Cost analysis of the electrical infrastructure that is required for offshore wind energy

An experience curve based survey

Final report

Ad Peeters
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The final report of a three-month project at the Department of Science, Technology and Society, Utrecht University

Utrecht
February 2003
Supervised by:
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and
Dr. André Faaij
Preface

This report was written as part of a three-month research project at the Department of Science, Technology and Society. The three-month project is embedded in the research of Martin Junginger, who investigates the possible cost reductions of offshore wind energy. The research is based on the theory of experience curves and is carried out with a bottom-up approach. This means that the costs of offshore wind energy will be split up in several components. The experience curves of the different components can then be finally combined to an experience curve for the technology as a total. This report focuses in this context on the electrical infrastructure for offshore wind parks that is responsible for a large portion of the costs, as will be shown in this report. During the research, the largest obstacle turned out to be the struggle to get enough data. The results after three months include two experience curves based on very scarce information, covering only a part of the electrical equipment. However, an overview of the market is sketched and some cost trends that can be very helpful to construct experience curves. This result could never have been reached without the help of some people that kindly supplied me information, whom I want to thank here:

- Mr. Jan van Eerde of Pirelli Cables & Systems, who helped with the theory on (submarine) cables
- Dr. Ir. Pavel Bauer of the Department of Power Electronics and Electrical Machines of the Delft University of Technology, who provided information on the HVDC technology
- Mr. Anne Zander of ABB, who kindly provided reference lists on (submarine) cables

The project was done under supervision of Martin Junginger and André Faaij. I want to thank them for their support and their advise in the sharpening of this document.

Ad Peeters,
January 2003
Executive summary

The objective of this study is to survey the possible cost reductions in the future for the electrical infrastructure of offshore wind energy as described in more detail in paragraph 1.2. In the introduction the actual status is sketched of wind energy world wide. The technology is a very fast growing player in the energy market. At the moment however, the technology only accounts for several tenths of percents of the world energy production. Leading countries like Denmark and Germany show that wind energy could potentially cover a much larger part of the energy production. A large potential for wind energy can be found offshore. Wind energy in general however is relatively expensive compared to conventional energy generating technologies. Offshore wind energy is even more expensive. Studies like done for example by Neij have shown the possible drop in costs for wind energy. To get an idea of the investment that should be done before the technology of offshore wind energy will be competitive with conventional technologies it is very interesting to research the possible decline in costs for offshore wind energy as well. In this research the electrical infrastructure that is required will be studied in a bottom-up approach using experience curves.

The theory of experience curves is based on the drop of costs per doubling of cumulative production / installation. The concept of experience curves cannot be considered an established theory or method, but rather a correlation phenomenon, which has been observed in several kinds of technology. Experience curves can be described by the following equations:\(^1\):

\[
C_{\text{CUM}} = C_1 \times \text{CUM}^b
\]

(1)

\[
PR = \frac{C_1 \times (2 \text{CUM})^b}{C_1 \times \text{CUM}^b} = 2^b
\]

(2)

Where \(C_{\text{CUM}}\) is the cost per unit as a function of output, \(C_1\) is the cost of the first unit, \(\text{CUM}\) is the cumulative production over time, \(b\) is the experience index and \(PR\) the progress ratio. The progress ratio indicates the cost reduction with every doubling of cumulative production. For example a progress ratio of 0.8 (80%) indicates a cost reduction of 20% with every doubling. Several uncertainties that can occur in experience curves are described in this chapter as well.

The contribution of the power collection and grid connection (indicated as electrical infrastructure) to the costs of offshore wind energy as reported in literature, roughly ranges from 17 to 36%. This indicates the importance of investigating the possible cost reductions of this component, as will be done in this research.

The choice between AC (Alternating Current) and DC (Direct Current) is very important for the costs of the electrical infrastructure. The choice between these transmission techniques is generally based on economical considerations that can be split up in two components: the differences in investment costs and the differences in electrical losses. Moreover environmental considerations could be part of the choice as well. The costs of the submarine cables are lower for HVDC as well as the losses; the terminals however are more expensive. Therefore an economic break-even distance exists. The break-even distance for submarine transmission is estimated at 25 km\(^2\). Chapter 3 describes the HVDC technology and the consequences for the choice between AC and DC on the design and cost of the electrical infrastructure for offshore wind parks.

In chapter 4, the submarine power cable market is described. In general it can be said that the market is dominated by a few players. Both the differences in design and the world-wide production statistics for AC cables and DC cables are described in this chapter. One remarkable point that can be made up from the production figures of several components is a strongly increased production after 1983. This ‘kink of 1983’ will be further discussed in chapter 7. Finally, an experience curve is constructed from a few cost data on HVDC cables. The experience curve shows a PR of 69.7% and was constructed from 9 data points from the period 1988-2000.
Chapter 5 discusses the power electronics that are required for power transmission from an offshore wind park to shore. The production figures of converter stations that are needed at each terminal of an HVDC transmission line show the same kink as reported for cables in chapter 4. A part of the data concern Back to Back (B-B) converter stations that are used to connect two asynchronous AC-systems to each other. It is clear that these stations are not used for transmission applications. The fact that the production of B-B stations strongly increased after 1983 as well, adds an interesting point to the discussion in paragraph 7.3. Because of the large variability in AC power electronics, no production figures for AC power electronics were found. In chapter 5 furthermore, an estimated cost distribution over converter station components is shown, as well as the typical variability of HVDC converter costs. An experience curve could be constructed from the converter capital cost data that were found. The PR of this curve is 59.4%.

In chapter 6 the experience curves resulting from this research are integrated. The integration gives an idea of both the applicability of the bottom-up approach and the possible cost reduction. To provide an production axis, the HVDC production of the period 1995-2000 was extrapolated to 2015. In combination with the experience curves generated in this research this scenario resulted in a proposed reduction of the cost of power transmission of 25% for a 1000 MW park at 50 km from shore. A second production scenario was generated by adding an assumed production of HVDC connections for offshore wind energy. For the period 2006-2010 the assumption was made for an addition of 4 GW of HVDC-connected wind energy at an average distance of 40 km to shore, and for 2011-2015 10 GW at an average distance of 50 km. The results of this scenario can be found in table 1.

<table>
<thead>
<tr>
<th>year</th>
<th>costs of converter stations (MEuro)</th>
<th>costs of cables incl. laying (MEuro)</th>
<th>Total transmission costs (MEuro)</th>
<th>Cost reduction of transmission</th>
<th>Total cost reduction due to transmission</th>
</tr>
</thead>
<tbody>
<tr>
<td>2000</td>
<td>211.55</td>
<td>83.06</td>
<td>294.61</td>
<td>0%</td>
<td>0.0%</td>
</tr>
<tr>
<td>2005</td>
<td>192.10</td>
<td>70.69</td>
<td>262.79</td>
<td>11%</td>
<td>1.9%</td>
</tr>
<tr>
<td>2010</td>
<td>168.86</td>
<td>60.72</td>
<td>229.58</td>
<td>22%</td>
<td>4.0%</td>
</tr>
<tr>
<td>2015</td>
<td>143.48</td>
<td>50.92</td>
<td>194.40</td>
<td>34%</td>
<td>6.1%</td>
</tr>
</tbody>
</table>

In chapter 6 furthermore, the possibilities for cost reductions specified for each component of the electrical infrastructure are summarized, as shown in table 2. The more detailed information is one of the advantages of the bottom-up approach that was chosen for this research. The chapter summarizes the advantages and disadvantages of this approach into more detail. The uncertainties that occur in this study are discussed related to the results of the integration of the HVDC experience curves. In general, the largest part of the uncertainty can be addressed to the large variability that is present in the data of all components. As a rule of thumb it can be said that the difficulty in constructing an experience curve increases with the complexity and/or variability of the component. A very rough estimation of the variability in the different components gives the following order: Cable laying > AC power electronics > AC cables > Converter stations > HVDC cables.

<table>
<thead>
<tr>
<th>component</th>
<th>possible improvement</th>
</tr>
</thead>
<tbody>
<tr>
<td>Cables</td>
<td>Applicability of XLPE insulation to higher voltage DC</td>
</tr>
<tr>
<td></td>
<td>Standardizing the design of HVDC cables</td>
</tr>
<tr>
<td></td>
<td>Improving the techniques for surveying the route and cable laying</td>
</tr>
<tr>
<td></td>
<td>HVDC-light / HVDC-plus</td>
</tr>
<tr>
<td></td>
<td>Improving control, protection and communications technology</td>
</tr>
<tr>
<td></td>
<td>Standardization of the design</td>
</tr>
<tr>
<td>Power electronics</td>
<td></td>
</tr>
<tr>
<td>General</td>
<td>Standardization of park-layout</td>
</tr>
</tbody>
</table>
In chapter 7 the results from the preceding chapters are discussed in more detail. First of all the uncertainties in the HVDC experience curves are discussed. The experience curve of the cables (PR = 69.7%, $R^2 = 0.9315$) is thought to be more realistic than the experience curve for converter stations (PR = 59.4%, $R^2 = 0.7469$). The possible cost reduction that was calculated based on the latter experience curve for 1995-2000 (18.7%) however, is comparable to the estimations of two vendors for the same period (6.9%-17.7% and 30%). Furthermore, this chapter indicates some possible origins for cost reductions.

For AC transmission the variability of the components is indicated as reason for the difficulty of the construction of an experience curve. Furthermore, some points are made that can explain ‘the kink of 1983’. Chapter 7 ends with the conclusions and recommendations for further research.

Besides the quantitative results of this research, the bottom-up approach implicated new possibilities for the use of experience curves. The advantages of this approach can be summarized by the following points:

- A higher level of detail is achieved, which creates the possibility to indicate the possible cost reductions in the future for each of the components of the studied technology.
- Different scenarios can be studied by the changing of a few variables.
- Changes in the market of one of the technology’s components can be introduced in the combined experience curve with relative ease.

Furthermore some methodical lessons can be learned from this research, which can be summarized by the following points:

- It is important to be aware of the differences in assumptions that are made for the construction of the experience curves for the different components when combining the experience curves.
- The variability of the data, which is mentioned above as advantage of this approach, will be maintained if the experience curves of each component is handled as a separate variable until the last step of cost analysis.
- When combining the experience curves to one general curve, the variables in each curve should be compatible.
- When using a bottom-up approach the optimal level of detail should be found.
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Chapter 1: Introduction

The demand for renewable energy is growing. One of the promising players in this market is wind energy. In this chapter the situation of wind energy at this moment will be sketched. Furthermore the principles of the experience curve will be presented as a method to estimate economical developments of wind energy in the future.

1.1 Wind energy

Wind energy is a fast growing player in the market of electricity production. The first wind turbine producing electric energy was built in 1891 by the Dane Paul LaCour. The energy shortages in the First and Second World War thrived Danish researchers to develop more wind power. In the Second World War the 53 m tall construction of Smith can be seen as a forerunner of the modern wind turbine generators. In the 1950’s two major projects were performed in Denmark and Germany, but it lasted until the energy crises in 1974 that wind energy expanded. In the late 1970’s and the early 1980’s the first large scale projects (1-4 MW) were installed in Denmark, Sweden, the United States and Great Britain. In the last decade the global wind energy has grown dramatically as can be seen in figure 1.1 and the forecasts for the coming years show the same trend. In 2001 all annual records were broken by the addition of 6770 MW capacity world-wide.

Despite the fast growth of wind energy, the total share of wind energy in the total electricity consumption is still marginal. According to IEA, the global electricity generation amounted to 14,764 TWh in 1999. Assuming a capacity factor of 23% for wind energy, the estimated amount of energy produced by wind energy in that year was only 27.2 TWh. This is 1.8‰ of the global electricity generation. World leader countries on the wind energy market like Denmark, Germany and Spain show however that wind energy may potentially cover a much larger part of the world energy demand for its. In Denmark for example 2340 MW of wind power capacity was installed at the end of 2000 and a wind energy production covering 12% of the national energy consumption. The targets for installed wind energy in Denmark published in ‘Energy 21’ in 1996 were 1,500 MW of wind power by 2005 (12% of electricity consumption) and 5,500 MW of wind power by 2030 (40% to 50% of electricity consumption), out of which 4,000 MW will be offshore. As shown later, the targets for onshore wind power have already been surpassed, while the offshore development is just beginning. Like in other countries, a problem for the Danish market is that the number of feasible sites for onshore wind energy become scarcer. The tendency to develop offshore wind energy is driven by this fact. But there are more reasons to go offshore. Due to the fact that windless periods at sea are very rare, the capacity factor of offshore wind farms will be much higher. In literature, the capacity factors for offshore wind energy range from 30% to even 50% Which is also due to the fact...
that the mean wind speed offshore lies in the range of 10-13 ms\(^{-1}\), while this is 6-9 ms\(^{-1}\) onshore. This results in the possibility to develop much larger turbines offshore, with hypothetical capacities of several MW, up to 6 MW. Currently, prototypes of 3.6 and 4.5 MW are in operation. The trend of increasing turbine sizes, which was already visible onshore as can be seen in table 1.2, could be continued offshore. When the new source of offshore wind energy can be tapped, the potential of wind energy will grow to more than the world electricity consumption. This implicates that there is at least enough room for offshore wind energy.

<table>
<thead>
<tr>
<th></th>
<th></th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>Germany</td>
<td>10,000</td>
<td>2,659</td>
<td></td>
</tr>
<tr>
<td>USA</td>
<td>4,251</td>
<td>1,695</td>
<td></td>
</tr>
<tr>
<td>Spain</td>
<td>3,712</td>
<td>933</td>
<td></td>
</tr>
<tr>
<td>Denmark</td>
<td>2,458</td>
<td>120</td>
<td></td>
</tr>
<tr>
<td>India</td>
<td>1,627</td>
<td>287</td>
<td></td>
</tr>
<tr>
<td>Italy</td>
<td>700</td>
<td>245</td>
<td></td>
</tr>
<tr>
<td>Netherlands</td>
<td>569</td>
<td>42</td>
<td></td>
</tr>
<tr>
<td>U.K.</td>
<td>499</td>
<td>66</td>
<td></td>
</tr>
<tr>
<td>China</td>
<td>399</td>
<td>59</td>
<td></td>
</tr>
<tr>
<td>Japan</td>
<td>310</td>
<td>150</td>
<td></td>
</tr>
</tbody>
</table>

Table 1.2: Average wind turbine capacities in Denmark

<table>
<thead>
<tr>
<th>Year</th>
<th>Average power (kW)</th>
</tr>
</thead>
<tbody>
<tr>
<td>&gt;1990</td>
<td>99</td>
</tr>
<tr>
<td>1990</td>
<td>213</td>
</tr>
<tr>
<td>1991</td>
<td>199</td>
</tr>
<tr>
<td>1992</td>
<td>208</td>
</tr>
<tr>
<td>1993</td>
<td>256</td>
</tr>
<tr>
<td>1994</td>
<td>360</td>
</tr>
<tr>
<td>1995</td>
<td>482</td>
</tr>
<tr>
<td>1996</td>
<td>515</td>
</tr>
<tr>
<td>1997</td>
<td>561</td>
</tr>
<tr>
<td>1998</td>
<td>677</td>
</tr>
<tr>
<td>1999</td>
<td>760</td>
</tr>
<tr>
<td>2000</td>
<td>825</td>
</tr>
</tbody>
</table>

At the moment the experience with offshore wind energy is very small. As can be seen in table 1.3 the first experimental offshore wind turbine was installed in 1990 in Nogersund. This experimental project is followed in 1991 by the first experimental wind park. 11 Bonus 450 kW were installed in the Vindeby project in 1991. Between 1991 and 2000 several medium size wind parks have been built like the one near Dronten in the Netherlands, which consists of 19 Nortank 600 MW turbines. In 2000 the first large-scale projects were commissioned with modern state-of-the-art turbines with capacities over 1 MW. In Utgrunden 7 Enron 1.425 MW turbines form a wind park of 10 MW capacity and in Middelgrunden 20 Bonus WTG 2 MW turbines were installed to form a 40 MW wind park. At the moment of writing the installation of a large wind park near the coast of Denmark is just finished.

Figure 1.2: Cumulative installed offshore wind energy and planned wind energy after 2002
Table 1.3: existing and planned wind energy projects. This list is not assumed to be complete. Moreover the status of part of the planned projects is rather unsure.

