Clingendael International Energy Programme

Wind and Gas

Back-up or Back-out
"That is the Question"

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Definitions

Capacity credit: The capacity of a power plant that can be regarded as firm capacity. The capacity credit of a conventional power plant (gas, coal or nuclear) is usually around 90-97% of the nameplate capacity. Capacity credit of wind can vary between 5-40 % (see Box 1.).

CCS: Carbon Capture and Storage

Efficiency of a power plant: the ratio between the total input and output of a power plant (in MWh)

Full load hours: the average annual production divided by the maximum capacity

LCE: Levelised Cost of Energy, the lifetime discounted cost of generated power, expressed in the cost per unit of generated energy (e.g. €/MWh)

Load factor: the ratio of the average demand or supply to the peak demand or supply over a period of time

Long-term back-up capacity of wind: In this study 'long-term' back-up capacity refers to the generation capacity that has to be available in the power generation mix in case of longer periods (more than four hours) without wind supply.

Nameplate capacity or *maximum capacity* or *installed capacity*: the technically maximum output capacity of a conventional power plant or wind turbine (usually given in MW or GW)

Part load operation: when a power plant operates at lower than its nameplate capacity

Peak demand: the period of maximum demand in a year's time (in NW Europe it is usually in the winter period around 6 pm)

Ramp rate: the rate of change in output of a power plant

Renewable energy: energy which comes from natural resources that are naturally replenished over a period of time, such as wind, sun, hydro, biomass, biofuel and geothermal

Short-term back-up capacity of wind: In this study the 'short-term' back-up capacity of wind means the increase of the conventional generation capacity that has to be reserved 1-4 hours before production to compensate for the uncertainty of the electricity demand and electricity supply.

Spinning reserve: extra generating capacity that is available by increasing the power output of generators that are already connected to the power system

Variable costs: In this study variable costs comprise the fuel costs, carbon costs and variable operational costs of a power plant.

Variable energy source: a source of energy that is not continuously available due to some factor not directly controllable, such as wind and solar power

Wind penetration level: the percentage of the total annual electricity consumption that is produced by wind

1.

Preface

The European Union has set a target that in 2020 its CO_2 emissions should be at least 20% lower than they were in 1990. It is also aiming for an 80% reduction in CO_2 emissions by 2050 as compared to 1990 levels. To achieve this goal the CO_2 emissions from power generation should approach zero by 2050. Several studies have been published on the different ways to achieve a future low-carbon European power generation mix. The potential of fossil power generation suggested in these studies differs considerably; some even come to the conclusion that a power generation mix based on 100% renewable power generation could be possible. At the same time, the technical and economic difficulties of a power system which has a large share of variable renewables are increasingly being raised. Furthermore, in the public debate, when addressing the variable nature of wind energy, the partnership between wind and natural gas is often emphasised.

The focus of this study is to explore the effect that the deployment of a large share of wind energy has on the Northwest European power generation mix in the current market circumstances. The starting point of the study is that wind power is added to the power generation system with the aim to reduce CO_2 emissions. Several other studies, papers and reports have been published on this subject which underline the complexity of the issue. Facts, projections and speculations from these studies have been assembled and analysed to give an as objective as possible overview on the foreseen effects of an increasing share of wind energy. As such, the study aims to give general insight in what would happen to the power mix if more wind energy were to be introduced, what the contribution to CO_2 emissions reduction would be, and the potential role of natural gas and other fuels in handling long periods (> 4 hours) of low wind supply. The goal has not been to deliver an all-encompassing literature study, nor to calculate every scenario we could envisage, but rather to unravel some of the complexities related to back-up capacity required in an electricity system with a large share of variable power.

The study is a result of many debates and discussions at CIEP. When the study was beginning to take shape a consultation group was assembled to structure these discussions. This consultation group consisted of experts from Eneco, Energy Delta Institute, Gasunie, GasTerra, NAM, Nuon and Shell. CIEP wishes to thank those people who participated in the consultation group. They provided useful industry insights and created the opportunity for reflection throughout the course of this work.

2.

Summary and Conclusions

2.1 The contours of this paper

There are a number of reasons for adding wind energy (and various other renewable energy sources) to national energy systems:

- it reduces dependency on fuel imports,
- it replaces fossil fuels, a finite source of energy, and
- it contributes to a low-carbon future.

Of all renewable options, wind energy has become the most prominent in Northwest Europe[1]. Targets for installed wind capacity for 2020 are on the order of 100 GW (See Figure 1).

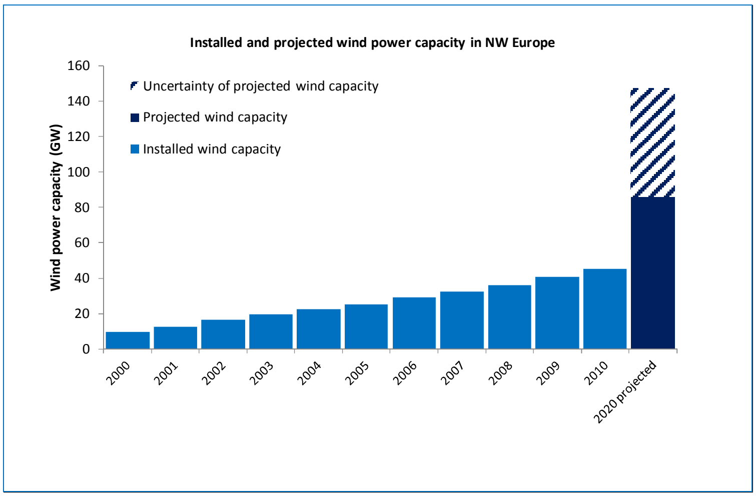

Figure 1: Installed and projected wind power capacity. Source of information: EWEA

Natural gas is often mentioned as a suitable partner for wind. This paper tries to substantiate and quantify the current and potential relationship between gas and wind in Northwest European electric power supply in the context of the transition towards a low-carbon energy economy. The effect of wind power is analysed from the perspective that reducing CO_2 emissions is the principal driver behind installing wind energy. Other effects of wind power have not been analysed in this study.

Wind energy is not dispatchable, i.e. it cannot be called upon at will. The running hours of wind power are limited and its variability poses a challenge for the reliability of the power generation system of which it forms a part. This paper deals with the "longer-term" aspects of wind variability, i.e., arranging for the availability of other power generation sources in order to be able to deal with long periods (> 4 hours to days) of low wind supply, the impact of wind energy

[1] NW Europe: Belgium, Denmark, France, Germany, the Netherlands and the UK.

on CO_2 emissions, and the complementary role that gas can play in ensuring a reliable power supply. The optimisation of "short-term" (<4 hours) balancing is not the subject of this paper.

