR cents/kWh.

In July 2004 there was a substitution of the EEG 2000 with its additions and amendments by a completely changed EEG, consisting of 21 articles. The overhaul had officially been dictated in the EEG 2000 and reinforced the development reflected in the previous additions. To ensure a higher investment security of independent power production some articles were added that detailed the process of remuneration payment and grid connection. The limitation of the EEG apportionment for large electricity consumers was extended to include all companies that used more than 10 GWh of electricity and had a share of electricity costs in gross value added of more than 15%.

By increasing the remuneration for rooftop PV and by removing the ceilings for maximum plant size the German PV installations experienced a fundamental boom. The installed capacity rose from 435 MW at the end of 2003 to more than 6 GW at the end of 2008. Because PV created domestic jobs, CO2-free electricity supply and innovation, the assessment of the law was positive. Especially the growing number of jobs in companies which produced and installed PV modules and manufactured equipment led to an excitement among politicians of all parties. The EEG was praised as a success story in many debates.

*2004-2011*

Before 2006 the SPD and the Greens, who were the initiators of the EEG, had been able to justify the public costs for PV. They mentioned the positive economic, ecological and social side effects of the feed-in tariff. They also mentioned the large amount of public spending that have been received by other energy technologies like nuclear power, in the past. On the other side, some members of parliament of the CDU and FDP criticized the high social costs resulting from the FIT for PV, e.g., in a large interpellation in 2004. At the end all parties agreed to support PV. After a government consisting of SPD and CDU had been elected in 2005, the EEG was accepted by the large parts.

From 2004 to 2008, the costs that was paid by the electricity consumer became increasingly noticeable, while there was a steep increase in PV deployment. Due to PV support through the feed-in tariff, in 2008, the extra cost for electricity consumers amounted to almost 2 billion EUR, which means an increase of more than 600% compared to the level of 2004. This fact is shown in Fig. 17[17].

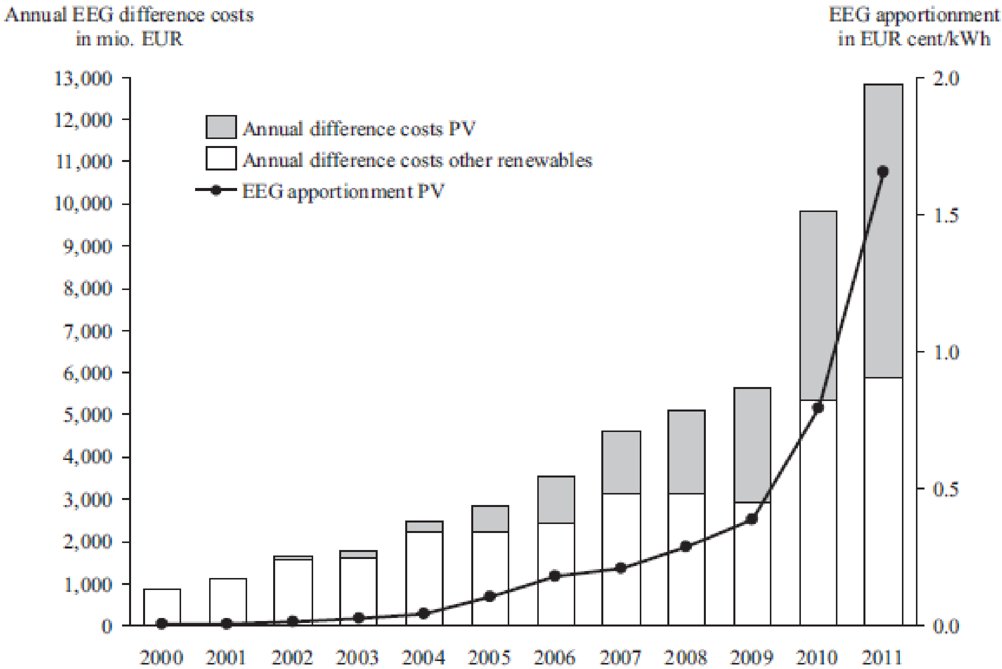


*Figure 17: Development of annual EEG difference cost and apportionment for solar PV in Germany. Source: Hoppmann et al. 2014. Data: BDEW (2011).*

[17] (Hoppmann et al. 2014)

Furthermore, production costs for PV modules during the years 2004-2008 had decreased at a faster rate than the remuneration paid through the FIT system. These cost reduction were the result of successful innovation efforts of firms and economies of scale.

In 2009, a new EEG was enforced. This version of the EEG contained specific measures to slow down the market development, limit additional costs for consumers and reduce unexpected profits. One of the significant changes was the substitution of the static degression of 5% by a dynamic degression. So the level of remuneration paid for new plants was dependent on the installed capacity of the PV in the previous year. To damp adverse effects of PV on grid stability and avoid investments in distribution grids, the 2009 complement of the EEG also introduced targeted incentives for self-consumption of electricity. The amendment to the EEG in 2009 also contained a new section which required plants with a size larger than 100 kW to implement a remote control and power measurement unit. With this measure in case of instability grid operators were able to disconnect larger plants from the grid. Plant operators were guaranteed compensation at the level of lost income, to make up for the financial losses occurred during a period of transitional grid enforcement. The EEG also reformed the redistribution mechanism. Grid operators were now required to directly market the electricity which they bought from PV plant operators at the electricity sport market. Before that electricity was purchased and bundled into contracts to be sold to electric utilities. The renewables had to be slowly integrated into the market. The mismatch between electricity demand and the supply had to be reduced. So according to the EEG 2009 the plant operators had the option to forgo the feed-in tariff and directly market their electricity to the third parties.

Deployment of PV kept rising rapidly although there was an increase in degression of feed-in tariff. PV system prices fell rapidly by 29% from 4225EUR per $kW_p$ at the end of 2008 to 3000EUR per $kW_p$ at the end of 2009 (Fig.18[18]). The reason were overcapacities among producers of PV modules, an increasing supply of low-cost modules from Asia (especially China) and a drop in prices for silicon.

[18] (Hoppmann et al. 2014)

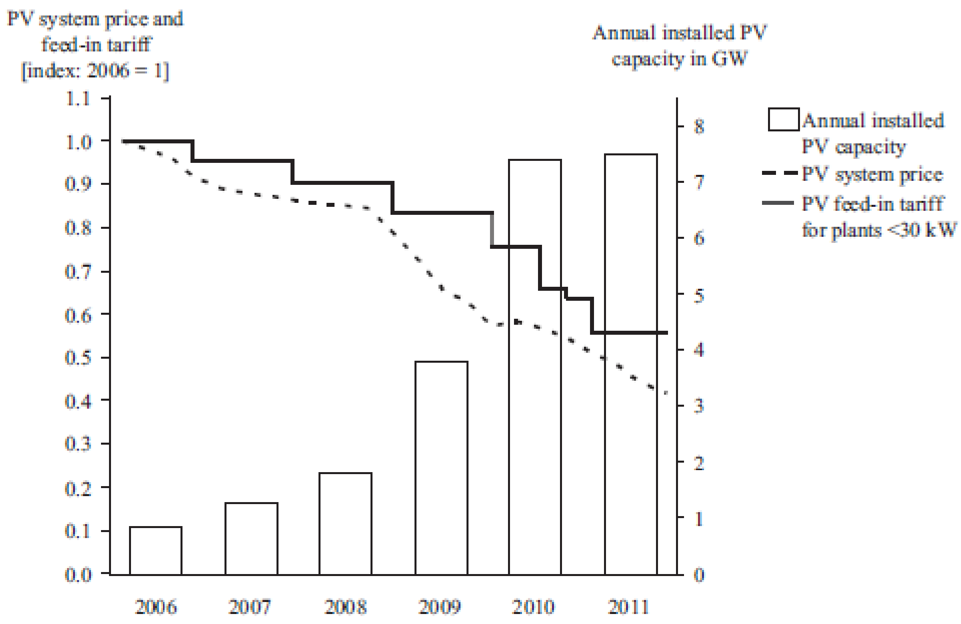


*Figure 18: Development of feed-in tariff, PV system price and annual installed capacity of PV in Germany. Source: Hoppmann et al. 2014. Data: BMU (2011), BSW (2012) and EPIA (2012).*

The feed-in tariff level decreased in a much lower rate. So profits of both producers and investors increased. In 2009 there was also a breakdown of the Spanish PV market. The large amount of PV modules produced could no longer be absorbed. Therefore Germany experienced a record PV capacity of 3.8 GW being installed in 2009. This further raised the annual difference cost to be paid by the consumers. The share of German manufacturers in global PV cell production had fallen significantly since 2007. Germany bought its PV cell from Chinese manufacturers (see Fig. 19[19]).

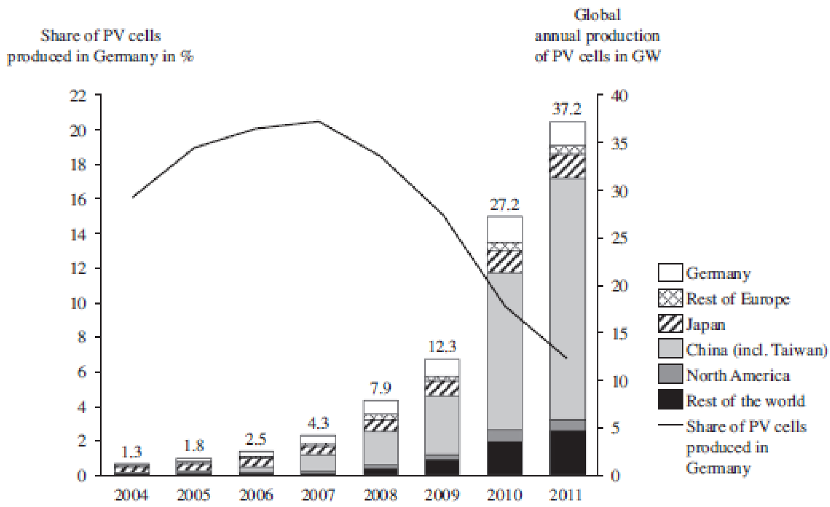


*Figure 19: Global PV cell production and share of PV cells produced in Germany. Source: Hoppmann et al. 2014. Data: Photon (2012).*

[19] (Hoppmann et al. 2014)

Although the influence of China in Germany's PV market became greater through the PV modules, Germany preserved a stronger position in the fields of inverters, manufacturing equipment and poly-silicon production. This fact is shown in Fig. 20[20]. However, some media reports appeared that saw the feed-in tariff itself as one of the main reason for the competitive disadvantage of the German PV industry. The support for PV was now criticized even by proponents of the German feed-in tariff system. They worried that the development within PV could decrease the public acceptance of renewables and subvert the legitimacy of the feed-in tariff system as a whole.

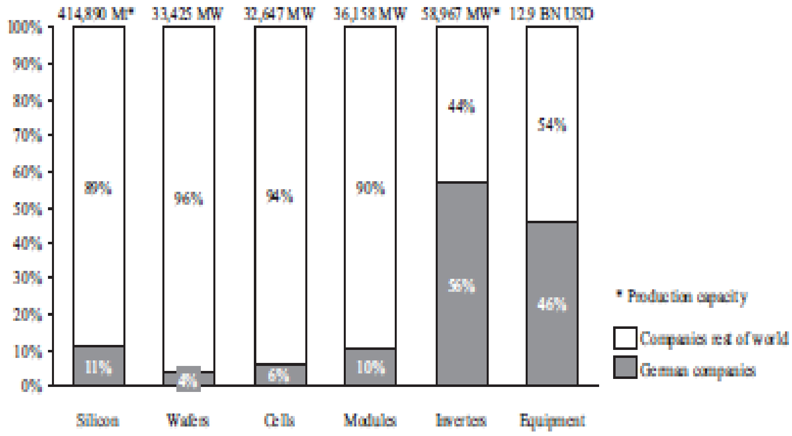


*Figure 20: Global share of German firms in PV products in 2011.Source: Hoppmann et al. 2014. Data from GTM Research, VDMA and NPD Solarbuzz.*

In September 2009, the conservative government consisting of CDU and FDP introduced a legislative draft according to which feed-in tariff levels of PV ought to be cut by 20%. With this measure they wanted to react to the previous development. Through an amendment of the EEG, which was enforced in August 2010 the remuneration for all system sizes retroactively for July 2010 was significantly reduced. Degression for the years 2010 and 2011 was adjusted upwards. In addition two reductions were applied which lowered remunerations by 10% and 3% in July and October 2010 respectively. The majority of PV cell and module producers are located in the eastern states. They rejected any one-time reductions in the feed-in tariff beyond 10%. That was the reason why reductions were much lower as expected.

Although these measures were performed, 2010 was a record-breaking year in annual installed capacity, which was more than 7.4 GW. As a result degression rates were further raised in another amendment of the EEG in May 2011. The feed-in tariff levels at the beginning of 2012 reached a level of only 40% of those in 2004. 2011 was another record-breaking year with a annual installed capacity of 7.5 GW, while the target was 4-5 GW. In 2011, the annual difference costs made up more than 6.8 bn EUR. It was obvious that cost was an important topic in the public and political debate leading the way to the EEG 2012.

[20] (Hoppmann et al. 2014)

*2011-2014*

Officially to mitigate potential negative consequences from increasing electricity prices, with the EEG 2012 the government further extended the reductions in the EEG apportionment for energy-intensive companies. This implied an additional increase in the EEG apportionment for non-privileged consumers. Nevertheless, because increase in PV deployment and decline in prices of PV systems, two issues appeared. Frist, increasing capacity of discontinuous power into electricity grid weakens its stability. Second, the feed-in tariff scheme has to be phased out once cost competitiveness is reached.

Deployment continued to increase in 2009 and 2010, the problem of grid integration became more important. While some experts were of the opinion that there wouldn't be any immediate problem with regard to the grid, others alert of "considerable conflicts" and "massive problems" with grid stability, if no action were taken. Thus, in the political debate the issue of grid integration was taken on more seriously. So it was addressed in the EEG 2012. The EEG consisting of 88 articles required new plants of any size to have a remote control. In this way the grid operator was allowed to disconnect the plant from the grid. Besides a self-consumption bonus paid in addition to substituted retail electricity prices was implemented. Prior a fixed remuneration for self-consumption became effective. So household investments in energy storage and demand-side management should be promoted.

Operators were granted a market premium if they forgo the feed-in tariff and directly market their electricity on the spot market. In this way market integration of PV should be supported. Since 2012, the costs of PV were still relative high. Only a small amount of PV electricity was directly marketed. Political support through the feed-in tariff could slowly end, because LCOE fell below retail prices and direct marketing of PV was expected to play an increasing role in the future.

*Since 2014*

The EEG 2014 Act aimed for an annual increase of 2.5 GW in the form of plants, which produce electricity through solar energy. This goal was continued in the EEG 2017. Funding was granted for new large photovoltaic open-space systems and new large photovoltaic systems on buildings or other structures with an installed capacity of more than 750 kW through tenders.
The annual tendering volume for this segment was 600 MW. The Federal Network Agency is the tendering authority and will conduct three rounds of calls a year. Subsidies for all other new small and medium-sized PV systems on buildings, other structures or open spaces, the installed capacity of which is 750 kW or less, will continue to receive a statutory subsidy under the EEG 2017. These smaller and medium-sized PV systems must therefore do not participate in a call for tenders to receive funding under the EEG. The amount of the subsidy is defined in § 48 in conjunction with 49 EEG 2017 and is granted for the injected electricity. The delivery height is based in each case on the extension of the previous months (atmender Deckel). Altogether, smaller and medium-sized PV plants with an output of 1900 MW are to be added annually.

The mechanism of the breathing lid was slightly adjusted with the EEG 2017. With the new EEG 2017, the reference period for the extension was shortened from one year to six months, so that the breathing lid can respond more quickly to overshoots or underruns. In addition, the breathing lid was adjusted below the target corridor of 2500 MW in such a way that the rates of remuneration can rise a little faster if the extension remains well below the target corridor for a long time. This change has responded to the reduced construction of PV systems on buildings in recent years. The potential for PV systems on buildings is very large and planning times are relatively short compared to other technologies.

The segment of smaller and medium-sized PV systems on buildings is characterized by a large variety of players, a great importance of the segment of systems smaller than 100 kW and thus a good competitive situation. In addition, the self-consumption of photovoltaic systems on buildings is very important. Due to the sharp drop in compensation in recent years, self-consumption was a major reason for the construction of these facilities. The self-consumption is therefore financially attractive, since for the self-generated electricity neither network charges (if the grid is not used) nor electricity tax had to be paid. Only a reduced EEG had to be paid, so that the own power generation often is cheaper than the purchase of electricity from the Network.

In addition, the PV systems on buildings, other structural installations or open spaces with an installed capacity of 100 kW or less could continue to supply their electricity to the grid operator after connecting the systems to the grid and receive fixed remuneration from the network for the injected electricity. This remuneration is implemented in the EEG 2016. All PV systems above 100 kW must directly market their electricity and receive the so-called sliding market premium.

The design of funding for new PV systems according to the EEG 2017 was discussed with the involved stakeholders. The BMWi submitted a proposal for the framework of future PV funding in 2015 and put it up for discussion in a public consultation.

The market analysis as well as the results of two specialist workshops organized by the BMWi in March and May 2015 were included in the decision on the future design of funding for new PV systems in accordance with the EEG 2017.

### 3.1.3 PV Solar Market of Japan

Before the Fukushima incident happened Solar PV played a minor role in supplying the energy demand. The main reason why PV was not supported was the fact that the regulatory structure which emphasized on renewable energy was not that strong. The Ministry of Economy, Trade and Industry (METI) which has been traditionally allied with organisations that monopolize the utilities and industry, and are pro-nuclear control the energy sector.

Nevertheless, some programs were carried out which helped to increase the development of PV. With regard to research and development (R&D) activity, in 1974, the Ministry of International Trade and Industry (MITI) supported the Sunshine Project, with a goal of providing energy from non-fossil sources by 2000 (Moe 2012). Because of the oil crisis in 1979 and the flop of the solar thermal project 1981, the Sunshine Project received a generous budget from the government, with an increase of more than 200% compared to the initial funding. This project also helped the solar PV manufacturing industry to succeed. For example companies like SANYO, SHARP and KYOCERA benefited from the Sunshine Project.
In 1992, the net billing programme was implemented. This programme was the first programme related to solar PV. As a voluntary programme 10 utility companies participated. Each company purchased surplus electricity generated from PV plants with the purchase rate at the same level to the retail electricity price (approximately ¥23 per kWh or €0,14 per kWh) (Kaizuka I. 2012). In 1993, a specific guideline related to grid connection for solar PV was introduced by the government.

In 1994, a national subsidy programme for residential installations of solar PV was implemented by the government. With a maximum ceiling price of ¥900000 per kW (€7300 per kW). The installed capacity per household varied from less than 1 kW to 5 kW. The subsidy was revised yearly until it ceased in 2005 as the subsidy value was set to ¥20000 per kW (€146 per kW). Because of the programme 250000 installations with a capacity of over 930 MW were supported. The average installation cost of the system decreased from ¥1920000 per kW (€15500 per kW) in 1994 to ¥661000 per kW (€4800 per kW) by 2005.

In 2003, parallel to the subsidy programme, the government introduced another renewable energy policy called the Renewable Portfolio Standard (RPS) (Japan Renewable Energy Policy Platform 2010) Due to this policy the utility companies were obliged to generate a specific percentage of the electricity from renewable sources, which was 1.35% by 2010. The utility companies were less interested in investing into renewables, because there were little incentive from the government as well as the termination of the national subsidy for solar PV installations. Due to the influence of the utility companies, Japan chose the RPS system instead of feed-in tariff, which is the main driver for renewable energy in Europe (Moe 2012). This affected Japan to lose its leading place in terms of solar PV installations in the world. As result, the annual installation rate experienced a decline from 2005 to 2008.

The government realized that the target of achieving 1.35% of the national electricity from renewables by 2010 could not be met. So the subsidy scheme was restarted in January 2009 with ¥70000 per kW (€538 per kW) (Plastow J. 2010). In November 2009, also a feed-in tariff scheme was adopted. Only solar PV with an installation of up to 500 kW was affected by the scheme. For a duration of 10 years domestic installations up to 10 kW got a feed-in tariff of ¥48 per kWh (cents36 per kWh). Both measures were controlled annually. The utility companies were obligated by the Japan feed-in tariff scheme to purchase only surplus electricity generated from the solar PV panels. Despite the constraints, the installed capacity grew by more than twice the value in 2008. It is estimated that most of the installations were made in residential buildings (Yamamoto Y. 2012). The feed-in tariff scheme was terminated in the end of June 2012. In Fig. 21[21] one can see the progress of solar PV installation from 1992 to 2011.

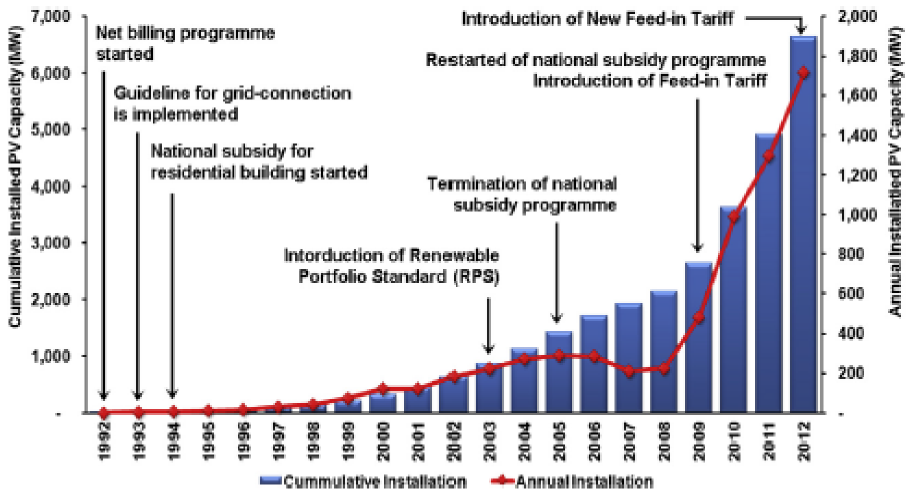


*Figure 21: Progress of solar PV installations in Japan from 1992 to 2001. Source: Muhammad-Sukki et al. 2014*

Due to the Fukushima event the country's energy policy was forced for an aggressive reform. An Act was passed in August 2011, in which a more comprehensive feed-in tariff was introduced. The beginning of the new feed-in tariff was on the 1st July 2012. Besides solar PV other renewable energy sources like wind, geothermal, biomass and hydro were included.

The objective was to achieve between 20% and 30% of the energy from the renewables by 2030. For solar PV, it was expected that the installed capacity to increase up to 28 GW by 2020 and to 50 GW by end of 2030 (Boone C. 2012). The consumers themselves financed the feed-in tariff with an average increase in the electricity bill of ¥100 (cents98) per month.

The feed-in tariff was targeted at large-scale projects in the commercial and industrial sectors. Due to the lucrative feed-in tariff, which was more than double the tariff offered in Germany and over three times the amount paid in China, it was expected that Japan could surpass Italy to become the world's second-biggest market for solar power and possibly take the top spot from Germany in the terms of installed solar PV capacity.

Due to this lucrative feed-in tariff within 3 month of the launch date the domestic shipment of solar related products into Japan increased by 80% (627 MW). To take advantage of the scheme also international solar PV companies (for example from China) started entering the Japanese market. At the end of 2012, 1.7 GW of solar PV has been installed in Japan with a cumulative value of 6.6 GW. Compared to the previous year there was an increase of 33%. The non-domestic sector increased from 15% in 2011 to 30% in 2012.

By 2012, several big solar projects have started their operations. ORIX Corporation and KYOCERA Corporation were amongst the companies, which were involved in these projects. In June 2013, the ORIX Corporation announced that it is planning 28 plants around Japan with a total installation of 143.2 MW, which were expected to start operations between July 2013 and June 2015. Kyocera launched a 70 MW solar plant in Kagoshima covering an area of 1270000 m². The commission date

[21] (Muhammad-Sukki et al. 2014)

was November 2013. The cost of this project amounted to ¥27 billion (€192 million) and should produce 78.8 GWh electricity annually, which was enough to cover the electricity requirement of 22000 households.

The feed-in tariff for domestic installations was similar to the previous feed-in tariff scheme with a rate of ¥42/kWh (cents30/kWh) paid for 10 years, whereas ¥40/kWh (cents29/kWh) were paid for 20 years to the non-residential sector. In 2011, the annual installation of the residential sector share reduced to 70% from 85.4%.

Fig. 22[22] shows the solar PV installation capacity development of Japan from 2000 to 2016.

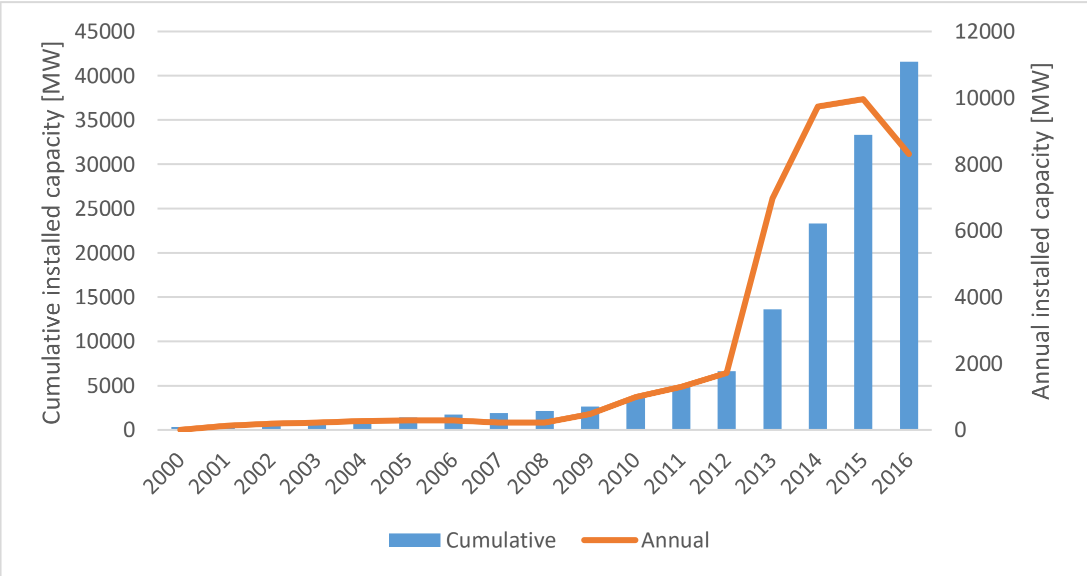


*Figure 22: Cumulative installed capacity and annual installed capacity of solar PV in Japan from 2000 to 2016. Data: IRENA.*

According to the Agency for Natural Resources and Energy between April 1, 2012, and February 28, 2013 photovoltaic power facilities accounted for 1559000 kW of the 1662000 kW of the whole renewable energy.

Japans energy generation from solar PV accounts for about 4-5 TWh, which makes up less than 1% consumption of the country. After 2012, there was an increase in R&D in renewables in Japan. The renewable support policies were strengthened. Consequently the rate of solar PV installation increased, whereas solar PV installation of Germany slowed. So the difference in PV installation between Japan and Germany has reduced and will most likely close in the near future.

22 (IRENA 2018)

### 3.1.4 PV Solar Cost Development *1975 – 2001 ( by Nemet 2006 )*

The author took the time period from 1975, where commercialization of PV solar began, to 2001. In this time period cost of PV modules decreased by a factor of 20. Inverters, storage and supporting structures (BOS) were excluded. Only cost of PV modules were observed. Since crystalline was the dominant technology for PV over this period the study was limited to PV modules produced from poly-crystalline and mono-crystalline. Crystalline silicon account for over 90% of production over this period and in the second half of the period its share increased. PV modules produced from other materials, such as cadmium-telluride and copper-indium-diselenide were available. But the share of this materials was low. Because PV market became global in this time period, worldwide data rather than country-level data was used. The price data in the study are weighted averages of mono-crystalline and poly-crystalline. To restrict the influence of potentially confounding factors, two simplifying aspects were predetermined:

- PV panels have been sized on the order one square meter per panel for three decades (No significant change in per unit scale in PV panels).
- There are no O&M costs associated with PV. PV panels only are cleaned regularly and inverters are replaced. So there is no "learning-by-using".

The average of two comprehensive world surveys of PV prices[23][24] was used by the time series for cost. To avoid the large uncertainties associated with making assumptions about capacity factors, lifetime, and financing mechanism, the model uses module cost.

Fig. 23[25] shows experience curves based on the two world surveys mentioned above. Maycock's survey produces a progression rate (PR) of 74% while the Strategies Unlimited data give 83%. Due to this 2 different data sets the crossover point for the 0.26 learning rate is 2039 and for the 0.17 rate, 2067. According to McDonald and Schrattenholzer[26] the range of learning rates for energy technologies in general is even larger.