<table>
<thead>
<tr>
<th>Location</th>
<th>Capacity (MW)</th>
<th>Turbines</th>
<th>Date installed/planned</th>
</tr>
</thead>
<tbody>
<tr>
<td>Nogersund (SE)</td>
<td>0.22</td>
<td>Wind World 220 kW</td>
<td>1990</td>
</tr>
<tr>
<td>Vindeby (DK)</td>
<td>5</td>
<td>11 Bonus 450 kW</td>
<td>1991</td>
</tr>
<tr>
<td>Lely, IJsselmeer (NL)</td>
<td>2</td>
<td>4 NedWind 500 kW</td>
<td>1994</td>
</tr>
<tr>
<td>Tune Knob, Jutland (DK)</td>
<td>5</td>
<td>10 Vestas V39 500 kW</td>
<td>1995</td>
</tr>
<tr>
<td>Dronten, IJsselmeer (NL)</td>
<td>16.8</td>
<td>28 Nordtank 600 kW</td>
<td>1996</td>
</tr>
<tr>
<td>Bockstigen (SE)</td>
<td>2.75</td>
<td>5 Wind World 550 kW</td>
<td>1997</td>
</tr>
<tr>
<td>Middelgrunden (DK)</td>
<td>40</td>
<td>20 Bonus WTG 2 MW</td>
<td>2000</td>
</tr>
<tr>
<td>Ulgrunden, (SE)</td>
<td>10</td>
<td>7 Enron 1.425 MW</td>
<td>2000</td>
</tr>
<tr>
<td>Blyth, (UK)</td>
<td>4</td>
<td>2 Vestas 2 MW</td>
<td>2000</td>
</tr>
<tr>
<td>Yltre, Stengrunden (SE)</td>
<td>10</td>
<td>5 NEG Micon 2 MW</td>
<td>2001</td>
</tr>
<tr>
<td>Horns Rev (DK)</td>
<td>160</td>
<td>80 Vestas 2 MW</td>
<td>2002</td>
</tr>
<tr>
<td>Hakefjorden (SE)</td>
<td>44</td>
<td></td>
<td>2002</td>
</tr>
<tr>
<td>Klasfjorden (SE)</td>
<td>42</td>
<td></td>
<td>2002</td>
</tr>
<tr>
<td>Rostock (GE)</td>
<td>60</td>
<td></td>
<td>2002</td>
</tr>
<tr>
<td>Scroby Sands (UK)</td>
<td>76</td>
<td></td>
<td>2002-3</td>
</tr>
<tr>
<td>NOVEM N. Shore Q7 (NL)</td>
<td>100</td>
<td></td>
<td>2003</td>
</tr>
<tr>
<td>Rødsand (DK)</td>
<td>150</td>
<td></td>
<td>2003</td>
</tr>
<tr>
<td>Læsø (DK)</td>
<td>150</td>
<td></td>
<td>2003</td>
</tr>
<tr>
<td>Lillgrund (SE)</td>
<td>72</td>
<td></td>
<td>2003</td>
</tr>
<tr>
<td>Gros Vogels GEO (GE)</td>
<td>80</td>
<td></td>
<td>2003</td>
</tr>
<tr>
<td>E-Connection (NL)</td>
<td>120</td>
<td></td>
<td>2003</td>
</tr>
<tr>
<td>Dublin Bay (IR)</td>
<td>240</td>
<td></td>
<td>2003-4</td>
</tr>
<tr>
<td>Låbeck (SKY) (GE)</td>
<td>100</td>
<td></td>
<td>2004</td>
</tr>
<tr>
<td>Electrabel (BE)</td>
<td>100</td>
<td></td>
<td>2004</td>
</tr>
<tr>
<td>PNE, Borkum (GE)</td>
<td>60</td>
<td></td>
<td>2004</td>
</tr>
<tr>
<td>Two projects (UK)</td>
<td>260</td>
<td></td>
<td>2004-5</td>
</tr>
<tr>
<td>Eirtricity (Arklow) (IR)</td>
<td>500</td>
<td></td>
<td>2005</td>
</tr>
<tr>
<td>Omø Stålgrunde (DK)</td>
<td>150</td>
<td></td>
<td>2005</td>
</tr>
<tr>
<td>Helgoland (GE)</td>
<td>500</td>
<td></td>
<td>2005</td>
</tr>
</tbody>
</table>

The Horns Rev project contains 80 Vestas 2 MW turbines that account for a total capacity of 160 MW, making Horns Rev unique in its size. In Table 1.3 installed and planned projects are shown. As can be seen in Figure 1.2 the actual installed capacity, when Horns Rev is included amounts to 260 MW. This means that only one percent of the actual wind energy capacity is offshore. Because offshore wind energy is such a new technique the costs are still relative high. Of course some of the parts of onshore windmills can be used offshore as well. The turbines for example can have the same design as onshore, although as discussed above, the turbines can be developed to larger ones. The more severe conditions offshore than onshore has its consequences however on the design of the most parts of offshore windmills. The apertures have to be protected against the offshore conditions. The fact that the offshore parks are difficult to reach makes maintenance of offshore wind parks more expensive and the connection to the grid will be more costly as well. Due to the large horizontal forces that are exerted on the windmills, the design of foundations will be different to existing offshore foundations. All these facts together, combined with the fact that the offshore experience is still very small give rise to higher costs of offshore wind energy compared to its onshore variant. The costs of onshore wind energy at a windy site is estimated Euroct 4.0-4.5 whereas the energy costs of existing offshore wind farms range from 4.9 Eurocents (Horns Rev) to 6.4 Eurocents (IJmuiden). (Compare to energy costs of conventional techniques that range 2.5-3.5 Eurocents) Because these high costs form a barrier for the development of offshore wind power at the moment it is very interesting to dedicate this survey to the possible decrease in costs of offshore wind energy in the future.
1.2 **Objectives of this study**

As described in the previous chapter the offshore wind energy could potentially take a substantial part of the world's energy consumption for its account. Although this wind energy, and more specifically offshore wind energy, is in general believed to be an environmentally friendly source of energy, the economical feasibility of this type of energy will be most determining for a possible breakthrough of wind energy. Therefore, it is interesting to study how much should be invested in this relatively new technology to make it economically competitive with conventional energy sources. In order to get an answer to this question the use of experience curves can provide a good basis, as will be described in the next chapter. To come to a more detailed answer, a bottom-up approach is chosen for this research. In this report the economical features of one large component of offshore wind energy will be surveyed: the required electrical infrastructure. The objectives for this study can be further split up in the following parts:

1. The survey of cost reductions of the electrical infrastructure of existing offshore wind parks and/or substitutes.
2. The construction of one or more experience curves of (components of) the electrical infrastructure for offshore wind energy.
3. Analysis of the origin of the achieved cost reductions.
4. Identification of possible cost reductions in the future.

Because the use of experience curves in a bottom-up approach is relatively new, the objectives of this study furthermore are to study the methodological possibilities of this new variant on experience-curve based studies. From this methodological question, some more objectives for this study can be formulated:

5. Identification of the problems that arise upon combining different experience curves, and solutions to these problems.
6. Recommendations for the use of experience curves in a bottom-up approach.

As is clear from the formulated objectives, ‘experience curves’ will be used to study the possible cost reductions. In chapter 2 the principles of experience curves will be described. The experience curves will be used in a bottom-up approach, the experience curves of the different components of offshore wind energy will be used to construct an experience curve for the entire technology. Because in this research the electrical infrastructure will be studied, chapter 2 furthermore describes how large the contribution of the infrastructure to the cost of an offshore wind park. The theory on the different options for transmission (Alternating Current, AC or Direct Current, DC) is described in chapter 3.

The research will be spliced out in two parts: the submarine cables and the power electronics, which will be described in respectively chapters 4 and 5. In both chapters, first some theory is given to be able to understand the data, followed by a survey of the production figures. Finally, experience curves are shown for the HVDC options. In chapter 6 the data are integrated. This integration gives an estimation of possible cost reductions in the future for the electrical infrastructure that is required for offshore wind energy. The origin of the achieved, as well as the possible cost reductions is shortly depicted in chapter 7, which also includes the conclusions of this research.
Chapter 2: The bottom-up approach

2.1 The experience curve concept

A clear example of experience curves is the following text from Ackermann: ‘In the 90s, the cost for manufacturing wind turbines declined by about 20% every time the number of manufactured wind turbines doubled. Currently, the production of large-scale, grid-connected wind turbines doubles almost every three years. Similar cost reductions have been reported for PV solar and biomass, however, these technologies have slightly different doubling cycles.’ The experience curve is based on the cost reduction of a product plotted against its cumulative production. In many cases it expressed as a fixed cost reduction of the product with every doubling of its production. In long-range terms, it is a powerful instrument for predicting cost developments for varied products. An experience curve can be described by the following function:

\[ C_{\text{CUM}} = C_1 \times \text{CUM}^b \]  

(2.1)

where \( C_{\text{CUM}} \) is the cost per unit as a function of output, \( C_1 \) is the cost of the first unit, \( \text{CUM} \) is the cumulative production over time, and \( b \) is the experience index. The experience index is in this formula in principle a negative number. In other texts the experience parameter is used as a positive number, hence a minus sign is applied in the formula. The more negative the experience index, the steeper the curve will be, indicating a high learning rate. The progress ratio (PR) can be calculated from \( b \):

\[ \text{PR} = \frac{C_1 \times (2\text{CUM})^b}{C_1 \times \text{CUM}^b} = 2^b \]  

(2.2)

The learning rate can be calculated from \( b \) as well \((1-2^b)\). The concept of experience curves cannot be considered an established theory or method, but rather a correlation phenomenon, which has been observed in several kinds of technology.

Figure 2.1: Progress ratios for 108 cases observed in 22 field studies. The studies estimated the behavior of cost with cumulative volume in firms and include manufacturing processes in industries such as electronics, machine tools and system components for electronic data processing, papermaking, aircraft, steel, apparel, and automobiles. Industry-level progress ratios are excluded. The outliers at 55-56% and 107-108% indicate cases where cost decreased by 44-45% and increased by 7-8%, respectively, for each doubling of cumulative volume. Adopted from Dutton and Thomas.
The observed values of PR for different technologies cover a range from approximately 70\% (e.g. oil products and electronics) to more than 100\% (e.g. coal-burning and nuclear power plants). In the case of a negative learning rate or ‘organizational forgetting’ the costs increase instead of decrease. Figure 2.1 shows the distribution of progress ratios from 108 observed cases in manufacturing firms. The average value and the most probable value for the distribution are both 82\%. Industry-level progress ratios have a similar distribution\(^1\). The reasons for the decrease of costs can be addressed to varying subjects. Arnulf Grübler\(^1\) mentions that besides learning via R&D and actual experience significant learning takes place through large-scale production. Large-scale production can be subdivided in three classes:

- Learning by upscaling production units
- Learning through consecutive production or mass production (e.g., the Model T Ford)
- Learning through continuous operation: both increasing scale and consecutive repetition. The best examples are base chemicals such as ethylene or PVC where cost reductions have been spectacular.

A statistical analysis of learning rates across many techniques by Christiansson\(^1\) has shown that these three forms of large-scale learning show different learning rates. The learning rate in this survey for upscaling was found to be 13\%, for mass production 17\% and for consecutive production 22\%. An example of an experience curve is shown in figure 2.2. In the research of Neij, the Progress Ratio of Danish produced wind turbines turned out to be 96\%. The slope of this experience curve is modest, which is not the same for the wind energy market as a total. The Progress Ratio from wind energy as a total is about 20\%\(^1\). The PR for energy costs can be different than the PR for installed capacity\(^1\), but the large difference indicates that the slope of the experience curve can be addressed to different factors, like the learning in choosing sites for wind power, the installation of the turbines, maintenance, power management etc. Considering this fact, a remarkable point can be made. The turbine production is based on old techniques (although they had to be adapted) in contrast with the other activities that are all new and specific for wind energy development. Moreover, this older part of the technique adopts a lower learning rate than the entire technique.

![Figure 2.2: Experience curve for Danish-produced wind turbines produced by Bonus, Micon, Nordtank, and Vestas 1982, 1986–1997 (based on data from the Danish Institute of Technology). The PR of the curve, using average list prices, is 96\%. The same PR is found when using list prices weighted by sales. Adopted from Neij\(^9\).](image-url)
Experience curves are often used as tools to set targets to make new energy generating technologies commercial. New technologies in general will be more expensive than old technologies. The new technologies will become cheaper because of learning effects. According to the experience curve theory the costs of the new technology will drop faster then the costs of the old one, even when the progress ratios of both techniques are the same. When from a new technology only 100 MW capacity is installed, the next doubling will be achieved with the installation of another 100 MW. With older techniques like coal power plants, where about 1000 GW of capacity exists already, the addition of 100 MW of capacity will have a negligible effect on the drop of costs. With the use of experience curves, estimations could be made how much investment should be made before the new technique would be competitive with the older technique\(^{11}\).

Plotted in a double logarithmic diagram, the experience curve is expected to follow a straight line. A number of factors however can disturb this straight line. An example of this is an R&D breakthrough. The breakthrough can introduce a whole new technology variant, but a breakthrough may be as well a complete new insight in the production of the technology. In both cases the experience curve will show a discontinuity. When the technology structural change is limited to the production, the learning rate will most probable remain the same after the transition period as shown in figure 2.3. In the case of a shift to a complete new variant of the technology this may not be the case.

![Figure 2.3: Expected behavior of the experience curve during a shift of technology from variant A to variant B. When variants A & B are very different the slope of the line before transition can differ from the slope of the experience curve before transition. Adopted from IEA\(^{11}\)](image)

In many cases it is difficult to get cost data for the construction of the experience curve. When this is the case, it is possible to use price data instead. The use of price data however, brings an uncertainty with it. The prices of products are market driven. Typical price-cost relations for new products are shown in figure 2.4. From this figure it is clear that the use of price data in this case would be problematic. In the phase of stability however it is a good alternative. In the case of a market with a few large players the price cost relations will be even more unpredictable and even cannot be predicted anymore to by the cost-price relationship that is indicated in figure 2.4.

The experience curve is a measure of the efficiency of the feedback, or learning loop within the learning system, as described by the IEA\(^{11}\) (Figure 2.5). The learning system could be considered as a black box, where the learning rate is expressed by the experience curve in costs per unit. When the learning curve of the complete technology is spliced up in experience curves of the different components of the technique, it will give more insight in the cause of the cost development. It can be shown where investment should be made to make the technique competitive and eventual discontinuities or kinks in the line could possibly be addressed to one of the technique’s components.
This research is meant to give insight in the cost development in the past and the future of offshore wind energy. As mentioned above offshore wind energy is a relatively expensive and new technology. Because it is a new technique, learning effects could account for a significant drop of the costs of this technology. Although offshore wind energy is a new technique, parts of the technology are older. Combined with the fact that the history of offshore wind energy is too short to construct serious experience curves, this makes it interesting to choose for the above-mentioned bottom-up approach of the problem. The different aspects of the offshore wind projects will show different learning rates as was already observed for onshore wind energy by Neij. For the wind energy sector in general, numerous experience curve studies have been done. But the idea of constructing an experience curve from experience curves from parts of the technology is a rather new approach. This approach makes it possible to get an idea of where cost reductions can be achieved and which costs can be assumed to have a constant value. For this new technology the construction of the experience curve from the experience curves of the different components is the only possibility to get a reliable experience curve. In addition the fact that the layout of an offshore wind park is fairly dependent from its location, could create problems with the construction of an experience curve. Variables like the distance to shore, the choice of turbines, the sea bottom conditions and mean wind speed, could effect for example the choice for AC or DC, the expense of the foundations and O&M and the costs for the submarine cable laying. With the bottom-up approach, experience curves for different park layouts could be constructed. A lot of information could be abstracted from this kind of experience curves.
2.2 The cost distribution over the components of offshore wind energy

The cost distribution over the various components of an offshore wind park is of course different than for an onshore wind park. The distribution of the farm will vary with the design of the wind park. Besides the choice for AC or DC – as will be described in the next chapter – factors like the distance to shore, weather conditions, seabed conditions and dimensions of the farm will effect this distribution. Because the possible differences in park layout, the estimations of cost distributions that can be found in the literature do show relatively large variations. In all estimations however, the costs of electrical infrastructure and the foundation is respectively higher for offshore wind energy than onshore as can be seen in figure 2.6. The contribution in the costs from the electrical infrastructure for offshore wind farms is substantial as can be seen as well in this figure.