2.2 The importance of the CO_2 price

Wind power is not cheap relative to other power generation options, at least not with the current CO_2 prices being less than €15/tCO_2e. Nevertheless, once installed, wind power comes at very low cost. Conversely, the full unit cost of gas-fired power generation may be relatively low, but once installed, its variable costs today (again, at current CO_2 prices) are often higher than those of other (conventional or renewable) power sources. The "merit order", i.e. the order in which power generation sources are ranked as based on the variable costs of electricity production, plays a major role in the order in which different supply options are employed to meet demand. The fuel prices and the CO_2 price are the most important factors that determine the variable costs of wind, gas and coal-fired power generation, and as such also their position in the merit order. Based on these costs, wind power – when available – will usually find a place in the market sooner than fossil fuel-based power, due to its low variable costs. It thus replaces either gas- or coal fired electricity, depending on their positions in the merit order. In both cases it will reduce CO_2 emissions, but the level of reduction will differ significantly, depending on which fossil fuel it replaces.

This paper illustrates that the contribution of wind to a low-carbon energy system depends heavily on the (fuel and) CO_2 price[2].

2.3 Adding wind power to the energy system: the "back-out" effect

The effect of a new investment in a power generation plant is generally that its production replaces more expensive production from other, less efficient plants and that older plants of similar capacity will be retired (with constant levels of demand).

For new investments in additional wind power capacity on the power generation mix in the current market, the first point is the same: the main effect is that the wind power replaces electricity produced by nearly any other source. The relative cost of new wind power for an energy system can be high compared to alternatives with more running hours, but, once installed its generated power has very low variable costs and will replace electricity from other plants. Regarding the second point, however, the amount of capacity from other sources that becomes redundant as a result of new wind capacity is small.

In the current (2011) merit order, with the current CO_2 price and the prevailing fuel prices, gas-fired power generally has the highest variable costs and is the first to be displaced ("backed out") by wind, sooner than coal, in generating systems which include both gas and coal fired generation.

From a CO_2-reduction perspective, the volume of CO_2 thus saved by wind power is the CO_2 otherwise emitted by a gas-fired plant. Gas-fired plants are at least twice as CO_2 efficient as coal-fired plants. From that perspective the cost of investing in wind to reduce CO_2 could be as high as €85/tonne[3,4,5,6] of CO_2 saved (that is, from onshore wind investments; from offshore wind it

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[2] This study addresses only the effect of the CO_2 price as a means to contain CO2 emissions. It did not address alternative policy measures to reduce CO_2 emissions.

[3] Gas price: US$10/MBtu, coal price: US$120/tonne. CO_2 price: €15/tCO_2.

[4] This CO_2 abatement cost by wind is based on CIEP data assumptions (appendix D) of today's costs. These assumptions are based on midrange values from a fairly wide range of cost and performance data in literature. They do not offer a more accurate reflection of costs in absolute terms, but are reasonably consistent in relative terms. Also, these assumptions ignore the projected decrease in investment costs for wind from improved technologies. This cost reduction can be as high as 20-30% (expert's opinion).

would be around €170/tonne of CO_2 abated). This is in sharp contrast to the current market price, as developed in the ETS, of less than €15/tonne of CO_2.

If the positions of variable costs of gas and coal-fired power in the merit order were reversed, as would be the case under higher[7] CO_2 prices, coal-fired power would sooner be replaced by wind power than gas-fired power. Consequently, the relative cost of wind, from the perspective of its effect on CO_2 reduction, would be much lower. Given the much higher CO_2 emission per unit of power of coal plants, twice as much CO_2 emission would be eliminated if wind energy were to replace coal power generation. Consequently, and using the same CIEP cost and performance assumptions, the unit costs of using *onshore* wind to reduce CO_2 emission would become lower, at some €45/tonne of CO_2 saved (using offshore wind the costs would be around €80/tonne CO_2).

2.4 Designing a new energy system to include wind: the back-up effect

When designing a new energy system with a substantial role for wind it is necessary to include "back-up" of nearly the same installed capacity of other sources of power supply as the installed wind capacity, because of the low "capacity credit" from installed wind turbines. Aside from the costs of alternative sources, from the point of view of moving towards a low-carbon energy system, the preferred "back-up" sources should also be renewable:

- Hydropower from Norway is already being used as a back-up source, though mostly for short-term balancing (within a day). There is a physical limit to the back-up capacity from hydro-electricity. Currently it is also limited by the available interconnection capacity. More connection capacity may be technically possible, but even if in the future the total technical hydro potential of Norway would be developed and interconnection capacity would further be expanded, the available Norwegian hydro capacity for NW Europe is probably not more than 11 GW.
- Solar power, like wind power, is a variable source and cannot be relied upon to be available whenever wind power falls away. In NW Europe it does not play a significant role due to its low capacity factor. Interconnection with southern regions may in time offer some back-up support, but this could be costly and has not been investigated in this paper.
- Biomass as a source of power could be a potential back-up option. Today it can be used as a fuel for power generation in combination with coal, with coal usually accounting for the larger share, some 70-80%. Based on this ratio, the back-up provided by this combination would still be high in CO_2 emissions. Even if the contribution of biomass in a coal-fired power plant grows to 50%, the combined result in CO_2 emissions would still be higher than the CO_2 emissions of a gas-fired power plant. Currently developed technologies already offer prospects of fully biomass-fired power generation. Technically this could provide a suitable back-up option with zero CO_2 emissions, but at the moment it would be at very high cost.
- Demand-side management is not yet applied on a large scale; however, its estimated potential to reduce peak demand within a day is about 15-20%. It could make an important contribution to total capacity requirements of any energy system. With regard to wind power, it could also help any short-term balancing, but would probably not meet the longer-term back-up requirement in any significant manner.

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[5] See also Appendix F.

[6] These costs are also strongly sensitive to fuel- and carbon prices and other variable operating cost.

[7] The exact CO_2 price at which coal-fired and gas-fired power generation will be reversed in the merit order is strongly sensitive to, among others, the assumed fuel prices and efficiency of power plants. It was therefore not specified in this study. In Section 6 it will be shown that a CO_2 price of €60/t would be, under the assumptions made in this study, already sufficient.

This paper concludes that renewable sources of energy at this time do not offer adequate feasible options for back-up. Under the considered fuel and CO_2 prices, gas-fired power generation appears to be the most economic and environmentally efficient back-up for wind power in a new energy system. Not only is coal more expensive in a new design system as a back-up (based on the levelised cost of energy instead of the variable costs), it also defeats the objective of CO_2 reduction.

In a high CO_2 price environment a major step in CO_2 reduction can be realised, notably as CCS becomes economically attractive. The application of CCS to gas-fired power generation is more economical and results in lower emissions than CCS for coal-fired generation[8]. If also used as a partner for wind, combined CO_2 emission levels would be further reduced significantly.