[23] (Maycock 2002)
[24] Strategie – Unlimited 2003
[25] (Nemet 2006)
[26] (McDonald and Schrattenholzer 2001)

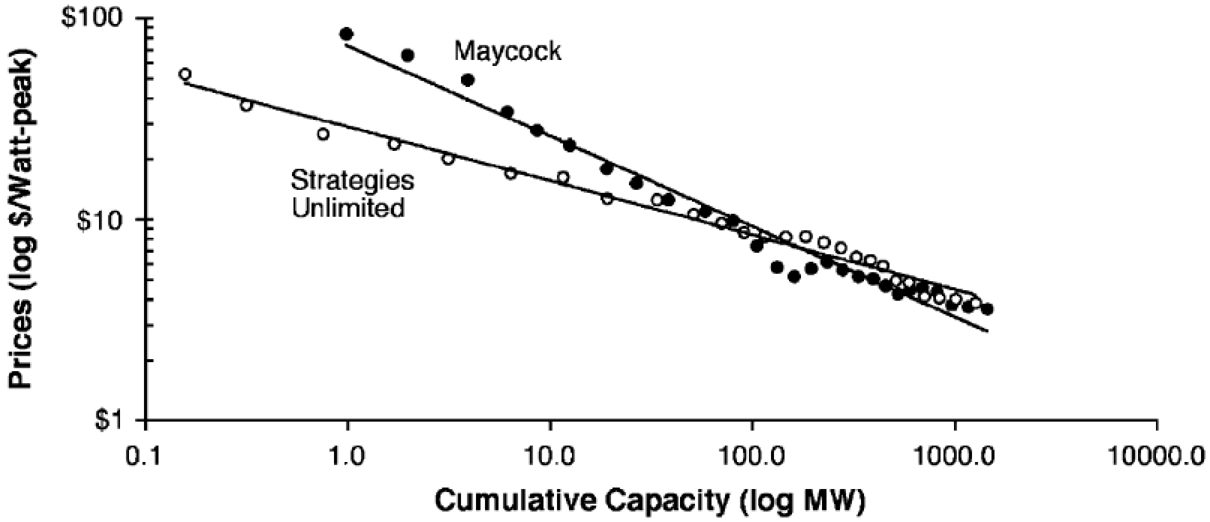


*Figure 23: Experience curves for PV modules and sensitivity of learning rate to underlying data.1975 – 2001. Source: Nemet 2006.Data: Maycock (2002) and Strategies-Unlimited (2003).*

Nemet identified 7 factors, which changed over time and had an impact on PV cost.

By improving the *energy efficiency of PV modules* the rated power output of each square meter of PV material produced nearly doubled [ (Maycock 1994), (Grubb and Vigotti 1997)]

Due to the growth in the expected future demand for PV the annual output of PV manufacturing plants increased of more than two orders of magnitude (Maycock 1981). Manufacturers increased *plant size* to meet the demand.

The proportion of useable production units available at the end of the manufacturing process (*yield*) have increased due to improved cell and module processing techniques. To make the wafers more space-saving they were designed thinner over time. Therefore, they became more fragile and set off some of the gains in yield delivered by automation.

*Poly-crystalline wafers* rather than mono-crystalline ones have accounted for an increasing share of world production. Based on assumptions poly-crystalline modules cost 90% that of mono-crystalline modules (Sarti and Einhaus 2002).

Over the study period the *cost of solar-grade silicon* feedstock has fallen by nearly a factor of 12 (Bruton 2002). Material cost from 1975 to 2002 is shown in Fig. 24[27]. Costs of other materials, such as glass, aluminum, ethyl-vynil acetate (EVA) and framing materials were not considered, because they were much cheaper than silicon.

[27] (Nemet 2006)

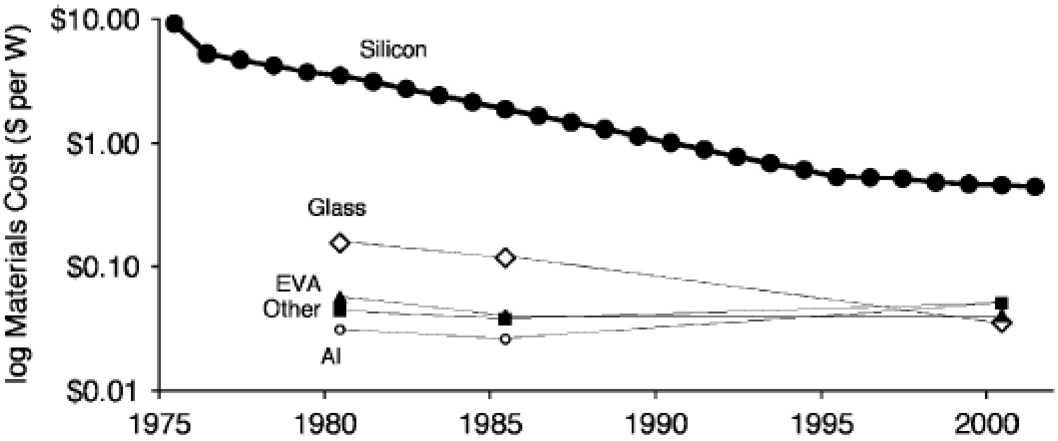


*Figure 24: Material costs for PV modules. Source: Nemet 2006. Data: Christensen (1985) and Maycock (2002)*

Over the period the *amount of silicon used* per Watt of PV module has fallen by a factor of 1.5 (Maycock 2002). The thickness and kerf losses of silicon wafers was reduced from 500 to 250 µm and from 250 to 190 µm, respectively.

By improving crystal growing methods cross-sectional area of each wafer increased by a factor of 4 (Christensen E. 1985). In the cell and module assembly processes where there are costs that are fixed per wafer, *larger wafers* help to achieve savings. It is believed that post-wafer processing accounts for 40% of the cost of producing a module in all periods (Moore 1982).

**Model result**

Nemet determined 3 factors – plant size, efficiency, silicon cost - , which were most important. The other four factors together account for less than 8% of the cost decline. All 7 factors together declare less than 60% of the change in cost over the period.

In order to obtain meaningful results with his model, the author divides the period into 2 time periods: Period 1: 1975-79; and Period 2: 1980-2001. The breakdown of the period has 3 reasons. First, terrestrial application had become dominant over space-based application, by 1980. Niche markets for navigation, telecommunications, and remote residences signaled the start of a viable commercial market.
Second, global public R&D spending on PV reached $370m, in 1980 (IEA 2014). Shortly thereafter there was a decline in R&D, which reflected a less active government role in technology development as the experiences of the 1970s oil crisis disappeared.
Third, governments began subsidizing commercial applications. A shift from research-oriented to diffusion-oriented policies happened.

*Period 1: 1975-1979*

In this period cost declined by a factor of three. As mentioned cost of silicon, plant size and efficiency accounted for the most change in cost. Yield and silicon consumption played a role, although they were of less importance. Poly-crsytalline share and wafer size did not change. 59% of the change is unexplained, because the seven factors fail to explained change. It is important to understand the early period of commercialization, because many technologies tend to attract widespread interest as they find their first commercial applications. Therefor policy and investment decisions must be made at early stages.
Over these 4 years there was an enormous change in the market for PV. During this period, space-based satellite applications lost their dominance to terrestrial applications. In 1979, the market share of terrestrial applications was 64%. Five years before, in 1974, it was just 4%.
At the following the author discusses the large residual with four explanations, each of which is associated with shift in end use.

- **Reduction of cost due to lower quality**:
  Shift from space to terrestrial applications led to a reduction in the quality of modules. Manufacturers switched to less costly processes, because the shift away from space applications rendered certain characteristics nonessential.
  -To maximize watts delivered per m² spatial and weight constraints on rockets *required high-efficiency panels*. These specifications do not apply to terrestrial applications. So manufacturers were able to employ two cost-saving processes (Moore 1982).
  The entire area of the silicon wafer could be used by the modules.
  Satellites required an expensive ground optical finish, which was not necessary for commercial modules. In this case chemical polish was applied to enhance the light transmission.
  -Satellite programs needed PV modules, which could operate reliably without maintenance for about 20 years. Terrestrial applications need PV modules with only 5-years reliability. Therefore cheaper materials were used and the production was cheaper. Module lifetime is illustrated in Fig. 25[28].

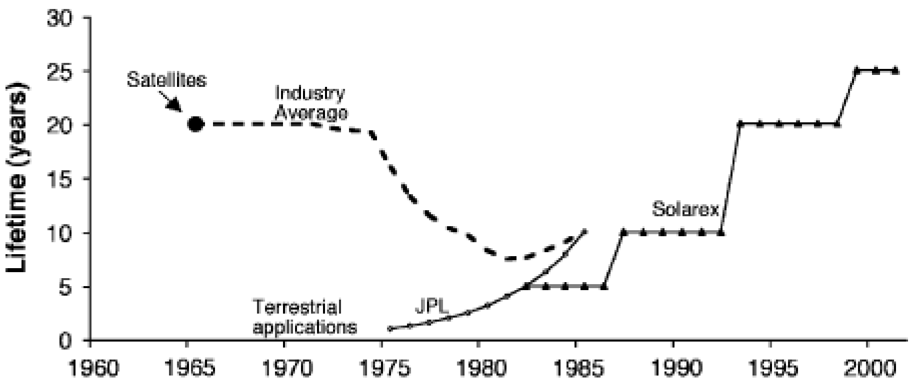


*Figure 25: Module lifetime. Source: Nemet 2006 (Data: Moore [1982], Christensen [1985] and Wohlgemuth [2003])*

[28] (Wohlgemuth et al. 2003)

- **Demand elasticity:**
  Shift from satellites to terrestrial applications affected prices because two types of customers have different demand elasticities. From 1974 to 1979, the price per watt of PV modules for satellite use was 2.5 times higher than the price for terrestrial use(Moore 1982). Investors for satellite PV panels were ready to pay more than customers of terrestrial applications. For some of the price difference the difference in quality must account. On the other hand the willingness to pay may have led to higher differences between price and cost for satellite than for terrestrial applications.

- **Competition**
  The more market participants a market has, the more competition and the lower profit margin there is.  From 1970 to 1975 there were only two US firms shipping terrestrial PV (Wolf M. 1974). The top three firms made up 77% of the industry and about 20 firms were selling modules, in 1978 (Roessner 1982). By 1983, the largest three firms accounted for only 50% of the megawatts sold, while dozens of firms were present (Maycock 1981).The Herfindahl-Hirschmann Index (HHI) can be used to represent the industry concentration. It is calculated by summing the squares of the market shares of all firms in an industry. 10000 is the maximum possible HHI. During Period 1, 1975-1979, the data show a less concentrated US market (Fig. 26.). In the 1990s, concentration in the global market remained stable. The relevant scale of analysis shifted from a national market in the early years to an international market in the time this study was written. So the analysis would imply not only the trends in the curves themselves but also the shift from national curve to the lower global curve.

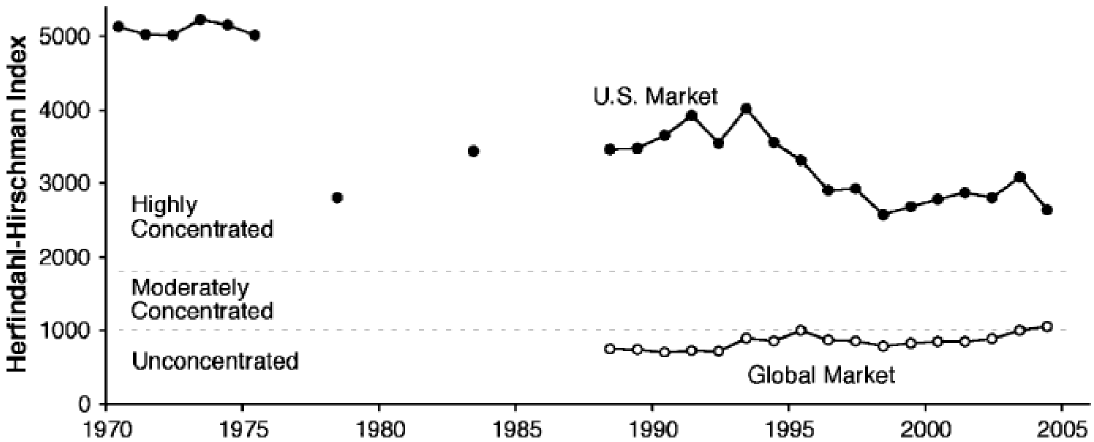


*Figure 26: Industry concentration (HHI). Source: Nemet. (Data: Wolf (1974), Roessner (1982) and Maycock (1984, 1994, 2002, 2005)).*

- **Standards**

Due to an increase in the number of customers and the types of products they demand changes in production methods occurred. In the early-1970s, a single customer, the US space grogram accounted for almost all sales. In 1976 The US government accounted for only one-third of terrestrial PV purchases (Costello and Rappaport 1980). Over the time more customers emerged with the rise of the terrestrial industry. The result of this change of structure of demand was the shift away from customized modules to producing increasingly standard products at much higher volumes.

*Period 2: 1980 – 2001*

In this period PV cost declined by a factor of 7. The model of the study explains the change in the second period well. Over 5% of the changes was unexplained. This was not much in contrast to Period 1. The model indicates that the factors above to explain the residual – quality, demand elasticity, competition, and standardization – were either stable or were dynamic but offsetting in Period 2. Two important factors in period 2 were plant size and efficiency, which account for 43% and 30% for change in PV cost, respectively. Declining cost of PV accounts for 12%. The residual each have impacts of 3% or less. Model results are shown in Table 3.

*Table 4: Summary of model results for time period 2: 1980 – 2001. Source: Nemet 2006*

| Factor | Change | Effect on module cost (\$/W) |
|---|---|---|
| Plant size | 125 kW/yr → 14 MW/yr | −9.22 |
| Module efficiency | 8.0% → 13.5% | −6.50 |
| Si cost | 131 \$/kg → 25 \$/kg | −2.67 |
| Wafer size | 45 cm$^2$ → 180 cm$^2$ | −0.67 |
| Si consumption | 28 g/W → 18 g/W | −0.62 |
| Yield | 88% → 92% | −0.43 |
| Poly-crystal | 0% → 50% | −0.38 |
| Sum of factors | | −20.48 |
| Actual change | | −21.62 |
| Residual | | −1.13 |

**Roles of learning and experience**

Experience curves are applied by firms to evaluate the reduction of cost of a technology by costs decline in logarithmic proportion to increases in cumulative capacity. In the case of PV technology, cumulative capacity is a strong predictor of cost. However, the results indicate that the most important factors are only weakly explained by cumulative capacity (Table 5). At the end the “learning” and “experience” aspect does not seem to have much impact in enabling firms to reduce the cost of PV, which is the assumption underlying the learning curve model.

*Table 5: Role of learning-by-doing (lbd) in each factor (1980 - 2001). Source: Nemet 2006*

| Factor | Cost impact (%) | Main drivers of change in each factor |
|---|---|---|
| Plant size | 43 | Demand and risk management |
| Efficiency | 30 | R&D, some lbd for lab-to-market |
| Silicon cost | 12 | Spillover benefit from IT industry |
| Wafer size | 3 | Strong lbd |
| Si use | 3 | Lbd and technology spillover |
| Yield | 2 | Strong lbd |
| Poly share | 2 | New process, lbd possible |
| Other factors | 5 | Not examined |

Experience and plant size

While Mitsubishi Electric had decades of experience in research and satellite PV applications, its cumulative production was minimal. There was an expansion from almost zero production in 1997 to 12 MW in 2000 and the firm planned to expand to 230 MW in 2006 (Waldau 2005). A German company called Q-Cells began producing cells in 2001 with a 12 MW line. 2 years later it increased its production to 50 MW(Maycock 2005). In 2006, Sharp was considering construction of a 500 MW/year plant. It would amount to 10-fold expansion in the firm's capacity in 5 years. According to Nemet, the ability to raise capital and to take on the risk of large investments that enable construction of large manufacturing facilities appear to have played much bigger roles than learning by experience in enabling cost reduction. Dutton and Thomas[29] find out that "sometimes much of what is attributed to experience is due to scale".

Experience and module efficiency

Since 1980, only six out of 16 advances in efficiency were achieved by firms that manufacture commercial cells. Universities achieved most of the improvements. That 10 of the 16 breakthroughs were produced by government and university R&D program, while producing a trivial amount of the industry's cumulative capacity suggests module efficiency had little to do with learning-by doing. The development in cell efficiency is shown in Fig. 27. Due to an investment of $1.5b in worldwide PV R&D in the previous years there was a rise in laboratory cell efficiency from 1983 to 1990 (IEA 2004). The author believes that experience may help firms generate ideas for incremental efficiency improvements or it may also play a role in facilitating the transition from producing efficient cells of a few watts in a laboratory to producing large modules. But at the end R&D offer more reasonable explanations of efficiency improvements than learning-by-doing.

[29] (Dutton J.M. and Thomas A. 1984)

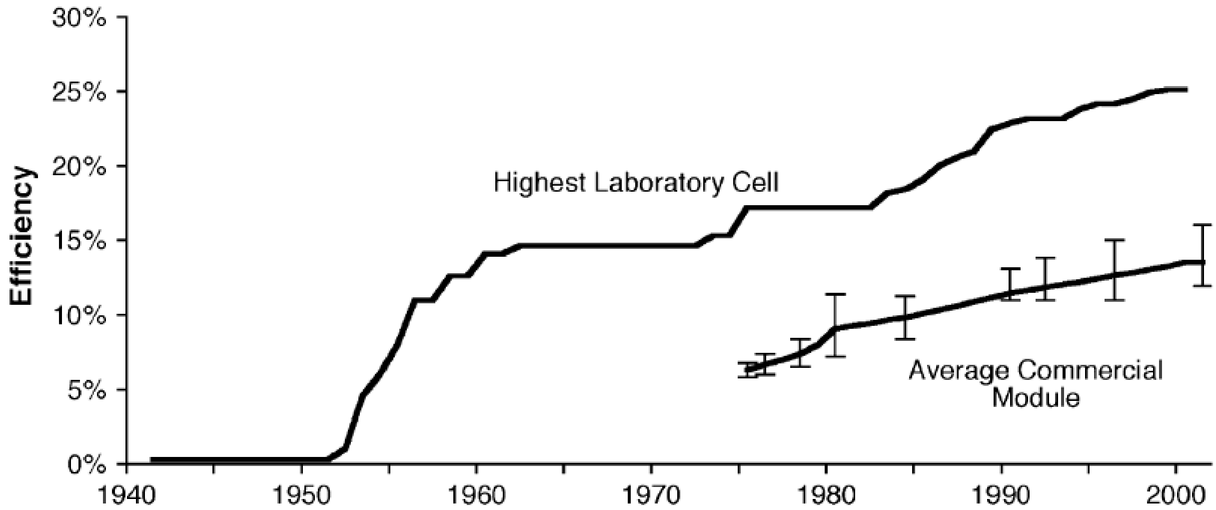


*Figure 27: Crystalline PV efficiency: highest laboratory cells vs. average commercial modules. Source: Nemet 2006. Data: Christensen (1985), Maycock (1994, 2002), Grubb and Vigotti (1997), Menanteau (2000) and Green et al. (2001).*

<u>Cost of Silicon</u>

Because of manufacturing improvements in the microprocessor industry, cost of purified silicon decreased. The PV industry accounted for less than 15% of the world market for purified silicon during the study period (Menanteau 2000). The PV industry purchased silicon from producers whose main customers were in the much larger microprocessor industry. In the microprocessor industry purity standards were higher. So the PV industry had no use of experience for silicon cost reduction.

***<u>Conclusion of Nemet's study</u>***

According Nemet, learning derived from experience is not the only explanation for the cost reduction in PV. Its impact on the two most important factors identified in the study – plant size and module efficiency – is low compared to those of expected future demand, risk management, R&D and knowledge spillovers. To predict technical change this weak relationship suggests careful consideration of the conditions under which one can rely on experience curves. When applying experience curves to technologies at early stages, market dynamics identified in Period 1 requires extra caution. Firms' profit margin is an additional area to consider.

## 3.2 Onshore Wind Energy

### 3.2.1 Technology of Wind Energy

Wind turbines based on the principle of converting the kinetic energy of the wind into useful mechanical energy. A generator converts this mechanical energy into electricity. The use of wind turbines to produce electricity began in early twentieth century. The first large-scale implementation started in the late 1970s. Denmark and the USA acted as trailblazers. Different types of horizontal and vertical axis wind turbines with 1 to 4 blades were built at that time. Since then three-blade horizontal-axis wind turbine caught on. In the 1970s the capacity range was 10-30 kW. In 2010, 5 MW wind turbine were available, and 6 MW or more as prototypes (Enercon, Repower, Bard), which has not changed until end of 2016. In 2008, the average capacity of wind turbines installed was 1.57 MW (BTM Consult, 2009)[30]. The average wind turbine size in Europe was about 1.7 MW, while in the Americas and in Asia, the average was 1.34 MW and 1.22 MW respectively. The wind turbine technology is still ongoing, but its development got a saturation. Therefore the wind turbines currently deployed can be considered as technically mature.

Typical onshore wind turbines, which are installed on land have 50-100 m tower heights with a rotor diameter of 50-100 m. To increase tower height and rotor blade length is the trend in wind turbine designs. They get the best yield in areas with low wind energy potential by installing a combination of high pole and long blades (IEA Wind 2014).

Wind turbines, which were installed in the 1980's work on a rotor and hub assembly speed of 60 RPM. Modern turbines work in much lower speed of 12-20 RPM. Therefore, modern turbine are able to generate power more effectively at much lower wind speeds. They also have a higher electricity generation capacity in comparison to older models. Due to storm controlled techniques wind turbines nowadays are able to operate even during very high wind speed conditions. Onshore wind turbines grouped together into wind power plants are known as wind project or wind farms. The size of this wind power plants is usually 5-300 MW, but also smaller or larger plants are in operation. The Chinese Gansu Wind Farm Project has a capacity over 5000MW. Until 2020, the capacity should increase to 20000 MW (Reuters, 2014).

***Wind turbine design***

Two primary motives of wind turbine research are maximum wind capture and cost reduction. Due to continuous research and advancement of turbine technology nameplate capacity rating has risen enormously over the last decades. Nowadays, wind turbines from several kilowatts to megawatts are commercial. To get the best yield the trend is toward large turbines with long blades, which sweep wind from larger area and produce greater output energy.

Due to their greater efficiency and energy output in comparison to vertical axis wind turbines horizontal axis wind turbines dominate the majority of the wind industry. Vertical axis wind turbines have less power output, because they are installed close to the ground and therefore have less exposure to wind. To achieve the same output as that of horizontal axis wind turbines, vertical axis wind turbines require more materials. But vertical axis wind turbines have also their advantages. They are able to produce some electricity in low winds and can capture wind from any direction.

[30] (BTM Consuslt 2009)

Vertical axis wind turbines are effective in rooftop and small scale applications. Fig. 28 shows the comparison between horizontal axis wind turbines and vertical axis wind turbines.

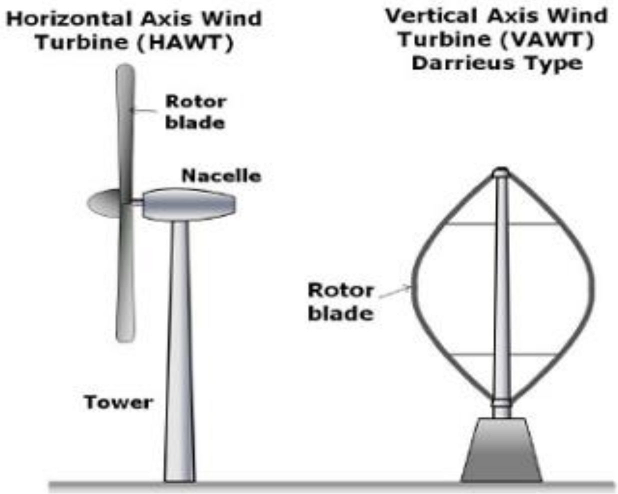


*Figure 28: Typical constuction of a horizontal axis wind turbine and a vertical axis wind turbine. Source: ResearchGate*

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Blades, a rotor, a tower, a gearbox and a generator are the parts of a wind turbine. Fig. 29 shows all the components of a wind turbine.

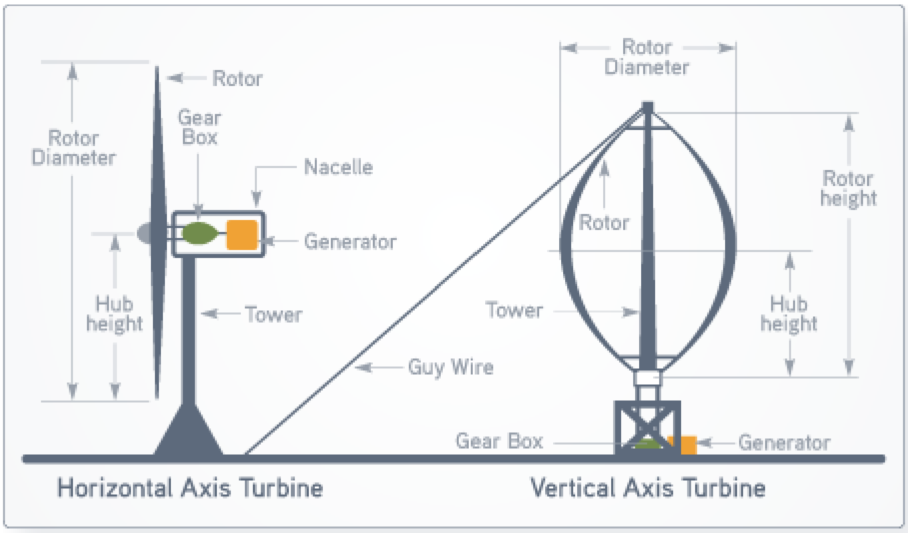


*Figure 29: Main components of wind turbine. Source: Hill Country Wind Power*

*Rotor*

Three blades turbine are universally accepted, also functional are 2 blade turbine. The size of rotor blades is very large. In the last years, Siemens has launched 246 ft. long B74 rotor blades, which were installed into a prototype 6 MW offshore wind power system at Osterild test station in Denmark (American Wind Energy Association. Anatomy of a wind turbine, 2014). In high wind speed conditions a component called “pitch drive” reduces the effect of lift forces (Rexroth, Bosch Group. Drive and control of wind turbines; 2014). So the pitch driver ensures a stable power system operation range of 1000-3600 rpm (revolutions per minute), which has to be guaranteed.

*Nacelle*

At the top of the turbine tower there is the nacelle. Containing the main technical parts, such as the rotor shaft, gearbox, and generator. To harness the maximum wind energy the nacelle is able to rotate with respect to the wind direction. It is also connected to the tower with bearings.

*Gearbox*

Most generators need 1000-3600 RPM to generate electricity. The rotor normally has a speed of less than 100 RPM. So the low rotor speed has to be converted into higher speed to make the generator operational. This task is done by the gearbox.

*Generator*

The mechanical energy of the rotor is converted to electrical energy by the generator.

*Tower and foundation*

The higher the construction, the faster the rotor rotates, the better the quality is (less turbulence and turmoil), and the higher the quantity is. In order to capture more wind energy a tower is used to place the rotor at high altitudes.

Other important components in a wind turbine are an anemometer, controller, heat exchanger and wind vane. As a computer operated system a controller controls the turbine’s operation. The generator works in higher temperatures. So the heat exchanger leads the heat from the generator away. The anemometer is used to measure the wind speed. The wind vane detects wind direction.

***Global scenario and statistics***

The two main global objectives that need to be addressed by 2050 are sustainability and reduction in carbon emission (World Business Council for Sustainable Development. Vision 2050: the new agenda for business; 2014). Reduction in carbon emission can be achieved by adopting low carbon electricity power generation techniques as 40% of CO2 emissions result from the power sector (Greenpeace, GWEC 2012). Conventional electricity generation goes hand in hand with environmental issues. Wind energy provides advanced cost reduction, therefore it represents an attractive alternative. Wind energy had an enormous growth in the past few years. In 2012, 19% of the global energy consumed was provided by renewable energy. Wind energy made up 0.39%. Shares of different energy sources in the total energy consumption are shown in Fig 30[31].

In 2016, over 54 GW of new capacity was installed globally. At the end of 2016, the total installed wind power capacity reached 487.6 GW. Fig. 31 illustrates the total annual and total cumulative installed wind capacity over the period 2001-2016. In 2013 more than 35 GW of new wind power was brought online. But this was a sharp decline in comparison to 2012, when global installation was 45 GW. There was an uncertainty in the expectations for wind power market growth at the end of 2012. Projections were difficult to make due to continued economic slowdown in Europe and the political uncertainty in the US. Mainly due to the dramatic drop in the US market after record installations in 2012, 2013 turned out to be another difficult year for the industry (GWEC 2013).