![Pie charts showing cost distribution for offshore and onshore wind farms](image)

*Figure 2.6: Examples of different component contributions to cost for on- and offshore wind farms. Adopted from CA-OWEE and Opti-OWECS.

The costs of the electrical infrastructure are strongly dependent of the distance to shore as well as the choice for AC or DC (which on it self is dependent on the distance as well), the size of the farm, the park layout and the seabed conditions. Greenpeace compared the costs for offshore wind farms at 30 km, 50 km and 70 km offshore \(^{16}\). In this research the estimated contribution of grid connection to the costs of the park are as follows: 17.1% - 27.7% for 30 km offshore, 21.5% - 30.0% for 50 km and 26.8% - 36.8% for 70 km. This large contribution of the electrical infrastructure shows the importance of studying this component. It should be clear that the figures shown here concern the investment capital cost for both onshore and offshore wind energy. An important difference in costs exists for operation and maintenance, where again offshore wind energy will be the most expensive, because the parks are more difficult to reach. Because maintenance for offshore wind parks is more expensive, it will be more rewarding to design systems that have a higher reliability. Hence, this could increase the construction costs.

In addition to the large contribution of the electrical infrastructure to the costs of offshore wind energy, it should be noted that the electrical infrastructure represents a rather new technology. As will be shown in chapter 4, the amount of installed submarine cables world-wide is small relative to the amount of cables - that would be needed for a large-scale application of offshore wind energy. Moreover, the history of power transmission over large distances is relatively short. Furthermore, the adaptation of power electronics for the purpose of using it for offshore wind parks is responsible for the relative expensiveness of the electrical infrastructure. In the light of the experience curve theory, these facts on the electrical infrastructure implicate the possibility of a relatively large contribution of this component to the decline in costs of offshore wind energy in the future.
Table 2.1: Investment costs by components (%) for an offshore site, relative to actual cost distribution from existing offshore windfarms in Denmark. Adapted from Barthelmie[17]

<table>
<thead>
<tr>
<th>Component</th>
<th>Onshore</th>
<th>Large Offshore</th>
<th>Kuhn et al.[18]</th>
<th>Vindeby</th>
<th>Tunø Knob</th>
<th>Middelgrunden</th>
</tr>
</thead>
<tbody>
<tr>
<td>Foundations</td>
<td>5.5</td>
<td>16</td>
<td>25</td>
<td>22.4</td>
<td>23.3</td>
<td>21.5</td>
</tr>
<tr>
<td>Turbines</td>
<td>71</td>
<td>51</td>
<td>45</td>
<td>46.5</td>
<td>40.5</td>
<td>58.1</td>
</tr>
<tr>
<td>Internal electrical grid</td>
<td>6.5</td>
<td>5</td>
<td>7</td>
<td>6.1</td>
<td>1.4</td>
<td></td>
</tr>
<tr>
<td>Electrical system</td>
<td>0</td>
<td>2</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Grid connection</td>
<td>7.5</td>
<td>18</td>
<td>21</td>
<td>15.3</td>
<td>24.7</td>
<td>9.9</td>
</tr>
<tr>
<td>O&amp;M facilities</td>
<td>0</td>
<td>2</td>
<td>2</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Engineering &amp; administration</td>
<td>2.5</td>
<td>4</td>
<td></td>
<td>4.5</td>
<td>4.7</td>
<td></td>
</tr>
<tr>
<td>Miscellaneous</td>
<td>7</td>
<td>2</td>
<td></td>
<td>9.5</td>
<td>5.5</td>
<td>5.8</td>
</tr>
</tbody>
</table>
Chapter 3: AC and DC

In the design of the electric infrastructure there is a choice to be made between the use of alternating current (AC; See appendix A for abbreviations) and direct current (DC) to transport the energy to shore. The choice between AC and DC determines to a large extent the design of the wind park and therefore will be very important. In this chapter the differences between AC and DC will be outlined. As will be shown in this chapter, the distance of the park to the shore is a very important variable in the choice between AC and DC, but the choice depends on other factors as well. For example the size of the park and even the type of wind turbines can influence this choice.

3.1 The history of alternating current and direct current

The first commercial electricity generated by Edison was direct current electrical power. When the first power transmission lines were produced in the early 1880s, DC was used as well. But very soon AC replaced DC in power transmission. This replacement was due to several reasons. First of all, DC could not be transformed to a higher voltage. This created a problem because the transmission of low voltage direct current over longer distances would generate enormous losses. AC transmission on the other hand could overcome this problem because it can easily be transformed to high voltage. Second, the advance of the induction motor, which is powered by alternating current, stimulated the use of AC instead of DC for power transmission. Third, on the power generation side the superior synchronous generator stimulated the use of AC and fourth, the possibility of converting AC to DC when needed completed the gradually replacement of AC by DC. The introduction of the mercury-vapour rectifier by Hewitt in 1901 gave rise to a new interest in HVDC transmission. In the 1930s experimental plants were set up in Sweden and the USA to investigate the possibility of using mercury arc valves in the conversion processes for transmission and frequency changing. The increasing demand for energy after the Second World War increased the research for the possibility of HVDC transmission. In 1950 the first experimental HVDC transmission line was commissioned from Moscow to Kasira at 200 kV over 116 km. The power rating of this line was 30 MW. In 1954 the first commercial HVDC project was commissioned in Sweden. It was a 96 km submarine cable with ground return between the island of Gotland and the Swedish mainland. In the 1960s several thousands of MW HVDC capacity is installed with the mercury arc valve based technology. In the late 1960s solid state valves were developed which lead to the development of thyristor converters. In 1970 the first thyristor-based converter stations were build in Sweden. They were used as an upgrade to the Gotland project. The first station using exclusively thyristor valves was the Eel river scheme in Canada, commissioned in 1972. Thyristors have the advance of the capability to be switched off, which makes it possible to delay conduction. In the late 1980’ s the development of valves that have the capability to be both turned on and off took place. The converters that are equipped with this type of semiconductors are called Voltage Source Converters (VSC). The most commonly used types of semiconductors in VSC’s are GTO’s (Gate-Turn-Off Thyristor) and IGBT’s (Insulated Gate Bipolar Transistor). Both of them are widely used for industrial purposes since the early 1980’s. The VSC is controlled by Pulse Width Modulation (PWM). The first Voltage Source Converter was installed in 1999 in Gotland. Nowadays more than 50 HVDC systems have been installed as will be shown in chapter 5.

* This paragraph is based on Rudervall19, Woodford20 and Lucas21
3.2 The HVDC technique

In most cases, the choice between HVDC and AC transmission is based on economical reasons. In the past a diverse sum of reasons have led to the choice of HVDC solutions in a large number of cases:

- The losses in DC cables are lower than in AC cables. Of course, this is relative because if a larger cross-section would be applied to an AC cable than to a DC cable, the losses of the AC cable would be lowered. But at the same expense, the losses in an AC cable will be higher.
- The costs of DC cables is lower than of AC cables at the same power rating.
- Asynchronous AC networks can be connected by DC. This has also led to the production of Back-to-Back stations. For large wind parks, this creates the possibility to run the wind park at another frequency than the electricity network it is connected to.
- AC transmission has its technical limitations in cable length due to the capacitive currents that exist in AC cables. These restrictions lie in the range of 70-100km. For larger lengths, loading stations will be required.

These advantages of DC should compete with the expense of the converter stations at both sides of the line. The difference in price of AC and DC submarine cables in combination with the fact that the converter stations needed for DC transmission creates a so-called break-even distance. This break-even distance depends on several factors, as can be seen in figure 3.1. For offshore connections, this distance is about 25km. With longer lengths to be crossed over sea, the HVDC solution will be the economical cheaper one when only installation costs are considered.

![Figure 3.1 The break-even distances for DC transmission depend on several factors. Adopted from Rudervall](image)

To make HVDC transmission possible, AC should be converted into DC (rectifier) and DC should be converted back to AC (inverter) by converter stations. The main part of a converter station is the valve or valve arm. Single valves are built up from diodes (non-controllable) or thyristors in series. One thyristor can handle loading voltages in the order of several kVs. Placing a couple of hundred thyristors in series makes it possible to handle hundreds of kilovolts.
Figure 3.2: six pulse valve group, adopted from Woodford

The standard used configuration of valves in a converter station is shown in figure 3.2. This so-called six pulse valve group makes it possible to convert the three phase AC current into DC and the other way around as the current is flowing in the AC direction. This makes it possible to use the converter as both inverter and rectifier. Hence, at both ends of the connection, the same converter station can be used. The voltage is transformed to a higher voltage for transmission at the AC side of the valve. The six pulse configuration is used in most converter stations that are based on mercury arc valves. In thyristor based converters the twelve pulse configuration depicted in figure 3.3 is adopted. The twelve pulse configuration is built up from two six pulse valves. The DC side of one of the transformers is situated in a star configuration and the other in a delta configuration. The AC voltages supplied to both six pulse valves have a 30 degree phase difference, resulting in a saving of harmonic filters. As can be seen in figure 3.3 the valve group can be divided in three groups of four valves in a vertical stack. These are called quadrivalves. Since these quadrivalves contain four thyristor groups, which for large-scale converter stations contain hundreds of thyristors, these quadrivalves are mechanically very large. They may reach to the ceiling of the valve hall as can be seen in the intermezzo.

Figure 3.3: twelve pulse valve group, adopted from Woodford
The Kii-Channel system was installed in June 2000 as first part of a 2,800 MW transmission system to be built in Japan. The size of the converter unit was brought down to 60% compared to conventional units. Phase I is built up from two 12 pulse HVDC systems carrying 700 MW each, at ±250 kV.

<table>
<thead>
<tr>
<th>Capacity</th>
<th>700 MW</th>
</tr>
</thead>
<tbody>
<tr>
<td>DC voltage</td>
<td>250 kV</td>
</tr>
<tr>
<td>DC current</td>
<td>2,800 A (3,500 A -30 min. over-load)</td>
</tr>
<tr>
<td>Main devices</td>
<td>8-kV, 3,500-A direct-light-triggered thyristors (LTT’s)</td>
</tr>
<tr>
<td>Insulation</td>
<td>Air-insulated</td>
</tr>
<tr>
<td>Cooling</td>
<td>Deionized water</td>
</tr>
<tr>
<td>Structure</td>
<td>Quadruple multi-valve unit (MVU)</td>
</tr>
<tr>
<td>Dimension</td>
<td>5.2 m x 3.8 m x 9.5 m</td>
</tr>
</tbody>
</table>

3.3 Expected developments

According to Bauer et al., the latest developments, using the voltage-source converter topology introduce large advantages for offshore wind energy. Both Siemens and ABB have started developing this new type of converters which they call respectively HVDC-plus and HVDC-light. Although the technique has only been installed at a lower voltage (80 kV, Gotland), ABB claims the applicability in the 7-600 MW range. Besides the fact that this technique improves the power control of a power transmission system, Bauer et al. claims a drop of the required area for a converter station of about 2 orders of magnitude. This substantial drop of the area of the footprint of a substation can lower the costs of foundation of an offshore converter station dramatically.
3.4 AC and DC transmission & offshore wind energy

As described above, the choice between AC and DC is dependent on numerous factors. In the case of wind energy an extra factor is added to this. The choice of variable speed generators or constant speed generators will have different consequences for the costs of an AC and DC solution for the power transmission to shore. The consequences are well described by Pierik\textsuperscript{25} and will not be discussed here in detail, because this report deals with the power collection and transmission cost as a stand-alone problem. Moreover this report is not meant to show the cheapest option for one certain project, but it should evaluate the cost development of the several components to come to a complete figure of the possible cost decrease for offshore wind energy in the future. Of course the electric infrastructure data should be coupled to the other components of the wind park. The choice of generators could influence -in addition to the AC/DC decision- for example the power control in the transmission system, but the consequences of these variations on the total costs are assumed to be relatively small.

The costs of the electrical infrastructure will vary with the distance to shore, the park layout, the choice between AC and DC and many other factors. Pierik\textsuperscript{25} investigated the cost and loss figures for 13 park layouts for wind parks of 100 MW and 500 MW at a distance to shore of 20 and 60 km. An idea of the initial cost fluctuations that exist in the choice between AC and DC can be made up from figure 3.6. As can be easily seen in this figure, the break-even distance of the initial costs of DC transmission compared to AC transmission is well above 20 km to shore when a 100 MW park is considered. In table 3.1 an example is given of the loss and costs figures of an offshore wind park. In both figure 3.6 and table 3.1 the variation in the costs is striking. The variability in the cost figures and cost distribution over the different components account for the fact that it makes sense to consider the cost developments of the different components (cables, switchyards, transformers, converters) apart.

So far, only AC transmission has been used in the short history of offshore wind energy. According to Christiansen\textsuperscript{26}, the possible solutions for the 150 MW Horn Rev wind park ranged form 150 kV HVDC transmission line to a 400 kV AC connection to shore. The scheme that has been installed finally is a 150 kV AC connection, with space reserved for 150 kV additional\textsuperscript{27,28}. When larger projects will be planned however, or larger distances to shore, the use of HVDC will surely have a chance to be the best option for power transmission.
The power transmission within the wind farm will be mainly carried out at middle voltage (10-35kV). The reason for this choice is that the losses at lower voltages would be to high and that higher voltages would create the need of relatively expensive high-voltage switches at the power collection points. The distances within a wind farm are quite large, because the mills are positioned in the range of 4 to 8 rotor diameters apart from each other, dependent from the mean wind direction. This enlarges the need for the highest possible voltage power collection within the wind farm (The higher the voltage, the lower the current and thus the losses). The most generators produce power at about 600 V, therefore a step up transformer is applied to the individual generators to step up to the inner wind farm voltage. The power of the wind park is collected at one or more power collection sites, or substations. From there the power is transported to shore. In CA-OWEE\(^5\) three possibilities for the transmission are mentioned:
1. multiple medium voltage links (up to 35 kV)
2. single high-voltage link (100 to 200 kV)
3. HVDC link
The economical most feasible power and distance conditions for these transmission solutions are addressed as well:
1. few kilometres offshore, up to 200 MW
2. longer distances and larger farms
3. distances to shore above 25 km and power levels above 200 MW
The electrical infrastructure has to be adapted to the sea conditions, which makes it more expensive.

According to Pierik, both the park layout and the park control will be important aspects of multimegawatt offshore wind parks. As mentioned above, the effect of the park layout will not be discussed in this report. The so-called park control has to do with the layout of the park, because the park control should minimise the negative effects on the high voltage grid and it should assist in frequency and power control\(^25\). Apparently, the power control could potentially add to the learning effects, having a declining effect on the costs of the electrical infrastructure. Because no experience exists with large multimegawatt wind parks and because it is hard to find substitutes for the power control of this kind of parks, this effect will not be described in more detail in this report.