2.5 Conclusions

Wind power has a low capacity credit (in NW Europe). This means that wind power does not significantly replace other generating capacity; alternative power sources need to be in place, together with new installed wind capacity for at least 80% of installed wind capacity, to ensure that there is sufficient back-up to meet market demand at times of reduced wind power supply. Most of this will have to come from conventional power plants. If hydro capacity from Norway is available, this back-up capacity could be reduced to approximately 70%.

Wind capacity will thus essentially be "surplus" to the necessary dispatchable system capacity, and thus costs of wind capacity will essentially come on top of the costs of the base conventional capacity. The extra costs of wind capacity can be reduced or compensated by the abated fuel and carbon costs from conventional generation.

The effectiveness of wind power to reduce CO_2 emissions is directly related to the level of CO_2 prices. In today's energy market with low CO_2 prices, new installed wind power tends primarily to replace gas-fired power, resulting in limited CO_2 reduction, and thus becomes an expensive and less effective way of reducing CO_2 emissions.

Sufficiently high CO_2 prices would reverse the position of gas and coal in the merit order (irrespective of wind), reducing CO_2 emissions by around 10-25 %. Other or complementary ways to achieve CO_2 emission reduction (for example, the use of an Emission Performance Standard) were not analysed in this paper.

With higher CO_2 prices, wind would replace coal-fired power, further reducing CO_2 emissions and significantly improving the effectiveness and costs of wind in reducing CO_2 emissions.

In a conceptual design for a future low-carbon energy system in which wind plays a prominent role in reducing CO_2 emissions, gas-fired power is the most suitable and economic partner, as long as other renewable options remain unproven, technically limited and/or uneconomical.

A high CO_2 price would be a tool for forcing additional low carbon measures, such as CCS. With CCS, gas fired generation remains more competitive than coal with CCS and offers an attractive and competitive low CO_2 option, in its own right, as well as in combination with wind.

An additional question which arises is whether the present market model for organising and dispatching electricity is appropriate and effective in an environment with a significant share of wind power. In this context there are implications of large-scale partnering with wind power for the performance and economic viability of gas-fired power plants (with or without CCS) as well as for the gas supply. These will need to be further examined to ensure that the gas and power industries are ready to become secure partners..

[8] See the calculations in Section 6.

3.

Aim of this study

The aim of this study is to take stock of what is currently known, assumed and expected about the role of natural gas as a back-up for wind. The geographical area taken into account is NW Europe[9]. The starting point of the study is that the principal driver behind installing wind energy is the established aim to reduce CO_2 emissions. Other effects of installing wind (for example, reducing import dependency) are further not considered.

The study focuses on the "longer-term back-up" questions, i.e., the alternative support measures which have to be in place to maintain power supply in case of a reduction in wind power for more than 4 hours. It addresses questions such as:

- how much back-up capacity and back-up volume would be necessary to be able to integrate wind into the power generation mix, assuming that the security of power supply is (at a minimum) maintained at the current level;
- how effective is wind power in reducing CO_2 emissions; and
- what are the options and implications for costs and CO_2 emissions of power generation with a substantial share of wind energy.

The different back-up options for wind (gas, coal, nuclear) are viewed against technical limitations as well as economic and environmental impact, all based on today's knowledge. Alternatives such as interconnections, demand-side management, electricity storage and biomass co-firing and their limitations are also addressed. The study is based on publicly available data and publications.

Several studies, papers and reports have been published on this subject. From these studies the facts, projections and speculations have been assembled and analysed in order to offer further insight in the options, their implications and the range of their uncertainties, with the aim of contributing to the public debate on ways to achieve CO_2 reduction.

[9] Belgium, Denmark, France, Germany, the Netherlands and the UK.

4.

Wind and gas: back-up or "back-out"?

When discussing the integration of wind energy, a distinction must be made with regard to economic and environmental implications between adding wind to an *existing* power generation mix and making wind energy part of a *new* energy mix (as may be the case in connection with the conceptual design of a Roadmap 2050). The two situations will be addressed separately in the following subsections.

4.1 Adding wind to an existing system: the "back-out" effect

When a new *conventional* power plant is added to an existing power generation and supply system, at first its capacity is surplus to system requirement. The consequences for the system are that:

- its production will be in competition with other sources, and
- older, less efficient capacity will be retired – in the case of static market demand, for roughly the same level of capacity.

When new wind turbines are installed, their generated wind power will be in competition with other sources but will normally take precedence in electricity supply over fossil fuel-based generation on the strength of its very low variable production costs. However, unlike conventional plants, the new wind capacity will not lead to any significant retirement[10] of other power generation capacity because of the variability of wind power supply (see also the box 1 on page 18 about capacity credit). Wind capacity will therefore need to remain largely surplus to system capacity. The main effect of the added wind power is that it replaces fossil fuels and hence reduces CO_2 emissions and fuel costs. The existing conventional generation mix will run at a lower load factor and will be forced to operate in a more flexible way.

With regard to the economics of reducing CO_2 emissions, an important question is whether wind replaces coal or gas in the power generation system. Of course, from a CO_2 reduction perspective, replacing coal-fired power is far more effective than replacing gas-fired power. However, in current market economies with a mix of coal and gas-fired power plants, in which the penalty for CO_2 emission is low or non-existent, wind power will in most cases sooner replace gas-fired power, as the variable costs of gas-fired power are usually higher than those of coal[11]. This may be economically sound, but it is less effective in achieving CO_2 reduction: replacing coal would double the reduction in CO_2 emissions.

Both the economic competitiveness of wind power and the effectiveness of CO_2 reduction from wind energy in NW European markets would be considerably improved in a market in which CO_2 prices are raised at least to levels at which coal, rather than gas, will be replaced by wind. This will be further illustrated in Section 6.

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[10] If load factors for fossil power capacity were to become too low because of high wind penetration, this could lead to retirement of some assets and as such could deteriorate security of supply.

[11] Most often, wind energy will replace gas-fired power generation. In some cases, for example at night when gas-fired is already switched off because of low demand, or under special price conditions (such as the summer of 2009 in the UK), wind power will replace coal-generated power.

4.2 Design system: the back-up effect

When designing the low-carbon[12] power generation mix for a future situation, wind becomes an integral part of the system. Installed wind energy has to be planned, together with a sufficient amount of reliable power supply capacity to preserve the integrity of the total system, covering cases when there is less or no wind supply for a longer period (hours to days).

In a design system the full costs of power generation and supply investments and operation will define the best choice for the fuel mix. The back-up options for wind, i.e., filling in the gaps created by reduced wind power and the implications hereof, will be discussed in the next sections.

[12] A low-carbon energy mix in this case means the power generation mix for the lowest generation costs to meet a certain CO_2 emissions reduction target.

5.

How much back-up capacity does wind need?