China, USA, Germany, Spain, and India together share 73% of the global wind capacity. Countries with less onshore wind resources will be attracted by the potential of offshore wind energy. The generating potential of offshore wind energy in the USA in areas with less than 100 ft of water is equal to the total generating capacity of the current US electricity system (US Department of Interior 2014). It could generate four times the current electricity generation of the country, if all offshore wind potential of US is leveraged (Harris Roen 2014) While onshore wind market in the European Union decreased by 12%, offshore wind installations grew by 34%.

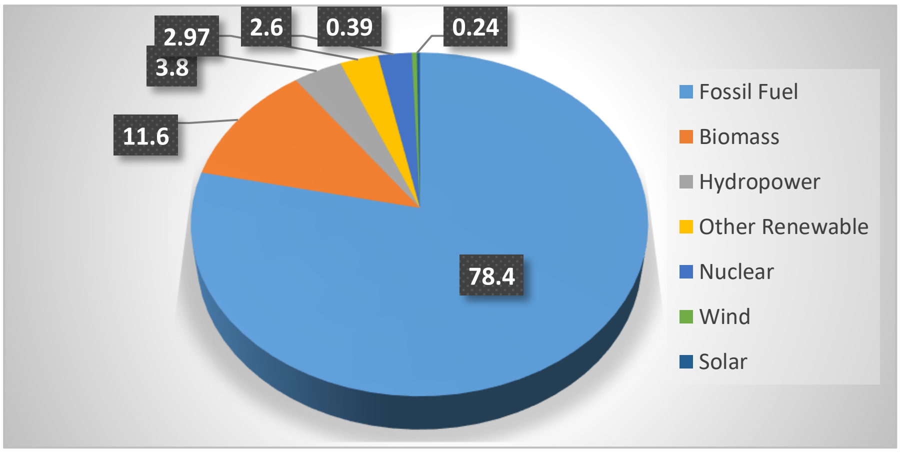


*Figure 30: Share of different energy sources in the total energy consumption in the year 2012 expressed in a percentage. Data: REN21, Renewables. Global status report; 2014*

[31] (REN21 2014)

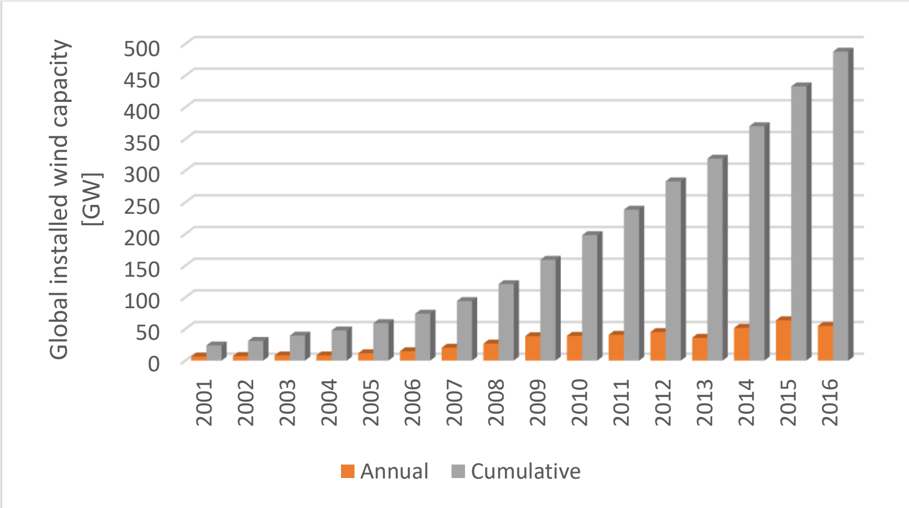


*Figure 31: Annual and cumulative global installed wind capacity for 2001-2016. Data: GWEC*

### *Wind energy suppliers*

In 2013, 318.1 GW of power were generated by wind energy worldwide. Supplying about 70% of global wind power the largest wind energy companies in the world are GE Energy, Vestas, Goldwind, Gamesa Enercon, Suzlon Group, Guodian United Power, Siemens Wind Power, and Nordex. Fig 32[32] shows the largest wind energy companies and their share in the global market.

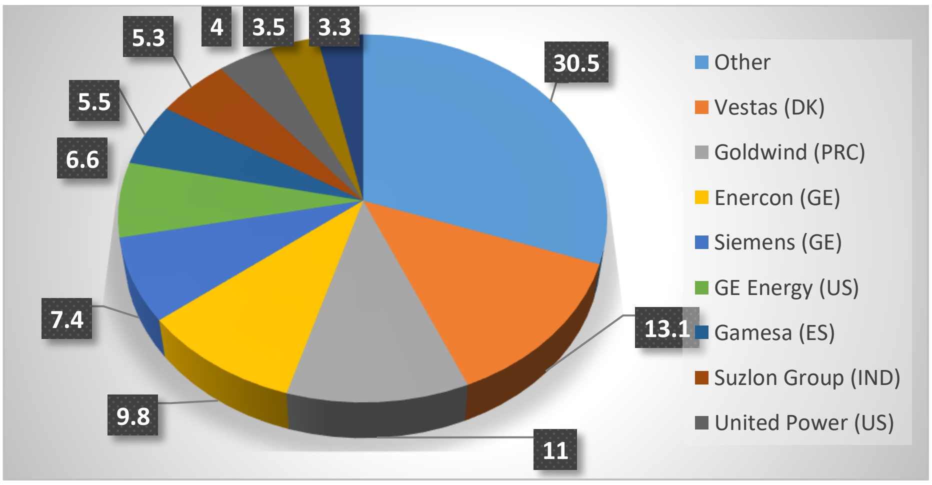


*Figure 32: Share in global wind energy market of major suppliers of the wind turbines as of 2013 expressed in a percentage. Data: Kumar et al. 2016*

*GE Energy*

Being a US-based wind energy company GE Energy had 6.6% of the total market share in 2013. It is one of the largest wind companies in the world.

[32] (Kumar et al. 2016)

*Enercon*

In 2013, Enercon had a market share of 9.8% of total installed wind power capacity worldwide. The company manufactures its own gearless direct drive mechanism turbines with annular generator.

*Vestas*

Being the largest wind energy company Vestas has installed more than 48000 wind turbines all over the world. Its power generating capacity is 55 GW. Wind turbines of Vestas are installed in Denmark, Germany, India, Italy, Romania, Britain, Spain, Sweden, Norway, Australia, China, and the United States. More than 17240 people are employed at Vestas.

*Siemens*

Siemens' turbine models include 2.3 MW SWT-2.3 and 3.6 MW SWT-3.6 series. The biggest turbine model of Siemens is the 6 MW SWT-6-154 with a rotor diameter of 150 m.

*Suzlon Group*

Suzlon Group has a market share of 5.3% and has more than 25 GW of installed capacity in 33 countries (Navigant Research 2013) speed conditions (Windpower 2014). In United Kingdom, were installed 1000 MW of wind energy capacity by Repower, which is a Subsidiary of Suzlon Energy.

In the 1980s Denmark and the USA were the main leading countries for wind turbine installations. After 1990 Germany took over the position as main driving forces. In this time frame, the globally installed wind capacity has grown exponentially. About 75% per cent of the global cumulative wind capacity was installed in five most productive countries (2003-2008). In 2008, almost 70% per cent of all wind turbines sold were delivered by six manufacturers (Vesta, Gamesa, GE Wind, Enercon, Suzlon and Siemens).

In the 1980's, significant public RD&D support have been made in Germany, the USA, Sweden, UK and the Netherlands (Söderholm and Klaassen 2007). Especially in Germany, the USA, Sweden and Sweden, the R&D support should help developing large-scale turbines in the MW-size area. But the test turbines built during that time delivered poor results, due to several reasons including technical problems. Domestic demand for wind energy couldn't be established. So the possibilities to put the lessons learnt into practice was limited. Only Denmark chose the strategy to start with small-scale turbines. Step by Step they scaled up and gradually improved their design, which was possible through learning-by-doing, while supported by a steady domestic demand.

Since the 1980's, they tried to improve the models used for wind turbines. Aerodynamics, aeroelastics and wake models were on focus. For a better behavior at different load levels control strategies were developed. Improved meteorological models gave a better prediction for the energy output of the wind farms.

Various kinds of investment subsidies or investment tax credits in the USA, Germany, Finland, the Netherlands and Sweden were granted to stimulate the wind energy market. In California they achieved growth of installed wind energy capacity. But the electricity production was not that much improved. The most effective policy incentives have been long-term guaranteed feed-in tariffs, tax credits or other electricity production incentives. Best example is the feed-in tariff in Germany. The feed-in tariff was modified over time, but it was the main driver to install over 20 GW of wind capacity in less than two decades.

### ***Wind energy systems***

Wind turbines are either installed individually or they are grouped as wind farms. Such wind farms are integrated with other renewable energy sources or they are connected to a utility power grid. In this section various wind systems configuration, applications, and devices to harness wind energy will be discussed.

*Wind parks*

A group of wind turbines installed for bulk electricity generation are called a wind park (or farm). Based on the location where wind parks are installed they can be categorized as onshore and offshore.

Wind turbines, generators, power transformers, and a connection to the power grid are typical parts of a wind power system. There are three kinds of wind systems: the constant speed wind turbine system with a squirrel cage induction generator (SCIG), the variable speed wind turbine system with a double-fed induction generator (DFIG), and the variable speed wind turbine with a full rated power electronics conversion system and a synchronous generator (M. Liserre et al. 2011).

Two types of wind systems exist.

- Grid connected system: Grid connected systems usually have very large size and nameplate capacity. Integration with power grids introduces technical challenges, because of the variable output of wind power systems. When connecting a wind power system with a grid issues concerned to voltage, frequency, power quality, harmonics, and flickers occur, which have to be controlled. Therefore, before a wind system is connected to a grid it has to satisfy some stability requirements governed by various parameters such as voltage and frequency in order to ensure stability.
- Off-grid or stand-alone systems: Standalone wind power systems are used where an electricity transmission and distribution system is not efficient. So they are remote area power supply (RAPS) scheme suitable. Especially in developing countries, Wind RAPS can be very efficient for the electrification of remote and rural areas. Standalone wind power systems provide an uninterrupted, cost efficient power supply for homes, schools, and offices.

### 3.2.2 Denmark's Wind Market

Support policies for onshore wind energy in Denmark began in 1976. From 1976 and 2000, several policies concatenated each other and also overlapped sometimes. Between 1976 and 1989, the Danish government refunded part of the investment for constructing wind turbines. The state began the support with 40% of the investment cost. The support was then reduced gradually until it was cancelled in 1989. From 1984 to 2001, the producers of wind power got 85% of the local retail price of electricity excluding taxes for the electricity they produced. A fixed price premium of 36€/MWh was introduced in addition to the previous scheme in 1991, which was active until 2001.

The liberalization of the electricity market in Denmark was determined in 1999. Due to this liberalization existing wind turbines were covered by a special feed-in-tariff. So producers had a comparable income as under the previous support scheme. Producers received a feed in tariff of 80€/MWh for a number of full load hours (25000 full load hours for turbines below 200 kW, 15000 full load hours for turbines below 600 kW, 10000 full load hours for turbines larger than 600 kW). Until the turbine was ten years old, producers received a feed in tariff of 58€/MWh, after full load hours were used. A price premium of maximum 13€/MWh was set until the turbine was 20 years old. The limit for sum of market price and price premium was 48€/MWh. To cover the balancing costs in the electricity market an additional price premium of 3€/MWh was paid. To support wind power in Denmark four wind support policies were in place from 2000 onwards. Between 2000 and 2002, for turbines connected to the grid, producers got a feed in tariff of 58€/MWh for the first 22000 full load hours. Until the turbine is 20 years old, after 22000 full load hours they received the wholesale spot market electricity price of 32€/MWh (in 2008) in addition to a premium of 13€/MWh. The limit for the sum of the market price and the price premium was at a maximum of 48€/MWh. In 2002, the support scheme of a feed in tariff was replace by a support scheme of a variable premium to better integrate with the recently liberalized electricity market. Turbines that were connected to the grid between 2003 and 2004 the premium scheme was associated with a cap on the total remuneration per kWh electricity produced. Producers received the wholesale spot market electricity price in addition to a premium of 13€/MWh for the first 20 years (typical turbine lifetime) of the turbine lifetime. The limit of sum of the market price and the price premium was set to 48€/MWh. In 2005, the cap on the total remuneration per kWh electricity produced was abolished. Producers received the whole sale spot market electricity price in addition to a premium of 13€/MWh for the first 20 years of the turbine lifetime for turbines that were connected to the grid between January 2005 and February 20th 2008. The current scheme came into effect when the premium was enhanced in 2008. Producers received the wholesale spot market electricity price in addition to a premium of 34€/MWh for the first 25000 full load hours for turbines connected to the grid after February 21st 2008. Under all four regimes and for the entire lifetime of the turbine the producers got and additional allowance of 3€/MWh to cover balancing cost. Table 6 shows the support schemes according to the date of connection of the wind turbines to the grid.

*Table 6: Support schemes for wind energy in Denmark since 1976. Source: Jaureguy-Naudin, 2010[33].*

| Date of connection to the grid | Support scheme |
|---|---|
| From 1976 to 1989 | Financial support from the Danish state. |
| From 1984 to 2001 | Electricity price paid to producers: 85% of the local retail price, excluding taxes |
| From 1991 to 2001 | Fixed premium of 36€/MWh in addition to the previous scheme |
| Existing turbines bought before the end of 1999 | Feed-in tariff of 80€/MWh for a number of full load hours<br>Then feed-in tariff of 58€/MWh until the turbine is 10 years old<br>Then premium of 13€/MWh or less until the turbine is 20 years old |
| From 2000 to 2002 | Feed-in tariff of 58€/MWh for 22000 full load hours<br>Then premium of 13€/MWh or less until the turbine is 20 years old with a limit of 48€/MWh on the sum of market price and premium<br>Additional premium of 3€/MWh |
| From 2003 to 2004 | Premium of 13€/MWh or less until the turbine is 20 years old, with a limit of 48€/MWh on the sum of market price and premium.<br>Additional premiumof3€/MWh |
| From 2005 to February 20th 2008 | Fixed premium of 13€/MWh until the turbine is 20 years old<br>Additional premium of 3€/MWh |
| After February 21st 2008 | Premium of 34€/MWh for the first 25000 full load hours<br>Additional premium of 3€/MWh |

In Fig. 33 the cumulative wind capacity in the last decades in Denmark is illustrated. One can see that in parallel with the support policy and the support scheme most of the progression in wind capacity happened either between 1995 and 2002, or after 2008. That means there was either a premium of 36€/MWh, a feed in tariff of 58€/MWh or a premium of 34€/MWh. The feed in tariff of 58€/MWh can be seen as equivalent to a premium of more than 30€/MWh under revenue certainty equivalence, given electricity prices in 2000-2002. Therefore it is reasonable to say that there is a threshold effect. There is a support level above which new turbines are connected to the grid and below which no new connection are made.

With a share of 40% in 2015 (Energinet.dk), in 2012, Denmark had the World's highest wind power penetration (World Wind Energy Association). Before 2020, 500 MW additional near-shore turbines and 500 MW additional on-shore capacity. Until 2020, the objective is that wind power should account for half the Danish electricity demand. Resulting in a power and heating sector 100% dependent on renewable energy sources by 2035, by 2030, coal should be phased out of Danish energy supply (Ministry of Climate, Energy and Buildings, 2017).

Despite a general support for wind power in Danish population (Megafon, 2015), Denmark is also experiencing a certain political resistance. In 2012, the Danish parliament confirmed the Danish energy policy for the period from 2012 to 2020 (Danish Government, 2016). This agreement includes the establishment of further wind turbines, but especially near shore turbines have given rise to political disputes. In September 2017, a Swedish state-owned power company called Vattenfall won the bid for a 350 MW near-shore tender with a price bid of only 63 €/MWh (Vattenfall, 2017), which was guaranteed for a period of 12 years and thereafter the market price. Over a 25 years lifetime this would mean an average payment around 40-50 €/MWh. At that time, the Danish government wanted to cancel the bidding because of the high cost. In November 2016, the new formed coalition reconstituted the plans. So we can see, that the political will behind the political agreement of 2012 is doubtful.

[33] (Jaureguy-Naudin 2010)

Technologies like wind power are supported with extra production payment in the first 7-12 years of production, because they want to ensure a robust base for investors in renewable energy systems (RES) in Denmark. In 2016, the Danish government contended that the Public Service Obligation (PSO) fee, would rise during the next years and would have an impact to the competiveness of Danish industry. But the Danish Association of Wind turbine producers challenged this claim. They reasoned wind power prices with 80-100 €/MWh were too high. This was also confirmed by the bid by Vattenfall. However, in November 2016, the Danish government ended the PSO system over a five year period. The PSO system was replaced by funding via the annual Danish fiscal budget. So support for renewable energy in Denmark is step by step being shifted from a PSO system - in which the polluter is paying – to a tax financed system.

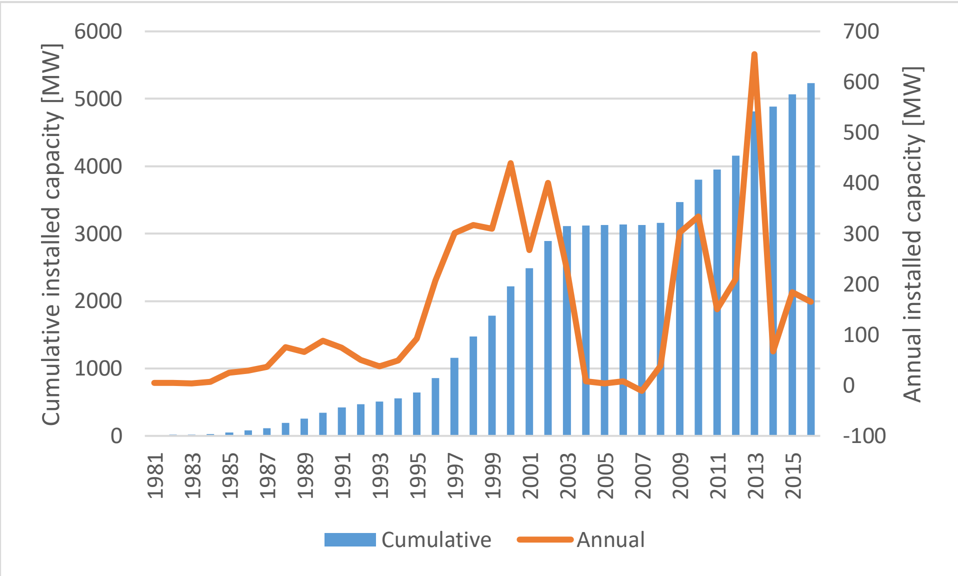


*Figure 33: Cumulative installed and annual installed wind capacity in Denmark 1981-2016. Data: IRENA*

### 3.2.3 Cost Development of Wind Power (by Neij [1981 – 2000])

The data for wind turbines include some of the largest wind turbine manufacturers: Kuriant, Micon, Nordtank, Vestas, Windworld, Bonus and NEG Micon (a merge between Nordtank, Micon and Windworld). The data contain year of installation, manufacturer, turbine type, rated power, rotor diameter, hub height, annual production, number of units installed, turbine prices, cost of foundation etc. 6427 electricity-producing wind turbines have been installed in Denmark until year 2000. 3226 of these turbines were included in this project. This is equivalent to 50% of the turbines installed in Denmark. The study cover 81% of all turbines installed in Denmark, expressed in terms of manufacturers. Turbines made by small manufacturers, turbines sold only in small numbers and turbines for which data were unavailable or unreliable have been excluded.

Energi- og Miljodata (EMD) and the Danish Energy Agency (DAE) were the two main sources for the data. From the late 1970s up to the mid 80s data were collected by the Test Station for Wind Turbines at Riso National Laboratory. The Danish Technological Institute collected data between the mid 80s and the late 90s. For the last period, EMD in Aalborg took over the data collection. In Fig X., the development of cumulative installed capacity is illustrated. Fig. 34[34] shows the experience curve for wind turbines installed in Denmark.

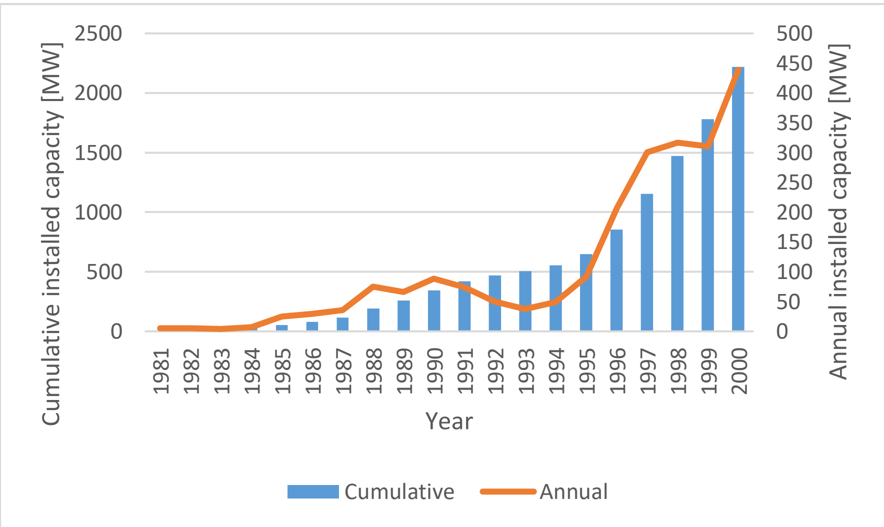


*Figure 34: Development of cumulative installed and annual installed capacity in Denmark. Data: Neij et al. 2003)*

[34] (Neij et al. 2003)

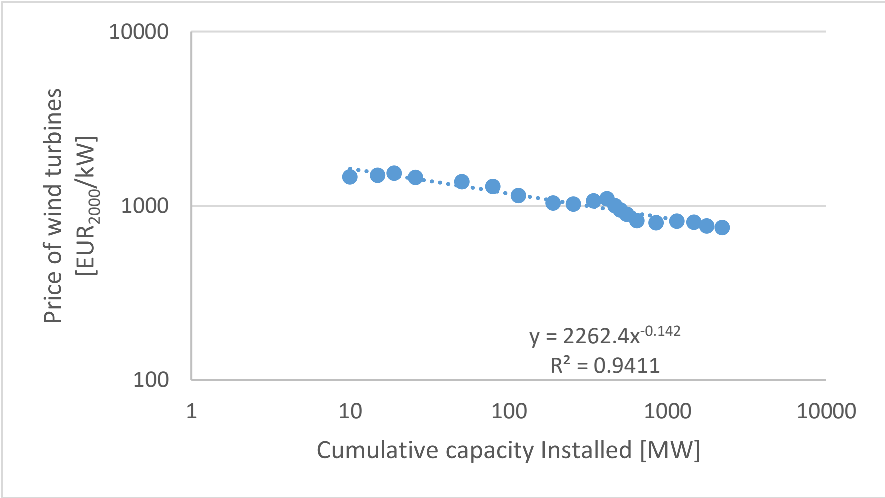


*Figure 35: Experience curve for wind turbines installed in Denmark 1981-2000. Source: Neij et al. 2003*

To compare the development of prices of wind turbine installations and the price of total installations, which also include foundations, ground preparation, grid connection etc.., Fig. 36 was constructed. The experience for wind turbine installed has a progression ratio of 91% and the experience curve for the total installation price has a progression ratio of 90%. For the experience curve for wind turbine installed the coefficient of determination is greater with 94%. The Danish Data included for the cost of wind turbines alone, are based on the accumulated installations in Denmark and the ex works prices of wind turbines on the Danish market. Danish firms produced all turbines installed in Denmark. Over the years several of these companies have been sold to foreign interests, also many vital components of the turbines are manufactured in other countries. But the turbines and the manufacturers are usually referred to as Danish.

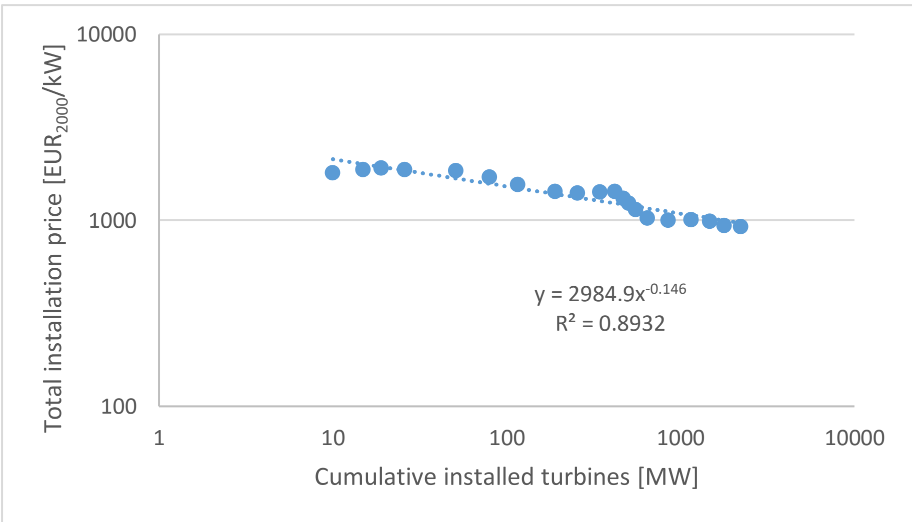


*Figure 36: Experience curve for the total installation cost for wind turbines in Denmark. 1981 - 2000. Data: Neij et al. 2003*

### 3.2.4 Germany's Wind Power Market

Federal wind power policies in Germany started soon after the oil crisis of 1973. They went through 2 phases, representing two quite different approaches. Focusing advanced turbine concepts, which produced valuable results in fundamental wind energy research, the first period from 1975 to 1984 was characterized by R&D support. But this support initially had no influence on the commercial development of the wind power. The second period which took place from 1985 to about 2003 was characterized by a combination of a favourable market policy for electricity produced by wind turbines, favourable loans, subsidies to investors, and a monitoring programme.

*RD&D subsidies from the national budget*

As a follow-up to a private charitable donation in 1972 for the construction of a small turbine on the island of Sylt federal support for RD&D started in 1975. In 1974 the government offered to finance a testing program for this turbine. A literature study of larger turbine concepts was commissioned at the same time. The RD&D budget started with 130,000 EUR in 1975.

With the budget of EUR 3.3 million in 1977 RD&D activities started more substantially. In 1981, the budget was increased 10-fold to EUR 33 million. Then it fell rapidly to EUR 11 million in 1983. For the rest of the 1980s it remained at that level or below. There were companies that were sceptical about wind energy, but were forced by the government to engage in wind power research. These companies got a large part of this funding. With only token financial contribution from the private sector the government bore nearly all costs. The best example of this was the Growian project, a 3 MW turbine. The Growian project received almost 40% of all RD&D support from 1977 to 1989. Another 40% was used to test a small number of advanced concepts that were quite expensive in terms of RD&D cost but never gained any commercial significance.

After 1988, RD&D activities have been modest. Focus was mostly on generic activities, such as a monitoring program for a large number of turbines, research into the problems of grid connection, research on early recognition of turbine failure, or demonstration of the use of wind power for sea water desalination. Specific turbine development projects in the MW range also received some money, but compared with the 1980s this type of support for a specific turbine concept has been quite weak. Both company funding and dedicated federal RD&D support were the reason why in the 1990s proprietary technologies by German companies, such as Enercon, successful developed.

Two programs for the support of wind energy stand out during the covered time period. The "Eldorado wind" program was established for promotion of wind turbine manufacturers and the "250 MW wind" program was a support for the wind turbine operators with scientific monitoring .In the period between 1975 until end of 2001 a total of approximately DM 667 million (EUR 341 million) was spent in wind energy. The "250 MW wind" program alone cost about DM 297 million (EUR 152 million) (Hoppe-Kilper, 2004).

For the wind energy boom in the early 1990's the important planning security for investors and the state funding incentives were the significant factors. In general, investments were made by the farmers and landowners who erected wind turbines on their own land (INTVW 03 Project developer, 2015). The feed-in tariff did not depend on the specific site and therefore on the wind conditions. In the northern regions close to the coast the feed-in of wind was very attractive and led to increase of WTG installations.

With time, wind turbine technology improved and turbine sellers achieved increasing sales Figures. Especially the installation of WTG with a capacity between 20 – 150 kW during the early 1990s was popular. Since the mid-1990s turbines of the 800 kW have been used more in the German market. So they have become a new industrial standard. The average capacity of newly installed wind turbines increased from 170 kW in 1992 until 1280 kW in 2001. The average capacity of new installed wind turbines and the average cumulated capacity of wind turbines from 1992 to 2016 is shown in Fig. 37[35].