<table>
<thead>
<tr>
<th>Size (MW)</th>
<th>Dist (km)</th>
<th>(E_{\text{loss}}) (%)</th>
<th>Cost (MEuro)</th>
<th>Rel. Cost (Ect/kWh)</th>
</tr>
</thead>
<tbody>
<tr>
<td>100</td>
<td>20</td>
<td>2.3</td>
<td>19.73</td>
<td>0.8</td>
</tr>
<tr>
<td>100</td>
<td>60</td>
<td>3.0</td>
<td>36.93</td>
<td>1.5</td>
</tr>
<tr>
<td>500</td>
<td>20</td>
<td>4.1</td>
<td>91.75</td>
<td>0.7</td>
</tr>
<tr>
<td>500</td>
<td>60</td>
<td>5.2</td>
<td>132.95</td>
<td>1.1</td>
</tr>
<tr>
<td>100</td>
<td>20</td>
<td>4.5</td>
<td>29.73</td>
<td>1.2</td>
</tr>
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<td>100</td>
<td>60</td>
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<td>46.93</td>
<td>1.9</td>
</tr>
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<td>20</td>
<td>6.2</td>
<td>141.75</td>
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<td>60</td>
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<td>182.95</td>
<td>1.5</td>
</tr>
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<td>100</td>
<td>20</td>
<td>4.1</td>
<td>61.41</td>
<td>2.5</td>
</tr>
<tr>
<td>100</td>
<td>60</td>
<td>4.5</td>
<td>73.97</td>
<td>3.0</td>
</tr>
<tr>
<td>500</td>
<td>20</td>
<td>6.1</td>
<td>263.71</td>
<td>2.1</td>
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<tr>
<td>500</td>
<td>60</td>
<td>7.5</td>
<td>288.83</td>
<td>2.4</td>
</tr>
</tbody>
</table>

\(^{25}\) Pierik

Table 3.1: Losses and initial investments of electrical systems \(C_1, IV_1\) (as described above) and \(PV_1\), Park coupled variable speed. The size of the generators is taken 5 MW, the voltage within the wind park 36 kV. The costs per kWh are based on a capacity factor of 50-53%, as described by Pierik\(^{25}\). This capacity factor is relatively high compared to capacity factors for offshore wind energy reported in other literature (30-35%). Combined from Pierik\(^{25}\) and Bauer\(^{25}\).
Chapter 4: Submarine cables

One of the effects of the choice of the park layout and the (kind of) power transmission to shore, is the variability in cable types and length that will be required for chosen layout and transmission option. The choice between AC and DC influences the design of the cables. In this chapter the properties of AC and DC submarine cables will be discussed. Furthermore the submarine power cable market will be surveyed, which will give an idea of the cost trends and the possible developments in the future.

4.1 Cable design

4.1.1 Cable design in general

Whereas the cable market is more than a century old, the large scale production of submarine cables started only short after the Second World War. Anyhow, the design of the underground cables and submarine cables generally only differs in armouring and mostly a lead shield in submarine cables, functioning as a water protectant. The components of submarine cables can be roughly divided into three categories:

- Conductor(s)
- Insulation
- Protection, the cable has to be protected against physical stress and humidity

In figure 4.2 the components of a submarine cable can be seen in more detail. In the last two decades fibre optics have been applied in three core cables in addition. This does not direct have to do with power transmission itself, but it can lower the costs of power transmission, because of the combined use of the cable. The insulation of the cables presents the most important variability in the design of cables, but the other components do possess differences as well of course. The insulation types of submarine (and underground) cables can be divided in three groups:

- Low Pressure Oil Filled (LPOF/LPFF)
- Mass Impregnated, Paper impregnated with viscous fluid (SOLID/MIND)
- Extruded insulation: Cross-Linked Polyethylene (XLPE) replaced to a large extend (butyl) rubber, PVC and ethylene propylene rubber (EPR). The latter however is still used for the lower voltage levels (<69 kV)

Mass impregnated cables have an insulation of numerous paper layers impregnated with a viscous compound. The cable is produced by the lapse of extra-dry paper tapes around the conductor. The impregnation of the cables is done under high pressure. For this purpose the entire cable is placed in an impregnation tank, which will therefore be determining for the maximum length of the cable. The quality of the cable is mainly determined by the effectiveness of the paper drying process, the saturation degree of the paper (as close as possible to 100%) and the art of the impregnant. A problem with the paper-based
insulation. The different components and their function are briefly described here:

As mentioned above a submarine cable has more components than only one or more conductors and their function is to conduct the current. A part of the impregnant can be pressed out of the paper, which cannot return at the same place in some cases, because of the degree of saturation of the paper and the viscosity of the impregnant. This effect could cause voids to form in the insulation. To overcome this problem, fluid filled cables were designed. By filling the paper-insulated cables with fluid oil and applying expansion tanks, the insulation was able to deal with the differences in pressure effected by the temperature differences in the cable. A problem with the fluid-filled cables is however, the possibility of oil-leakage and the need of costly refilling stations, approximately every 50 km. The chance of oil leakage, which could case environmental hazards, the cost of auxiliary equipment and the development of cheaper alternatives have lead to the reduced use of fluid filled cables in general and the choice of applying mass-impregnated cables for most recent submarine HVDC cables. A more recent development that was introduced in the early 70s in the cable industry and is developed in the last decades for the use in the higher voltages is the extruded polyethylene insulation (XLPE). An advantage of XLPE cables is that they are cheaper than LPOF and Mass-impregnated cables as will be described briefly in chapter 7. On the other hand the nature of an extruded isolation is that one discontinuity in the isolation can cause a cable fuse. The chance of a cable discontinuity in a lapped insulation is much smaller. The isolation amounts to several hundreds of layers for high-voltage cables (~ 1 layer per kV), a failure in one layer causes a drop in the insulating capacity of 1% in the case of 100 layers. This makes the probability of a cable melt caused by production failures smaller. The choice of insulation and the design of the cable depend on the use of the cables. In the following sub-paragraphs the consequences of the differences between AC and DC on the design of cables will be described.

![Figure 4.2: The design of a single core XLPE cable, ABB’s Long Island Cross Sound Cable. The connection consists of two specialized, underwater direct-current (DC) cables. Steel armor on the outside, and solid flexible plastic protect and insulate the copper wire. The cable is 10 cm in diameter, the conductor 4.1.](image)

As mentioned above a submarine cable has more components than only one or more conductors and insulation. The different components and their function are briefly described here:

- **Conductor(s):** The conductor of a middle or high-voltage submarine cable is copper, or less commonly aluminium. Aluminium has a lower current-carrying capacity (ampacity). The size of a conductor ranges up to 2000mm². This upper limit has to do with the binding radius of the cable (up to ~6m). For AC-cable applications cables are designed with three conductors, if possible. It decreases the cable laying costs and electromagnetic fields around the cable. When the conductor sizes increase however, the cable will become unwieldy, because of the high bending radius as discussed above. Therefore one-core cables are applied for higher loads.

- **Screening:** The screening layer is placed around the conductor to smooth the electric field and ovoid concentrations of mechanical stress. It also assures a complete bond of the insulation to the conductor. The screening is always made up from a semiconducting compound.

- **Sheathing:** The metallic sheathing, mostly lead, protects the cable from moist. Furthermore it gives the cable more mechanical strength.

- **Armor:** A final steel armouring protects the cable. This armouring is protected by a serving that protects it from corrosion.
4.1.2 AC cables

The technical limitation of the cable length of AC cables is determined by the charging current. The charging current \( I_c \) of the cables is directly proportional to the capacitance \( C \), as given in the following formula

\[
I_c = \omega C L V
\]  
(4.1)

Where \( L \) is the length of the cable and \( V \) is the voltage across the insulation. The capacitance is proportional to the dielectric constant \( (\varepsilon) \) and the radii of the insulation \((r_s)\) and the conductor shields \((r_c)\). The capacitance is expressed in units per length.

\[
C = \frac{\varepsilon}{2 \ln \left( \frac{r_s}{r_c} \right) \cdot 9 \times 10^{11}} F cm^{-1}
\]  
(4.2)

The critical cable length is the length where the charging current becomes equal to the loading current. This critical length \((L_c)\) can be derived from (4.1)

\[
L_c = \frac{I}{\omega C V}
\]  
(4.3)

Of course, the critical cable length should be as long as possible. The choice of insulation type for AC transmission is mainly based on this problem. The dielectric constant of mass impregnated cables is 3.6 whereas the dielectric constant of XLPE is 2.4. Combining formulas (4.2) and (4.3) indicates that this would cause a factor 1.5 difference of the critical cable lengths in favour of the XLPE insulation. In table 4.1, the guidelines to the ampacity (current carrying capacity) of 5000kcmil copper conductor for paper oil insulation, provided by Endacott\(^{34}\) are shown. These data are combined with the typical insulation thickness for different voltage classes. From these data the cable capacitance and the critical length have been calculated. As can be seen the critical length for this size of conductor range from 110 km for 138 kV to 53 km for 500 kV. The use of aluminium or smaller copper conductors will lower this length.

Table 4.1: Critical Lengths of Naturally Cooled self-contained Oil-paper Insulated Cables with 5000 kcmil Copper Conductors; ampacities According to Endacott\(^{34}\)

<table>
<thead>
<tr>
<th>Voltage (kV)</th>
<th>Insulation thickness (cm)</th>
<th>Ampacity (A)</th>
<th>Transmission capability (MVA)</th>
<th>Capacitance (pF/cm)</th>
<th>Critical length (km)</th>
</tr>
</thead>
<tbody>
<tr>
<td>138</td>
<td>1.28</td>
<td>2000</td>
<td>478</td>
<td>6.07</td>
<td>110</td>
</tr>
<tr>
<td>230</td>
<td>2.12</td>
<td>1900</td>
<td>757</td>
<td>4.01</td>
<td>95</td>
</tr>
<tr>
<td>345</td>
<td>2.60</td>
<td>1850</td>
<td>1105</td>
<td>3.42</td>
<td>72</td>
</tr>
<tr>
<td>500</td>
<td>3.18</td>
<td>1690</td>
<td>1464</td>
<td>2.95</td>
<td>53</td>
</tr>
</tbody>
</table>

The difference of the values of \( \varepsilon_{\text{pap}} \) and \( \varepsilon_{\text{XLPE}} \), has large consequences on the electrical loss figures of both insulation types as will be described below. In the phasor diagram in figure 4.3, it is shown how the useful load current \( I_L \) combines with the charging current \( I_c \) for a resistive load of unity power factor. As can be seen from this figure, \( \tan \alpha \) will indicate the relation \( I_c/I_L \). In quality measurements of cables \( \tan \alpha \), indicated as \( \tan \delta \), is measured. Hence, when given as a value per meter, \( \tan \delta \) will be the charging current losses per meter cable length. Oil-paper insulated cables have a \( \tan \delta \) value of \( 25 \times 10^{-5} \), which indicates a charging current of 0.25% every meter. In the case of XLPE cables this is in the order of 0.01%. Because power is proportional to the square of the current (\( P=I^2 R \)), the difference in power losses due to charging current between both isolation types is even larger. The electrical power losses are converted into heat and thus in

\[ CV_{IL} = \frac{1}{11} \left( 1 + \ln 2 \right) \cdot F cm^{-1} \]

\[ CV_{IL} = \frac{Fcm}{L_c w} \]

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* This paragraph is based on Graneau\(^{32}\) and contact with van Eerde\(^{33}\)

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the heating up of the cable. In the case of oil-paper cables the heating up of a 100 kV cable will be in the order of a few Kelvin, for a 400 kV cable it will be 25 Kelvin. This could cause serious problems in stability of the cable when the cable is used in warmer regions. For XLPE insulation the heating of the cable is in the order of tenths of Kelvin for a 400 kV cable, which is negligible. These figures have resulted in the trend towards the use of XLPE insulation for longer middle and high-voltage AC cables.

As can be derived from the combination of (4.2) and (4.3), a larger conductor diameter as well as a thinner insulation, which is desired to save materials, both increase the capacitance of the cable. These disadvantages however are outweighed by the fact that a greater ampacity is made possible by the larger conductors and walls of lower thermal resistance. To restore the transmission capability of long AC cable circuits several techniques can be used. These techniques are in general interesting when the length / critical length ratio is greater than 0.6 and thus the transmission capability is lowered by more than 20%. First of all, cooling techniques could be used to increase the transmission capability. As described by Graneau, reactive compensation with shunt reactors can be used as well to increase the transmission capability. Reactive compensation is based on the fact that inductive loads allow the charging current to be greater than the ampacity of the cable without overheating the cable.

In an AC cable the current is not uniformly distributed over the cross section of the conductor. The current density is higher in the outer region, which is called the skin effect. This results in under utilisation of the conductor cross section. Another effect that occurs in AC cables is the so-called corona effect: local partial discharges around the conductors of power transmission cables that occur under some conditions. The corona effect can be minimized by bundling more conductors in one cable. This explains the existence of three-conductor cables.

4.1.3 DC cables

While there is a long-term experience with AC cables, the experience with DC cables lasts since 1954. The knowledge about AC cables is much larger than about the processes that play an important role in a DC cable. A large difference between AC and DC cables is that in DC cables no significant charging currents occur. The losses in a DC cable consist of three components: resistive losses, partial discharge and space charges, as will be described below. The losses in AC cables are largely due to the oscillation of particles and polar elements in the dielectric, due to the alternating field. This effect is absent when the applied voltage is constant.

As mentioned above the losses in DC cables are due to three effects. First of all the resistive losses, that are caused by the limited permitivity of the cable. This effect is known form AC cables as well of course.
Anyhow, these losses will not be the same. The electrical field in both cables is different, which causes different resistive losses in the cable. An important difference in the electrical field between AC and DC is the so-called field inversion effect. This effect describes how the electrical field changes upon operation. The second component is the partial discharge. This discharge is very well known from AC cables as well. Partial discharges can occur for example in the voids that can occur in oil-paper cables by cooling down of the cable. The insulation becomes locally weaker, which can cause a melt of the complete cable. Partial discharges can be caused by irregularities that originate from the production of the cable as well. The third effect in contrast with the two above-mentioned effects is not known from AC transmission. Space charges are charges that occur within the insulation. They can cause local disruptions in the electrical field and thereby larger loads on the isolation than the isolation is designed for. The cause of space charges is yet unknown. The space charges however, do have a large impact on the design. Despite the positive characteristics of polymer insulation (cheaper, lower maintenance costs, good mechanical and thermal properties), all commercial submarine HVDC cables are of the paper-type insulation because XLPE insulation is unreliable due to space charges. Experimental lower voltage cables have been installed with XLPE. Inorganic fillers are used in these experiments to deal with the space charges. Recent experiments with insulating materials with low space charge accumulation and high resistivity at ±250 kV (1997) and ±500 kV (2002) have shown that the use of XLPE insulation for HVDC applications will be feasible in the near future. Hence, this would mean a cost reduction for HVDC cables.

DC cables can carry more power with the same conductor size than AC cables. Lucas calculated the reduction of conductor cross-section $A_d$ over $A_a$ for the same transmitted power, same power losses and the same peak voltage. This calculation is based on the fact that the mean transmission voltage is lower than the peak voltage in AC transmission cables, and the effect of larger power losses in AC cables. In this calculation skin effects are neglected. The values that are found for $A_d/A_a = \cos^2 d/2$, this is 0.5 at unity power factor and 0.32 at power factor 0.8. This clearly indicates the effect of the power factor, mentioned in the previous paragraph. From these data it is clear that only the half to one third of the amount of copper is needed for the transmission of the same amount of power with DC compared to AC. As mentioned above skin effect was neglected in this calculation. Skin effect under conditions of smooth DC is completely absent. This means that the current is uniformly distributed and the cross-sectional area of the conductor is fully utilised. This adds to the above-mentioned effect.

Finally it has to be remarked that DC cables show hardly any corona-effects, which eliminates the need to bundle conductors and lowers the environmental impact of the cable. In Table 4.2 the technical limitations for AC and DC submarine cables are shown for the different isolation types.

<table>
<thead>
<tr>
<th>System</th>
<th>AC: 3 single-core cables</th>
<th>DC: bipolar operation, 2 cables</th>
</tr>
</thead>
<tbody>
<tr>
<td>Insulation</td>
<td>LPOF XLPE</td>
<td>LPOF MIND XLPE</td>
</tr>
<tr>
<td>Max. Voltage</td>
<td>500 kV 400 kV</td>
<td>600 kV 500 kV</td>
</tr>
<tr>
<td>Max Power</td>
<td>1500 MW 1200 MW</td>
<td>2400 MW 2000 MW</td>
</tr>
<tr>
<td>Max length</td>
<td>60 km 100 km</td>
<td>80 km Unlimited</td>
</tr>
</tbody>
</table>

### 4.1.4 Possible learning effects for submarine power cables

The learning effects that can be expected for submarine power cables in general will be mainly due to large-scale production. Because the number of produced HV submarine cables is relatively low as will be shown in the next paragraph, these cables are specially designed for each project. The lower voltage cables however, are already produced in larger amounts of standard cables (indicated as mass production in paragraph 2.1). When larger amounts of higher voltage cables would be used in the future, the production of a certain set of standard cables can possibly be applied to higher voltage cables as well.