To keep an electricity system in balance with an assured availability is a challenge even without variable renewable energy sources in the energy mix, given the variability of the demand and the probability of failure of conventional power generation plants. Both demand and supply can be forecasted to a certain extent, but the electricity system has to be kept in balance even at times of unexpected supply failures or unexpected peaks in demand. The availability of the generation capacity of a power plant is never 100%, not even for conventional generation techniques, due to planned maintenance and unplanned outages. Therefore any kind of power generation source, including conventional generation, needs a certain amount of back-up capacity[13].

Apart from the effect of planned and unplanned outages for technical reasons, the average availability of wind generation is much lower relative to its nameplate capacity than is the case for conventional power plants, due to the variable nature of wind. Integrating wind in a fuel mix in a way that allows the total availability of power to remain robust creates major challenges for the power generation system, notably with regard to back-up capacity.

A distinction is made between short term and long-term back-up capacity requirements. An increasing share of wind energy means more variability of power supply with more significant forecast errors. Short term back-up deals with standby generation capacity that has to be in place 1-4 hours before production to compensate for the uncertainty of the electricity demand and electricity supply.

Long-term back-up capacity of wind in this study means the necessary generation capacity that has to be available in the power generation mix in case of longer periods (several hours to days) without or with reduced wind supply. Short-term back-up and long-term back-up each have their own characteristics and supply measures, although they are not completely unrelated: after all, in a design system the choice of the back-up capacity may be affected by the flexibility requirements of the short-term back-up capacity, since part of the long-term back-up capacity should be suitable for the short-term balancing of the power generation system. The main focus of this study is the long-term back-up capacity of wind. Appendix A gives a brief overview of the short-term back-up capacity and the effects of wind energy on balancing the electricity grid.

[13] Conventional gas- and coal-fired power plants generally need a back-up capacity of around 5-15%, depending on the age and type of the power plant.

Box 1. Capacity credit

Capacity credit is a measure of the contribution of any new generation capacity (wind or conventional) toward securing the availability of an energy supply system. It is expressed as the percentage of the installed nameplate capacity of the new power generation source. The capacity credit of a conventional power generation plant is influenced by the type and age of the power plant itself, the size of the balancing area, demand characteristics and the availability of the total power generation mix. A new CCGT power plant, for example, has a high capacity credit (the literature refers to levels of around 90-95%[14,15,16]), which means that when added to a power generation system, other generation capacity can retire to the amount of 90-95% of the nameplate capacity of the CCGT plant and still retain the same system reliability (if demand stays stable). The capacity credit of wind power is lower than the capacity credit of conventional power generation techniques due to the variable nature of wind. It depends on the number of full load hours of wind, the wind penetration level, the geographical spread, timing of wind delivery relative to peak demand periods and the availability of the "rest" of the power generation mix. Increasing wind penetration level leads to a lower capacity credit for wind.
For wind, the capacity credit varies in the literature from approximately 5-40%; for NW Europe it is usually estimated at 5-20% (see also section 5.1).

5.1 Long-term back-up of wind energy

One of the preconditions of keeping the electricity system in balance with a certain probability of availability[17] is that there be sufficient power generation capacity at all times. Long-term back-up capacity is necessary for long (hours to days) periods of low wind supply or long-term failure of a conventional power plant. The requirement for long-term back-up capacity of wind is mostly determined by the capacity credit (see box 1).

Several studies have analysed the capacity credit of wind. Estimations of the capacity credit in the literature show a wide range, about 5-40%, depending on the wind penetration level, geographical area, fuel mix and demand characteristics. The higher capacity credit results are found at low wind penetration levels. Also, studies concerning the US tend to show higher results for capacity credit of wind. As calculations of the capacity credit are usually based on simulation models without published details and assumptions, it is difficult to compare the results. From the literature for NW Europe a range of capacity credit for wind power of 5-20% has been found (see Table 1). This translates into a requirement for back-up capacity of 80-95% of installed wind power capacity.

Apart from the effect of capacity credit, a few other options are being addressed in studies which could potentially reduce the need for back-up from conventional power plants, such as interconnectors, demand-side management and electricity storage. In the following subsections the potential contribution of these options to back-up capacity will be discussed.

[14] Dena, 2005. Planning of the Grid Integration of Wind Energy in Germany Onshore and Offshore up to the Year 2020 (Dena Grid study). Deutsche Energie-Agentur Dena (2005).
[15] Mott MacDonald: UK Electricity Generation Costs Update (2010).
[16] M. Lienert (2008): Leistungsvorhaltung auf Regelenergiemärkten – Excel Add-In, Beschreibung und Anleitung. EWI Working Paper 03.08
[17] A commonly used reliability target is an outage probability of 1 day per 10 years, known as the loss of load expectation.

Literature results on wind power capacity credit	
Germany	- 6-8 % at 20% capacity penetration, 5-6% at 45% capacity penetration level[18] - 6% capacity credit in 2008, increasing to 20% by 2050[19]
Ireland	16% at 2.5 GW wind which decreases to 14% at 3.5 GW wind[20]
Norway	14 % at 15% wind penetration level[21]
UK	15%[22] - 20%[23] capacity credit
Europe	8-14% depending on the available interconnection capacity[24]

Table 1: Literature results on wind power capacity credit

5.2 CO_2-neutral back-up for wind: the effect of interconnectors

Interconnectors can play a role in smoothing the variations of the total electricity supply and demand by connecting a larger geographical area. This smoothing effect is strongly influenced by the size of the connected area and the examined time period (minutes, hours or days)[25].

The effect of interconnectors on the long-term back-up requirement for wind is determined by the probability of a localised low wind supply compared to probability of low wind supply for a larger geographical area. In other words, if wind always blows somewhere in a larger geographic area, this will enhance the reliability of wind power. However, most studies suggest that the correlation of wind supply in the NW European region is high[26,27]. Especially winter's high-pressure "cold and calm" areas can extend for 1500 km, so that periods of low wind generation are often correlated even across Europe[28]. The WindTrade model[29] showed limited benefit from interconnection across Europe: the capacity credit of wind increases from 8% (for separate EU countries) to not more than 14% (assuming power exchange between the same countries). Another study[30], focusing on the Nordic countries, comes to a different conclusion: correlation of hourly wind production is strong (> 0.7) for distances of less than 100 km but become weak (< 0.5) with distances of 200-500 km in the region of the Nordic countries. This would suggest a