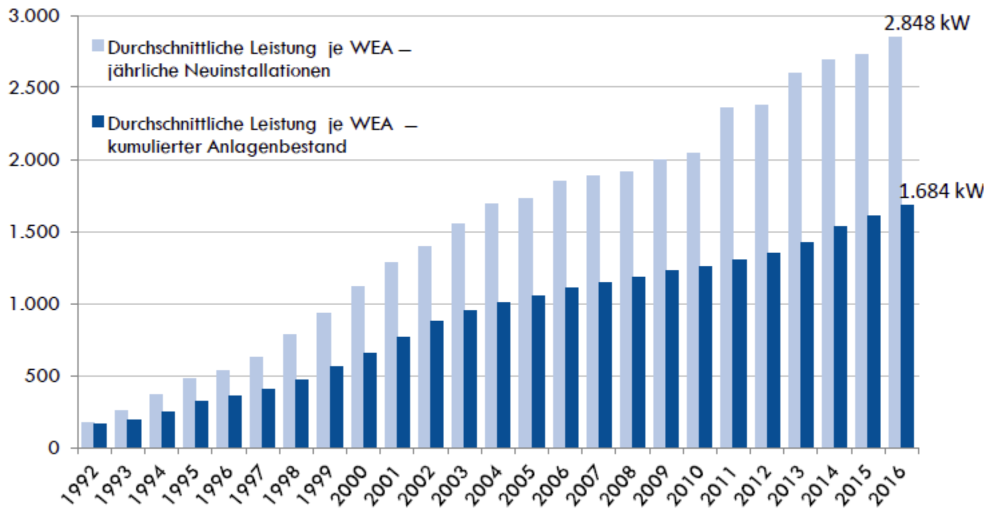


*Figure 37: Average capacity of new installed wind turbines and the average cumulated capacity of wind turbines from 1992 to 2016 in Germany. Source: Deutsche Windguard.*

Increasing demand for turbines due to the planning security and the feed in tariffs and the increasing technical development led to an increase of the installed capacity as well as strongly increasing number of installed turbines in Germany. From 1990 to 2000 more and more wind turbines were also constructed in inland areas and in the low mountain ranges in Germany (Volker Berkhout et al. 2012). In this time period, the installed turbines increased from 488 turbines to 9375 turbines, which means an increase of 1,821 % (BWE[36], 2002). The capacity of the installed wind turbines increased from 60 MW in 1990 and 6357 MW installed capacity in 2000. Fig 38[37] shows that the annual installed has almost doubled since 1998. The reason for these high growth rate in annual installation was a change in Building Code in 1997. Since 1997 wind turbines have been considered privileged construction projects (§ 35 BauGB). The adoption of the Act for the priority of Renewable Energies (EEG[38] 2000) in the year 2000 was another reason for the increase.

[35] (Deutsche Windguard 2016)

[36] Bundesverband WindEnergie

[37] (IRENA 2018)

[38] Erneuerbare Energiegesetz

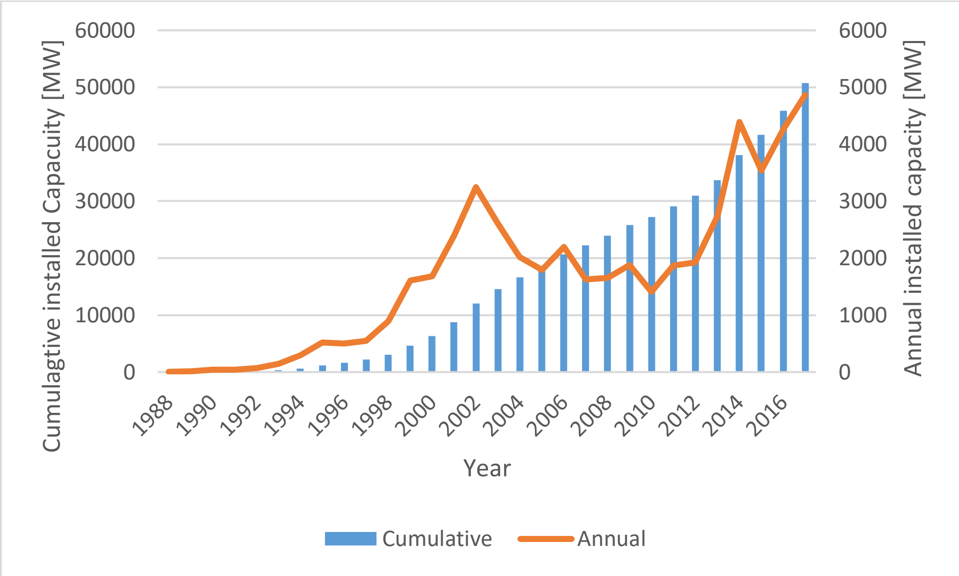


*Figure 38: Cumulative installed wind turbine capacity and annual installed wind turbine capacity in Germany 1987-2000. Source: IRENA*

In the 1990s there were rarely project financing. Due to a statement of a German banker, the first wind energy project established between the mid and the late 1990s. The introducing of the EEG was an important force to make wind energy projects financially viable.

On March 29, 2000, the German government replaced the Electricity Feed-in Act by the German Renewable Act, which herald the end of nuclear power and stipulated the increased use of renewable sources. The EEG stimulated the wind energy market through subsidization and risk reduction. Important improvements of the EEG for wind energy were the introduction of a fixed feed-in tariff over the operation period of the turbine, staggered by the site location of the turbine. In comparison to the old electricity Feed-in Act two necessary reforms were implemented: The Transmission System Operators (TSO) had to accept electricity which comes from renewable energy sources and also had to priorities them over electricity from fossil or nuclear sources. To accept the energy from renewable energy sources they were even obliged to expand their grids. Another reform of the EEG was the implementation of redistribution and circulation mechanism throughout Germany. So the TSO are allowed to pass on the expenses which result from the EEG, to the end consumer. The first EEG was followed by five other big EEG (EEG 2004, EEG 2009, EEG 2012, EEG 2014, EEG 2017).

The introduction of the EEG allowed banks to structure non-recourse financing. There was no more market price risk in the German wind energy market. So the influence of the financial sector in the wind energy market increased.

Through the financial incentives the operation of wind turbines spread across Germany. Wind turbines could also operate economically in light-wind locations due to the reference yield model. This measure meant a building boom of turbines in regions with lower wind conditions, which led to a specialization within the turbine manufacturers. They began to develop turbines which are optimized for these lower wind conditions (Agora 2013). For a greater capacity the hub height increased and the turbines' rotor diameters were enlarged. Also for better wind conditions the turbine technology has emerged steadily, and this evolution process continues. The main reason for the quick success of the wind turbine manufacturers was the gradual and steady increase in performance of the turbines. But the government research efforts failed. The increase in quality standards evolved together with technical progress.

In the late 1990s, the number of manufacturers in the wind turbine market began to disappear. In 2001, only 10 manufacturers had significant revenues (Firthjof Staiß 2003). In 1995 there a total of 132 manufacturers, but 104 manufacturers left the market (Menzel and Kammer 2011). During a phase of an extensive mergers and acquisition, some smaller manufacturers ended operation and disappeared from the German market. Most of the companies attended a consolidation process (Menzel and Kammer 2011). They start to convert in to a joint stock company. REpower Systems AG is one famous example company. In 2001, the REpower Systems AG was formed from the merger of the companies Jacobs Energie, Brandenburgischen Wind- und Umwelttechnologien GmbH (BWU), pro + pro Energiesyteme GmbH & Co. KG (Rendsburg) and Denker & Wulf (REpower Systems AG, 2011).

In the phases of specialization there were also barriers and the first signs of crises. For example in the years 2002 and 2006 on the German market there was an over-supply of wind energy projects because of overestimation by excessively high wind assessments. Projects came into financial difficulties as more wind was expected in advance. Commerzbank was one of the largest financiers for these projects. Because of difficulties in projects which were supported by Commerzbank, Commerzbank had to end his financing (INTVW 26 Manufacturer, 2016).

Technology and advancing age of the operating turbines progressed and the repowering potential has grown. In this case repowering means to replace wind turbines from the first generation with modern turbines which have a higher efficiency, whereby the cost of electricity generation by wind power is minimized. Due to modern turbines there also is a better integration into the electrical grid. Through Repowering installation a total capacity of 1729 MW was reached.

Since 2000, they thought that there will be not enough space for onshore wind energy in the near future. The development of turbine technology for low-wind sites was not that advanced that it could be used in wind energy market. Furthermore some German states politically blocked further expansion of onshore wind energy. So the government also introduced feed-in tariffs in the EEG for offshore wind energy to stimulate the development of wind energy in the sea. In 2010, Germany's first offshore wind park called alpha ventus started its operation. The member companies of the project were EWE AG, E.ON Climate & Renewables GmbH and Vattenfall New Energy GmbH (alpha ventus, 2010). A total capacity of 2313 MW offshore wind energy was installed in Germany by the end of 2014.

The Electricity Feed-in tariff Act, the predecessor of the EEG was introduced in Germany on December 1990. From the beginning of 1991, it regulated two important objects. (1) Utilities had to take electricity from renewable sources. (2) The electricity from renewable sources were remunerated. The utilities were demanded to pay 90% of the average revenues from electricity sales. In Northern Germany the Electricity Feed-in Act turned out very successful and the wind turbine capacity increased significantly. For each kWh fed into the German grid Table 7 shows that the remuneration for the wind energy lay between 0.165 DM and 0.173 DM, which according to the official conversion rate is equal to 0.084 EUR/kWh and 0.088 EUR/kWh. In 2015, the feed in tariff for turbines that feed into the grid for the first time with the increased initial tariff was 0.089 EUR/kWh.

Nowadays the Electricity Feed-in Act did not aim to implement significant increase in capacity installations. It should only help small electricity producers by allowing them to feed in to the national grid. The Act had no essential impact on the German market, although it stimulated some investments in renewable energy source. However, the introduction of the Electricity Feed-in Act was paved the way for to a long series of laws and regulations for the promotion and support of all renewable energies and thus also for wind energy. Table 6 shows the remuneration rates for wind energy fed into the grid from 1991 to 1998.[39]

*Table 6: Remuneration rates for wind energy fed into the grid from 1991 to 1998. Source: www.iwr.de.*

| | 1991 | 1992 | 1993 | 1994 | 1995 | 1996 | 1997 | 1998 |
|---|---|---|---|---|---|---|---|---|
| [EUR/kWh] | 0.085 | 0.084 | 0.085 | 0.086 | 0.088 | 0.088 | 0.088 | 0.086 |
| [DM/kWh] | 0.166 | 0.165 | 0.166 | 0.169 | 0.173 | 0.172 | 0.172 | 0.168 |

[39] (IWR 2018)

### 3.2.5 Cost Development of German Wind Power (by Neij [1978 – 2000])

The experience curve for Germany include turbines built by German companies as well as turbines manufactured in foreign countries. Almost 60% of the supply to the German market were domestic. 40% of the installed turbines were manufactured in Denmark. The Netherlands provided about 2% of the installed turbines. Most of the turbines from Denmark installed in the early 1990s were small or medium size turbines (50 kW up to 250 kW). The remaining turbines were imported from UK, Belgium and Japan. Due to the origin of the wind turbines, the experience curve in Fig. 39 constitute a mixture of German and Danish wind turbine manufacturing experience. The progress ratios for wind turbines installed in Denmark and Germany show little difference. The experience curve for wind turbines installed in Denmark has 91% that for Germany has a progression rate of 94%. One possible reason for the difference in progression rate is that Danish manufacturers charged the prices for German customers, which were above those of the Danish market. In addition, economic and legislative conditions were often determined by Danish turbine salesman. Therefore a turbine installed on the German side of the Danish-German border was more expensive than the same turbine installed few kilometers away on the Danish side of the border. The difference between Denmark and Germany in price of wind turbines installed is illustrated in Fig. 40. In this experience curve a tendency towards real price stagnation since 1996 also can be observed.

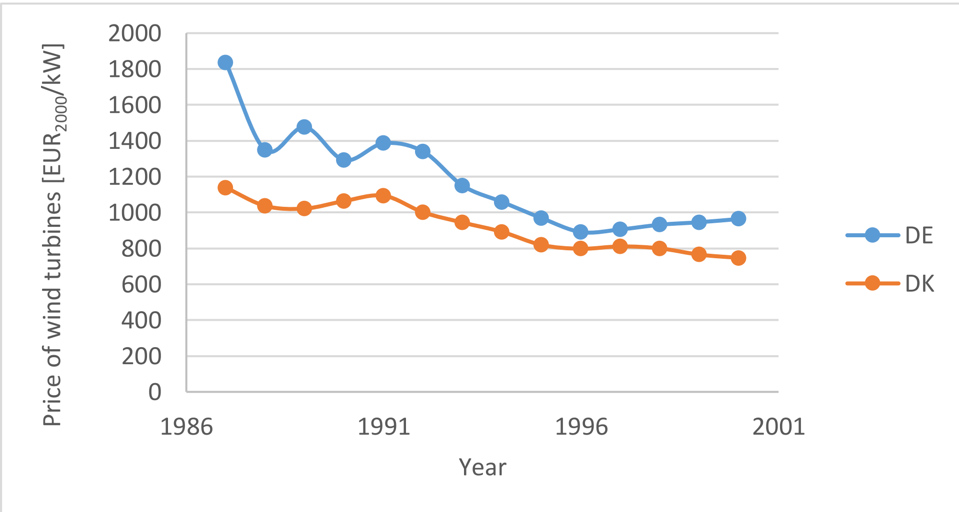


*Figure 39: Price of wind turbines installed in Germany compared to price of wind turbines installed in Denmark. Source: Neij et al. 2003*

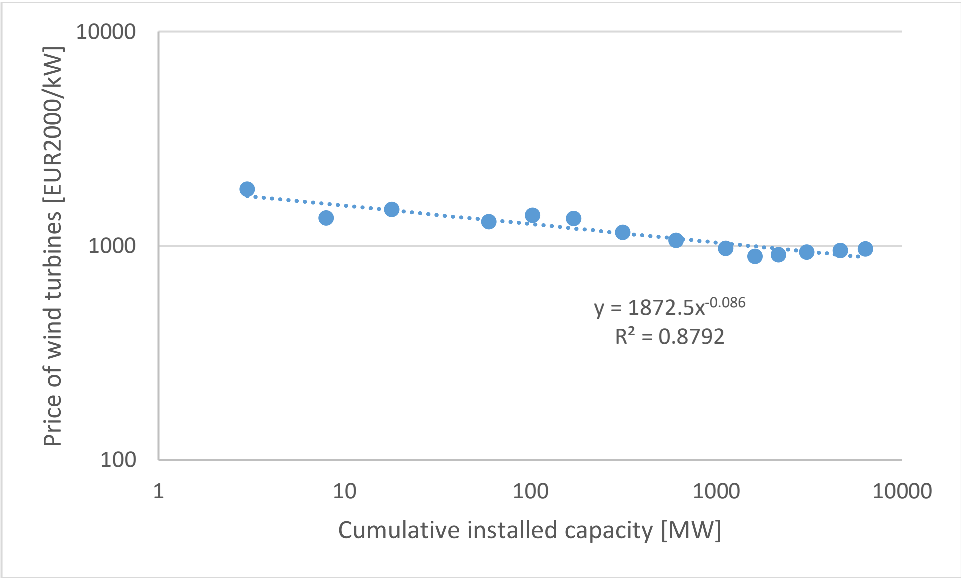


*Figure 40: Experience curve for wind turbines installed in Germany [1987-2000]. Source: Neij et al. 2003*

# 3.3 Biofuel

### 3.3.1 Ethanol Energy Production

Accounting for more than 90% of total biofuel usage, Bioethanol is the most common biofuel. There are two types of production techniques, the conventional production and the advanced production.

Conventional production is based on enzymatic conversion of starchy biomass into sugar, and fermentation of 6-carbon sugars with final distillation of ethanol to fuel grade, while cereal corps, corn (maize), sugar cane, sugar beets, potatoes, sorghum, and cassava, which are available as feedstocks, serve as a source. Conversion to sugar is easier, if sugar cane is used. For heat and process powering crushed stalk can be used. Brazil (sugar cane) and the U.S. (corn ethanol) are the world's largest producers of bio-ethanol. Ethanol is used in low 5%-10% blends with gasoline (E5, E10) but also as E-85 in flex-fuel vehicles. In Brazil, the share of bioethanol in gasoline accounts for a minimum of 22%.

While conventional process use only the sugar and starch biomass components, advanced bioethanol production deals with the usage of the all available lingo-cellulosic materials. Due to these processes there is a potential to increase the variety and quantity of suitable feedstock including cellulosic waste, maize stover, cereal straw, food-processing wastes, as well as dedicated fast-growing plants such as popular trees and switch-grass. An additional advantage is the fact that cellulosic feedstock could be grown on non-arable land or be produced from integrated crops, which could increase land availability.

*Biodiesel*

Biodiesel production is based on trans-esterification of vegetable oils and fats through the addition of alcohols and a catalyst, whereby glycerol forms as a co-product. The oil is extracted chemically or mechanically from rapeseeds, sunflower seeds, soy seeds and palm oil seeds which are included in the feedstocks.

Due to advanced process it is possible to replace methanol of fossil origin by bioethanol. So fatty acid ethyl ester is produced instead of fatty acid methyl ether which is the traditional biodiesel. The process hydrogenation of oils and fats can produce a biodiesel that can blended with fossil diesel up to 50% without any engine modifications. There is also a technique called synthetic biofuel production which uses the Fischer-Tropsch process to convert biomass to liquids (BTL).

*Energy input and emissions*

Fossil energy emissions and inputs levels from biofuel production depend on process, feedstock, energy embedded in fertilizers, and local conditions.

Since the crop produces high yields per hectare and the sugar is easy to extract, production of ethanol from sugar cane (in Brazil) is energy-efficient. If bagasse is used for heat and power for the process, and ethanol and biodiesel are used for crop production and transport, the fossil energy input needed for each ethanol energy unit be low compared with 60%-80% for ethanol from grains. Therefore, $CO_2$ emissions for vehicles driven by ethanol can be as low as 0.2-0.3 kg$CO_2$/litre ethanol compared to with 2.8 kg$CO_2$/litre for conventional gasoline. Ethanol from sugar beet requires more energy input and provides 50%-60% emission reduction compared with gasoline

There is a technique which is even more energy-intensive. In 2007, it was estimated that ethanol from maize may displace petroleum use by up to 95%, whereas total fossil energy input currently amounts to some 60%-80% of the energy contained in the final fuel, from which 20% being diesel fuel and the rest being coal and natural gas. Therefore, the $CO_2$ emissions reduction may be as low as 15%-25% compared to gasoline.

Ethanol production from lingo-cellulosic feedstock needs more energy input compared to bioethanol production from corn. However, in some cases most of such energy can be provided by the biomass feedstock itself. Therefore, net $CO_2$ emissions reductions from lingo-cellulosic ethanol can be close to 70% compared to gasoline.

For biofuel, typical values are fossil fuel inputs of 30% and $CO_2$ emission reductions of 40%-60% compared to diesel. $CO_2$ emission reduction can be improved by using recycled oils and animal fats.

### 3.3.2 Global scenario and statistics

Main reasons for the development of bioenergy are the aim to reduce the emissions resulting from fossil fuel use, improvement of energy efficiency and security of supply. Biomass materials have a limited storage life and are therefore harvested as needed. For commercial use, biomass is converted into a more compact and durable form such as biomass pellets.

In the recent years, a major driver for development of bioenergy markets has been the GHG mitigation. Compared to earlier years, where main argument was security and high import costs of fossil fuels, nowadays, substitution of fossil fuels, and the reduction of fossil carbon emissions are major arguments for bioenergy.

Carbon taxes which is a key instrument for energy transition, is another major driver. To reduce fossil fuel use and increase energy efficiency carbon tax is a simple and effective measure. As other taxes like income tax can be reduced carbon tax can be tax neutral, which will also lead to a more sustainable lifestyle and investment for the future. Due to the "Paris agreement" there has been a global call for introduction of carbon pricing. This agreement took everyone in responsibility including governments, NGO's, companies etc. Among other countries, Sweden have successfully implemented the carbon tax leading to increase use of bioenergy. Fig. 41[40] shows the share of biofuels production by region.

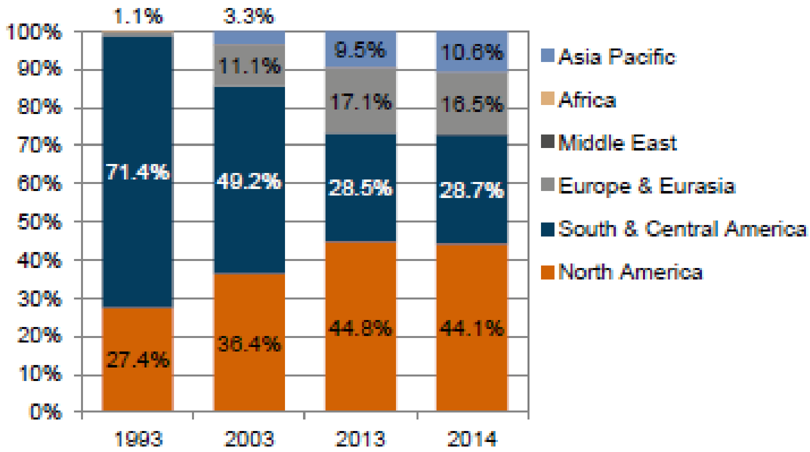


*Figure 41: Share of biofuels production by region. Source: BP (2015) Statistical Review of World Energy.*

For countries that do not have considerable natural hydrocarbon resources bioenergy is the opportunity to become net producers of energy products for export. For this, developing the necessary industry and infrastructure and enough land and water resources to support the economic production of the feedstock crops is necessary. Due to its long experience of forestry and converting forestry by-products into forms of bioenergy Finland is an example for this. In Sweden, bioenergy accounts for almost 33% of all final energy consumption. Some developed countries have already started to develop bioenergy as a more export-oriented industry besides supplying domestic demand. Fig. 42 shows the share of the cumulative installed capacity of bioenergy by its forms. Solid

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[40] (BP 2015)

biomass accounts for the greatest proportion. Global cumulative installed capacity is shown in Fig. 43[41].

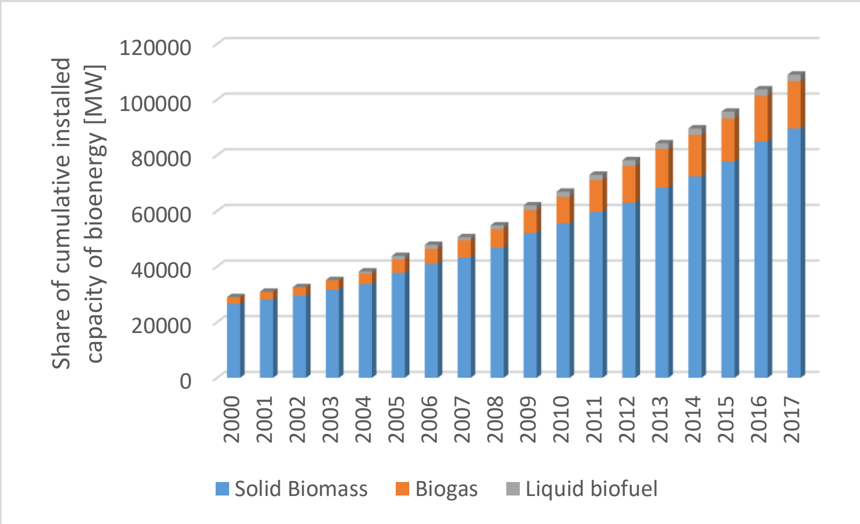


*Figure 42: Share of cumulative installed capacity by its forms 2000-2017. Data: www.bp.com*

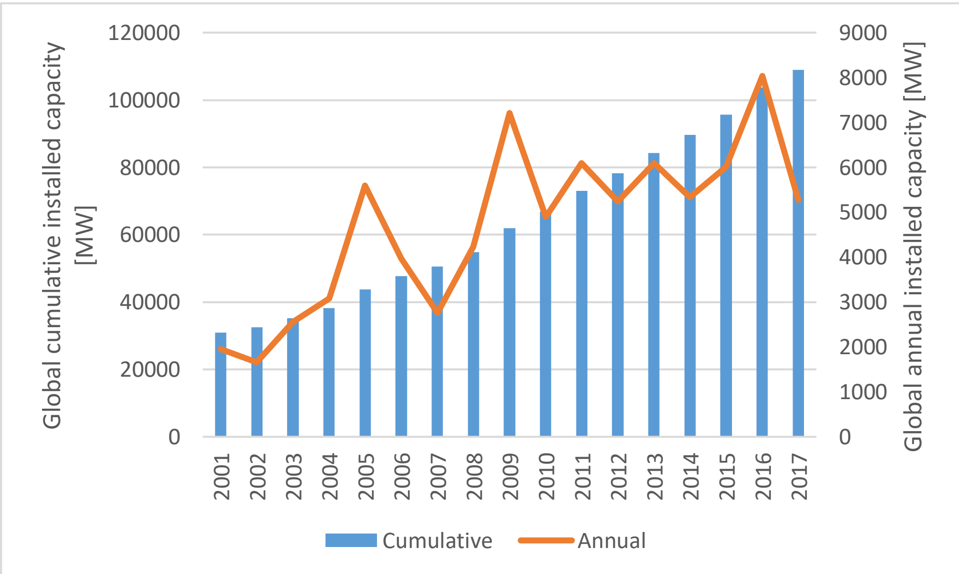


*Figure 43: Global cumulative installed Biomass capacity 2001-2017. Data: www.bp.com*

[41] (BP 2018)

### 3.3.3 Ethanol Production in Brazil (1980 – 2002)

In 1975, with the purpose of reducing oil imports an Alcohol Program called PROALCOOL was established. They wanted to produce ethanol by own sugar cane cultivation. PROALCOOL had become the most important biomass energy program in the world, and had positive environmental, economic and social aspects. Yielding 6 Mt of sugar and 555 km³ of ethanol, in 1975, 91 Mt of sugar was produced. In 2002, sugarcane production was 320 Mt. The yield was 22.3 Mt of sugar and 12.6 Mm³ of ethanol. In 2002, the land area used for sugarcane plantation in Brazil was approximately 4.9 Mha. 60% of this land area was in Sao Paulo.

Ethanol is used in one of two ways in Brazil. Either it is used as an octane enhancer and as oxygenated additive to gasoline, blended in the proportion of 20-26% in volume of anhydrous ethanol to gasoline (gasohol) or in neat-ethanol engines, in the form of hydrated ethanol.

Since 1997, the creation of PROALCOOL, prices for ethanol and other fuels were determined by the federal government. The liberalization of anhydrated ethanol was in May 1997. The same happened to the price of hydrated ethanol in February 1999.

In 1980, ethanol production costs were close to 100 US dollar a barrel. As production increased, prices paid to producers reflected average costs of production. Because of the gains in agricultural yield and economies of scale, prices fell during the initial phase. After 1985, while the federal government wanted to lower inflation by controlling public prices, inclusive fuels, price was set below the average costs of production. Due to this measure, together with economies of scale, the price fell more rapidly. This fact is shown in Fig. 44[42].

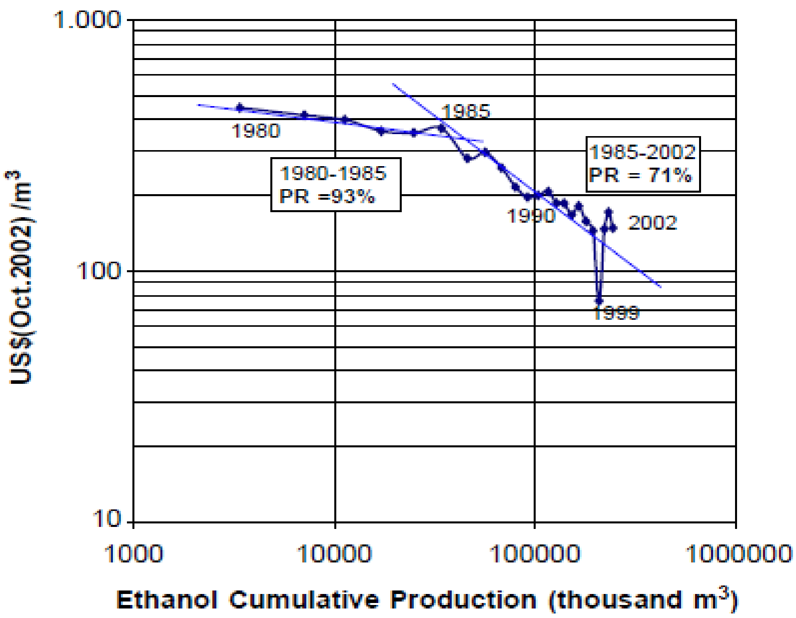


*Figure 44: Ethanol learning curve. Brazil: 1980 - 2002. Source: Goldemberg et al. 2004*

[42] (Goldemberg et al. 2004)

Because of high competition in the ethanol activity the prices moved towards production cost in the medium and long term.

From 1980 to 1985, the progression ratio for sugarcane ethanol produced in Brazil was 93%, while from 1985 to 2002 progression ratio was 71%. Compared to Rotterdam gasoline prices Fig. 45 illustrates the price paid to alcohol producers. Assuming the low heating value of each fuel, prices were converted to US$ per GJ.