For HVDC cables this learning effect can be accompanied by the applicability of cheaper XLPE insulation to higher and higher voltage DC cables. As will be described briefly in chapter 7, this could result in a significant cost reduction of HVDC cables. Hence, the experience curve can then be expected to follow the ‘double knee’ pattern as suggested in figure 2.3 for an R&D breakthrough.
4.2 The submarine cable market

The submarine cable market is dominated by a few large players. In a study of the European Community on possible market concentration as a result of the companionship of two large players, the situation of the European power cable market is sketched. In this study no distinction is made between AK and DC cables, isolation types or submarine and underground cables, but it certainly gives an idea of the power cable market in general. The study distinguishes four cable groups, based on voltage level. Extra-high voltage (EHV) and high voltage (HV) are used for energy transmission whereas middle voltage (MV) and low voltage (LV) are used for power distribution. These voltages are indicated as follows: LV: up to 1kV; MV: 1-33 or 1-45 kV; HV: 33/45-132 kV; EHV 275 kV, 400 kV power cables. Five large manufacturers dominate the HV and EHV market: ABB, Alcatel (now Nexans) NKT, Pirelli and BICC. LV and/or MV cables are produced by these large firms as well, but also a significant number of ‘secondtier’ manufacturers produce LV and/or MV cables. Manufacturers mentioned in this study are Draka, Carena Cavi, Ariston Cavi Tratos and AEI. The market shares of the larger players in the power cable market are summarized in table 4.3.

Table 4.3: European market shares of large manufacturers in power cables. After the fusion of Pirelli and a part of the BICC activities, the market share of Pirelli/BICC for LV mounts to 25-35%, combined with the second large player, Nexans to 45-55%, for MV 50-60%. Pirelli/BICC for HV/EHV 45-55% and Nexans 10-20%. Based on data of the European Commission.

<table>
<thead>
<tr>
<th></th>
<th>LV '97-'98</th>
<th>LV '99-'00</th>
<th>MV '97-'98</th>
<th>MV '99-'00</th>
<th>HV '97-'98</th>
<th>HV '99-'00</th>
</tr>
</thead>
<tbody>
<tr>
<td>Pirelli</td>
<td>5-15%</td>
<td>20-30%</td>
<td>10-20%</td>
<td>25-35%</td>
<td>20-30%</td>
<td>30-40%</td>
</tr>
<tr>
<td>BICC</td>
<td>5-15%</td>
<td>5-15%</td>
<td>5-15%</td>
<td>5-15%</td>
<td>15-25%</td>
<td>6-25%</td>
</tr>
<tr>
<td>Alcatel(Nexans)</td>
<td>15-25%</td>
<td>15-25%</td>
<td>15-25%</td>
<td>15-25%</td>
<td>10-20%</td>
<td>10-20%</td>
</tr>
<tr>
<td>ABB</td>
<td>below 5%</td>
<td>below 5%</td>
<td>below 5%</td>
<td>below 5%</td>
<td>1-10%</td>
<td>1-10%</td>
</tr>
<tr>
<td>NKT</td>
<td>below 5%</td>
<td>below 5%</td>
<td>below 5%</td>
<td>below 5%</td>
<td>below 5%</td>
<td>below 5%</td>
</tr>
<tr>
<td>Draka</td>
<td>5-15%</td>
<td>1-10%</td>
<td>1-10%</td>
<td>1-10%</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>SAT-Sagem</td>
<td>1-10%</td>
<td>1-10%</td>
<td>1-10%</td>
<td>below 5%</td>
<td>below 5%</td>
<td>below 5%</td>
</tr>
</tbody>
</table>

The European cable HV/EHV manufacturers have the monopoly of the cable markets in the rest of the world as well, except in the far east, where other manufacturers like Hitachi Cable have major market shares as well. In the study XLPE and oil/fluid filled cables are considered as substitutes, which is not entirely correct when we consider the difference in applicability of both insulation types for AC and DC applications. The assumption made in this study can be explained by the fact that no differences between AC and DC are considered. Interesting figures about the shift of the AC EHV/HV market towards the XLPE insulation are mention in the study. In 1999 38% of the EHV cables adopted paper insulation, for 2000 a drop to 20% is forecasted and the estimation for 2001 was 10%. Of course the data are not directly applicable for the submarine cable market, but at least they can give an implication of the market shares of the different cable manufactures. Moreover, the data show that the market is completely dominated by a few large players. An indication of the differences between the submarine cable market and the total power cable market can be found in a prospect of Nexans, where Nexans claims to have a N1 position world-wide for submarine power cables, whereas a N2 position world-wide for power cables in general is claimed. Because complete lists of HVDC connections world-wide are easily available at several places, a good documentation of the world-wide production of submarine HVDC cables is achieved. In table 4.4 all submarine HVDC connections are listed. From these data figure 4.4 and 4.5 are constructed. In figure 4.4 the cumulative installed submarine HVDC cable length is shown and in figure 4.5 the cumulative installed submarine HVDC capacity. In both figures a twist can be seen around 1983. This kink was observed in other data as well as will be shown below. In the data of HVDC submarine cabling another trend can be seen as well. In figure 4.6 it is clearly shown, how the current per cable has steadily increased during the past decades. The trend has been the same for the power ratings per cable. According to Jeroense, the developments of submarine cables will not pass the 1.2 GW, the aim of the actual studies, because the dependence on one cable would be too risky.
Table 4.4: All HVDC submarine connections world-wide. Based on several sources. Abbreviations: (c): cables, (s): substations, §: ground return, #: retired from service, OL: overhead lines. In 2000 Alcatel cable became Nexans.

<table>
<thead>
<tr>
<th>Connection</th>
<th>Cntry</th>
<th>dist. (km)</th>
<th>Volt (kV)</th>
<th>cap. (MW)</th>
<th>Year</th>
<th>Manufacturers</th>
<th>comments</th>
</tr>
</thead>
<tbody>
<tr>
<td>Gotland I</td>
<td>Swe</td>
<td>96</td>
<td>±100</td>
<td>20</td>
<td>1954</td>
<td>ABB</td>
<td></td>
</tr>
<tr>
<td>Cross Channel I</td>
<td>UK-F</td>
<td>2*65</td>
<td>±100</td>
<td>160</td>
<td>1961</td>
<td>Nexans (c), ABB (s)</td>
<td></td>
</tr>
<tr>
<td>New Zealand (Inter Island)</td>
<td>NZ</td>
<td>42</td>
<td>±250</td>
<td>600</td>
<td>1965</td>
<td>ABB (s)</td>
<td></td>
</tr>
<tr>
<td>Konti-Scan I</td>
<td>Swe-Den</td>
<td>64</td>
<td>285</td>
<td>250</td>
<td>1965</td>
<td>ABB (s) installation: Nexans</td>
<td></td>
</tr>
<tr>
<td>It-Corsica/ Sardinia</td>
<td>It-F</td>
<td>119</td>
<td>200</td>
<td>200</td>
<td>1965</td>
<td>Pirelli (c) GEC Alsth. (s)</td>
<td>SOLID, 340 mm², max.</td>
</tr>
<tr>
<td>Sardinié- Corsica</td>
<td>It</td>
<td>121</td>
<td>200</td>
<td>200</td>
<td>1967</td>
<td>Nexans (c), ABB (s)</td>
<td>2 parallel cables, + 290 km OL, §</td>
</tr>
<tr>
<td>Vancouver pole I</td>
<td>Ca</td>
<td>3*33</td>
<td>300</td>
<td>312</td>
<td>1969</td>
<td>Nexans (c), ABB (s)</td>
<td>3 parallel cables, + 41 km OL, §</td>
</tr>
<tr>
<td>Gotland Ib</td>
<td>Swe</td>
<td>96</td>
<td>+±50</td>
<td>+10</td>
<td>1970</td>
<td>ABB</td>
<td>Addition, first Thyristor system</td>
</tr>
<tr>
<td>Konti-Scan I:74</td>
<td>Swe-Den</td>
<td>32</td>
<td>285</td>
<td></td>
<td>1974</td>
<td>ABB</td>
<td>MIND 630 mm²</td>
</tr>
<tr>
<td>Vancouver II</td>
<td>Ca</td>
<td>2*30</td>
<td>-300</td>
<td>370</td>
<td>1974</td>
<td>Pirelli (c), General Electric (s)</td>
<td>1 cable per pole, + 113 km OL,</td>
</tr>
<tr>
<td>Skagerrak I&amp;II</td>
<td>Den</td>
<td>2*12</td>
<td>±250</td>
<td>500</td>
<td>1976</td>
<td>Nexans (c) &amp; ABB (s)</td>
<td></td>
</tr>
<tr>
<td>Hokaido-Honshu I</td>
<td>Jp</td>
<td>43</td>
<td>125</td>
<td>150</td>
<td>12-1979</td>
<td>Hitachi (s)</td>
<td>+27 and 97 km OL, Main cable: Oil Filled, 600 mm² - Cu, Return cable: XLPE, 500 mm² - Cu</td>
</tr>
<tr>
<td>Hokaido-Honshu II</td>
<td>Jp</td>
<td>43</td>
<td>250</td>
<td>+150</td>
<td>06-1980</td>
<td>Hitachi (s)</td>
<td>comments: Hokaido-Honshu I</td>
</tr>
<tr>
<td>Gotland II</td>
<td>Swe</td>
<td>91</td>
<td>150</td>
<td>160</td>
<td>1983</td>
<td>ABB (s)+(c)</td>
<td>MIND, 800 mm², 170m depth.</td>
</tr>
<tr>
<td>Cross-Channel II</td>
<td>UK-F</td>
<td>8*70</td>
<td>2x</td>
<td>±270</td>
<td>1985</td>
<td>Nexans, BICC &amp; Pirelli (c) CGEE/ GEC Althom (s)</td>
<td>SOLID, 900 mm², 60m depth, 4 cables</td>
</tr>
<tr>
<td>Gotland III</td>
<td>Swe</td>
<td>97</td>
<td>±150</td>
<td>160</td>
<td>1987</td>
<td>ABB, Installation: Nexans</td>
<td>MIND, 800 mm², 170m depth, Monopole, 1 cable</td>
</tr>
<tr>
<td>Konti Skan II</td>
<td>Swe-Den</td>
<td>64</td>
<td>285</td>
<td>300</td>
<td>1988</td>
<td>ABB, Installation: Nexans</td>
<td>MIND, 1200 mm², 80m depth, Monopole, 1 cable</td>
</tr>
<tr>
<td>Fenno-Skan</td>
<td>Fin-Swe</td>
<td>200</td>
<td>400</td>
<td>500</td>
<td>1989</td>
<td>ABB &amp; STK (both 100 km), ABB (s)</td>
<td>Monopole, MIND, 1200 mm², + 33 km OL, MIND, 1400 mm², 260m depth, 2 cables, 1 spare</td>
</tr>
<tr>
<td>Cook Straits</td>
<td>NZ</td>
<td>3*41</td>
<td>±270</td>
<td>1500</td>
<td>1991</td>
<td>ABB (2 cables) &amp; Nexans (1 cable)</td>
<td>MIND, 1200 mm², 80m depth, Monopole, MIND</td>
</tr>
<tr>
<td>Konti-Scan I:91</td>
<td>Swe-Den</td>
<td>64</td>
<td>285</td>
<td>300</td>
<td>1991</td>
<td>ABB</td>
<td>SOLID, 400/800 mm², 140 m depth, Monopole, MIND, 1400 mm², 140m depth, + 113 km OL, 1 cable</td>
</tr>
<tr>
<td>Cheju Island</td>
<td>Kor</td>
<td>2*96</td>
<td>180</td>
<td>300?</td>
<td>1993</td>
<td>Pirelli &amp; Nexans, each 1 cable Nexans</td>
<td>SOLID, 400 mm², 140m depth, Monopole, MIND, 1600 mm², 12 km OL, 45m depth, 1 cable</td>
</tr>
<tr>
<td>Skagerrak III</td>
<td>Nor-Den</td>
<td>128</td>
<td>350</td>
<td>500</td>
<td>1993</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Hokaido-Honshu III</td>
<td>Jp</td>
<td>43</td>
<td>±250</td>
<td>+300 (600)</td>
<td>04-1993</td>
<td>Hitachi (s)</td>
<td></td>
</tr>
<tr>
<td>Baltic Link</td>
<td>DK-Swe</td>
<td>250</td>
<td>450</td>
<td>600</td>
<td>12-1994</td>
<td>ABB Baltic Cable Install.: ‘Nexans’</td>
<td></td>
</tr>
</tbody>
</table>
It turned out that it was less easy to get full figures of the AC submarine cable market. Because the AC power transmission technique is much older, there is much more AC submarine cable than DC submarine cable. Because of the few players on the MV and HV cable market, reference lists of the manufacturers are of great use in the survey of this segment. Unfortunately, only two manufacturers supplied reference lists, ABB and Pirelli. Therefore it was not possible to get full coverage. In combination however, with the fact that these two manufacturers cover about the half of the market it can give a good insight. In case the market partition of the submarine cable market is comparable to the partition of the whole power cable market - which seems a rough estimation when we consider the above-mentioned claims of Nexans – table 4.3 can give us an idea of how covering these data are for every voltage level. This can be checked for one segment: the HVDC submarine cables. The cumulative installed HVDC cable length in 2000 was 4380 km (figure 4.4), the combined cumulative installed HVDC cable length of ABB and Pirelli was 2256 km, 51.5%. This corresponds to the market share of Pirelli/BICC and ABB in the period 1997-2000, 45-65%. It should be noted that market shares of the annual production of the last years are not per definition the same
as the market shares of cumulative production. Moreover the market share, based on trading results is not
directly proportional to the produced cable length, especially in markets with few players.

In figure 4.7 the total submarine cable production of ABB and Pirelli can be seen. The line shows the same
kink as figures 4.4 and 4.5. The data from the reference lists were combined and were divided in five
groups: HVDC and four voltage-ranges for AC cables. The insulation types of HVDC cables are as
expected paper based on both the mass and the oil filled type. ABB uses only mass type cables for HVDC
purposes (indicated as MIND: Mass-Impregnated Non-Draining HVDC cables), whereas Pirelli has
produced some oil impregnated HVDC cables as well. As can be seen in figure 4.7, the cumulative
production of both manufacturers until 2001 was 9372 km. The distribution between the manufacturers was
6653 km (Pirelli)/ 2719 km (ABB). The distributions over the two manufacturers in the different groups as
well as the distribution over the voltage-groups that were used to construct figure 4.8 are shown in table 4.5. As can be seen from this figure, ABB is – at the submarine cable market – specialised on HVDC cables. This is not surprising, because ABB produces power electronics for HVDC technology as well. To compare the submarine cable market to the total cable market, the references of ABB on XLPE cables in general (underground and submarine) give a good indication. ABB has produced more than 30.000 km below 30 kV, more than 5000 km 30-100 kV and more than 4900 km above 100 kV. ABB started the production of XLPE cables in 1973. This shows that the submarine cable market represents a small portion of the total power cable market.

Table 4.5: Cumulative submarine cable production by Pirelli and ABB, specified to voltage level and AC/DC (km). Based on Pirelli\textsuperscript{42} and ABB\textsuperscript{41} reference lists.

<table>
<thead>
<tr>
<th></th>
<th>Pirelli</th>
<th>ABB</th>
<th>Combined</th>
</tr>
</thead>
<tbody>
<tr>
<td>HVDC</td>
<td>1330</td>
<td>1372</td>
<td>2702</td>
</tr>
<tr>
<td>AC 1-10 kV</td>
<td>415</td>
<td>24</td>
<td>439</td>
</tr>
<tr>
<td>AC 11-39 kV</td>
<td>3471</td>
<td>679</td>
<td>4150</td>
</tr>
<tr>
<td>AC 40-99 kV</td>
<td>329</td>
<td>285</td>
<td>614</td>
</tr>
<tr>
<td>AC &gt;100 kV</td>
<td>1108</td>
<td>359</td>
<td>1467</td>
</tr>
<tr>
<td>Total</td>
<td>6653</td>
<td>2719</td>
<td>9372</td>
</tr>
</tbody>
</table>

In figure 4.8 the production of respectively 11-39 kV, 40-99 kV and higher than 100 kV AC submarine cables is shown. The production figures of the lowest voltage category are not shown. The cables of this category are all of the extruded type. In first instance predominantly (butyl) rubber and PVC insulated, later ethylene propylene rubber (EPR) takes over and the most recent development is XLPE. The largest amount of produced cable lies in the range of 11-39 kV. In the figure of the production of this voltage range the ‘kink of 1983’ can very clearly be seen. Moreover it can be seen that most of the additional produced cable is of the extruded isolation type. When the reference lists are studied in more detail, this moment roughly coincides with the switch of the extruded isolation types from (butyl) rubber insulation to both EPR and XLPE. ABB has never produced middle voltage submarine cables other than with XLPE insulation. They started producing XLPE cables in 1970.
Figure 4.8: the cumulative AC submarine cable production in different voltage ranges and different isolation types. Based on Firelli\textsuperscript{12} and ABB\textsuperscript{11}.
After 1992 the steepness of the line of 11-39 kV tends to decrease. When the additional production in the production of 40-99 kV cables would be added to this voltage range the slope of the line would remain the same after 1992. Therefore it could be concluded that the trend of increase of production due to the availability of the cheaper extruded insulation gradually applies to higher voltages. For the voltage range 11-39 kV no oil-impregnated cables were used, which can be explained by the fact that a lower power level will generate less cable heating and thus less cable expansion. For the higher voltages however, oil filled cables are used. In the voltage range 40-99 kV a much larger amount of oil filled cables compared to SOLID cables can be seen. Moreover, the contribution of XLPE cables is smaller. In the highest voltage range, the contribution of oil filled is very high. The contribution of extruded insulation is very small. Anyhow, it can easily be seen that the amount of XLPE insulation is increasing steadily the last two decades. Another interesting thing that can be seen in this figure is that the kink of 1983 seems to be absent, especially when the extruded isolation type is not taken into account. In chapter 7 this will be discussed in more detail.