[18] Planning of the Grid Integration of Wind Energy in German Onshore and Offshore Up to the Year 2020 (Dena Grid Study).
[19] Prognos: Energieszenarien für ein Energiekonzept der Bundesregierung, Project Nr. 12/10, 2010.
[20] ESB National Grid: Impact on Wind Power Generation in Ireland on the Operation of Conventional Plants and the Economic Implication (2004).
[21] Tande & Korpas: Impact of Large-Scale Wind Power on System Adequacy in a Regional Hydro-Based Power System with Weak Interconnections. Proceedings of Nordic Wind Power Conference NWPC 2006.
[22] SKM: Growth Scenarios for UK Renewable Generation and Implications for Future Developments and Operation of Electricity Networks. BERR Publication URN 08/1021, 2008.
[23] Strabac, G. et al. Impact of Wind Generation on the Operation and Development of the UK Electricity Systems. Electrical Power Systems Research, Vol. 77, Issue 9. Elsevier, pp. 1143-1238.
[24] Van Hulle et al. Integrating Wind – Developing Europe's Power Market for the Large-Scale Integration of Wind Power. Final Report Tradewind, 2009.
[25] The smoothing effect of interconnectors on wind power is especially important for the reduction of the short-term back-up capacity of wind. See, for example, the simulation results of the study "A North Sea Electric Grid [R]evolution" by Greenpeace (2008) or the IEA Wind Task 25 study (Phase One 2006-08).
[26] Bach: The Variability of Wind Power. Chapter: Geographycal Distribution and Wind Power Smoothing, 2010.
[27] Thomas et al. Long Term Wind Speed Trends in Northwestern Europe.
[28] Poyry: The Challenges of Intermittency in Northwest European Power Markets, 2010.
[29] Van Hulle et al., Integrating Wind – Developing Europe's Power Market for the Large-Scale Integration of Wind Power. Final Report Tradewind, 2009.
[30] Holttinen. The Impact of Large-scale Wind Power Production on the Nordic Electricity System. PhD thesis, 2004.

higher capacity credit from interconnection in this region. It is not clear whether this result is region-specific or that it reflects analytical contradiction between different studies.

Analysis of the hourly wind data for Ireland, Denmark and Germany for the period 2006-2010 showed that for about 400-600 hours per year, wind production was simultaneously less than 10% of total capacity in all three countries, implying that for this period extra interconnection capacity between these countries would not have reduced the need for long-term back-up capacity.

Hydropower potentially offers back-up supply for reduced wind power. Further interconnection capacity with Norway could contribute large-scale flexibility from conventional hydropower plants in Norway, using dammed water that could be run at full power in times of low wind supply and of which the output could be reduced in times of high wind power supply – at least, as long as there is reserve generation capacity in the Norwegian system. Balancing the NW European grid by hydro electricity from Norway is already happening to some extent, as Norway typically exports power during the day and imports during the night and on weekends. Based on the future potentially available hydropower capacity, we estimate that imported hydropower can provide long-term back-up for wind in NW Europe up to around 11 GW[31] of the installed wind power capacity. A significant amount of interconnection capacity should be installed to fully utilise this back-up option. The costs of this option has not been analysed.

In sum, the effect of more interconnection in NW Europe on the long-term back-up requirement of wind power is limited, mainly due to the high correlation of wind supply in NW Europe. More interconnection across the whole of Europe may offer some more capacity credit for integrated European wind power and hence some reduction in long-term back-up requirement, but studies are not conclusive and the benefits could well be overshadowed by the costs and complexity of developing such interconnections[32].

5.3 CO_2-neutral back-up for wind: electricity storage as a back-up option

Electricity storage can be used to store surplus power in case of high wind energy supply and low electricity demand. The stored energy can be used again in case of low wind supply.

There are several options to store electricity for a short period of time (minutes), but there are only a few techniques currently available to store electricity for a long period (> 4 hours). Compressed Air Energy Storage (CAES) can store electricity for days to weeks, but its relatively low efficiency and its natural gas component make it an expensive solution with relatively high CO_2 emissions. Batteries are widely used to store small-scale electricity but are not yet commercially available for large-scale electricity storage. Surplus wind energy could also be used to produce hydrogen and eventually, in a following step, methane; both could then be added to the natural gas system[33]. In this way the existing gas infrastructure could be used to “store” wind power[34]. In any case, the focus of this technological option is on not wasting surplus wind power, rather than on reducing the back-up requirement.

Pumped hydro storage is an existing and widely used technique for storing the surplus electricity from wind power in times of low electricity demand and producing electricity during periods of

[31] See Appendix J.
[32] The impact of large-scale interconnection across Europe on the energy system (for example importing solar energy from Southern Europe to NW Europe) has not been part of this study.
[33] Hydrogen can be added to the natural gas system up to around 5-15 %. Methane has no upper limit.
[34] Greenpeace: Windgas: What It Is and Why It Is Important.

low wind power supply, providing a CO_2-neutral[35] back-up for wind power. In NW Europe the available hydropower is negligible; therefore it should be imported from Norway or Switzerland. However, this option is limited by the available hydropower capacity, the volume of the reservoir concerned and the available interconnection capacity and mostly contributes to short-term (within a day) balancing, but may contribute to the 11 GW of potential hydro back-up from Norway (see section 5.3).

5.4 CO_2-neutral back-up for wind: effect of demand-side management

Demand-side management (DSM) is often seen as an important development in being able to balance future electricity networks with a large amount of wind energy. One form of demand-side management is the use of interruptible contracts, already applied on a relatively low scale. During periods of low wind supply, interruptible contracted power demand can temporarily be shut down, reducing the total peak demand. This way, interruptible contracts can contribute to the short-term balancing of the power grid, but it is unlikely that they will provide firm long-term back-up solutions for long periods of low wind supply, as this would imply that the parties accepting interruptibility can do without electricity for a number of days.

With or without wind, when DSM is introduced as part of a smart grid system, peak demand in any day can be smoothed using price incentives. DSM may thus contribute significantly to reducing the total capacity requirement of an energy system. However, as an instrument to reduce the long-term back-up requirement for wind power, its potential is limited. Short periods of low wind supply lead to higher electricity prices, which in turn could lead to reduced demand for these periods[36,37]. It is, however, unlikely that a large amount of electricity demand will be able to be shifted for longer periods than a day. Consequently, this paper concludes that DSM has a negligible effect on the necessary *long*-term back-up requirements for wind power, even though it offers many opportunities for dealing with variations of wind supply within a day.

5.5 CO_2-neutral back-up for wind: providing CO_2-neutral back-up through biomass

Biomass-based power generation could theoretically provide a CO_2-neutral[38] back-up for wind power. However, today biomass is mostly used in coal-fired power plants in combination with coal, coal usually accounting for the larger share of around 70-80%. Based on this ratio, the back-up provided by this combination would still be high in CO_2 emissions. Lower CO_2 emissions could be achieved with a higher percentage of co-firing, yet at an increased cost. The incremental investment cost for a higher share of biomass in a coal power plant is typically in the range of US$50-250/KW[39]. The fuel costs of a coal-fired plant would also increase due to the relatively high price of biomass and its low calorific value[40]. At a high CO_2 price the extra costs could be reduced or compensated by the reduced CO_2 costs. Currently built coal-fired power plants are planned to allow for co-firing of up to 50%. However, even if contribution of biomass in a coal-

[35] In this study hydropower is assumed to have zero CO_2 emissions, despite studies on possible CO_2 emissions of hydropower due to methane-emitting plants growing in water reservoirs and possible deforestation during construction of water reservoirs.