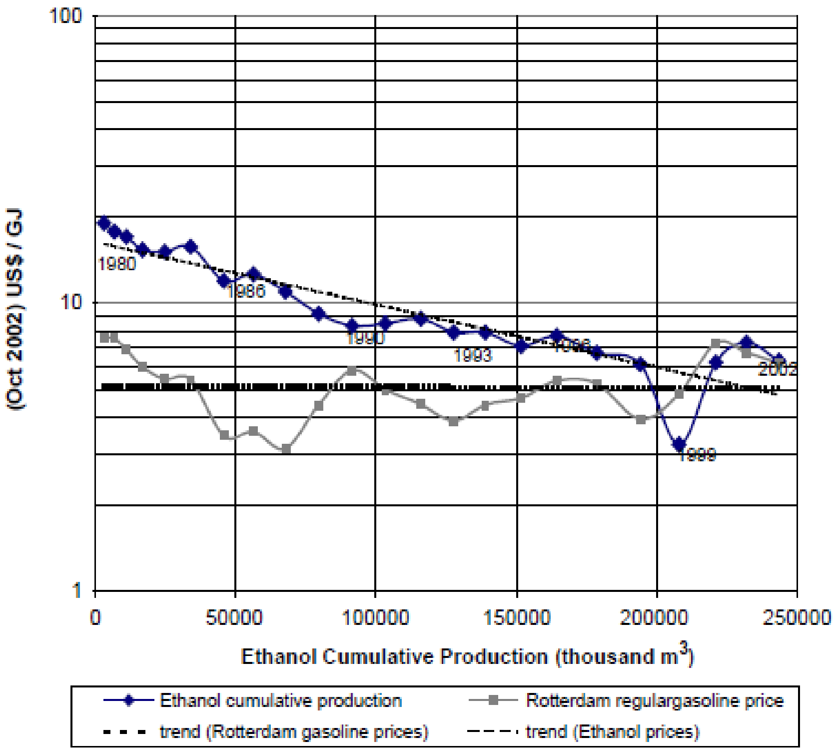


*Figure 45: Ethanol and gasoline prices. Source: Goldemberg et al. 2004*

Due to the pricing policy applied to fuels in Brazil, at the beginning of the alcohol program, ethanol use became viable to consumers. As fuel prices were liberalized, and the efficiency and cost competitiveness of ethanol production increased, this measure was no longer necessary and was not applied. 1975 to 1989 the total amount of investments in the agricultural and industrial sectors for the production of ethanol for automotive use was a total of US$4.92 billion (US$ of 2001). Due to no longer required imports there were savings, which have amounted to US$52.1 billion (Jan 2003 US$) from 1975 to 2002 (Datagro 2003).

In 2003, there were no subsidies for hydrated or anhydrous ethanol production. Because of significant reductions in production costs, hydrated ethanol was sold for 60-70% of the price of gasohol at the pump station. So ethanol became competitive to gasoline. For the consumer there was no difference between neat-ethanol for a price at the station of up to 80.67% of that from gasohol and gasohol itself, when one consider the higher consumption rates of neat-ethanol cars. Demonstrating the long-term competitiveness of the ethanol fuel, Fig. 46 illustrates a comparison for the most important transportation fuels used in Brazil in terms of the price paid in Real and the exchange rates to the US dollar.

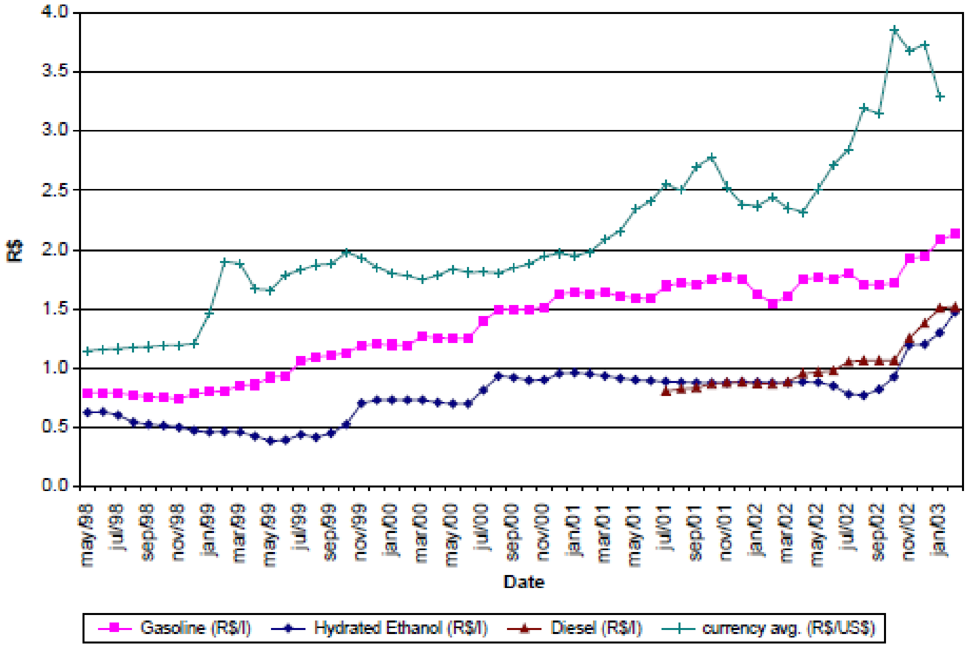


*Figure 46: Fuel prices in Brazil and currency rates. Source: Goldemberg et al. 2004*

# 3.4 Nuclear Energy

## 3.4.1 Nuclear Technology

A nuclear reactor produces and controls the release of energy, which results by splitting the atoms of certain elements. This reaction generates steam, which in turn is used to generate electricity.

The principle are the same for most types of reactors. Continuous fission of the atoms of the fuel releases energy, which is harnessed as heat in either a gas or water. This heat is used to produce steam. As in most fossil fuel plants, at the end the steam is used to drive the turbines which produce electricity.

Nowadays, 85% of the world's nuclear electricity are generated by reactors which derived from designs originally developed for propelling submarines and large naval ships. The pressurized water reactor (PWR) is the main design. It has water at over 300°C under pressure in its primary cooling/heat transfer circuit. The steam is generated in a secondary circuit. On the other hand, the boiling water reactor (BWR) makes steam in the primary circuit above the reactor core, at similar temperature and pressure. To slow neutrons, both reactor types use water as both coolant and moderator. Both popular types of reactors are shown in Fig. 47[43] and Fig. 48[44].

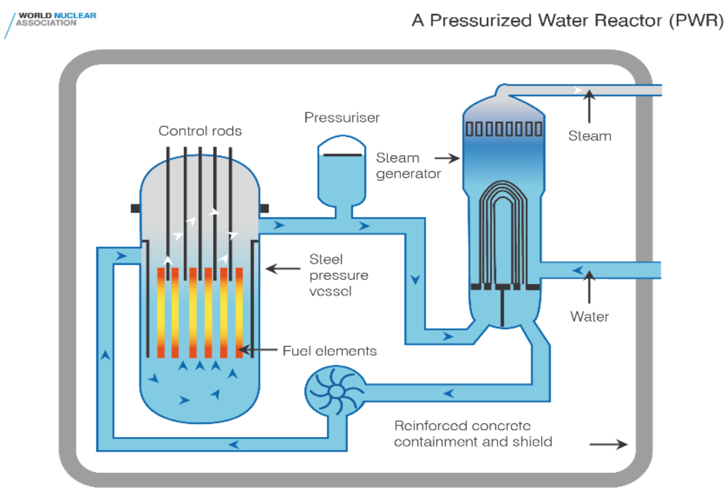


*Figure 47: Operation of a Pressurized Water Reactor. Source: World Nuclear Association.*

43 (WNA 2018)
44 (WNA 2018b)

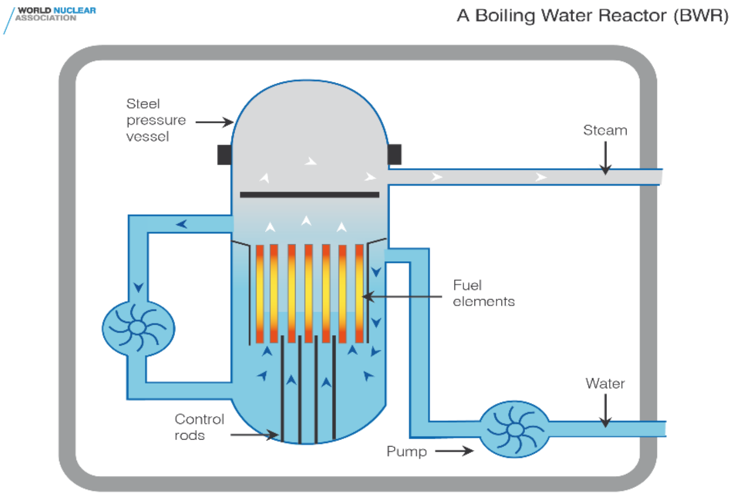


*Figure 48: Operation of a Boiling Water Reactor. Source: World Nuclear Association.*

In the following some components ware described, which are common to most types of reactors.

Fuel

The basic fuel is Uranium. Fuel rods made of pellets of uranium oxide ($UO_2$) are arranged into fuel assemblies in the reactor core. For example, in a 1000 MWe PWR there might be 18 million pellets formed to 51000 fuel rods.

Moderator

The material in the core which slows down the chain reaction of the neutrons caused by the fission is called moderator.

Control rods

Control rods are made with cadmium, hafnium or boron, which are absorbing neutrons. To control the rate of reaction, or stop it, control rods are inserted or withdrawn from the core. Usually, some in PWR reactors particular rods are used to enable the core to sustain a low level of power efficiently.

Coolant

The coolant is circulating through the core so as to transfer the heat from it. The water becomes steam in the in the secondary coolant circuit, except in BWRs. A pressurized water reactor has two to four primary coolant loops with pumps, driven either by steam or electricity.

Pressure vessel or pressure tubes

It is usually a steel vessel containing the reactor core and moderator/coolant. It may be a series of tubes holding the fuel and transferring the coolant through the moderator.

Steam generator

It works as a heat changer like a motor car radiator. In pressurized water reactors it is part of the cooling system where the high-pressure primary coolant bringing heat from the reactor is used to make steam for the turbine, in a secondary circuit.

Containment

Primarily designed to protect the reactor and associated steam generators. It is also preventing the effects of radiation, to protect those outside. Typically made of concrete and steel and is a metre thick.

The different types of reactors are indicated in Table 6.

*Table 7: Nuclear power plants in commercial operation or operable. Data: IAEA (end of 2015).*

| Reactor type | Main countries | Number | Gwe | Fuel | Coolant | Moderator |
|---|---|---|---|---|---|---|
| Pressurized water reactor (PWR) | US, France, Japan, Russia, China | 292 | 275 | enriched $UO_2$ | water | water |
| Boiling water reactor (BWR) | US, Japan, Sweden | 75 | 73 | enriched $UO_2$ | water | water |
| Pressurized heavy water reactor (PHWR) | Canada, India | 49 | 25 | natural $UO_2$ | heavy water | heavy water |
| Gas-cooled reactor (AGR & Magnox) | UK | 14 | 8 | natural U (metal), enriched $UO_2$ | $CO_2$ | graphite |
| Light water graphite reactor (RBMK & EGP) | Russia | 15 | 10 | enriched $UO_2$ | water | graphite |
| Fast neutron reactor (FBR) | Russia | 3 | 1.4 | $PuO_2$ and $UO_2$ | liquid sodium | none |
| | TOTAL | 448 | 392 | | | |

*Lifetime of nuclear reactor*

Most of the today's nuclear plants were designed for 30 or 40-year operation lives. Nevertheless, with investments in systems, structures and components lives can be extended. Most of the more than hundred reactors in the USA are expected to be granted license extensions from 40 to 60 years.

Steam generators which need to be replaced are the biggest reason for taking investment. Many have been replaced after about 30 years. Otherwise the reactor has the prospect of running for 60 years. Other components are easier to be replaced as they age. With time properties of materials may degrade, particularly with heat and neutron irradiation. To maintain reliability and safety, investment is needed.

### 3.4.2 Global scenario and statistics

The electricity generation from nuclear power began in the 1950s. The principle of energy-releasing process using nuclear fission serves as the basis of the technology, which was established in 1039. During the world war 2nd, the nuclear technology was developed further to produce functioning atomic bomb. In 1941, the *Military Application of Uranium Detonation* (MAUD) committee published a report in which they proposes the use of uranium as energy source. However, this recommendation was not pursued further until the end of the world war. After the war several countries (US, USSR, Canada and UK) increased their ambition to use the nuclear energy as energy source for driving turbines and produce electricity.

In 1952, the US built the first nuclear plant to generate electricity with a capacity of 100 kW in Idaho. After that the USSR built a 5 MW pant in Obninsk in 1954. But it was the UK, who first achieved to generate electricity from nuclear power on an industrial scale. The plant situated at Calder Hall in Cumberland was opened in 1956. In 1959, the plant with all four reactors activated had the total capacity of 200 MW (Emsley 2013).The plant was working until 2003 and had the dual function of electricity generation and plutonium production.

From the late 1950s, there was a rapid progression in the global civil nuclear power industry. In 1964, US launched the first commercially used nuclear power plants (Damian 1992). Between 1965 and 1973, an average of some 23 plants were ordered annually in the US (Damian 1992). By 1971, a total of 26 reactors were in operation in the UK. During this period, the unit size has increased tenfold (Emsley 2013). Other countries experienced similar development, albeit with different reactor technologies. Over time, the unit size got greater. During the 1980s, a total of over 200 plants were ordered. The plants had an average size of over 900 MW. At the beginning of the 1980s, the share of total global electricity production from nuclear power had reached 10%. The share increased to reach approximately 17% until the late 1980s. Nuclear electricity production and share of total electricity production is shown in Fig. 49[45] and Fig. 50.

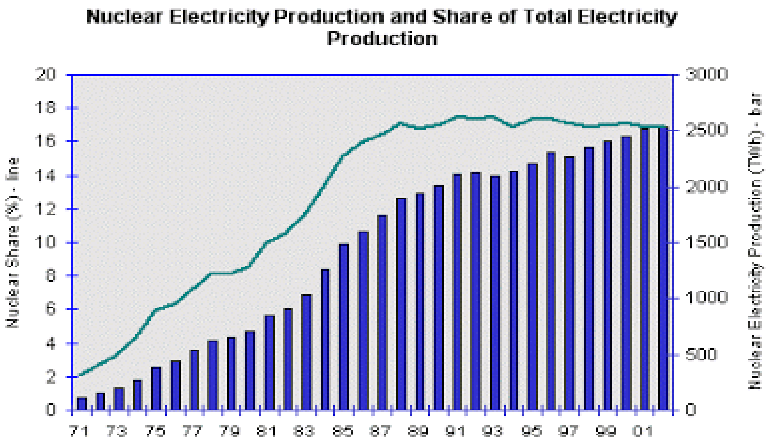


*Figure 49: Nuclear Electricity Production and Share of Total Electricity Production 1971-2001. Source: Bradish (2008). Data: World Nuclear Association.*

[45] (David Bradish 2008)

The 17% market penetration mentioned before that was achieved until the late 1980s has later turned out to be a peak. The share of annual total global electricity production of nuclear power had declined to 11% by 2013 (Fig. 50[46]).

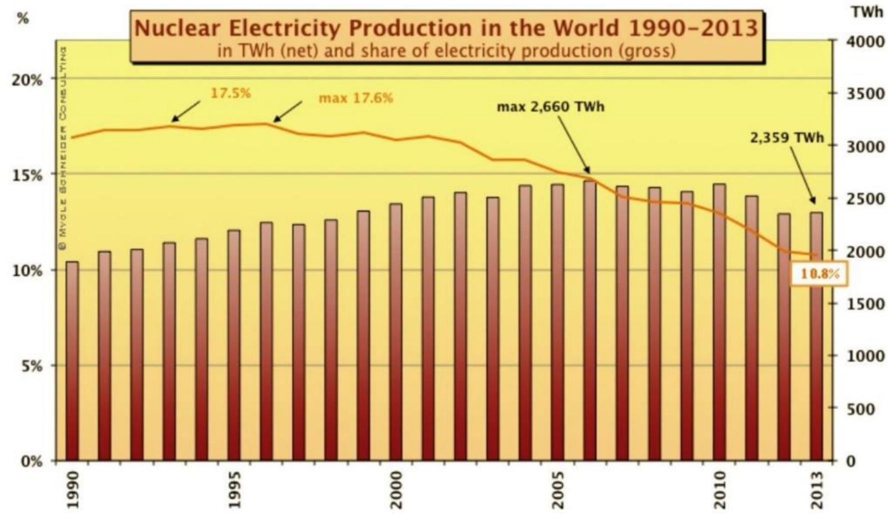


*Figure 50: Nuclear Electricity Production and Share of Total Electricity Production 1990-2013. Source: Schneider and Froggatt 2014*

Some authors who dealt with nuclear power development have questioned whether it has genuinely progressed to a fully commercially status. One argument was that the large US orders from the mid-1960s through to the mid-1970s are an evidence that nuclear power was a mature technology. It was even claimed that “initial attempt to transform nuclear power into a marketable commodity like any other has been a historical failure”. Due to a study by MIT in 2003 observing that all the ten operating nuclear power plants “were developed by state-owned or regulated investor-owned vertically integrated utility monopolies” (MIT, 2003).

Four decades elapsed between the establishment of the basic principles of nuclear power and the years by which the market penetration account for 10% of global electricity production. 1964 was the start year for the market deployment phase – commercially launch of nuclear plants in the US (Damian 1992). And the end year was 1981 when nuclear power reached 10% market penetration on an annual electricity production basis and experienced widespread commercialization.

[46] (Schneider M. and Froggatt A. 2014)

### 3.4.3 France's PWR program

In the early 1970s the French Pressurized Water Reactor (PWR) program was started. It is considered as the most successful scaling-up of a complex and capital-intensive energy technology system in the recent history of industrialized countries. With a total gross installed capacity of 66 GWe French built 58 PWRs. In 2000, where the program was ended the reactors produced 400 TWh/yr of electricity, which made up almost 80% of France's electricity production.

Three facts show the success of France's PWR program. First, as mentioned above, nuclear energy had a share of 80% in the electricity mix. Second, 50 GWe, or 75% of the total installed gross capacity went on-grid from 1980 to 1990, which was a very short duration. Finally, the industrial capacity to manufacture PWR components was developed. They were able to build reactors within short construction time. They also developed a domestic industry covering the whole nuclear fuel cycle. Therefore, France's PWR program stood out as the most successful of the comparable efforts worldwide. This was possible especially due to the specific political/technocratic system of France.

There was a well thought ought coordination between the state engineers of the *Corps d'État* (prevalent in the government and the CEA) and the *Corps de Ponts* (prevalent in the ÉDFs equipment department) and the government.

The most significant measure of success in the French nuclear scale-up was obviously the construction time. Compared to international standard construction time in France was short. This fact is shown in Fig. 51. The mean construction time was 76 months, whereas mean construction time in the US was 106 months (Koomey and Hultman 2007). 55% of reactors and 47% of total gross capacity added to the program had construction times of less than 72 months. More than 70-76% of reactors had construction times less than 84% months, which fewer than 35% of all US reactors built.

Special reference needs to be made to ÉDF, when discussing the importance of standardization in reactor designs as well as short construction time. According to ÉDF the success factors were (a) size of the order program, (b) standardization, (c) client engineering of the construction process, (d) thorough quality and cost control.

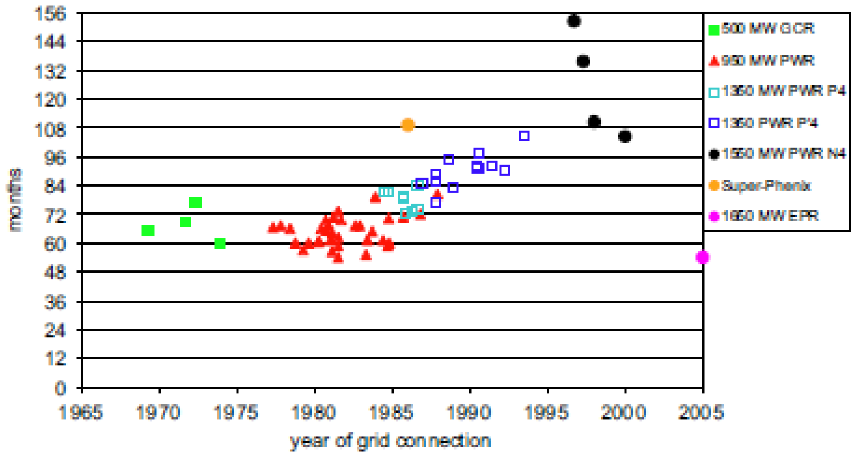


*Figure 51: Construction time of French reactors (construction start to first grid-connection in months). The implausible, optimistic projection for the new 1650 MW EPR reactor Flamanville-3 submitted by the French authorities to the IAEA is noticeable. Source: IAEA PRIS Data Base (2009).*

### 3.4.4 Cost of the French nuclear program

Reliable data on the costs of French nuclear program were not available before completion of the program in the year 2000. The regularly updated "reference cost" projections by the PEON (*Production d'Électricité d'Origine Nucléaire*) Commission were the only economic information widely used within France's nuclear nexus. Before 2000, French nuclear economics remained unknowable. For the first time, cost information was accessible in a Major scenario study (Boisson P. 1998) although it was only in graphical form. The ÈDF decided to open its nuclear reference cost projections of levelized costs. In 1999, a comprehensive study "concerning the economic data of the entire nuclear industry" (Charpin J-M. et al. 2000) was carried out by the order of Prime Minister Lionel Jospin. This study presents the advantages of France's centralized decision-making and institutional structure.

Only minimal adjustments to assure comparability were made to minimize deviation for the original data. The economic data was given in current French Francs (FF) or expressed in constant FF from 1995 to 1998. They have been harmonized to a common FF1998 denominator on the official French GDP deflator. Therefore, the cost data presented in the following do not include any adjustments for subsequent cost escalation beyond the general rate of inflation. The data described here, refer only to the situation up to 1998. Fig. 52[47][48][49] shows the nonmilitary costs of the French PWR program. Due to the different methods of converting to constant FF, the discrepancies across the different data sources are less than 10 percent. The total cost of the French PWR program account for 1.5-1.6 trillion FF98 (constant 1998 French Francs). Total costs are divided into 810 GF98 [billion FF1998] capital cost, which includes investment costs with its interest during construction and the R&D expenditures and 844 GF98 operation costs which includes operation and maintenance costs as well as fuel costs. The costs of the program refer to a total installed PWR capacity of 65.9 GWgross or 63.1 GWnet. Capital costs account for between 10400 and 12300 FF/kW (gross) installed, or 10900-12800

[47] (Grubler 2010)
[48] (Girard P. et al. 2000)
[49] (Bataille C. and Galley R. 1999)

FF98/kWnet installed. Investments in the fuel cycle facilities are not included in the capital expenditures.

| | | | |
|---|---|---|---|
| R&D < 1970 | | 104 | |
| R&D public > 1970 | 57 | 57 | |
| Investments | | | |
| PWR construction | | | |
| PWRs | 460[a] | 480 | |
| End-of-fuel cycle and decommissioning provision | 169 | 169 | |
| **Subtotal capital** | **686** | **810** | |
| Operation expenditures | | | |
| O&M | 400[a] | 402 | |
| Fuel | 419[a] | 431 | |
| **Subtotal operation** | **819** | **833** | |
| Total costs | **1505** | **1643** | **FF98** |
| | 255 | 278 | US$98 |
| | 208 | 227 | Euro2008 |
| | 304 | 332 | US$2008 |
| Levelized costs per kWh | | | |
| 5% discount rate | | **0.22** | **FF98** |
| | | 0.04 | US$98 |
| | | 0.03 | Euro2008 |
| | | 0.05 | US$2008 |

*Figure 52: Expenditures of French PWR program 1970-2000, low, ad reference ranges. Graphic: Grubler (2010). Source: Girard et al.(2000); Lower values denoted with³ are from Bataille and Galley (1999).*

In Fig. 53 one can see the annual specific construction expenditures over time. At the end of the PWR program the structure of the expenditures shifted from investment to operation. At the beginning of the 1980s, annual expenditures made up about 65 GF98, or nearly 1 FF98 per W capacity, or about 0.16 FF98 per kWh generated. At the completion of the program it produced 400TWh per year.

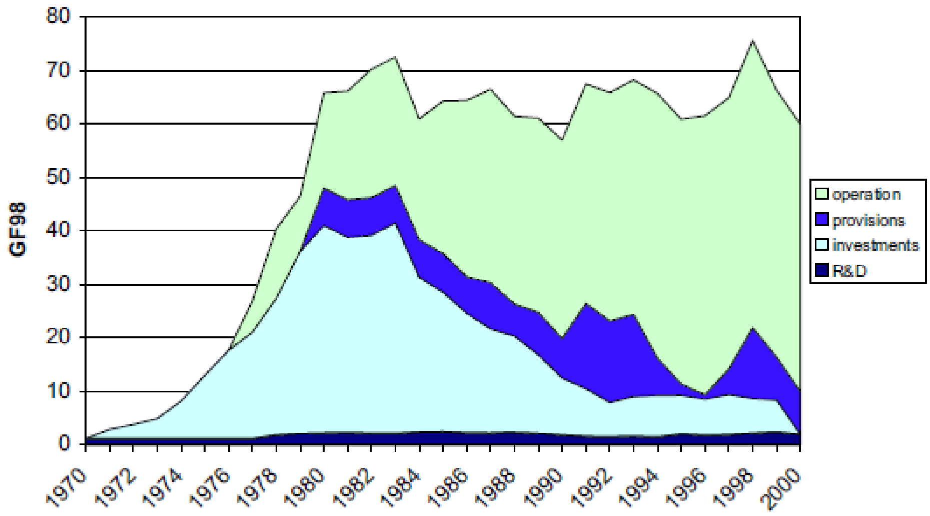


*Figure 53: Specific annual expenditures for French PWR program 1970-2000 in Billion French Francs1998 (GF98), Graphic: Grubler (2010). Source: Girard et al. (2000)*

Fig. 54 shows specific investment costs of French PWRs over time. Values plotted for 1972 and 1995 are averages for the entire period before 1974 and after 1990, respectively. The larger uncertainty range is reported only for completeness, because it implies the combination of quite implausible assumption. From 1974 to 1990, at least a total of 1 GW of nuclear capacity was under construction. In this period the method used allows a reasonable approximation. Not much happened before and after that period, to report meaningful annual results.

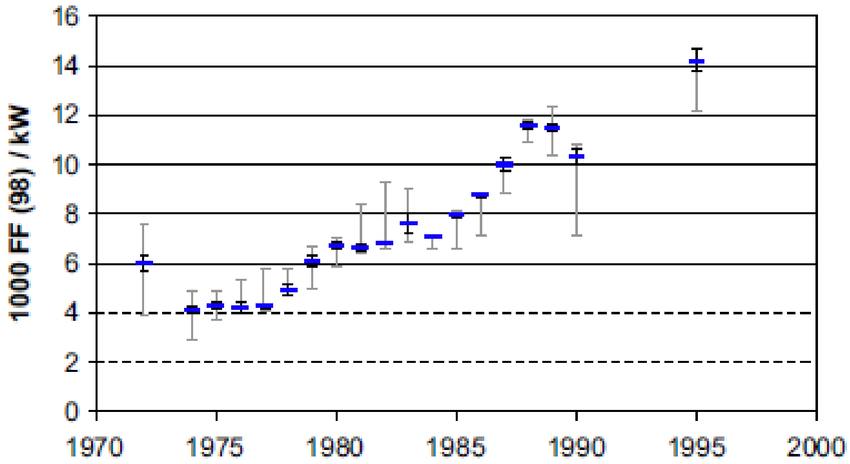


*Figure 54: Specific investment costs of French PWRs (1000 FF98 per yearly averages) over time, best guess model (blue) estimates and two uncertainty ranges (black and grey). The largest uncertainty ranges refer to minima and maxima of all cost estimation scenario. Source: Grübler 2010.*

From 1974 to 1984, specific real investment costs increased from 4200-7000 FF98/kW (gross capacity). There was also a cost escalation from 7000-10000 FF98/kW between 1984 and 1990. The most costly reactor built (Civaux-2) accounted for 20228 FF98/kW, whereas the cheapest reactor (Bugey-4) built accounted for 4538 FF98/kW. That is a difference of a factor of 4.5. The reasons for the cost escalation were the loss of the cost-dampening effects from standardization, partly due to upscaling to 1300 MW, but especially in the "frenchifying" of the tested Westinghaus design; longer construction duration after 1981 to maintain human and industrial knowledge capital during the significant scale-back of the expansion program as a result built-over capacity; an unsuccessful try to introduce a radically new French design.

This increase in construction costs in France's PWR program was substantially lower than in other countries, most notably the U.S. With almost the same technological characteristics of reactors in the U.S. compared to France, Fig. 55 shows the impacts of different institutional settings on the economics of scaling-up large-scale, complex technologies. The more decentralized, market-oriented, but regulatorily uncertain U.S system was less successful than the well thought out model of the French.