4.3 Cable costs

Although the fact that a few players dominate the cable market creates problems in obtaining cost data, a few data points were found for HVDC cables as shown in figure 4.9. The cost data that were found were very rough, because the individual cost information includes different add-ons. For example the costs could be given including laying / installation costs or excluding. As described above the costs of laying forms a relative large part of the total costs. Because some cost data do include the laying cost, an educated guess of the laying costs should be made, to be able to compare the data points to the other data and include them in the calculation of the experience curve. The differences in laying costs are due to the varying laying conditions like water depth, weather conditions and sea bottom conditions. Estimations roughly vary from one third of the cable cost to two or even three times the cable costs. The fact that in other cost figures the converter stations – with or without installation – are included, these figures cannot be used in this study. The data that are used to construct the experience curve shown in figure 4.9 are mainly based on cost estimations for large projects.a

![Experience curve for HVDC submarine cables from 1988 until 2000. The information concerning the experience curve that was fitted to the data is shown in the upper-right corner.](image)

\[ y = 1E+07x^{0.7042} \]

\[ R^2 = 0.8644 \]

\[ PR = 61.4\% \]
Because the cable costs roughly vary linear with the power rating in the power range of the data that were used (400-600 MW), the unit that was chosen was in currency per km per MW. To match the cost data with the cumulative production, the cumulative production was expressed in the transmission of 1 MW over 1 km. The data were corrected for inflation based on the inflation figures of the advanced economies. The currency that was chosen is 2001 Euro; the conversion to this currency and the inflation corrections are described in appendix B. The data range from January 1988 to April 2000, which corresponds to the cumulative capacity range of 370-1613 GW-km. The capacity range thus roughly represents two doublings. None of the cost data are cost data of real projects. The experience curve that is constructed from the data gives a PR of 61.4%. When the data are investigated in more detail, two of the most recent data points turn out to be based on XLPE insulation, whereas the other data can be assumed to be based on paper insulation. As mentioned above, XLPE insulation is cheaper than paper based insulation. In the experience curve this may effect in a double knee like figure like is shown in figure 2.3. In figure 4.9 it can clearly be seen that the two data points indeed are far below the curve. The omission of the two data point effect in a less progressive PR as shown in figure 4.10. The PR that follows from this curve is 69.7%, with an $R^2$ of 0.9315.

\[ y = 941429x^{-0.5204} \]
\[ R^2 = 0.9315 \]
\[ PR = 69.7\% \]

Figure 4.10: Experience curve for HVDC submarine cables from 1988 until 2000. Some data points were left out, as described in the text. In grey, the data points are shown that were deleted to obtain this experience curve. These two data points concern XLPE HVDC-Light or HVDC-plus cables.

Within the 9 data points that are left to construct this experience curve, six data points are ‘clean’ cable costs, three include the laying costs. For these three data points a ‘laying correction’ was applied. The omission of these three points hardly effect the progress ratio (PR = 70.3%, $R^2 = 0.9648$). The laying-cost estimations, that are based on the additional information of the data points (once 25% twice 50%) are therefore assumed to be acceptable.

For AC cables even less data points were found. No meaningful experience curve could be constructed from these data. The costs of AC submarine cables that are found roughly range from 1600 to 3500 Euro/MW/km for a three-core cable or three single core cables (1998-2002 cost data). This clearly indicates the much higher costs of AC cables compared to DC cables.
4.4 Cable laying

Cable laying accounts, as indicated above, for a quite large portion of the costs of submarine cables. To protect the cables from damage by ships’ anchors and trawl equipment, the cables are usually buried in the seabed. The need for protection depends on the location and the seabed conditions. When the seabed is hard, for example, the cable will need to be buried less deep than in areas with a soft soil, where the anchors penetrate the bottom deeper. On the other hand the burying process in a hard bottom will be more difficult and thus more costly than in the case of a soft bottom. To survey the bottom for cable laying several techniques are indicated by CA-OWEE:

- Multibeam bathymetry is for developing seafloor topography along a proposed route and enables swaths to be surveyed with a single pass of the survey vessel. Various systems are available on the market. Basically the higher the system frequency, the greater the resolution and data density, but the shorter the system range.
- Side scan sonar is for seabed imaging. Side scan provides excellent target detection and seabed classification capabilities.
- Sub-bottom profiling is for the collection of data concerning shallow geological and sedimentary conditions. The technique is an essential component in pre-installation surveys for buried marine cables.

It is clear that both the costs of the cable laying and the survey of the route will be very specific for each project. In general the survey of the route and the ploughing techniques will be sensitive to learning effects. As shown for the cable production, the specificity of the costs will create methodological problems for the construction of an experience curve. In combination with the scarce data as shown for the cable production costs, it is not possible to construct an experience curve.
Chapter 5: Power electronics

As already described in chapter 3, the power electronics that are required for DC connection to shore are very different than the installations that are required when AC transmission is used. In principle the power electronics required for the DC option will be more expensive, for large distances or power rates this will be compensated by the cost and loss differences of the submarine cables. In this chapter, the production figures of power electronics for HVDC transmission will be shown. Furthermore, the components of different offshore substations and the cost distributions over these components will be described, which will be combined with an indication of costs for substations. Finally, an indication of cost reduction options will be given.

5.1 HVDC technique production figures

As already indicated in chapter 4, the production figures of HVDC interconnections are easy available. The global market is dominated by three players: Siemens Energy & Autonomation, GEC Alsthom T&D Power Electronic Systems and ABB powersystems. Hitachi Ltd. and Toshiba’s Corp.’s Fuchu Works have also supplied all thyristor based state-of-the-art and very reliable HVDC installations within Japan, however their systems are regarded as expensive and have not entered the competitive international market. As will be described in the next paragraph, the costs of so called back-to-back (B-B) stations that are used to connect two asynchronous AC systems, will be lower than stations that are used for transmission. Moreover there are differences in costs between monopole and bipole converter station. Hingorany differentiates five configurations: Back-to-Back, monopolar, bipolar, three-terminal and multi-terminal, as described in more detail in the article. For transmission purposes, the bipolar configuration is generally adopted, except for some submarine projects, which adopt the monopolar configuration, and two three-terminal projects, Hydro Quebec – New England and Italy – Corsica.

![Figure 5.1: Cumulative installed HVDC-converter stations. The data are based on ABB references and a HVDC Projects Listing](image-url)
Woodford\textsuperscript{20} differentiates two configurations, Monopolar and Bipolar. He further splits up the systems into five converter arrangements:

1) Back-to-back
2) Transmission between two substations
3) Parallel and series multiterminal HVDC systems
4) Unit collection, when Hydro power of wind energy is fed into the rectifier
5) Diode rectifier, when current is supposed to flow in only one direction

Because the technique in the different converter stations that are so far generally based on the first two types and in the two above mentioned cases on the third type, are basically the same however, the total produced capacity will be considered as a surplus of all types. The figures are mainly based on a reference list of ABB\textsuperscript{41}, Hingorany\textsuperscript{46} and an HVDC Project Listing.\textsuperscript{47} In this listing future HVDC projects are listed as well. These data were corrected, which led to exclusion of the Iceland-Scotland Link and the Nordtied, which are both not commissioned. The production figures after 1995 are however expected to be not fully complete. In figure 5.1 a kink around 1983 can be seen, like in the figures of submarine cabling, although smoother. When the data are spliced in B-B and power transmission systems, the kink is seen in both charts (figures 5.2a and 5.2b). This will be discussed in paragraph 7.3.

Because the AC market is such a large and long existing market, it is much more difficult to generate global production figures of AC transmission power electronics. The power electronics for this purpose should be split in components like shunt reactors, transformers, high and middle voltage switchyards, etcetera. The problem is that these components are used for a differing number of other purposes. Transformers for example, are used for many applications in a large power range, therefore it is hard to get global production figures and moreover, the possible cost reductions in the future will be small. On the other hand shunt reactors, that are used for reactive power compensation, have a very explicit application. Of course this diversity problem exists for the HVDC transmission as well. Therefore the components of AC/DC converters could be considered separate as well.
5.2 **Substation components and costs**

5.2.1 **General**

In general the capital costs of the power electronics for submarine power transmission and collection for offshore wind parks are build up from the following components:

- Transmission terminals (converters)
- Switchyard (s) to connect the windmills to the submarine terminal
- Transformers
- Submarine substation (s) foundation
- Special equipment for submarine substation (e.g. moisture & salt protection, emergency power unit, helicopter platform, man-over-board-boat etc.)
- Reactive power control (AC)
- Permits, environmental assessments and licences
- Project commissioning & planning costs
- Reinforcement costs

These costs will be considered in more detail for both transmission options below.

5.2.2 **DC transmission**

According to CIGRÉ, most utilities have in-house up-to-date capital cost estimates for AC transmission, whereas this is not the case for DC transmission. For comparison of HVDC transmission options and even more for construction of experience curves, the cost estimates should have a comparable base. To be able to construct a suitable experience curve it is important to be aware of the possible origin of price differences:

- It should be questioned which add-ons are included in the cost and which are not.
- It should be questioned what is the cost breakdown with respect to the various equipment or DC components and what is the correct cost variation in respect of scheme size, voltage and configuration?
- The price-cost relation is disturbed by the fact that the market is dominated by a few players.
- Different components can be responsible for the cost reductions.
- Unusual specification requirements & geographical locations create variances.

In Table 5.1 the cost contributions over converter components for five representative converter stations are shown. The voltage levels shown in this table are assumed to represent optimal values for the used power ratings.

<table>
<thead>
<tr>
<th></th>
<th>Back-to-Back 200 MW</th>
<th>±250 kV 500 MW</th>
<th>±350 kV 1000 MW</th>
<th>±500 kV 2000 MW</th>
<th>±500 kV 3000 MW</th>
</tr>
</thead>
<tbody>
<tr>
<td>Valve Groups</td>
<td>$38/19</td>
<td>$50/21</td>
<td>$42/21</td>
<td>$35/22</td>
<td>$33/22</td>
</tr>
<tr>
<td>Converter Transformers</td>
<td>$45/22.5</td>
<td>$50/21</td>
<td>$44/22</td>
<td>$35/22</td>
<td>$33/22</td>
</tr>
<tr>
<td>DC Switchyard &amp; Filtering</td>
<td>$6/3</td>
<td>$14/6</td>
<td>$12/6</td>
<td>$10/6</td>
<td>$9/6</td>
</tr>
<tr>
<td>AC Switchyard &amp; Filtering</td>
<td>$22/11</td>
<td>$25/10</td>
<td>$19/9.5</td>
<td>$14/9</td>
<td>$13/9</td>
</tr>
<tr>
<td>Control, Protection &amp; Communication</td>
<td>$17/8.5</td>
<td>$19/8</td>
<td>$16/8</td>
<td>$13/8</td>
<td>$12/8</td>
</tr>
<tr>
<td>Civil Works</td>
<td>$26/13</td>
<td>$33/14</td>
<td>$28/14</td>
<td>$21/13.5</td>
<td>$20/13.5</td>
</tr>
<tr>
<td>Auxiliary Power</td>
<td>$4/2</td>
<td>$6/2.5</td>
<td>$5/2.5</td>
<td>$5/2.5</td>
<td>$4/2.5</td>
</tr>
<tr>
<td>Project Administration</td>
<td>$42/21</td>
<td>$43/17.5</td>
<td>$34/17</td>
<td>$27/17</td>
<td>$26/17</td>
</tr>
<tr>
<td>Costs $/kW/terminal 95/96</td>
<td>$111.9</td>
<td>$150.2</td>
<td>$110.9</td>
<td>$77.7</td>
<td></td>
</tr>
<tr>
<td>Costs $/kW/terminal 1998</td>
<td>$100</td>
<td>$120</td>
<td>$100</td>
<td>$80</td>
<td>$75</td>
</tr>
</tbody>
</table>

*Table 5.1: Estimated HVDC turnkey capital costs values given in 1998 US$. The costs of 1995/6 were adjusted for inflation based on the inflation figures of the advanced economies. Based on CIGRÉ and Hauth. The data in these assessments were based on the turnkey costs of ‘three vendors’. The data concern bipolar systems.*
From table 5.1 a number of cost trends can clearly be seen. First of all, the costs of converters per kW at optimal working voltage drops with a higher power rating. The cost variation as a function of power rating is not linear. The distribution of costs over the components is very constant among the bipolar transmission systems, but slightly differs from the cost distribution in the case of a back-to-back system. In addition the back-to-back station is relatively cheaper. Hingorani\textsuperscript{46} claims a cost difference of 15-20 percent in advance of a back-to-back station when compared to a bipole transmission station of comparable power rating. Finally, table 5.1 shows the decrease in different converter stations over 1995/6-98. In figure 5.3 typical variability of HVDC converter costs is shown. The cost ranges were adjusted for inflation.

![Figure 5.3: Typical variability of HVDC converter costs in 2001 US$. Based on EPRI’s HVDC Handbook\textsuperscript{50} (1992), Hingorani\textsuperscript{46} (1996) and CIGRE\textsuperscript{48} (1998). The costs were corrected for inflation.](image)

The figure clearly shows that the 1992 costs are much higher than the 1996 costs. The 1998 costs need a little more explanation. The 1998 costs were split in back-to-back and bipole transmission figures. This clearly shows the cost differences between these configurations. In this example, the mean costs for a 500 MW back-to-back station is about 69% of the mean costs for a bipolar transmission converter of the same power rating. When the costs of a 500 MW station from 1992 and 1996 from this figure are compared to the mean of the back-to-back and the transmission stations of 1998, a decreasing trend can be seen over all three data sets: 1992: $163/kW, 1996: $112/kW, 1998: $102/kW (2001$). To be able to compare the varying cost data, the cost trends at optimal voltage over the power are surveyed. From the trends shown in figure 5.3, the 500 MW systems were scaled to 1. The result is shown in figure 5.4. The two steeper lines at lower power range are due to the back-to-back cost figures. Because in this survey transmission converter stations are discussed, these data are not taken into account. To the mean values of the other data the black trendline was fitted with a linear regression ($R^2$) of 0.9959. Figure 5.5 shows in grey the converter station capital cost data that were found. Although the data were already corrected for the variance with the power rating and were all set to 500 MW converter systems it can be clearly seen that the variation is still very large. The data were checked for the other uncertainties mentioned at the top of this paragraph. Then this information was used to improve the data. First of all, the Back-to-Back data and the data that concern average values of both B-B and transmission converters were corrected with the use of the relationship calculated from figure 5.3.
Figure 5.4: Relative converter station capital costs per kW, based on figure 5.3. The costs for a converter station of 500 MW rating are scaled to one. The thick black line indicates the line fitted to the mean values of the relative costs as described in the text.