[36] Analysis of demand data of Germany, the Netherlands and Denmark suggest that the peak electricity demand can be reduced by up to 15-20%.

[37] Deutsche Bank Group: Natural Gas and Renewables: A Secure Low-Carbon Future Energy Plan for the United States (2010).

[38] CO_2 emission of biomass is often assumed to be non-zero due to transport, use of fertilizers, etc. However, this study focuses on the CO_2 emission during power generation; lifecycle CO_2 emissions were not taken into account.

[39] IEA: Energy Technology Essentials – Biomass for Power Generation and CHP, 2007.

[40] As of November 2011 the coal price is around US$115/tonne, while the price of wood pellet is around €135/tonne. The calorific value of wood pellets is about half that of coal.

fired power plant grows to 50%, the combined result in CO_2 emission would still be higher than the CO_2 emission of a gas-fired power plant. Techniques which allow 100% biomass firing are already available, although these are generally small units (up to 150 MW) and have relatively high power generation costs, in the range of €60-200/MWh[41] depending on the applied technique. It is questionable whether biomass (co-firing as well as dedicated) power plants are economically feasible and technically suitable to provide back-up for wind power. Further study is necessary on this subject.

At high CO_2 prices, certain biomass techniques could become an attractive method for carbon reduction, especially when combined with CCS. Applying CCS technique to coal power plants in combination with biomass co-firing can, at a sufficiently high level of co-firing, even lead to negative CO_2 emissions. Global availability of biomass, its environmental impact and costs might limit the potential of biomass fired power plants in NW Europe[42].

5.6 Summary of the necessary long-term back-up capacity for wind power

None of the above options makes a substantial contribution to the long-term back-up requirement for wind. The question remains as to how capacity credit affects the long-term need for back-up for wind power. Essentially, if wind energy does not offer an assured minimum power supply at all times, the back-up requirement for wind energy is equal to the installed wind capacity. Capacity credit offers savings, but these are found in the reserve capacity of any system, needed to compensate for the risk of outages of wind and other capacity (see Figure 2). For this analysis the assumption was made that back-up is required to the amount of wind capacity less its share of "reserve capacity", estimated at 80-95% of the installed wind capacity (assuming a capacity credit of 5-20%, see previous section).

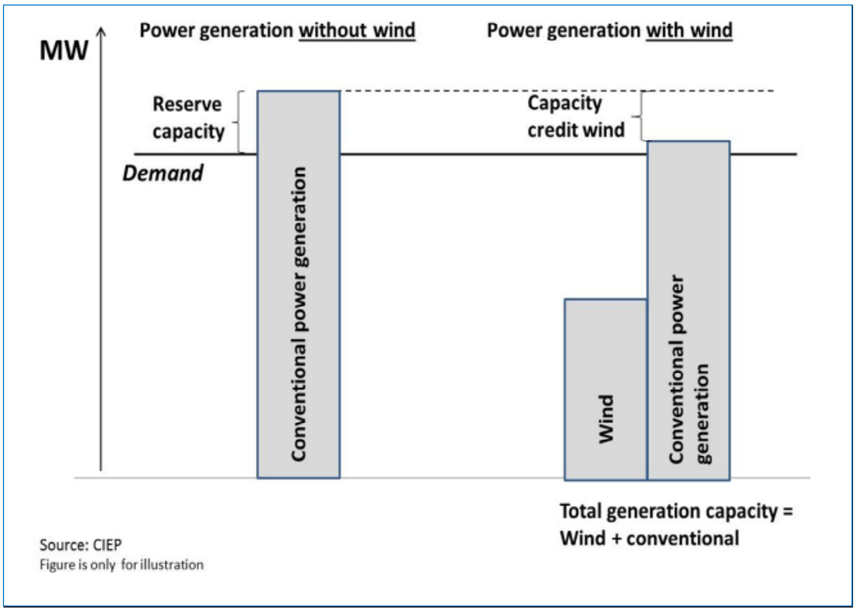


Figure 2: Illustration of the capacity credit

[41] Mott MacDonald: Costs of Low Carbon Generation Technologies, 2011.
[42] IEA: Energy Technology Essentials – Biomass for Power Generation and CHP, 2007

Table 2 below gives a summary of the long-term back-up options for wind, based on the current assessment of this study.

How much conventional long-term back-up capacity does wind need?	
Assuming a wind park of 100 GW in NW Europe	
Effect of capacity credit (5-20%):	80-95 GW necessary back-up capacity
Effect of demand management:	No significant effect on long-term back-up
Effect of imported hydropower:	Up to 11 GW
Remaining long-term back-up capacity required:	Approx. 70 GW or more

Table 2: The necessary long-term back-up for wind power

Summarising the different back-up options for wind (and excluding the impact of any future interconnection options with Southern Europe), conventional generation capacity of more than 70% of the wind power capacity has to be available to maintain the reliability criteria of the power generation system in NW Europe. If wind power is added to an existing power generation system, only a limited amount of the existing power generation capacity can be retired. In a designed system, back-up capacity of at least 80% of the nameplate wind power capacity has to be part of the power generation system. If hydropower makes a contribution, at least 70% of the back-up requirement remains, and based on the currently available techniques this will have to come from conventional plants.

Precise back-up figures from conventional power stations are not material for this study. The main conclusion is that a large part of installed wind power capacity needs back-up capacity, and that conventional power plants will be needed to provide a very high proportion of this capacity.

For the indicative cost calculations we will assume that the entire back-up requirement is met by conventional plants.

6.

Costs and economics of power generation

In a market-driven energy system, investments in power generation plants and their contributions to electricity demand are largely driven by competitive costs and expected return on investment. To illustrate the impact of the costs and performance of different generation options, data summarised in Appendix D has been used. The resulting figures in the following subsections should be regarded as illustration of competitiveness. Calculations of the costs of abated CO_2 emissions can be found in Appendix F.

6.1 Wind power in an existing energy system: the "back-out" effect

In a power generation system, once wind power is available, it will displace the supply with the highest variable costs (see also Appendix G on the merit order). Figure 3 compares the indicative variable costs of producing a MWh for a modern CCGT plant (efficiency around 60%), an older CCGT plant (efficiency around 50%), a single gas turbine (efficiency around 30%), a modern coal-powered plant (efficiency around 48%) and an old coal-powered plant (efficiency around 35%).