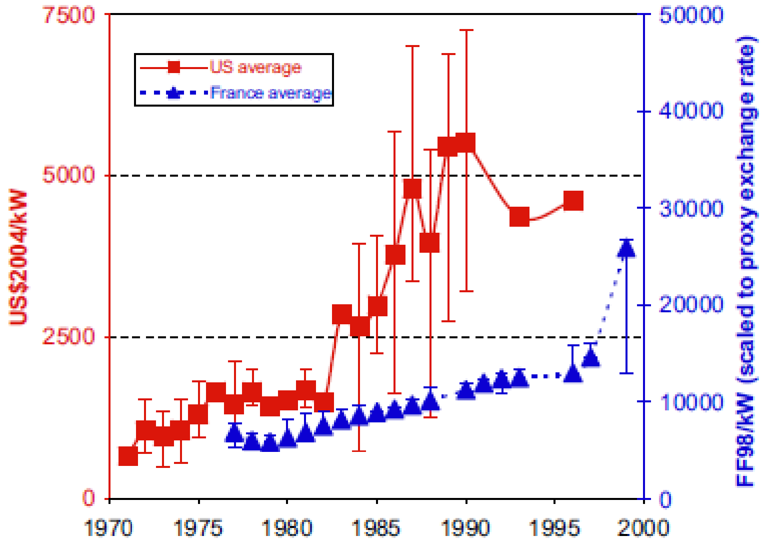


*Figure 55: Comparison of French (FF98/kW, Grubler, 2010) and U.S. (US$94/kW, Koomey and Hultman, 2007) nuclear construction costs, average and min/max per reactor completion year.*

The French nuclear case demonstrated the limit of the learning effect: the assumption that costs constantly decrease with accumulated technology deployment. Fig. 56 illustrates a useful reminder on the dangers of “logarithmic compression” in the customary double log learning curve presentation. In the case of nuclear in both U.S. and France the learning curve technique is clearly not applicable in technology studies and policy models. However, it allows an additional knowledge. As opposed to the different rates and extent, the rhythm of cost escalation between U.S and France seem to be similar. At the beginning, cost escalation is are positive until a threshold value of some 20 GW installed capacity is achieved. Then a phase of accelerated cost escalation to another threshold level at some 40-50 GW. From this point on, observation remains entirely presumed. To achieve a more reliable model, further evidence from more country studies are needed.

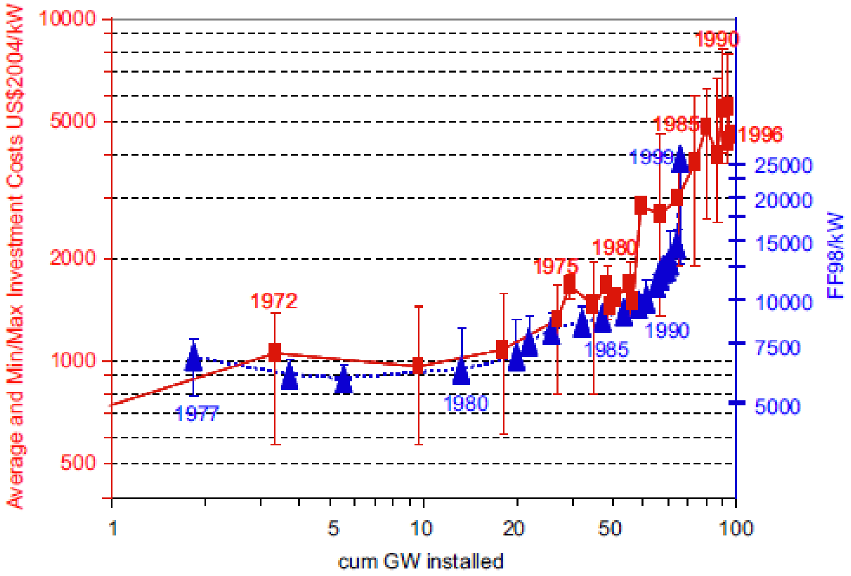


*Figure 56: Average and min/max reactor construction costs per year of completion date for U.S. and France versus cumulative capacity completed. Source: Grübler (2010).*

In the case of nuclear energy there also appears to be "forgetting by doing" instead of "learning by doing". (Lovins A. B. 1986) discusses this phenomenon in his work. The model in his work suggests that with increasing application - doing - , the complexity of the technology increases, which then leads to inherent cost escalation trends that limit or reverse "learning" possibilities. So there can be an unavoidable increase in system complexity due to technology scale-up.

Table 7 shows the Average French nuclear reactor construction costs inferred from annual expenditures. The reactor-specific construction costs can be calculated (at the price of an additional uncertainty margin) by dividing the cumulative average cost on basis of the respective fractional shares of capacity of the reactors. Thereby, it is assumed that construction costs over all reactors constructed in a particular year can be averaged.

*Table 8: Average specific French nuclear reactor construction costs inferred from annual expenditures. Best guess and min/max values for two uncertainty ranges (in 1000 FF98 per kW). Source: Grübler (2010)*

| 1000 FF98/kW | Best guess | Min-1 | Max-1 | Min-2 | Max-2 |
|---|---|---|---|---|---|
| Pre-1973 avg | 6.31 | 5.69 | 6.31 | 3.94 | 7.61 |
| 1974 | 4.23 | 4.01 | 4.23 | 2.88 | 4.84 |
| 1975 | 4.45 | 4.21 | 4.45 | 3.75 | 4.89 |
| 1976 | 4.42 | 4.04 | 4.42 | 4.01 | 5.30 |
| 1977 | 4.38 | 4.14 | 4.38 | 4.07 | 5.82 |
| 1978 | 5.16 | 4.72 | 5.16 | 4.70 | 5.83 |
| 1979 | 6.32 | 5.88 | 6.32 | 4.93 | 6.67 |
| 1980 | 6.91 | 6.57 | 6.91 | 5.88 | 7.07 |
| 1981 | 6.80 | 6.54 | 6.80 | 6.39 | 8.37 |
| 1982 | 6.89 | 6.74 | 6.89 | 6.58 | 9.28 |
| 1983 | 8.03 | 7.27 | 8.04 | 6.90 | 9.05 |
| 1984 | 7.03 | 7.03 | 7.13 | 6.63 | 7.14 |
| 1985 | 7.83 | 7.83 | 8.03 | 6.58 | 8.10 |
| 1986 | 8.73 | 8.65 | 8.85 | 7.19 | 8.89 |
| 1987 | 9.78 | 9.78 | 10.23 | 8.88 | 10.26 |
| 1988 | 11.47 | 11.43 | 11.72 | 10.93 | 11.83 |
| 1989 | 11.40 | 11.40 | 11.65 | 10.39 | 12.35 |
| 1990 | 10.01 | 10.01 | 10.66 | 7.19 | 10.79 |
| Post 1990 average | 14.54 | 13.76 | 14.68 | 12.22 | 14.74 |

## 3.5 Combined Cycle Gas Turbine

For the conversion of gas fuels to mechanical power or electricity the gas turbine is one of the most efficient technologies. The electric generator is driven by a gas turbine, which is part of a combined-cycle power system. Through the waste heat of the turbine exhaust steam is generated. This steam goes through a steam turbine to produce additional electricity. The electrical efficiency of a combined-cycle power system is typically in the range 50-60%. Compared to a simple, open-cycle application it is a substantial improvement of around 33% efficiency.

Combined –cycle power systems are used for most large onshore power generation plants. For over 10 years, the technology have also been used on a few offshore installations. Most of them are designed to generate power from open-cycle gas turbines which offer decreased capital costs, size and weight (per MW installed). However, they have lower energy efficiency and higher fuel costs per unit output. Combined-cycle systems are applicable for stable load applications, but for offshore applications, where the load profile is more transient, they are not that suitable. Combined-cycle technology is most cost-effective for larger plants. On excessive heat consuming installations the waste heat from the waste heat recovery unit will normally be used for other heating applications. Therefore, there will be little residual heat left for power generation.

A combined-cycle power system typically consists of the following equipment:

- Gas turbine
- Waste heat recovery units for steam generation
- Steam turbines
- Condenser
- Other Auxiliary equipment

Fig. 57[50] shows a schematic of a CCGT process.

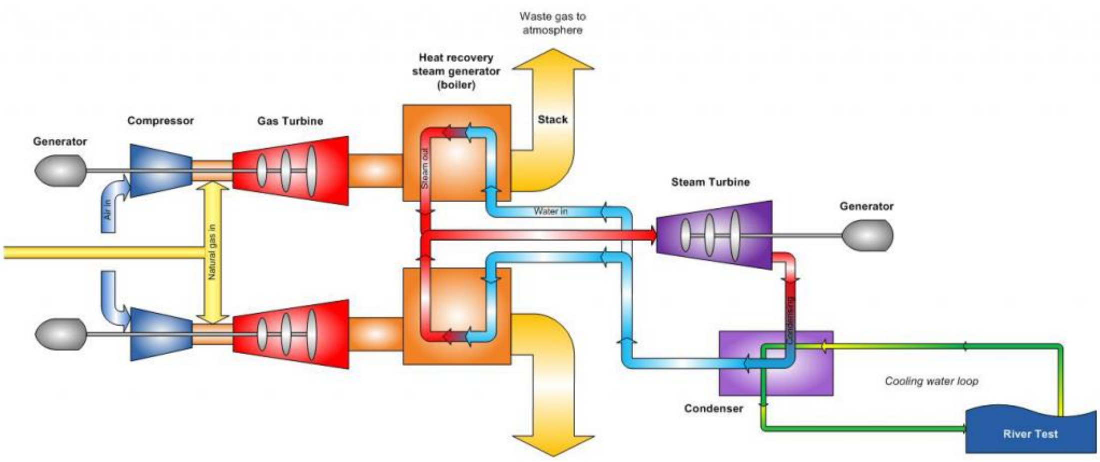


*Figure 57: Schematic of the CCGT process operated at Marchwood Power Station. Source: [www.marchwoodpower.com/ccgt/](www.marchwoodpower.com/ccgt/)*

[50] (Marchwood Power n.d.)

### 3.5.1 Global scenario and statistics

The first CCGT plant was built in 1949 (J. Watson 1997). In 1873, Frank Stolze's patents for designs similar to modern gas turbine technology, consisting of a compressor, combustor and were the first steps in this field. In 1905, Armengaud and Lemale constructed a prototype gas turbine capable of delivering useful power – albeit it suffered from performance problems (J. Watson 1997). Meanwhile, the concept of combined cycle had been developed with respect to mercury steam plants[51].

In 1939, Brown Boveri installed the first commercial, industrial gas turbine in Switzerland. Jet engine designs during the world war heavily influenced the design of gas turbines by key manufacturers such as General Electric and Westinghouse.

In 1949, General Electric installed a fully-fired combined cycle turbine in the U.S. In this cycle system a 3.5MW gas turbine operated in combination with a 35MW steam plant (J. Watson 1997). That was the first example of the use of waste heat from industrial gas turbine to provide a useful energy service for commercial buildings. In 1956, an installation of a CCGT took place in Luxembourg by Brown Boveri (J. Watson 1997). In the period from the 1950s to the mid-1960s, gas turbines developed more slowly than steam turbines. Gas turbines were too small to compete effectively. Hence, limited CCGTs were constructed, in which the gas turbines increased power generated from steam turbines (J. Watson 1997).

Due in particular to their fast start up speed, in the mid -1960s utilities in the US and UK installed gas turbines as an emergency resource. By 1970, gas turbines were being manufactured at a rate of GW per year globally. The first large CCGTs ( >100MW) were sold by Mitsubishi for location in Japan and by Brown Boveri for installation in France and could compete with the incumbent steam turbine power plants as far as efficiency is concerned(J. Watson 1997).

The oil crisis in 1973/74 prevented the progress of CCGT. The oil price increased by a factor of four. Therefore oil and gas were no longer a choice for power generation. Additionally, from the 1970s to the 1980s, there was a demand for larger units, which led to complexity of CCGTs and reliability problems. On the other hand this slowdown of progression gave the actors the opportunity to improve CCGT technologies, which was possible through state funding from the Japanese Moonlight programme and the American High temperature Turbine Technology programme. By 1985 the global market for gas turbines had decreased to 40% of the equivalent market in 1980 (J. Watson 1997)

Through the collapse in the oil price from 1986, associated decrease in natural gas prices and continuing decrease in electric utility gas prices throughout the 1980s, global demand for CCGTs emerged by the late 1980s. By the late 1980s, orders were in place for the construction of three CCGT plants by Japanese utilities. Three CCGT plants had already been ordered in 1981/82 (J. Watson 1997).

In 1978, the Public Utilities Regulatory Policy Act (PURPA) was implemented in the USA. By this measure transition was facilitated. Due to the PURPA independent generators were able to construct renewable and cogeneration power plants, particularly CCGT, and compete with the incumbent utilities. The outcome was that the capacity of CCGT grew steadily from the late 1980s (Fig. 58[52]). At the same time the price of natural gas fell.

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[51] Emmet, Wilillam Le Roy
[52] (Bergek et al. 2008)

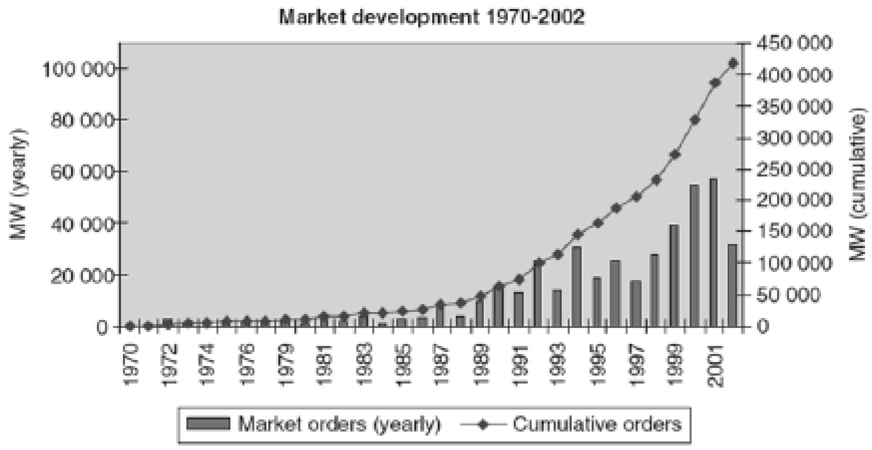


*Figure 58: Worldwide CCGT market development 1970-2002. Source: Bergek et al. (2008)*

Many American electric utilities worried about potential gas prices. Until 1990 they did not invest significantly in new CCGT plants (J. Watson 1997).

By the restructuring of the electric sector in the UK a *dash for gas* was created. From then on, private investors preferred the construction of CCGT power plants over coal-fired steam turbines and nuclear generation (Winskel 2002). By 1994, the share of UK electricity which was generated by CCGT plants accounted for 10% (DECC 2015). From the mid-to-late 1990s, the UK reached a 10% share of global electricity production due to CCGT plants(Winskel 2002).

### 3.5.2 Experience Curve Analysis of CCGT

This section is based on the work of *Colpier and Cornland (2002)*[53]. The time period chosen was 1980-1997 in order that the early use of the CCGT technology for power production as well as the important growth of installed capacity in the world was covered.

In scientific and engineering literature are not reliable sources for cost data, since such publications are often calculated theoretically or based on older references. It was not possible to construct an experience curve with the data found in the literature. Also manufacturers were no opportunity to get data, because companies are often unwilling to release information about their real costs.

Therefore, price was chosen as a proxy for cost. Since, power-generating plants, like the CCGT plant, are generally complex, that is, each plant is ordered more or less individually and no official price lists exist, for the CCGT technology the only real source of data was the published contract prices for projects which at that time were actual.

This study implies contracts from all major manufacturers of CCGT plants. Together with information given in articles in trade journals, it was possible to construct an experience curve for the specific investment price of natural-gas-fired CCGT technology. More than 200 data points describing combined cycle plants were collected. Specific-price data (USD/kW) were leveled to 1990 USD. As an experience index the cumulative installed capacity of natural gas-fired CCGT technology in the world was used.

Since differences in specific price between plants will always exist due siting and local requirements, a selection criteria on the data were applied. Fig. 59 shows the initial data set for CCGT plants. After selection criteria were applied the data points marked with circles indicate the CCGT plants remaining in the data set.

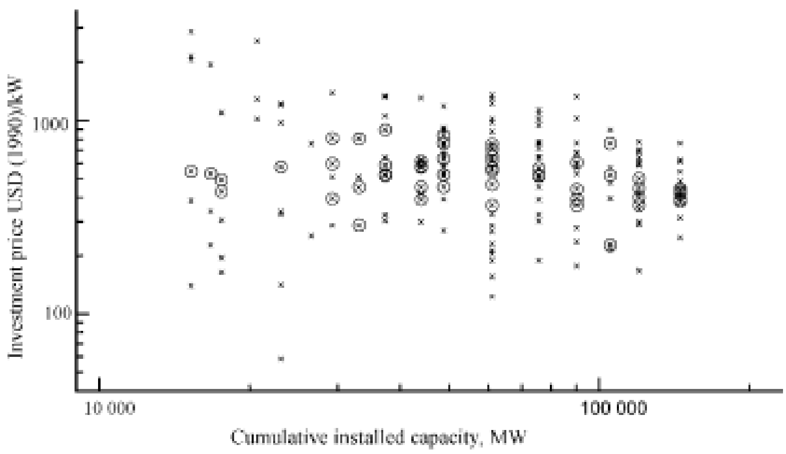


*Figure 59: The specific investment price for the cumulative installed capacity of CCGT plants 1981-1997. Inital data set is market with x's. Data remaining after applying the selection criteria are marked with circles. Source: Colpier and Cornland (2002)*

[53] (Colpier and Cornland 2002)

There were three criteria which were applied to provide a more homogenous data set.

First, mainly CCGT plants constructed to generate electricity were included. Contracts that included much more than power-producing plant and contracts that included only part of the equipment were excluded from the data set.

Second, the CCGT plants' capacity had to be more than 100 MW. A greater proportion of construction and manufacturing is shifted from the factory to the field. Production costs in the factory are often lower than corresponding costs in the field. To minimize price variation due to unit size, only plants larger than 100 MW were included in this study. Economies of scale referring to large-scale production were considered as a part of the experience effect.

Finally, the CCGT plant had to be situated in Europe or North America. CCGT plants in developing countries were not included because contracts for such plants do not always present the actual price. Due to financial support through the World Bank or aid agencies data in this region was not reliable. Also plants in Japan were not included due to their specific prices. Because of stricter environmental requirements plants installed in Japan were significantly more expensive and not comparable to other plants.

After applying these criteria, 55 plants were selected.

To achieve a significant experience curve several assumptions were made. A discount rate of 10 percent and a depreciation period of 30 years were used. This is a higher rate than the rates that are normally used in regulated electricity markets with one or a few large utilities. However, the real rate used is increased, since the electricity market was privatized and opened to independent power producers (J. Watson 1997)

Fig. 60 presents the experience curve for the specific investment price of the CCGT technology. One can see a PR > 100 percent, which indicates increasing prices. Around 1991, a bend in the experience curve can be observed. After 1991, indicating that prices declined by 25 percent for each doubling of installed capacity, the experience curve shows a decline with a PR of approximately 75 percent.

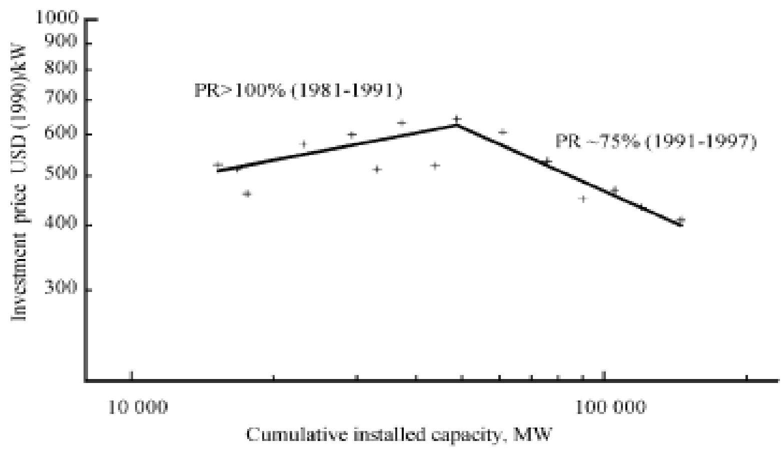


*Figure 60: The experience curve for the specific investment price of the CCGT technology (1981 - 1997). Source: Colpier and Cornland (2002).*

Fig. 60 also shows the market development of a technology. Until 1991, the curve describes the development phase and price-umbrella phase. Competition on the market was weak due to shortage of CCGT plants. Price also rose, since complexity and the use of new advanced materials increased and thermal efficiency improved.

The shakeout phase started in the beginning of the 1990s. This transition had several reasons (J. Watson 1997) among the turnkey equipment suppliers. Second, as private companies entered the electricity market in some countries structural market changed and the electricity market in some cases was deregulated. Third, the performance of the gas and steam technology improved. For the same or lower equipment cost, more kW output came from upgraded frames. Finally, CCGT modules became more standardized, pre-engineered and easily replicated.

*Future expectations*

Steep specific investment price decline was probably near its end (end of the shakeout phase) (Farmer, 1997). In this case, the experience curve for the investment price is likely to enter the stable phase, which means the progress ratio would be higher than the 75 percent of the shakeout phase.

As a mature, small-scale energy technology, the CCGT technology among other similar technologies shows a progress ratio in a range between 82 and 100 percent (Neij 1997). The gas turbine is a major component in the CCGT technology. It has a cost curve with a progress ratio of 90 percent (MacGregor et al. 1991). In the stable phase the price curve typically follows the cost curve. Therefore, it is reasonable to expect that the progress ratio for the CCGT technology will be around 90 percent in the stable phase. In Fig. 61 an extension of the experience curve for the specific investment price of the CCGT technology indicating a future progress ratio of 90 percent is included.

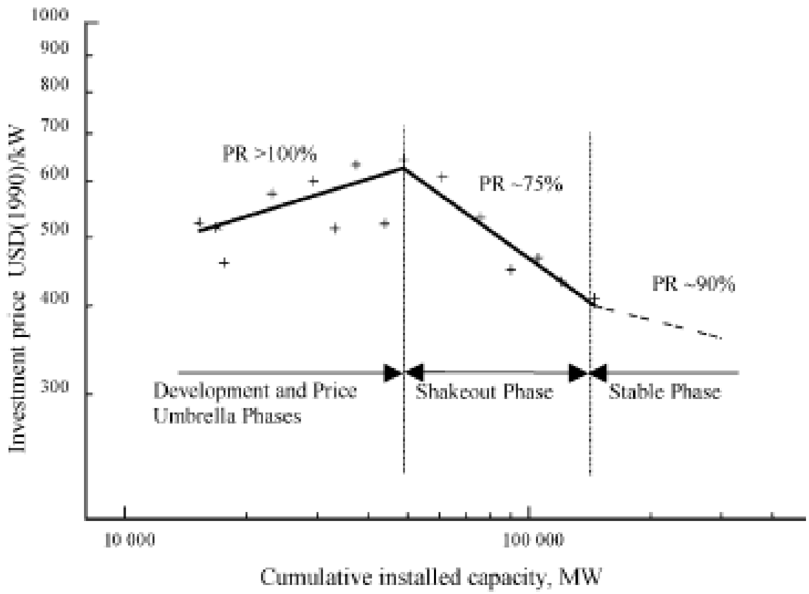


*Figure 61: The experience curve for the specific investment price of CCGT technology (1981 - 1997) extended with a progression ratio of 90%. Source: Colpier and Cornland (2002).*

The next doubling of installed capacity would occur around 2005 assuming a continuous expansion of CCGT capacity at the same rate as the years before (Hansen 1998, IEA 1998). In 1997, the average specific investment price for a plant was 410 USD (1990) per kW. The average specific investment price in 2005 would be 370 USD (1990) per kW, when a progress ratio of 90 percent is applied.

# 4 Data Series

## 4.1 PV Solar

### *4.1.1 California*

In 2006, the *California Solar Initiative* (CSI) was introduced. The CSI is a rebate program for California consumers that are customers of the investor-owned utilities. It is also a main part of the Go Solar California campaign for California.

The CSI has the following roles:

- The CSI program funds solar both solar PV, as well as other thermal generating technologies. It covers solar on existing homes, existing or new commercial, agricultural, government and non-profit buildings (CSI general market program).
- This program funds solar thermal systems on homes and business (CSI-Thermal program).
- A solar rebate program for low-income residents that own their own single-family home (Single-family Affordable Solar Homes).
- A solar rebate program for multifamily affordable housing (Multifamily Affordable Solar Housing).
- A solar grant Program to fund grants for research, development, demonstration and development (RD&D) of solar technology (CSI RD&D).[54]

According to the performance of their solar panels, including such factors as installation angle, tilt, and location rather than system capacity alone, the CSI offers solar customers different incentive levels.

Between 2007 and 2016, the CSI program has a total budget of USD 2167 billion and a goal to install approximately 1940 MW of new solar generation capacity. Fig. 62[55] shows the development of the cumulative installed solar PV capacity of California by residential and commercial sector. Since 2013, cumulative installed capacity in the residential sector grew significantly faster than the capacity of the commercial sector.

[54] (Anon. 2018a)
[55] (Anon. 2018b)

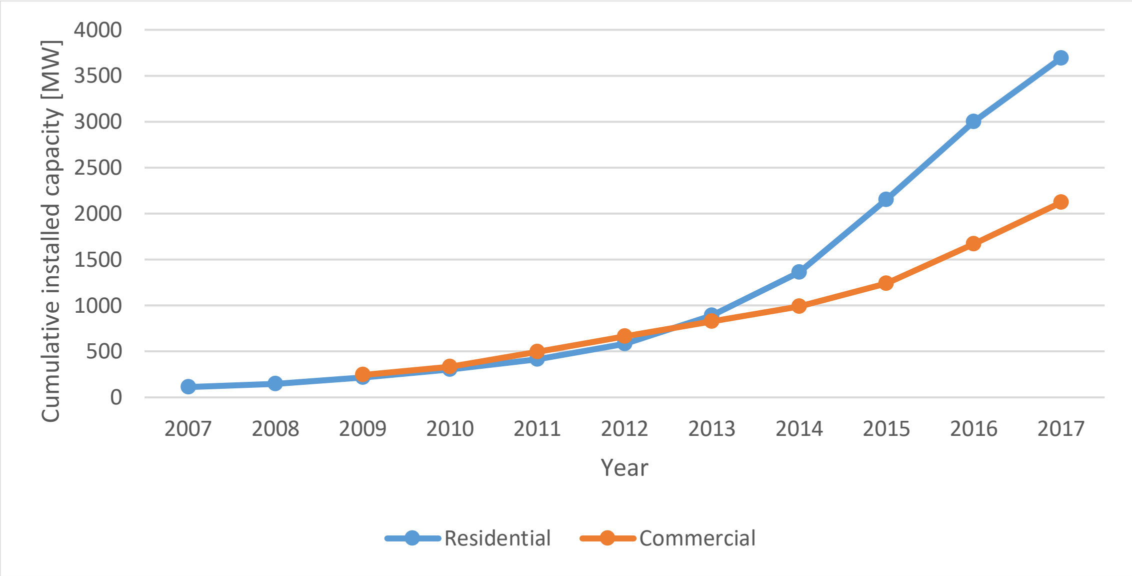


*Figure 62: Cumulative installed capacity by residential and commercial sector. Data: [www.californiadgstats.ca.gov](http://www.californiadgstats.ca.gov).*

Total cost of Solar PV in the commercial and residential sector decreased since 2009. Since 2014, price did not change significantly and gap between both curves is declining. Fig. 63 shows this fact.