Figure 5.5: Experience curve of converter cost data in costs per kW (1986-2002) The data were adapted to 500 MW systems. The rough data are shown in grey, the improved data set in black. In the left upper-corner, the information of the line fitted to the rough data is shown, on the right, the information of the line fitted to the improved data.

\[ y = 176193x^{0.6825} \quad R^2 = 0.308 \quad PR = 62.3\% \]

\[ y = 373034x^{0.7513} \quad R^2 = 0.7469 \quad PR = 59.4\% \]
Furthermore there are data taken from studies that assume the cost – power rating relation to be linear. Because the most recent projects converter station have maximum power ratings that do not exceed the 500 MW very much, it seems a good guess to take the options that are as close as possible to 500 MW. Finally, the data that seemed to contain large uncertainties were omitted. The result can be seen in figure 5.5 as the black data set. With this operations the PR remained almost unchanged: 59.4% (was 62.3%), but the $R^2$ was improved: 0.7469 (was 0.308). When the adjusted back-to-back data are omitted (2 data points) from these data both $R^2$ and PR values remain about the same (0.796; 61.3%). In the assessment of Hauth potential cost reductions are addressed to several components. First of all an estimation of cost reduction by two vendors is mentioned (1995): 6.9 - 17.7% & 30 % for the next 10 years (1995-2005). The vendors suggest that the largest savings would be realised if the converter transformer could be eliminated. Advancements in valve technology would also result in large savings. Advances in control, protection and communications technology are meant as feasible and cost effective. Finally the standardisation of design could reduce project administration, engineering, manufacturing and construction costs. In this last mentioned point, the learning effect can be clearly recognised.

5.2.3 AC transmission

Because of the even larger variability and enormous world-wide production of electronics for AC applications, it is difficult to get full figures of AC transmission electronics. The electronics that are required can be divided in transformers, switchyards & reactive power control. Because of the fact that the existing installed amount of AC electronics is much more than HVDC, the possible cost reduction will be much lower. To get experience curves for AC transmission (as well as the power collection) it will probably be the only feasible solution to split up these costs in the different components. If it is true that cost information for AC transmission exists as in-house information in many utilities, this could be a possibility.

5.2.4 Specification of possible cost savings per component

As already indicated in paragraph 3.3, the cheapest option for the longer distances to shore and the larger park sizes is already DC transmission. In this research very scarce information was found on AC transmission. A trend that is mentioned in literature is however, is that this difference in costs will only grow, because the costs of DC transmission are expected to drop faster than the costs of AC transmission. When the power electronics that are required for DC transmission are examined into more detail the fields of interest for cost reductions can be specified. In general it can be said that hardly any learning effects can be expected from the transformers. A number of possible learning effects is already indicated above: ‘Advancements in valve technology would also result in large savings. Advances in control, protection and communications technology are meant as feasible and cost effective. Finally the standardisation of design could reduce project administration, engineering, manufacturing and construction costs.’ Furthermore a technical change can be expected from ABB’s and Siemens’ HVDC-light/plus projects. According to Bauer this would also improve the power control, which would mean an extra cost saving.
Chapter 6: Integration of data

6.1 Application example of the obtained experience curves

In the preceding chapters cost trends in both submarine power cabling and power electronics are discussed. To indicate the possible application of data like these, an example will be shown in this chapter. When a large offshore wind farm of 1 GW, 50 km offshore is taken as system, according to DEA/CADDET the contribution of the grid connection to the costs will be 18%, the internal grid 5%. When the grid connection is assumed to be an HVDC connection, the possible cost reductions can be investigated with the data from chapter 4 and 5. The system that is taken for this calculation is a bipolar 1000 MW system. As possible production scenario, the cumulative production of the period 1995-2000 was extrapolated to 2005, 2010 and 2015 for both HVDC submarine cables and converter stations. These data were filled in in the formulas of figure 4.10 and 5.5 to generate the costs of respectively the cables and the converters in 2001 Euros. To correct for the laying costs, the cable costs were multiplied by 1.5 (one third of the costs concerned to be due to laying based on paragraph 4.3.) This means that the laying costs are assumed to adopt the same PR as the as the cable production costs, which is not necessarily correct. The calculation results in the data that are shown in table 6.1. A possible transmission cost reduction of 25% for 2015 is estimated from the experience curves of the preceding chapters. This cost reduction in the transmission system will apply to a cost reduction of 4.6% on the total wind farm.

Table 6.1: Possible cost reductions for the power transmission to shore from a 1000 MW wind park, 50 km from shore. The data are based on the experience curves shown in figures 4.10 and 5.6. Cable laying costs are assumed to add 30% to the cable costs, and the grid connection costs to account for 18% of the total park costs.

<table>
<thead>
<tr>
<th>year</th>
<th>costs of converter stations (MEuro)</th>
<th>costs of cables incl. laying (MEuro)</th>
<th>Total transmission costs (MEuro)</th>
<th>Cost reduction of transmission</th>
<th>Total cost reduction due to transmission</th>
</tr>
</thead>
<tbody>
<tr>
<td>2000</td>
<td>211.55</td>
<td>83.06</td>
<td>294.61</td>
<td>0%</td>
<td>0.0%</td>
</tr>
<tr>
<td>2005</td>
<td>192.10</td>
<td>70.69</td>
<td>262.79</td>
<td>11%</td>
<td>1.9%</td>
</tr>
<tr>
<td>2010</td>
<td>176.37</td>
<td>62.51</td>
<td>238.88</td>
<td>19%</td>
<td>3.4%</td>
</tr>
<tr>
<td>2015</td>
<td>163.34</td>
<td>56.60</td>
<td>219.94</td>
<td>25%</td>
<td>4.6%</td>
</tr>
</tbody>
</table>

The extrapolation of the HVDC data results in a addition of 22 GW transmission capacity in the period 2000-2015. This number is relatively small compared to the addition of wind energy, estimated by BTM. BTM estimates an addition of 40 GW wind energy capacity in the period 2001-2005, of which 2.4 GW will be offshore. As of today, no HVDC transmission is planned for this period. For the period 2006-2010 however BTM estimates the addition of 86 GW. In this period a larger portion of the added wind energy will have to be planned to achieve an addition of 86 GW. When ten percent (8.6 GW) would be planned offshore in this period, it seems plausible to assume 4 GW to adopt a HVDC transmission line to shore in this period, at an average distance to shore of 40 km. When we assume an extra addition of 10 GW offshore wind energy to be planned at an average distance of 50 km to shore in the period of 2011-2015, the total cost reduction in 2015 is calculated at 6.1% as can be seen in table 6.2. More interesting however is the decline in costs that is shown for the component itself: 34%.

Table 6.2: Possible cost reductions for the power transmission to shore from a 1000 MW wind park, 50 km from shore with the assumption of the application of HVDC transmission in a representative part of the wind energy additions in the period from 2006 to 2015.

<table>
<thead>
<tr>
<th>year</th>
<th>costs of converter stations (MEuro)</th>
<th>costs of cables incl. laying (MEuro)</th>
<th>Total transmission costs (MEuro)</th>
<th>Cost reduction of transmission</th>
<th>Total cost reduction due to transmission</th>
</tr>
</thead>
<tbody>
<tr>
<td>2000</td>
<td>211.55</td>
<td>83.06</td>
<td>294.61</td>
<td>0%</td>
<td>0.0%</td>
</tr>
<tr>
<td>2005</td>
<td>192.10</td>
<td>70.69</td>
<td>262.79</td>
<td>11%</td>
<td>1.9%</td>
</tr>
<tr>
<td>2010</td>
<td>168.86</td>
<td>62.51</td>
<td>229.58</td>
<td>22%</td>
<td>4.0%</td>
</tr>
<tr>
<td>2015</td>
<td>143.48</td>
<td>50.92</td>
<td>194.40</td>
<td>34%</td>
<td>6.1%</td>
</tr>
</tbody>
</table>
The possible cost reductions that can be achieved for HVDC transmission in a time range of ten years as calculated here (19-26%) lies in between the values suggested by the vendors for the period 1995-2005 as mentioned in paragraph 5.2.1.

Although the example of this chapter is based on a relative small amount of data it is able to show the applicability of the experience curves and the effect of different assumptions on the results. First of all it is clearly shown that when a technology is relatively young, different estimations of future production have large effect on the cost data. This effect becomes even larger at large progress ratios. It would probably be better to show the cost reductions with an additional production than against a time scale. Moreover, the data could than be easily used to calculate the total of the needed extra investments that are needed to make the technology competitive to conventional technologies, as indicated by OECD/IEA\(^1\). In the case of HVDC transmission to shore for wind energy, the totals of additional production are not only based on the part that is used for wind energy. This introduces another difficulty in the straightaway calculation of future cost reductions of offshore wind energy, using the sum of experience curves of its components. Because of the use of the components in different other markets as well (e.g. nacelles for onshore wind energy, cables for other power transmission purposes and foundations, although adapted in other offshore applications) the cost reductions of all components should be calculated, integrating the production figures with its specific market information. This means that for example in the case of an addition of 10 GW offshore wind energy with HVDC transmission, the addition in percents of offshore wind energy would be 400% whereas for HVDC converters 18%, for nacelles and other onshore wind energy components about 25%, and for the middle voltage, in-park cables far less. With the example it is shown that when this problem is handled with care, this does not have to form a large obstacle. The example further indicates that when full data can be achieved for all components, the possible cost reductions of many options could be surveyed by simply changing variables.

In the example the cost difference between XLPE and paper-based insulation could be incorporated as well. Because the cable portion of the total installation costs is relative small (26-31%), the effect is not dramatic. The use of XLPE cables in 2015 would reduce the installation costs for the power transmission with 31% to 39% compared to 2000-prices, respectively for the scenario without and with wind energy HVDC transmission included. The effect of the power transmission on the total wind park investment costs would than be a cost reduction of 5.5 – 7.0%. Of course the effect of the reduction on the total wind park is strongly influenced by the choice of the cost distribution over the different components.

The uncertainties in the example of this paragraph are considered in more detail in the next chapter. Moreover, the methodological implications that this example and its uncertainties show will be described.

### 6.2 Identification of possibilities for cost reductions for each component

Throughout this report a number of possible origins for cost reductions were mentioned. Because the most information was found for HVDC transmission, this paragraph will be focussed on HVDC transmission. First of all the bottom-up approach facilitates an examination of the possible effects of the cables and the power electronics each apart. The preceding paragraph shows the order of magnitude of the differences between possible learning effects in both subcomponents. At the time range from 2000 to 2015 the cost reduction for converters is calculated at 23-32% whereas the calculated cost reduction for the power cables in the same period is significant higher: 32-39%. For the calculated example (1000 MW; 50km) this means that the cable accounts for about 1/4 of the transmission costs, whereas this subcomponent accounts for over 1/3 of the possible cost reduction. More of the feasibility of cost reduction for each subcomponent can however been extracted from the specific information that was found in this research. Because the subcomponents were not further split up into more experience curves, the identification of possible sources of cost reduction is mainly based on literature. The points were cost reduction could potentially be achieved are indicated in table 6.3.
Table 6.3: Identification of possible sources for cost reductions specified for each subcomponent of HVDC power transmission from offshore wind parks to shore.

<table>
<thead>
<tr>
<th>component</th>
<th>possible improvement</th>
</tr>
</thead>
<tbody>
<tr>
<td>Cables</td>
<td>Applicability of XLPE insulation to higher voltage DC</td>
</tr>
<tr>
<td></td>
<td>Standardizing the design of HVDC cables</td>
</tr>
<tr>
<td></td>
<td>Improving the techniques for surveying the route and cable laying</td>
</tr>
<tr>
<td>Power electronics</td>
<td>HVDC-light / HVDC-plus</td>
</tr>
<tr>
<td></td>
<td>Improving control, protection and communications technology</td>
</tr>
<tr>
<td></td>
<td>Standardization of the design</td>
</tr>
<tr>
<td>General</td>
<td>Standardization of park-layout</td>
</tr>
</tbody>
</table>
Chapter 7: Conclusions, Discussion & Recommendations

While reading this report, one of the things that will be noticed is the incompleteness of data. Partly this is due to the availability of data, but also to the relative short time span that was dedicated to this study. In this chapter both the results of the study and the possibilities for further research will be discussed. Because the results show a clear division in HVDC and AC, the same partition will be made in the discussion of the results and possibilities for further research.

7.1 HVDC transmission

7.1.1 HVDC submarine cables

In this report experience curves for both HVDC submarine cables and HVDC converter stations are shown. In both cases, the cost data for the curves are mainly based on estimations and calculations from feasibility studies. Hardly any data of realized projects were found and when data were found, the data were in general not specified by components. The uncertainties introduced in the data by this fact are too large to use them to construct an experience curve. The origin of the data however has different effects on both components. Although the cables are no off-the-shelf products and are designed for every specific project separately, they show less variance than converter stations. This can be seen as one of the reasons that for the cables a relative reliable experience curve was found. The linear regression coefficient after the omission of the XLPE (0.9315) can be even considered to be relative high given the frame of the methodology. As described in paragraph 4.3, one third of the data do include laying costs. The correction that was applied for the laying costs can be assumed to be acceptable, because the omission of the data points hardly effects the PR and the $R^2$ values. Besides the uncertainties that are introduced by the small amount of data and the data variance, there is an extra uncertainty in the positioning of some of the data points on the x-axis. This uncertainty is caused by the fact that some of the data points concern estimations that are based on for example ‘1996-prices’ or ‘1993-prices’, combined with the fact that the annual production normally consists of a few cables it makes the place at the production axis uncertain. When cost data are based for example on ‘January 1992’ prices, it seems to be clear, that all HVDC ties that were commissioned in 1991 should be included in the cumulative production, whereas 1992 projects should be excluded. The exact cumulative production becomes less clear when ‘1993-prices’ are concerned. It could even be discussed whether prices will possibly be more affected by the contracting of projects than by the finishing of the projects. Because the installation-dates of the project available instead of the commissioning-dates the only possibility was to use the installation data.

From the experience curve shown in figure 4.10, the difference between paper-based insulation and XLPE insulation can be very roughly indicated. The mean value of the two XLPE data points is 399 Euro/km/MW, whether the value of the fitted curve indicates a value of 544 Euro/km/MW for the conventional insulation types at the same date. From this the cost of a XLPE cable is calculated at 72% of the cost of conventional cables. Because this estimation is based on only two data points, it can only be used as an indication. When the new isolation type could be used for HVDC transmission in the future, the experience curve may adopt the ‘double-knee trend’ as shown in figure 2.3 in the near future.

For the cables one large component lacks: the cable laying process. In fact, this component can not be assumed to have the same PR as the production of the cables as was done in chapter 6. For this part a few data were found (both laying and ploughing), but because the conditions may vary strongly, the costs per km or MW will be very variable as well. The construction of an experience curve will be very difficult, because the laying costs will be depending on cable weight, water depth, seabed conditions, weather conditions and cable length. An option would be to survey the costs of a laying vessel and a ploughing / burying machine per day. For specific projects the occupancy time of the equipment could then be estimated. However, it will still be difficult to specify a measure for the cumulative use of equipment. Moreover, it can be questioned whether this level of detail is not too high for the experience curve based
type of research. To get a better experience curve for the cables it would be helpful to get more exact cable data. It turned out to be really difficult to get these data. All cable manufacturers that were contacted could not give cost data. This problem is also reported by the HVDC research centre in Manitoba where a lot of research on HVDC transmission has taken place. Most researchers are looking for recent data that may help to compare HVDC and AC options in the actual situation. For the experience curve approach it will be very useful however, to get some older data as well. Probably these will be easier accessible. A possible way to get these data is trying to get the cost data of a part of the relative small amount of HVDC submarine ties. In many cases this is confidential information, but for the older projects, these data probably will not be confidential anymore.

A final remark on cost data of submarine cables is the following: The definition of cable cost per meter per MW capacity is an approximation that introduces some uncertainties. First of all, the cost will not have an exact linear relationship with the power rating. Moreover the cost of a cable for a certain power level can be reduced by the allowance of higher power losses. When the costs of the power losses would be amounted to the cable costs, the cheaper investment option could in the end be more expensive. Therefore it would make sense to define a maximum power loss level in the cost data as well, which could be done in further research.