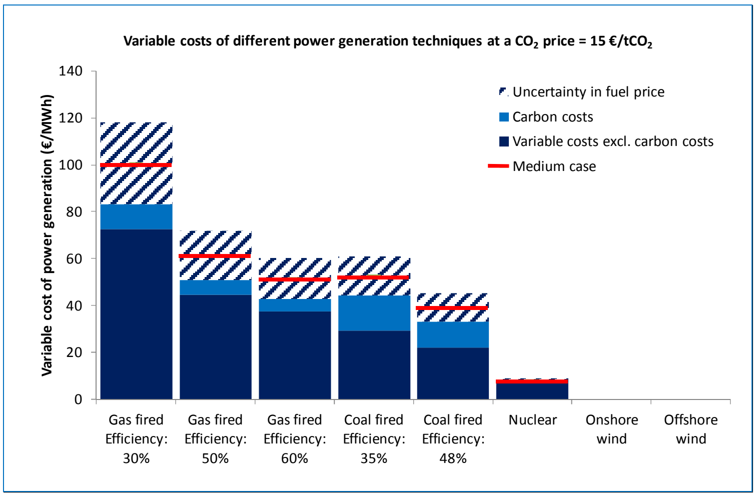


Figure 3: Variable costs of different power generation techniques

- Gas price: US$8-12/MBtu, Coal price: US$80-130/tonne, Uranium price: €4-6/MWh, LF = 7000 hours
- Carbon price: €15/tCO_2e
- Variable operational costs: €2.5/MWh for CCGT; €3/MWh for coal-fired; €2.5/MWh for nuclear
- See more details on the input parameters in Appendix D.

Figure 3 shows that in the current fuel- and carbon price environment, gas-fired generation usually has higher variable costs than coal does. Only modern and highly efficient CCGT plants, running under optimal conditions, might be able to compete with some of the old and inefficient coal-powered plants under particular gas and coal price conditions. Consequently, gas-fired power is generally the last option in a fuel mix to contribute to demand. The variable costs of wind power are lower than any other option. This implies that when available, wind power will always enter the system, displacing the supply source with the highest variable costs. This means that in a power generation system with commodity and CO_2 prices as experienced today, gas is generally the first fuel to be replaced by wind power.

From a CO_2-reduction perspective, the volume of CO_2 thus eliminated by wind power is the CO_2 otherwise emitted by a gas-fired plant. This is not a very effective way of reducing CO_2 emissions. The cost implications and environmental consequences will be addressed in Section 6.3.

6.2 The investor perspective

In the context of an investment decision for new power generation capacity in an existing power generation mix, the economic considerations include the levelised cost of energy (LCE), i.e., the full unit costs of power production (see box 2).

Box 2. Levelised cost of energy (LCE)

LCE is the lifetime discounted cost of generated power, expressed in the cost per unit of generated energy (e.g. €/MWh). It includes the investment costs, fuel costs, operational- and maintenance costs, carbon costs, insurance and decommissioning costs. LCE can be calculated by dividing net present value (NPV) of the annual costs by the NPV of the generated power for the lifetime of the power plant. The LCE is sensitive to the input parameters. A slight change in the assumptions about, for example, the efficiency of a power plant or on the length of the building period, the WACC[43], or about the fuel- and carbon prices can result in a significantly different LCE (see more in Appendix C).

Figure 4 compares the LCEs for different power generation techniques, based on current efficient technologies and the data assumptions summarized in appendix D. For an investor in wind energy, the need to secure back-up (and the costs thereof) does not play a role. Nevertheless, and in spite of its low variable production costs, wind power does not appear to be a competitive option in today's market on the basis of the data in Appendix D, mainly due to the limited running hours and relatively high investment costs. Application of a lower WACC could alter the competitiveness as shown in Appendix E. (Note: LCEs for gas-fired, coal-fired and nuclear plants assume 7000 full load hours[44], onshore wind 2500 full load hours, offshore wind 3500 full load hours. No account is taken of the impact of very high levels of wind penetration in an energy system on the utilisation of modern fossil fuel-based plants and hence on the economics. This will be discussed in Section 6. Also the short-term balancing costs- and grid integration costs of wind energy are not taken into account[45]).

[43] The WACC is the weighted average cost of capital that is dependent on, amongst others, the risk profile of an investment.
[44] For a comparison 7000 full load hours have been used for the calculation of the LCE in Figure 4. However, current business cases for investing in a gas-fired plant are probably based on a lower LF, anticipating the lower utilisation rate of gas-fired power plants currently positioned in the mid merit.
[45] According to the IEA-WEO 2011, the short-term balancing costs range from US$1/MWh to US$7/MWh. Grid integration costs of around US$2/MWh to US$13/MWh will come on top of that.

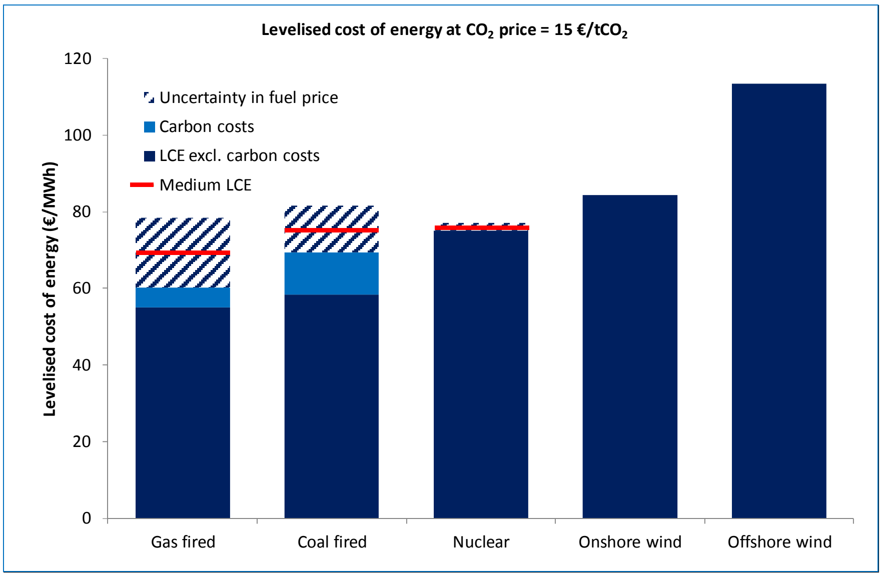


Figure 4: Levelised cost of energy of different power generation techniques

- Gas price: US$8-12/MBtu, Coal price: US$80-130/tonne, Uranium price: €4-6/MWh,
- Carbon price: €15/tCO_2e
- LF: 7000 hours for gas-fired, coal-fired and nuclear, 2500 hours for onshore wind and 3500 hours for offshore wind
- See more details on the input parameters in Appendix D.