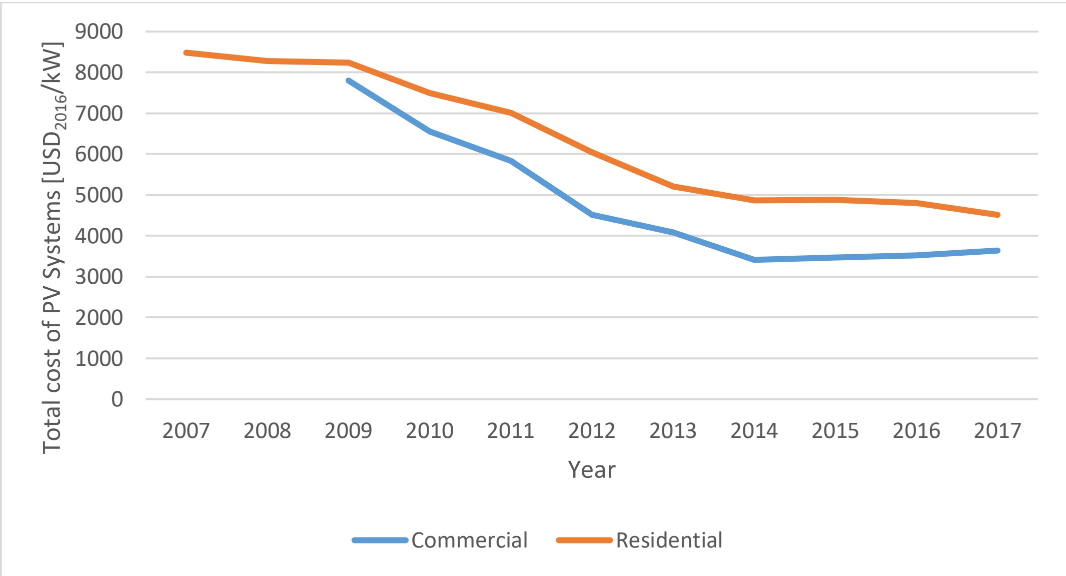


*Figure 63: Total Cost of solar PV systems in the residential and commercial sector in California. Data: IRENA*

This data series result in learning curves, which are shown in Fig. 64 and Fig. 65. The progress ratio PR for the residential sector accounts for 87%, whereas the commercial sector has a PR of 76%.

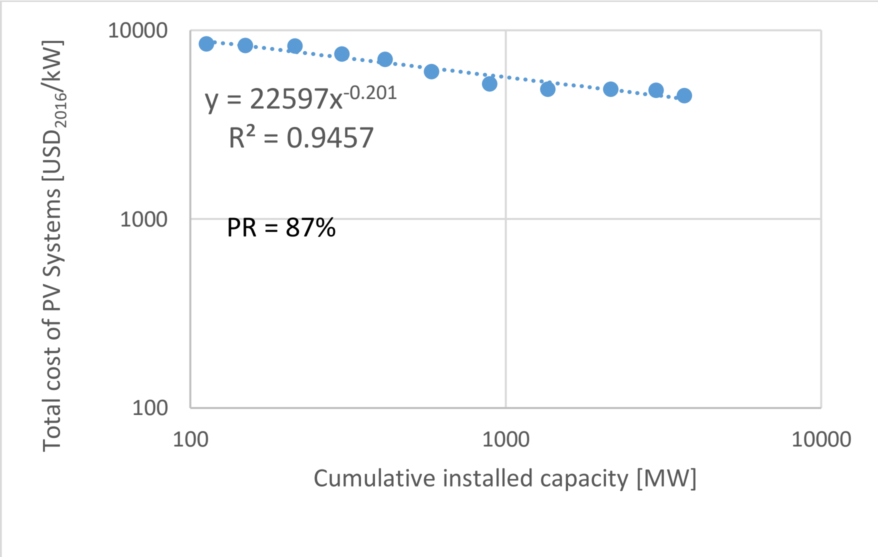


*Figure 64: Learning curve for residential solar PV in California 2007 – 2017. Data: IRENA*

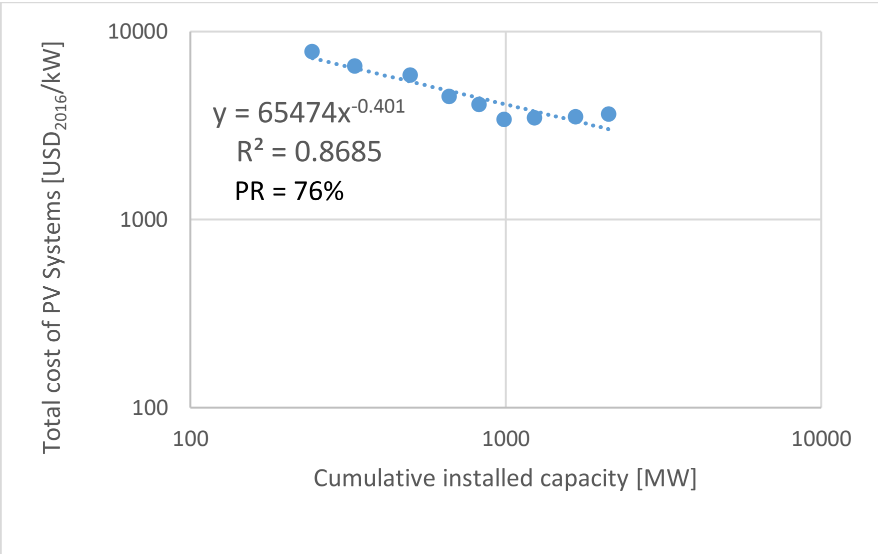


*Figure 65: Learning curve for commercial solar PV in California 2009 – 2017. Data: IRENA*

### 4.1.2 Germany

Germany's Solar PV market and its significant FIT System was mainly discussed before in section 3.1.2. The development of cumulative installed solar PV capacity is shown in Fig.16. Fig. 66 shows the cost development of PV systems in Germany. In 2008, total cost seems to have a little peak. However, cost was almost on a constant level at this period. Cost only decreased after 2008. (NREL)

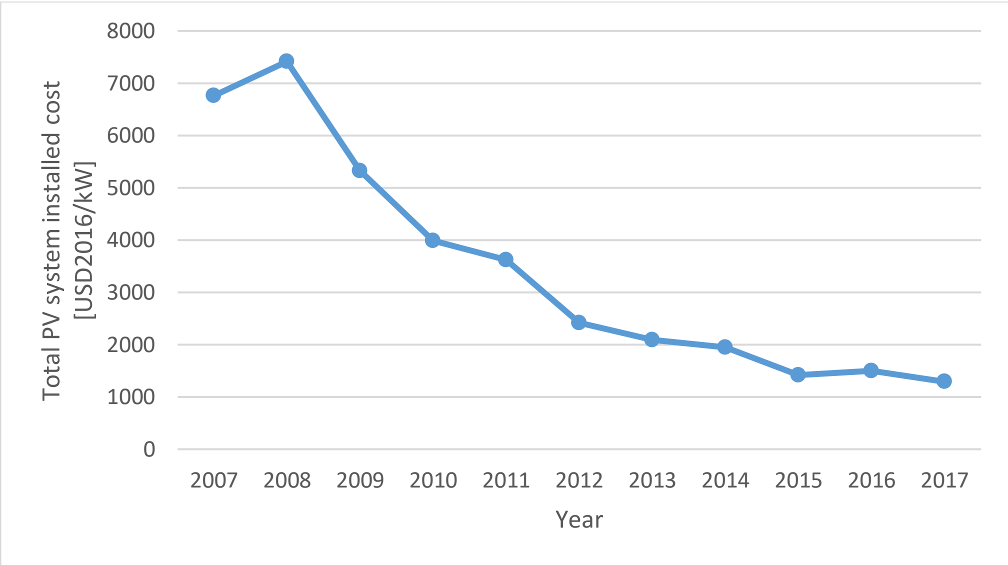


*Figure 66: Total cost of Solar PV in Germany 2007-2017. Data: IRENA*

Fig. 16 together with Fig. 66 result in learning curve shown in Fig.67. In this case PR accounts for 61%. This value is quite unusual. The historical average value is approximately 80%. The progress ratio has a reduction of 19%.

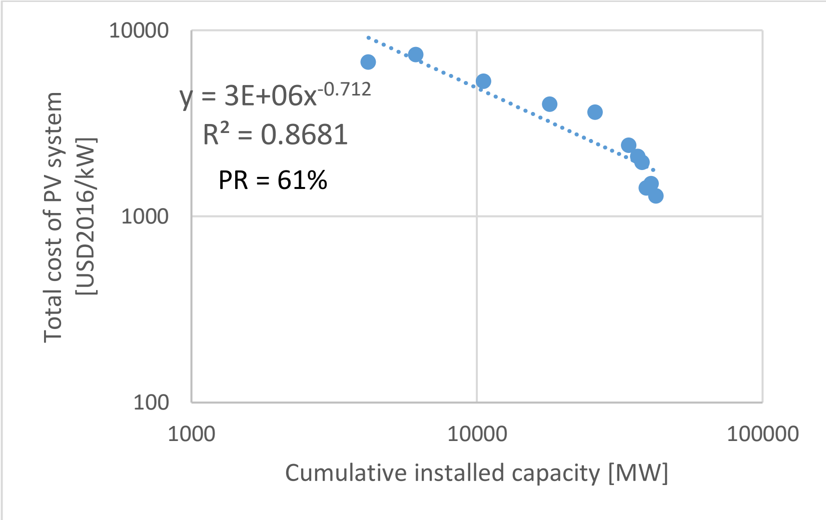


*Figure 67: Learning curve of solar PV in Germany 2007-2017. Data: IRENA*

### *4.1.3 Italy*

Conto Energia (FiT)

The first feed in tariffs specifically for photovoltaics connected to the grid were introduced in 2015. The payments for the Conto Energia schemes were designed to be made over a 20 year period. Due this scheme both smaller and larger producers should be encouraged to invest in the installation of photovoltaic plants and systems. Between 2005 and 2013, there have been five different versions of Conto Energia.

In 2005, the first Conto Energia brought a small amount of 163 MW of new PV installation. At this time solar power was not matured.

The second Conto Energia was applied in 2007. There was a massive increase of 6791 MW of new PV installations. With an annual cost of €3.27 billion it was the most costly scheme. Half of the cost was provided by Conto Energia 2.

Conto Energia 3 did not last long (August 2010 – May 2011), resulting in 1567 MW of installed power at an annual cost of €0.65 billion.

The largest increase in solar capacity so far was achieved by Conto Eergia 4, which resulted in a solar capacity at 7600 MW of installed power at an annual cost of €2.47 billion.

The final Conto Energia was introduced in 2012. They wanted to end the feed in tariff, when the total annual costs of the cumulative Conto Energia scheme reached €6.7 billion. This value was reached in 2013. On 6 July 2013, the final Conto Energia scheme was ended, resulting in 2095 MW of installed capacity at a cost of €0.22 billion.

Italy seriously began to apply Solar PV for electricity generation in 2007. In 2008, the share of total renewable generation was about 0.3%. In 2016, this share rose to more than 20%.

The cumulative installed Solar PV capacity strongly increased until 2012. From 2013, as Conto Energia was ended and there was no more significant installation of Solar PV. Fig. 68 shows this fact.

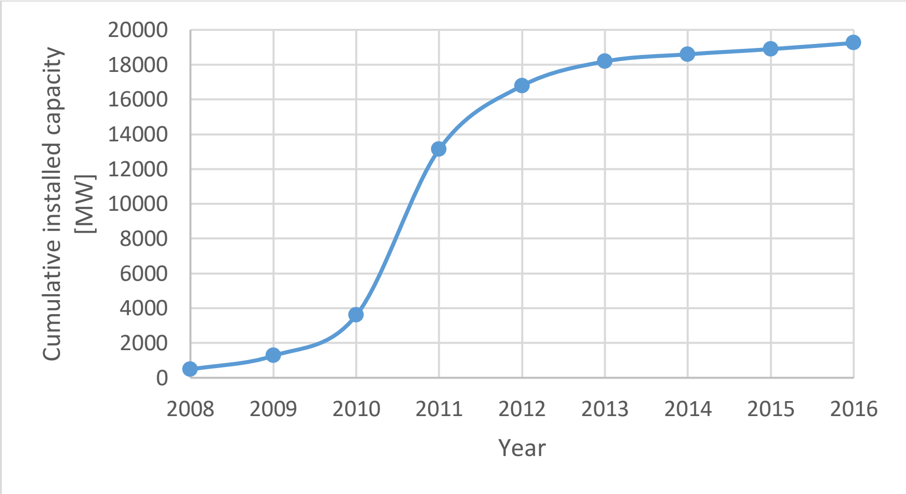


*Figure 68: Cumulative installed capacity of solar PV in Italy 2009-2016. Data: IRENA*

The annual cost of solar PV in Italy is shown in Fig 69. The costs constantly decreased since 2009. Compared to 2016 cost accounted for more than 5-fold in 2009.

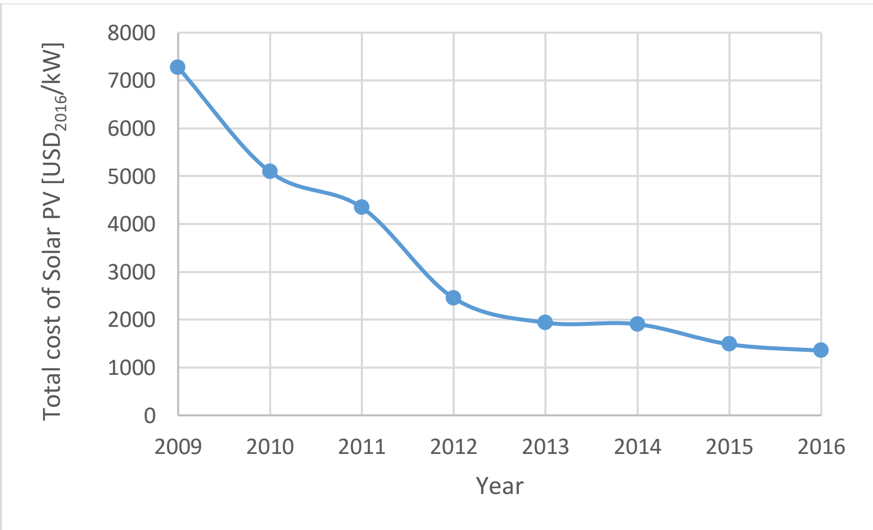


*Figure 69: Cost of Solar PV in Italy 2009-2016. Data: IRENA*

In Fig. 70 one can see the learning curve for solar PV in Italy. The Data was available from 2009 to 2016. For this time period the progress ratio is 69%. Compared to the progress ratio of previous experience curve analysis this means a reduction of about 10%.

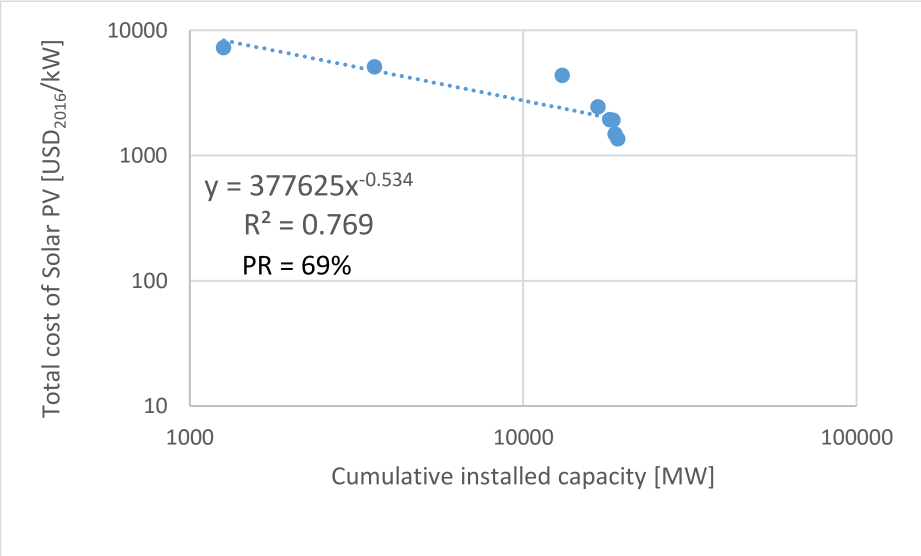


*Figure 70: Learning Curve of Solar PV in Italy 2009 - 2016. Data: IRENA*

### 4.1.4 Japan

The Solar PV market of Japan was discussed in section 3.1.3. The cumulative installed capacity is plotted in Fig. 22. Total average cost of PV systems in Japan is shown in Fig. 71. Cost stays almost constant until 2011 except 2008. From 2011 to 2017 cost decreased to 3-fold.

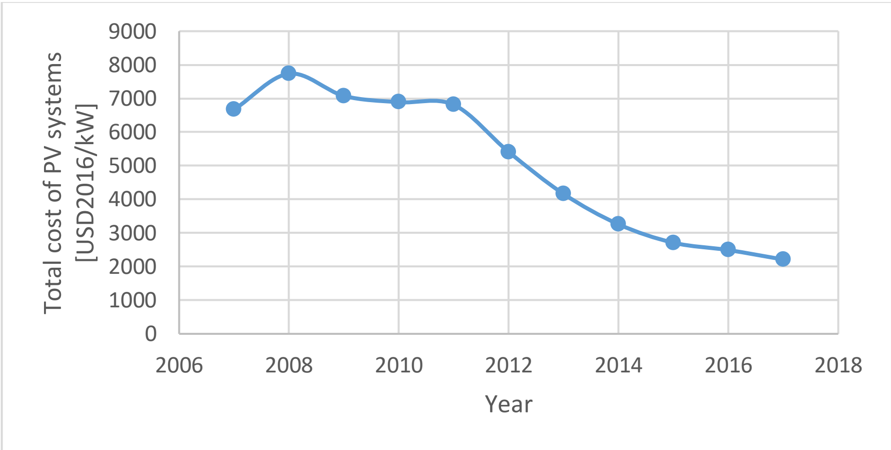


*Figure 71: Total cost of solar PV in Japan 2007-2017. Data: IRENA*

Learning curve for solar PV in Japan from 2007 to 2017 is illustrated in Fig. 72. Progress ratio in this case is 77%.

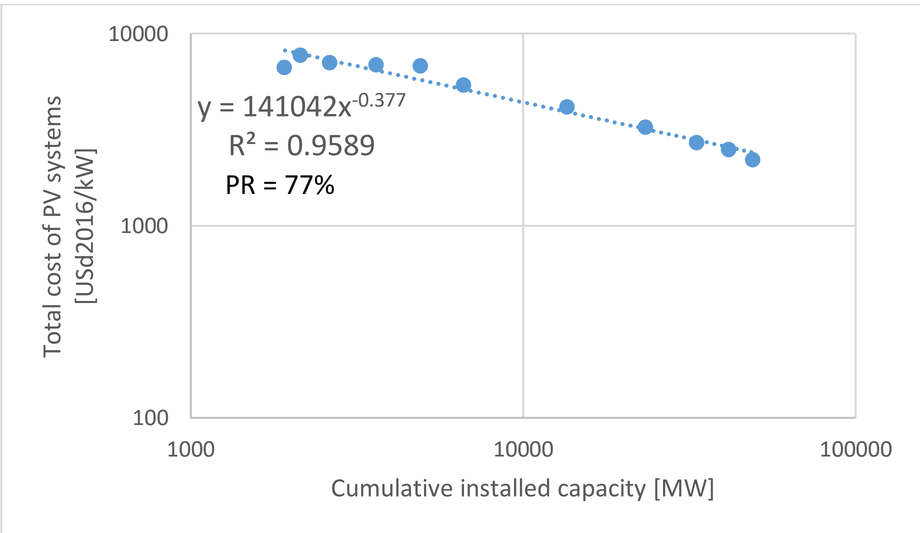


*Figure 72: Learning curve of solar PV in Japan 2007-2017. Data: IRENA*

## 4.2 Onshore Wind Power

### *4.2.1 Global*

Fig 73 shows the cumulative installed capacity global wind power from 1983 to 2017. Since the beginning of the 2000s installed raised enormously. From 1990 to 2000 installed capacity increased almost 10-fold, whereas the increase from 2000 to 2017 was almost 30-fold.

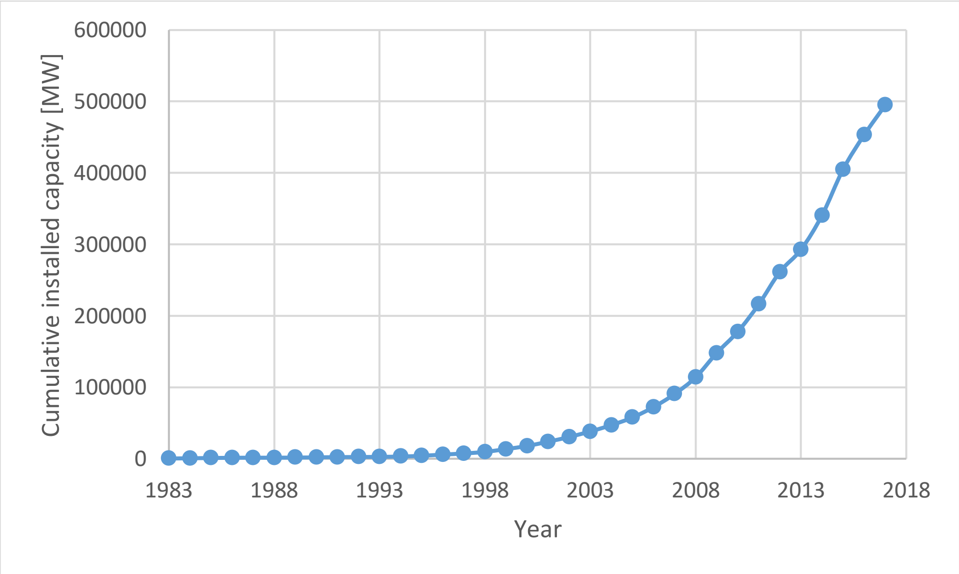


*Figure 73: Global cumulative installed capacity of wind power 1983 - 2017. Data: GWEC.*

Total average installed cost of wind projects worldwide is shown in Fig.74. In general cost of wind projects fell from about $USD_{2016}$ 4900 in 1983 to about $USD_{2016}$ 1400 in 2017. However, there is a little increase in 1990 and in 2008/2009. These increases will also be visible in cost curves of other countries. The reason for the increases is steel shortage, which lead to higher cost of raw material.

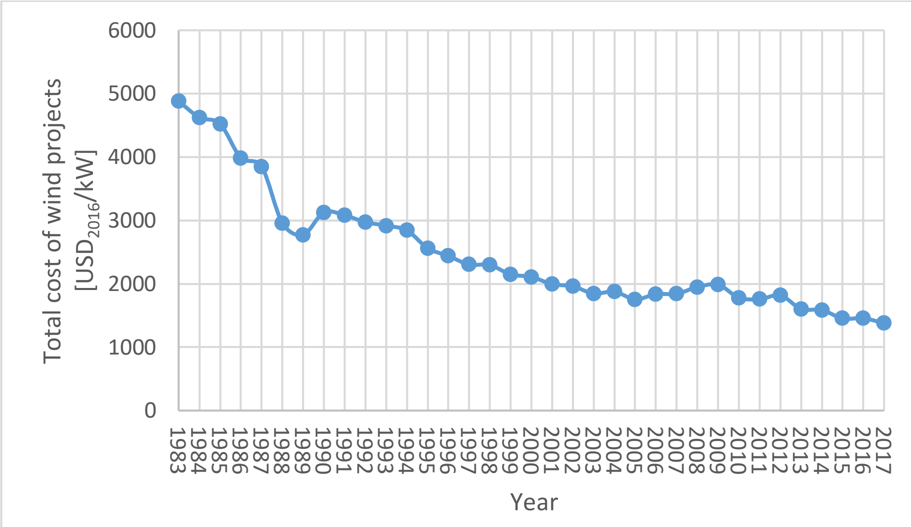


*Figure 74: Global total average cost of installed wind projects 1983 – 2017. Data: IRENA*

Learning curve of global wind power onshore is shown in Fig. 75. From 1983 to 1999 PR is 85%, whereas PR for the time period 2000 – 2017 accounts for 94%.

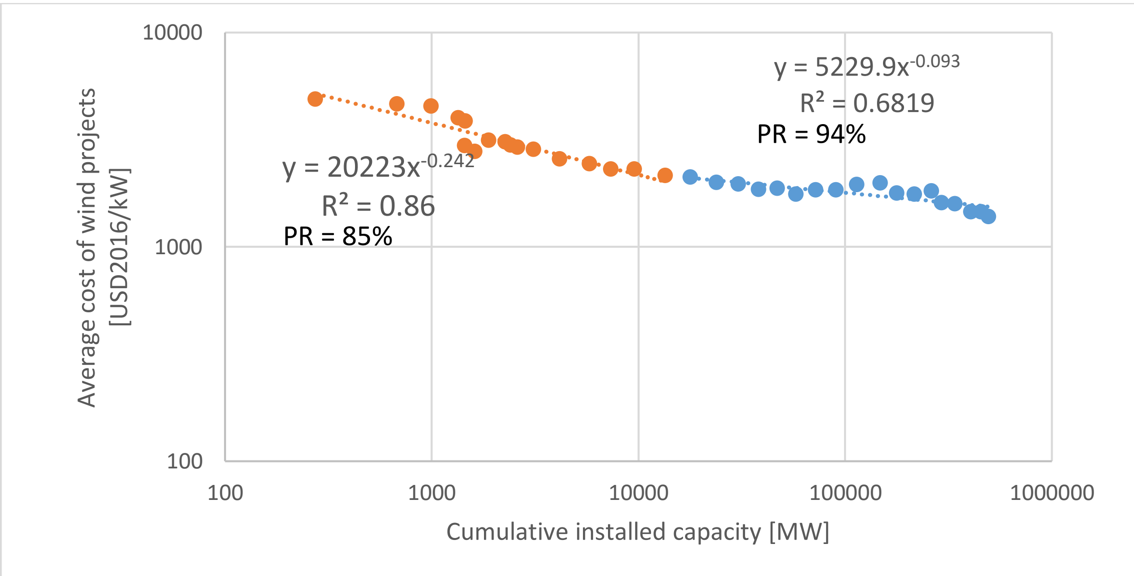


*Figure 75: Global learning curve of wind power. Split into time periods 1983 - 1999 and 2000 - 2017. Data: IRENA*

### *4.2.2 Denmark*

Wind energy market of Denmark is described in section 3.2.2. Fig. 76 shows the average cost development of Danish wind projects. Cost fell until 2009 except the 2 time periods in which raw material prices increased. However, since 2009 price did not change significantly.

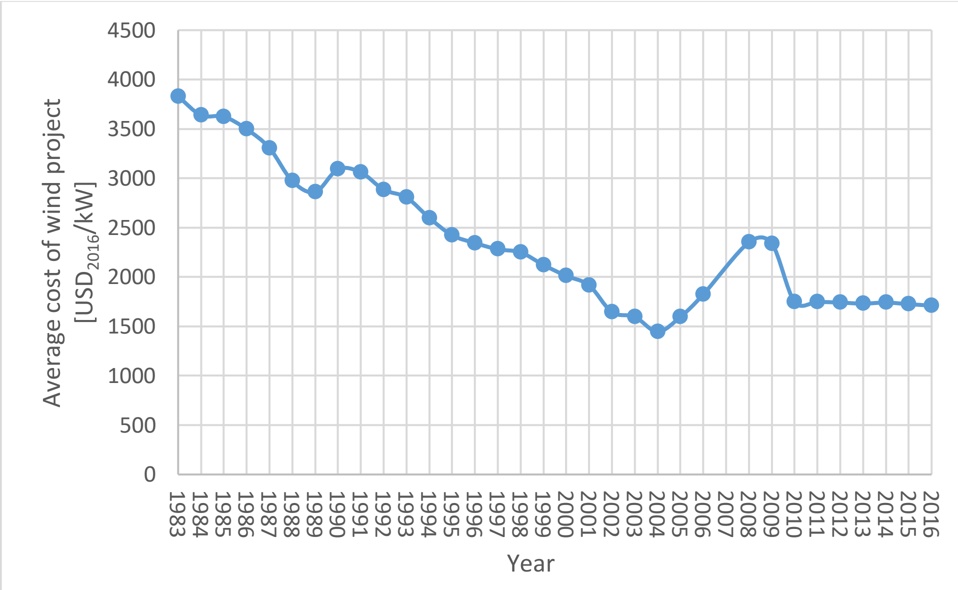


*Figure 76: Average cost of Danish wind projects 1983 - 2017. Data: IRENA*

Learning curve for Danish wind projects is shown in Fig. 77. To compare the time periods data series was split into two ranges – from 1983 to 1999 and from 2000 to 2017. From 1983 to 1999 PR is 91%. PR from 2000 to 2017 accounts for 89%.