7.1.2 Converter stations

The converter systems adopt even a larger variability than the cables. As shown in chapter 4, this makes it even more difficult to generate an experience curve. The curve that was constructed in this report shows a very low PR, but is according to the $R^2$ value far less reliable than the curve of HVDC submarine cables. Again the correction of the data result in an improvement of the reliability. The linear regression that is finally achieved (0.7469) seems to be acceptable, but the PR of this curve is even lower: 59.4%. Referring to the PR distribution that is shown in figure 1.3, this is an extreme value. In comparison to the cost reduction estimations of the two vendors, described in paragraph 4.2.2 however, this value seems to be realistic. When using the extrapolation from chapter 5, the cost reduction with this PR in the period 1995-2005 would be 18.7%. This value lies in between the estimations of the two vendors (which show a dramatic difference): 6.9-17.7% and 30%. The fact that the $R^2$ values as well as the PR of the curve are hardly effected by the omission of the adjusted back-to-back data, indicate that the adjustment is acceptable.

The difficulty of data-acquisition is again due to the reticence of the vendors to provide cost information. This reticence is to a large extend due to the dominance in the market. Again it will be most promising to investigate whether it is possible to get older cost data. Another possibility to construct an experience curve for the converter stations was indicated by P. Bauer. He claims that cost trends of components of converter stations and cost developments of these components are available. When these data are available indeed it would be very promising to combine the data of the converter station components (Thyristors, IGBT’s, transformers, switchyards, filters etc.) to an experience curve for converters. The experience curves for these components however were not found given the limits of available time. It is recommended for further research to search for these data.

7.2 AC transmission

The data on AC transmission that were found for this report were too scarce. In the CIGRÉ Working Group 14.20 Report however, it is reported that ‘Many Utilities have in-house, up-to-date and fairly valid capital cost estimates for most AC transmission equipment’. This indicates that the AC data should be much easier to get than DC data. Whether this accounts for historical data as well has to be investigated. One of the largest problems with AC data that will remain is the larger variability. Where in the investigation of DC cables there should be dealt with the existence of different isolation types, insulation thickness and power ratings, for AC cables the existence of three core cables and the much broader power range add to this. Furthermore, the existence of three-core cables that are cheaper options than three one core cables will disturb the experience curve. At higher voltages (roughly >60 kV) no three core cables can be applied.
because they get unwieldy. To generate experience curves for AC cables, the AC cable market will have to be split up in more parts. At least the splitting up in MV and HV cables seems to make sense, because of the large difference in cable size. With the splitting up of the market however, some problems arise. First of all it is hard to say where to put the boundaries. The boundary between MV and HV could for example be chosen somewhere in between 30 and 45 kV. It is however difficult to define this boundary, due to several reasons. Moreover, the experience in LV cables could cause cost reductions in other voltage ranges as well. This can clearly be seen in the development of the submarine cable market. In figure 3.8 it is shown how XLPE insulation is first introduced in lower voltage cables and steadily developed to higher voltage applications. Because of the relative small difference in design between underground cables and submarine cables, this ‘cross-boundary’ learning effect can be expected in this case as well. An important difference between MV and HV cables is that HV cables will in many cases be specially designed for every project apart, whether lower voltage cables will be produced in a semi-continuous project. According to Grübler this would mean that the lower voltage cables will in general have a more progressive PR than higher voltage cables. Most probable however, the boundary between ‘mass produced’ cables and specially designed cables – which will always be a smooth boundary – will have developed and will develop in the future to higher and higher voltages.

It is recommended to search for possibilities of constructing an experience curve for AC power electronics by the combination of the experience curves of components. The diversity of AC options makes it hardly possible to create figures of cumulative production of ‘power electronics for AC transmission’ as a general. Again, it should be considered whether this level of detail is desirable.

### 7.3 ‘The kink of 1983’

All through this report the phenomenon of ‘the kink of 1983’ was observed. It would be desirable to find an explanation for this kink. From the cable data shown in figure 4.8 it could be concluded that the introduction of the cheaper option of extruded insulation and the good applicability of XLPE insulation (better than the rubber type) stimulated the production of submarine cables. An explanation for the increased production after 1983 on the other hand could be searched for at the demand side as well. This could probably give a better explanation than the above addressed, because the same increase is observed for submarine HVDC cables as well. As described above, still no commercial HVDC connections with XLPE insulation have been produced. Moreover, the increased production of BB converters shown in figure 5.2, can of course not solely be explained by market changes in the cable market. B-B converters are built to connect electrical power systems. A market driven increase of production seems therefore to give more evidence in this case as well. The trend to couple electrical systems can however not explain the increase of AC-cable production. It seems to be most realistic to dedicate the origin of the increased production in a combination of technological changes and market changes.
7.4 Quality assessment of the bottum-up approach in this research

The quality of the final integration of all data as shown in the calculated example in chapter 6 can be divided into two classes, the quality of the data and the methodological possibilities, as described below.

7.4.1 Quality of the data

The data that were found for this research did show a relative high degree of uncertainty. The uncertainties in the data can be specified in the following points:

- The position of the data on the x-axis
- Data are not evenly spaced on the x-axis, difference in weighting
- Rough estimations
- The estimation of cost variance with power rating will not be perfect
- Small amount of data
- Cable laying
- Different converter station configurations
- Large spread in cost-data of the converters

Because for the integration of the data a number of assumptions were made, a number of additional uncertainties were introduced:

- Distribution of costs over the wind park components (power transmission set to 18%)
- Correction for cable laying (set to an addition of 50%)
- The production scenario (smaller uncertainty when cumulative production is taken as x-axis)

The largest part of the uncertainty in the cable cost can be addressed to the cable laying costs. The uncertainty in the converter station costs in general is larger, and for the converters it is more difficult, to address the largest part of the uncertainty to one or two components. As already indicated in paragraph 5.1, the differences in quality of the equipment can cause a (large) difference in prices. In principle this is the fact with all kind of products, but when products become more complex, the quality difference becomes larger and so will the prices. When the cheapest and most expensive light bulb are compared for example, the ratio will be much smaller than when this comparison is done for cars. The uncertainty specific for the integration done in the example of chapter 6 can be reduced by concerning only the possible cost reductions of the power transmission itself, and when cumulative production is taken as the x-axis. In the later option however still the cumulative cable length should be coupled to the cumulative power rating.

Because the decrease in costs of HVDC is larger than the decrease in costs for AC-transmission, the break-even distance for the choice between AC and DC will decrease. In literature this decrease can already be observed. This effect indicates that the probability of choosing for HVDC options will become larger, therefore, the scenario sketched in chapter 6 could be an underestimation.

7.4.2 Methodological advantages and disadvantages

Because of the fact that the bottum-up approach is a relative new approach in studies using the experience curve concept, it is interesting to list the advantages and disadvantages of this new approach towards the ‘standard’ experience curve based study here. First of all, the bottum-up approach indeed provides a basis for a better and more detailed understanding of the possible cost reductions in the future. This could therefore be useful to be able to pay attention to which investments could be most promising to decrease the costs. On the other hand the researcher should try to search for an optimal level of detail. When this research is taken into account, this choice is visualised by the converter stations. Because of the variability of the design of converter stations, the variability of the costs will be larger than for other products, like cables, which show a smaller technical variance. Taking every single part of the station into account,
however would affect the ‘black-box’ principle of the experience curve principle. Because in chapter 5 it is shown, that with educated corrections, it is possible to generate a reasonable good experience curve it should be questioned whether it is wise to go into more detail. This choice should however be made on the basis of insight in both the quality of the existing experience curve and the availability of standard cost data of the converter station components. Because of the relative short timeframe of this project, no final answer to this question can be given.

The uncertainties that were addressed to the integration in the proceeding chapter give an idea of the possibilities of experience curves in a bottom-up approach. It clearly shows how the breakdown of the problem provides more detailed insight in the cost development, but also that the data should be handled with care. Before using the experience curves and combining the calculated curves, it is important to be aware of the assumptions that were made for the construction of the curves. When one would like to combine the experience curves of chapter 4 and 5 to calculate the possible cost reductions for a system of 500 MW at 50km distance for example it should be noted that the (cost per kW / power rating) ratio is assumed to be constant in the experience curve for HVDC cables, whereas this is not the case for the experience curve constructed for converter stations. Because of the different cost trends of the separate components it seems wise to combine the different experience curves only at the very last step of the analysis. And when coupling the experience curves it should be considered whether all variables of both experience curves are compatible with each other.

The construction of stand-alone experience curves of each component also gives other advantages. First of all different scenarios, different park layouts, etcetera can be calculated by the changing of variables. Second, if the situation in the field of one of the components drastically changes -for example due to an R&D breakthrough-, the effects on the cost development for the whole technology can be calculated relatively easy.

An important advantage of the bottom-up approach that adds to the higher level of detail is the fact that it reveals a possibility for using experience curves for very new technologies. By the use of a set of substitutes for the components of a new technology, experience curves for these techniques could be constructed.

7.5 General conclusions and Recommendations

7.5.1 Objectives

In paragraph 1.2 the objectives of this study were split up in the following parts:

1 The survey of cost reductions of the electrical infrastructure of existing offshore wind parks and/or substitutes.
2 The construction of one or more experience curves of (components of) the electrical infrastructure for offshore wind energy.
3 Analysis of the origin of the achieved cost reductions.
4 Identification of possible cost reductions in the future.

Furthermore, some methodological objectives for this study were formulated:

5 Identification of the problems that arise upon combining different experience curves, and solutions to these problems.
6 Recommendations for the use of experience curves in a bottom-up approach.

(1) Because of the small number of existing offshore wind energy projects, the survey of cost reductions in this study was mainly based on the possible cost reductions of substitutes for the electrical infrastructure. (2) The study succeeded in the construction of experience curves for the HVDC transmission option, but not for AC options. Considering the possibility – sketched in paragraph 7.3 – that HVDC may be the
cheapest option for all wind parks in the future, the results that were found for HVDC transmission may be assumed to be sufficient. The experience curves that were constructed, led to an estimation of the possible cost reductions of HVDC transmission to shore as a total. (3) The analysis of the origin of achieved cost reductions was not worked out in this report to a high level of detail. The cost reductions were however split up in two parts (Cables and PE). Moreover it can be mentioned that no large technological change have taken place within the time frame of the experience curves (respectively 1988-2000 and 1986-2002). (4) The possible cost reductions in the future for power transmission of offshore wind energy to shore were estimated in chapter 6. Moreover the possible origin of cost reductions in the future were mentioned. For submarine cables, the application of XLPE insulation is mentioned, whereas some options are mentioned for converter stations as well. (5 and 6) The methodological problems and solutions to these problems are described in paragraphs 7.4.2 and 7.5.4.

7.5.2 Conclusions

Two experience curves were constructed in this report for submarine HVDC cables and converter stations, resulting in the estimation of a possible cost reduction for the entire HVDC transmission to shore. The PR that was found for both components was relative low (respectively 69.7% and 59.4%). Combined with the fact that a relative small amount of HVDC connections is commissioned so far, this results in a substantial possible cost reduction in the future, estimated at 34% in 2015. Due to the number of uncertainties summarised in paragraph 7.3, there is a relative large variability in this estimation possible. A larger cost reduction could be achieved when XLPE cables could be used for HVDC transmission in the future. Almost no cost reductions can be expected from the converter transformers, the largest cost reductions should be expected from the semiconductors (valve technology). Furthermore large cost reduction could be expected from advances in control, protection and communications technology and standardisation.

7.5.3 Recommendations for further research

DC cables
The cost data of some older projects could improve the experience curve. The submarine HVDC listing in paragraph 4.2 (table4.4) depicts all projects that could provide this information.

AC cables
Not too much time was invested in the collection of these cost data because of the time frame of the research. According to CIGRÉ working group 14.20 cost information on AC transmission should exist as in-house information in many utilities. This could therefore be a source of information.

Cable laying
Cable laying costs are very variable, an option could be to study the costs of a laying vessel and the costs of ploughing machinery at a time scale. This could possibly be the only way to standardise the cost for observing cost trends.

Power electronics
For AC Power electronics, the in-house information mentioned under ‘AC cables’ could be a source of information. Furthermore, it should be investigated whether cost trends of the different components could be found (IEEE transactions).

General
The cost differences between XLPE insulation and paper insulation for AC cables could be surveyed in more detail to get a better idea of the cost reductions for HVDC transmission that could be caused by the switch to XLPE insulation. It should however be remarked that the difference in XLPE design in DC cables compared to AC cables (think of inorganic fillers to control space charges) could change this cost relation.
The use of several substitutes for the transmission as for offshore wind energy in general, introduces the problem that all experience curves will be based on a different production-axis. Therefore it seems to be more achievable, to do estimations, based on certain scenarios, like in chapter 6, than to construct one experience curve for the whole technology.

7.5.4 Methodological implications

Besides the quantitative results of this research, the bottom-up approach implicated new possibilities for the use of experience curves. The advantages of this approach can be summarized by the following points:

- A higher level of detail is achieved, which creates the possibility to indicate the possible cost reductions in the future for each of the components of the studied technology.
- Different scenarios can be studied by the changing of a few variables.
- Changes in the market of one of the technology’s components can be introduced in the combined experience curve with relative ease.

This study has revealed some lessons for the use of experience curves in a bottom-up manner as well:

- Because there will always be a certain variance in the data (for example cost/quality of a certain product) one will always have to make assumptions in the calculation of an experience curve. Because these assumptions will be most probable different for each component, it is important to be aware of these differences when combining the experience curves.
- The flexibility of the data, which is mentioned above as advantage of this approach, will be maintained if the experience curves of each component is handled as a separate variable until the last step of cost analysis.
- When combining the experience curves to one general curve, the variables in each curve should be compatible. It could therefore create problems like they are sketched in paragraph 6.1 for this research: In the case of an addition of 10 GW offshore wind energy power with HVDC transmission, the addition in percents of offshore wind energy would be 400% whereas for HVDC converters 18%, for nacelles and other onshore wind energy components about 25%, and for the middle voltage, in-park cables far less. This adds to the recommendation to handle the experience curves of each component as stand-alone curves.
- When using a bottom-up approach, the optimal level of detail should be found. In general a number of factors can be mentioned that will be important for this judgement. On one hand, the research investments should be judged: ‘availability of (detailed) data’. On the other hand the possible improvement of data quality should be considered to judge whether the extra time-investment is worth it. The possible improvement of data quality has to do with both the availability of detailed data and the variability of the component. In this study for example, the increase of the level of detail in the experience curve for power electronics could be considered (breakdown into more experience curves of the subcomponents), whether this is not in question for the cable production. This has to do with the much larger variability in the power electronics.
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ABB, www.abb.com


ABB Reference lists of power cables, kindly supplied by Mr. Anne Zander (ABB).


EPRI’s HVDC Handbook (1992)


Contact with Dr. Ir. P. Bauer, Department of Power Electronics and Electrical Machines of the Delft University of Technology.
Appendix A: Abbreviations

AC : Alternating Current  
B-B : Back-to-Back converter station  
DC : Direct Current  
EHV : Extra High Voltage  
EPR : Ethylene Propylene Rubber  
GTO : Gate-Turn-Off Thyristors  
HV : High Voltage  
HVDC : High Voltage Direct Current  
IGBT : Insulated Gate Bipolar Transistors  
LPFF : Low Pressure Fluid Filled  
LPOF : Low Pressure Oil Filled  
LV : Low Voltage  
MIND : Mass Impregnated Non-Draining  
MV : Middle Voltage  
O&M : Operation and Maintenance  
PE : Power Electronics  
PWM : Pulse Width Modulation  
R&D : Research and Development  
VSC : Voltage Source Converter  
XLPE : Cross-linked Polyethylene

Appendix B: Inflation calculation

The currencies were converted to Euro’s using the average exchange rate between the currency and the German Mark (DEM) of the month or year whereto the data point refers. The historical exchange rates are taken from www.oanda.com/convert/fxhistory. The costs in DEM were then converted to Euro’s by multiplying with the exchange rate between the currencies, that is fixed since January 1st 1999. The prices were corrected for inflation using the inflation information from IMF. These data contain the annual inflation data for the last decade and the average annual inflation between 1982-1991. The factor by which the data referring to a certain date should be multiplied is calculated as follows:

\[ \text{year}_n \times \frac{100}{100-\text{inflation}_n} \cdot \text{year}_{n+1} \]  \hspace{1cm} (B1)

This formula gives the inflation factor for 2000, the inflation factor for 1999 is calculated by multiplication of the inflation factor for 2000 with the inflation factor for 1999-2000, which is calculated by formula (B1) and so on.