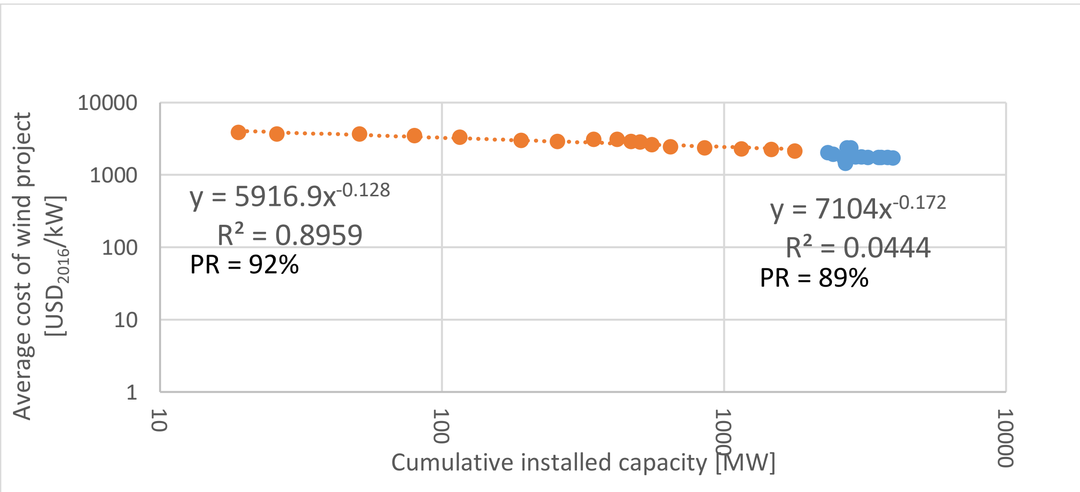


*Figure 77: Learning curve of Danish wind power. Split into time periods 1983 - 1999 and 2000 - 2017. Data: IRENA*

### 4.2.3 Germany

German wind power market was discussed in chapter 3.2.4. Fig 78. illustrates the cumulative installed capacity of wind power in Germany from 1990 to 2017. In 1994 Germany replaced Denmark as leading wind energy producer in Europe. At this time, German cumulative installed capacity accounted for 643 MW. Only the wind power market of US was greater. Cumulative installed capacity in the US accounted for 1663 MW in 1994. From 1997 to 2007 Germany was the global leader owning most installed capacity. In 2008, Germany lost first place to US. One year later one had to accept the third place due to China's immense expansion in wind power market.

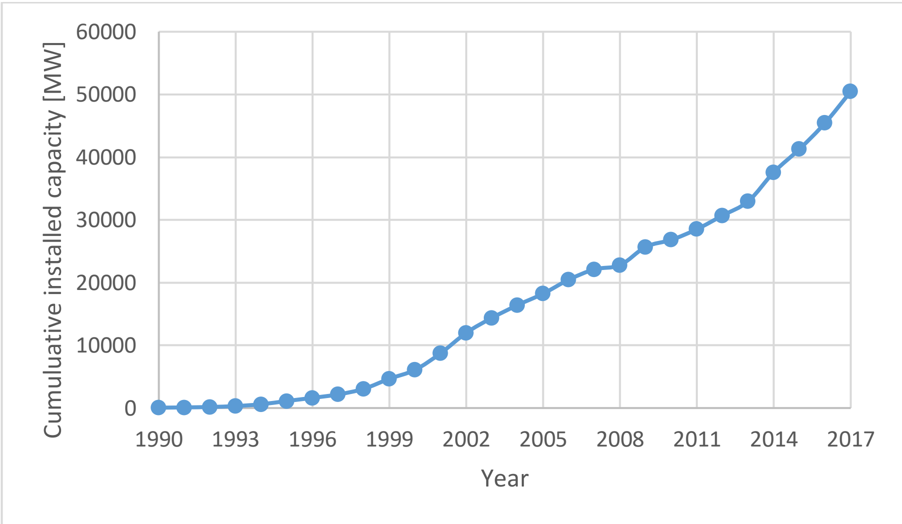


*Figure 78: Cumulative installed capacity of German wind power 1990-2017. Data: GWEC*

In Fig. 79 one can see the development of total average cost of wind projects in Germany. Compared to Denmark cost in Germany stabilized earlier. Since 1996 cost did not change significantly.

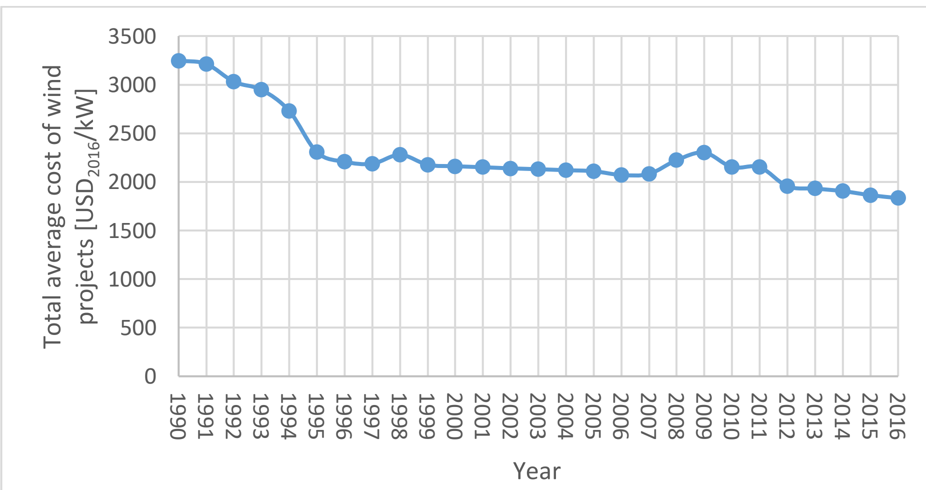


*Figure 79: Total average cost of wind power projects in Germany 1990 - 2016. Data: IRENA*

Learning curves of German wind power are shown in Fig. 80. The learning curve implements two parts. One part is constructed from the data from 1990 to 1999. Other part consists of the period 2000 – 2016. From 1990 to 1999 PR accounts for 93%, whereas PR for the period 2000 to 2016 accounts for 95%.

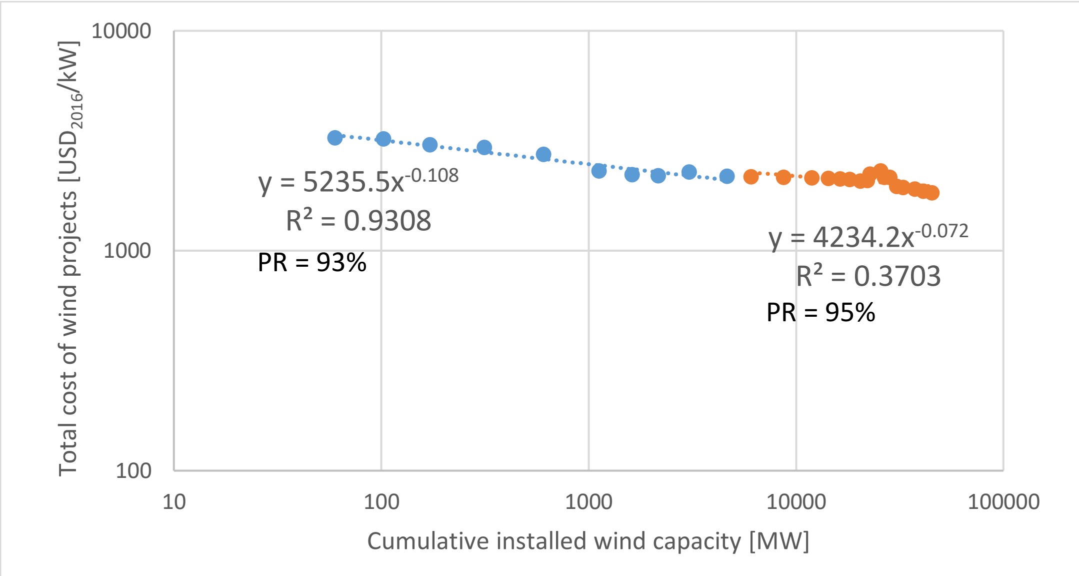


*Figure 80: Learning curve of German wind power. Split into time periods 1990 - 1999 and 2000 - 2016. Data: IRENA*

### *4.2.4 U.S.*

In 1978, the US congress passed the Public Utility Regulatory Policies Act of 1978. This act requires companies to buy certain amount of electricity from renewable energy sources, including wind. The first large (utility-scale) wind farms were installed in California in 1980. Many important lessons were learned, such as greater awareness of environmental affects and correct siting. So lower impact designs were developed. In 1981, NASA (National Aeronautics and Space Administration) scientists Larry Viterna and Bob Corrigan developed "The Viterna Method". This method became the most common method for predicting wind turbine performance resulting in increased efficiency of wind turbine output to this day. 1992 was the year the Energy Policy Act authorized a production tax credit of 1.5 cents per kilowatt hour of wind power generation. This act also re-established a focus on renewable energy use. In 1993, The National Wind Technology Center was built. The NWTC was the nation's premier wind energy technology research facility helping the industry reduce the cost of energy. In 2008, The U.S. Department of Energy published their 20% Wind Energy by 2030 report. U.S. installed capacity of wind power reached 60 GW in 2012. In 2015, showing that 35% wind energy is possible by 2050, the *Wind Vision Report was released.*

Fig 81 shows the cumulative installed capacity from 1983 to 2017. The period 1983 to 1999 is highlighted. In this period, cost even decreased slightly. Long-term PURPA (Public Utility Regulatory Policies Act) contracts began to expire and some wind projects ceased operating.[56]

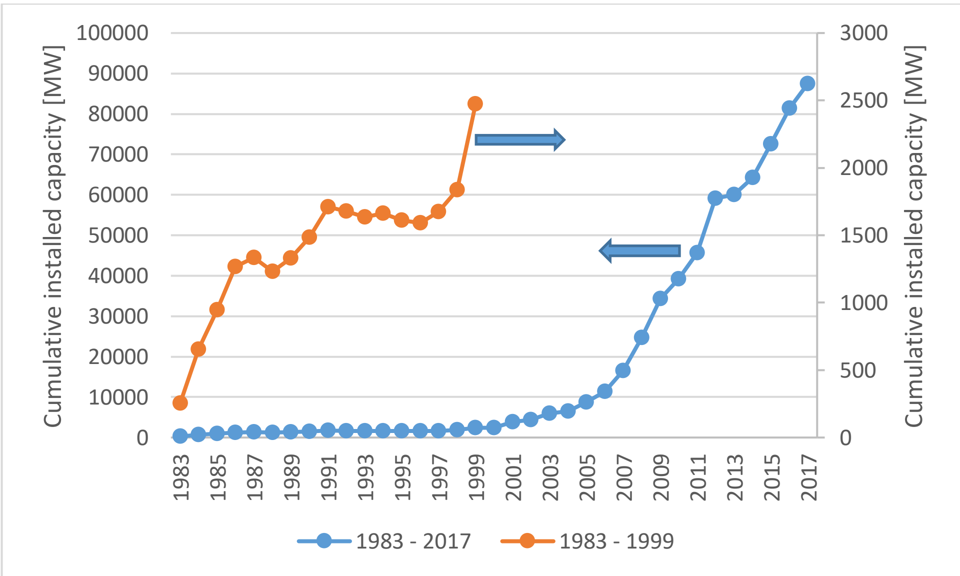


*Figure 81: Cumulative installed wind capacity of U.S. 1983 - 2017. Cost between 1983 and 1999 is highlighted. Data: IRENA*

[56] NREL, Technical Report 2013

Cost development of wind projects in the U.S. is illustrated in Fig 82. Unfortunately there is a data gap between 1991 and 1998. So learning curves were built for these two periods.

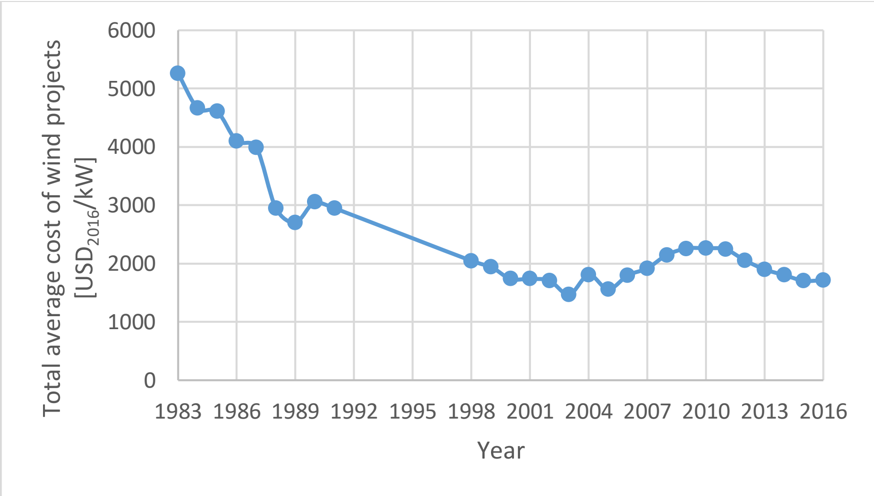


*Figure 82: Total average cost of wind power projects in the USA 1983 - 2016. Data: IRENA*

Fig. 81 and Fig. 82 result in learning curves shown in Fig 83. From 1983 to 1991 PR is 80%, whereas PR for the period 1998 to 2016 accounts for 102%. This means negative learning (LR = -2%). In this case it is remarkable that both coefficients of determination $R^2$ have low values. The $R^2$ calculated for the period 1998 to 2016 is even 9%. Usually, $R^2$ in learning curves accounts for about 80% and more.

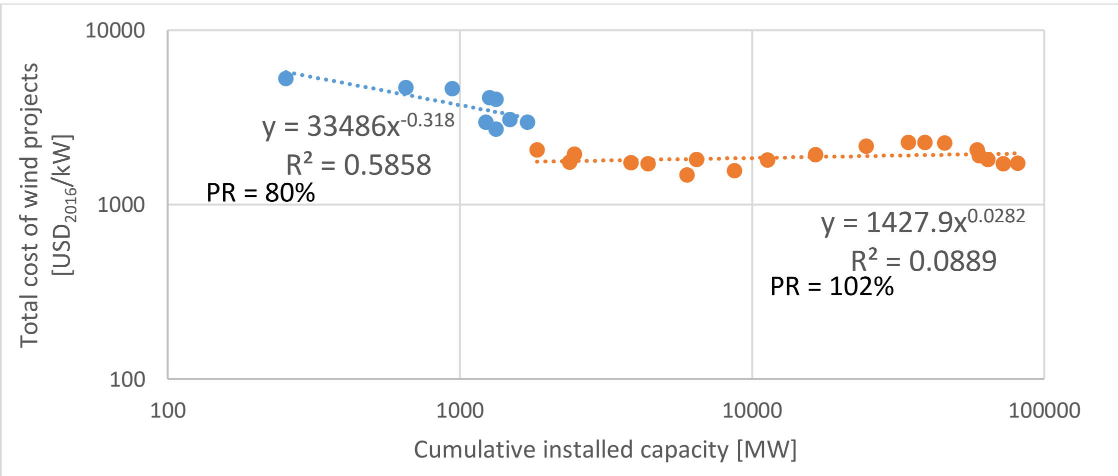


*Figure 83: Learning curve of wind power of U.S. One period implements data 1983-1991. Other period implements data 1998-2016. Data: IRENA*

### *4.2.5 Spain*

Spain began to operate in the wind energy market for the first time in 1991 by installing 5MW wind power. Generation of electricity first time took place on December 18, 1994. Between 2004 and 2011, about two-third of the current wind capacity was installed. Spain was one the strongest actors in the wind energy market thanks to public investment and premiums. Unfortunately a lot of the growth took place in a climate of speculation and arbitrary development. In 2011, Mariano Rajoy's *Popular Party* took power. Cost saving measures were introduced, thus there was a freeze on green energy. More than 40000 people were employed by the industry in 2008, whereas today industry employs half that. In 2015, Wind power in Spain was entering its darkest hour, while the most ambitious climate change agreement in history was being signed in Paris. There was no increase in capacity, thus India overtook and Spain was pushed into fifth place – after China, America and Germany. In 2013, wind energy was the top technology to generate electricity. Two years later, it got third place behind nuclear and coal. Thanks to new government auctions for renewable energy installation, the sector has on the move again in the recent years. Industry survived due to foreign demand. In 2015, Spanish companies exported all of their production. Spain was the third-biggest exporter of wind turbines in the world. Fig. 84 shows the development of the cumulative installed capacity of Spanish wind energy.

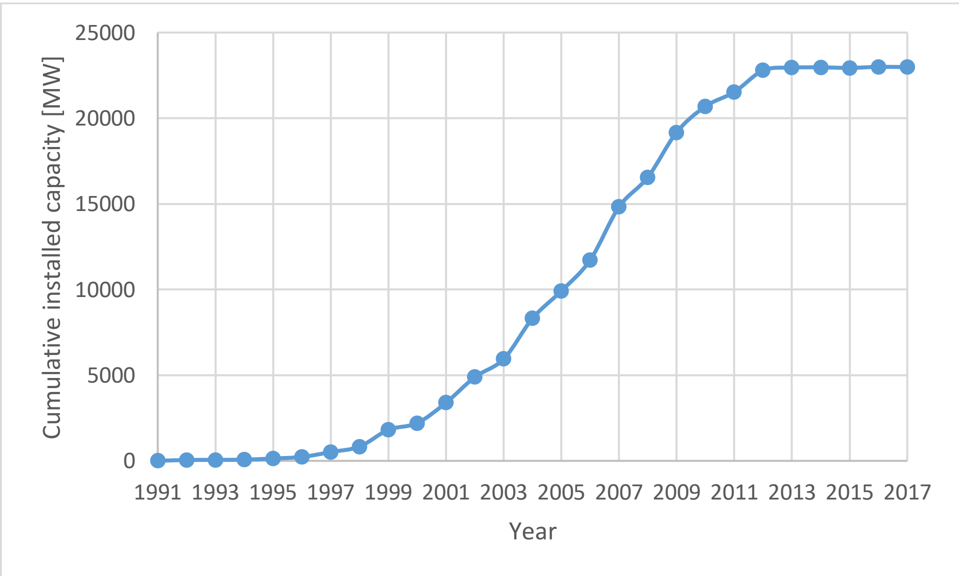


*Figure 84: Cumulative installed wind capacity in Spain 1991-2017. Data: GWEC*

In Fig. 85 total average cost of wind project is shown. The cost curve has almost the same shape like those of the other countries.

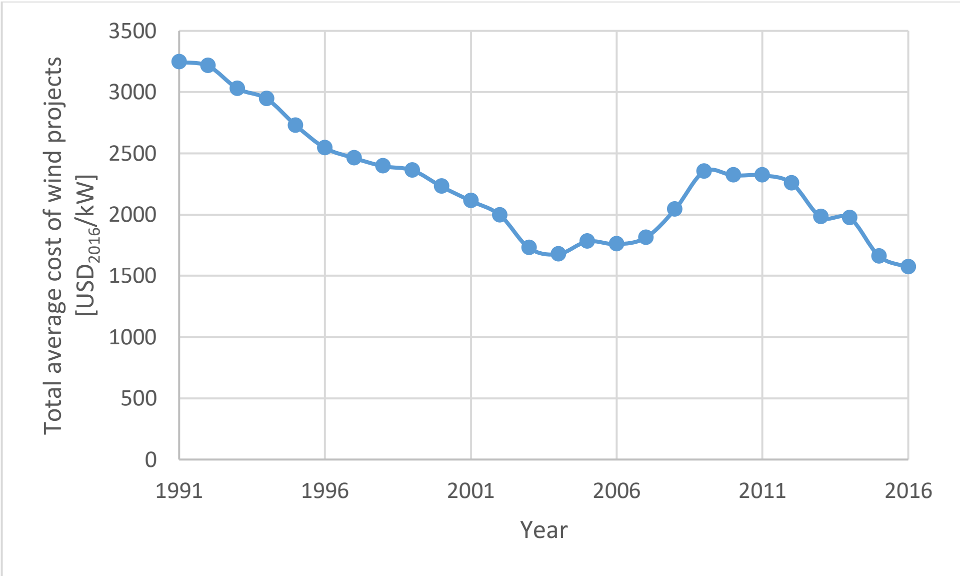


*Figure 85: Total average cost of wind projects 1991 - 2016. Data: IRENA*

For the learning curve, data was again split to two time periods. First one ranges from 1991 to 1999, the second one ranges from 2000 to 2016. PR from 1991 to 1999 accounts for 96%, that for the period 2000 to 2016 is 112%. Fig. 86 shows this fact.

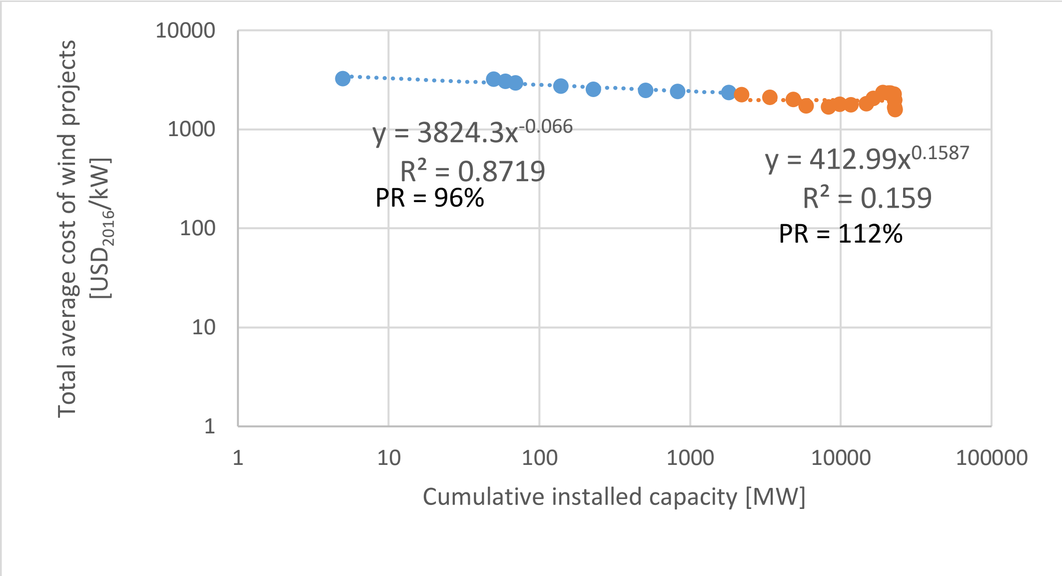


*Figure 86: Learning curve for Spanish wind power. Data split to 1991 - 1999, respectively 2000-2016. Data: IRENA.*

# 5 Conclusion

## 5.1 Historical comparison of learning curves of power production technologies

For the comparison investment costs of two renewable and two non-renewable power production technologies. Recent onshore wind power and solar PV learning curves are summarized in Fig. 87. For wind power Germany was chosen, and learning curve for solar PV in California serves as an example for solar PV power. California was chosen for PV example, because reliable data was available for both residential and commercial sector.

Nuclear power and CCGT are representatives for non-renewable power production technologies, whose learning curves are shown in Fig. 56 and Fig. 60. With a cumulative installed capacity of 30GW, Grübler observes in his work on French PWR program a trend break with escalating construction costs around 1983. Therefore, progress ratio for French PWRs is accounts for more than 100 per cent.

Most reduction is achieved by PV modules, which have a cost decline from several hundred euros/$W_p$ in the 1960s to the cost of around 30 cent/$W_p$ in 2017.[57] However, PV has the longest way to go before it reaches investment costs in similar range to those of fossil fuel technologies. Also onshore wind energy shows a clear reduction of investment costs until the beginning of the century. However, recent data shows a saturation. PR in this case approaches 100 per cent. CCGT display from 1981 to 1991 a PR of over 100 per cent which was due to increasing cost during early stages of development and weak competition. From 1991 to 1997, PR accounts for 75%. In this period a quick learning stage occurred, attributed to a shakeout phase.

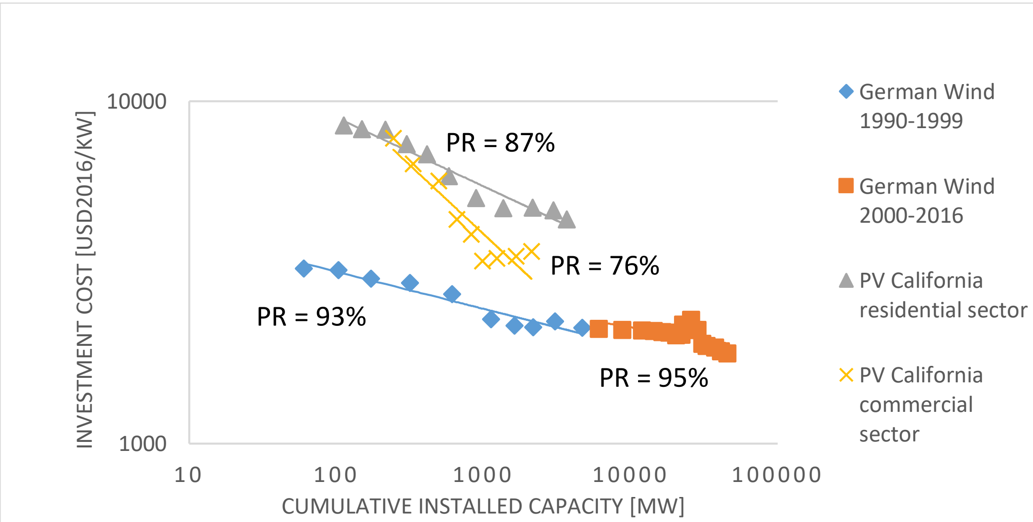


*Figure 87: Comparison of wind power and solar PV. German wind: 1990-1999,2000-2016; PV in California: resdential (2007-2017); commercial (2009-2017). Data: IRENA, www.californiadgstats.ca.gov, www.energy.ca.gov.*

[57] www.pv-magazine.de

## 5.2 Behavior of Learning Effects over Time

*Solar PV*

Depending on the data source and the time period considered, substantial differences were found in PR values. By comparing crystalline silicon PV module experience curves on the basis of two datasets, (Nemet 2006) found differing PV values – 74% and 83%. Datasets were provided by (Maycock 2002) and Strategies Unlimited (2003), respectively. In his work, Nemet does not mention the reason for PR differences from these two datasets. One possible reason may be the dataset the beginning of the experience curve, i.e. below 30 MW cumulative capacity. Including 2006 data, (Sark et al. 2008) has constructed an updated curve, which yields a PR of around 79%. Due to the silicon feedstock supply shortage, which occurred at the beginning of the 2000s, module price increased. This increase in price is expected to lead to an increase of the progress ratio compared to earlier determined PRs. At least, learning curve of residential solar PV in California (PR = 87%) in Fig. 62 would confirm this.

*Onshore wind energy*

In 2003, the most comprehensive overview and analysis of experience curves for onshore wind energy. In this survey wind energy developments in Denmark, Spain, Sweden and Germany were analyzed. Experience curves both for wind turbines produced and wind farms installed show a range of progress ratio of 91-94% for Germany, Denmark, and Spain. When global cumulative installed capacity is taken as measurement for experience, (Junginger et al. 2004) calculate progress ratios of wind farms of 81-85%, (Taylor M. et al. 2006) find 85%. Progress ratio for onshore wind projects calculated in this paper show a range of 85 (Global) – 95% (Spain) until 2000. Since 2000, the range is 89 (Denmark) – 112% (Spain).

*Combined Cycle Gas Turbine*

Claeson Colpier and Cornland (2002) make a distinction between three phases based on the market model of the Boston Consultancy Group (BCG, 1968). From 1981 to 1991, there is a negative experience curve with PR > 100 per cent. As mentioned in the previous section, this is attributed to the development stage. Shakeout phase occurred 1991-97. Unit costs decrease rapidly as a result of intense competition among producers. Also improvements were made in CCGT technology. A phase of maturity is assumed to start after 1997. In this phase progress ration is expected to reach approximately 90%. Learning in gas turbines was an indication.

*Nuclear power*

(Ostwald and Reisdorf 1979) analyzed 32 nuclear power plants in the USA in the period 1960-73. Cumulative capacity of this power plants was 20 GW. A progress ratio of 78-81% was calculated for the specific investment costs of these power plants. Probably due to the regulatory requirements associated the authors acknowledged that specific cost increased in the early 1970s. (Zimmerman 1982) analyzed learning effects for 41 nuclear power plants in the USA, which were completed between 1968 and 1980. In Zimmerman's opinion completion of the first plant reduces the cost of the next plant by 11.8% (PR = 88%), and that completing second plant reduces cost by 4% (PR = 96%).

The University of Chicago indicates, that the experience curve might be approximated by a constant average value of 95%.

## 5.3 National and international learning effects of Solar PV and Onshore Wind Energy

*Solar PV*

The market of PV modules is a global one. There are market players from all over the world. As reported by (Schaeffer G. and Hugo d. M. 2004) for the case of Germany, global progress ratio of 79.3% was found to be higher when considering national system boundaries. If favourable support scheme is in place, BOS learning can be fast on a national level. Thus, development in inverter manufacturing are increasingly on a global level. On the other hand, local learning will remain under influence of Support structures and installation labour (Shum K. L. and Watanabe C. 2008).

*Onshore wind*

Due to decline of production cost of wind turbines there was a drop of prices of more than 50% per installed capacity since the early 1980s. The upscaling of the capacity and size of wind turbines has been a key driver behind lower investment costs (Neij, 1999b). The gradual upscaling of wind turbines had the advantage that the setup of every new turbine class was based on past experience. It also allowed a slow introduction of new technological developments. Experience gained in the wind turbine manufacturing industry has continuously spilt over. Turbines produced by few manufacturers (mainly German and Danish) has been installed all over the world. This fact may be an explanation for the progress ratio of in the range of 81-85% for global installed cumulative wind capacity compared of that of 91-94% for national installed wind capacity.

> "*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*".(Junginger et al. 2005)[58]

[58] See page 147

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