Based on the cost and performance data of appendix D, figure 4 suggests that under the fuel- and CO_2 price assumptions used in this study onshore wind is already close to being competitive with conventional power generation, while offshore wind energy is still more expensive than any other techniques. It should be noted that wind power, especially offshore wind energy, is still an immature technique, and thus new technological developments could in future reduce the costs of wind power[46].

6.3 Environmental impact of wind power versus the price of CO_2

Once wind energy enters the system, it will displace the supply with the highest variable costs. Against the objective of reducing the CO_2 emission, the most effective way would be if wind energy replaces coal fired power generation as coal has the highest CO_2 emission per energy unit (see also box on CO_2 emission). From the perspective of the CO_2 emission of the total power generation mix, 0.7-0.9[47] tonne of CO_2 can be abated per MWh of electricity if wind energy replaces coal in the fuel mix for power generation. Around half of it, ca. 0.35[48] tonne of CO_2 per MWh, is abated if the same wind energy replaces gas.

Under current market conditions with a low CO_2 price, wind power will most likely displace gas-fired power (see section 6.1). If, under these conditions, society invests in onshore wind power to reduce CO_2, the cost could be as high as €85/tonne[49] of CO_2 eliminated (for offshore wind the costs would be around €170/tCO_2[50]). Given the much higher CO_2 emission per unit of power of

[46] Reduction of LCE of wind power due to technological developments can be as high as 20-30% in 2020 (experts' opinion).

[47] See box 3 on CO_2 emissions of different power generation techniques.

[48] See box 3 on CO_2 emissions of different power generation techniques.

[49] At a carbon price of €15/tCO_2e, gas price of US$10/MBtu and coal price of US$120/t and based on the CIEP cost assumptions. See more details in Appendix D and F.

[50] At a carbon price of €15/tCO_2e, gas price of US$10/MBtu and coal price of US$120/t. See more details in Appendix F

coal plants, around twice as much CO_2 emission would be eliminated if onshore wind energy replaces coal-fired power. If that were to happen, the unit costs of using onshore wind to reduce CO_2 emissions would be lower, at some €45/tonne[51] of CO_2 saved (compared to €80/tCO_2 if offshore wind replaces coal-fired).

Under today's prices for fuel and CO_2 emission, using wind power to reduce CO_2 thus appears costly and ineffective.

Box 3. CO_2 emissions of various power generation techniques

The CO_2 emission of natural gas when burnt at 100% efficiency is around 0.21 tCO_2e/MWh, of coal it is around 0.34-0.36 tCO_2e/MWh, depending on the composition of gas and type of coal.
In addition, the efficiency of the power plant plays a role in determining the total CO_2 emission during power generation. A modern CCGT power plant has an efficiency of about 60%. This means that to generate 1 MWh of electricity, 1.67 MWh (1/0.6) of natural gas is necessary. The CO_2 emission during the generation of 1MWh electricity in a CCGT plant is then about 0.35 tCO_2e (1.67*0.21). In a modern coal-fired power plant with an efficiency of 48%, 2.1 MWh of coal is necessary to generate 1 MWh of electricity. The total CO_2 emission during power generation in a coal-fired plant is then 0.71-0.75 tCO_2e per generated MWh. It should be noted that the efficiency parameters of gas- and coal-fired plants used in these calculations are typical only for very modern power plants running in ideal conditions. In reality most gas- and coal-fired power plants would emit more CO_2.
Nuclear power plants, wind and solar power generation techniques have zero CO_2 emissions (in this study only the CO_2 emission during power generation is considered. No cradle to grave analysis has been done).
The CO_2 emission from power generation can be reduced by using a different fuel type and/or by increasing the efficiency of the power plant. Adding biomass to coal or biogas to natural gas reduces the CO_2 emissions of gas- and coal-fired plants.

A higher, effective CO_2 price will have both an immediate and a long-term beneficial effect in achieving a lower carbon economy:

1. In a merit order which is based on a higher CO_2 price, gas-fired power generation will have a lower variable cost than coal-fired power; consequently gas-fired power, when available, will be used sooner and hence more frequently than coal to meet demand.
2. Wind power will first displace coal-fired generation.
3. Wind power will become more competitive.

Ad 1. A higher CO_2 price would affect the variable costs of power production and, at a sufficient level, would reverse the places of gas- and coal-fired power generation in the merit order. Figure 5 illustrates that at a carbon price of about €60/tCO_2e, under the assumptions used in this study, the variable costs of coal-fired power generation are higher than those of gas-fired power (except when compared to a single gas turbine with low efficiency, used essentially for short peak-shaving periods). Even without wind, the repositioning of gas and coal in the merit order would already lead to a reduction in CO_2 emissions in a mixed fuel energy system on the order of 10-25%[52,53,54].

[51] At a carbon price of €15/tCO_2e, gas price of US$10/MBtu and coal price of US$120/t. See more details in Appendix F

[52] If the load factor of CCGT plants in NW Europe were to increase from 45-50% to 60% while the load factor of coal-fired plants were to decrease from 60% to 45-50%, the CO_2 emission from power generation in NW Europe could decrease by 10-15%.

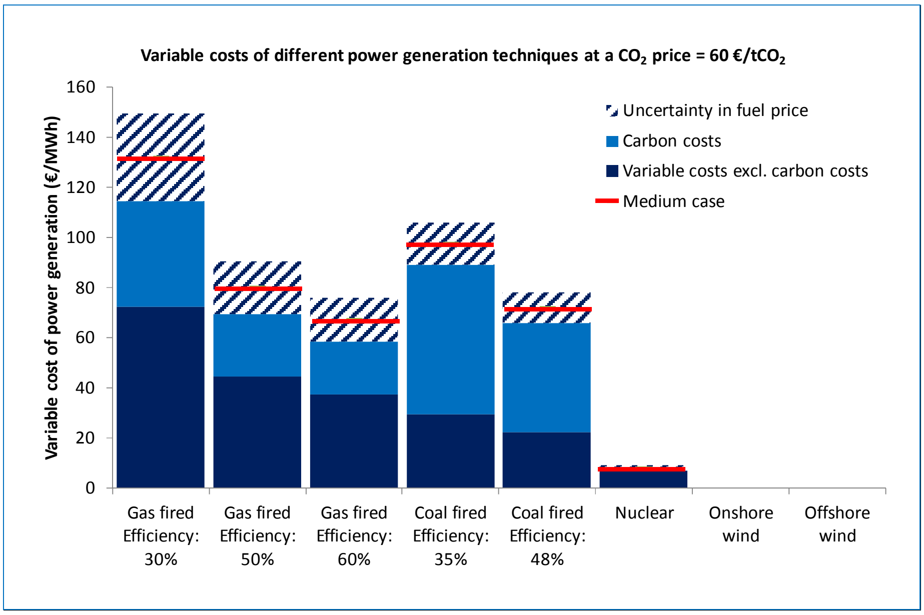


Figure 5: Variable costs of different power generation techniques

- Gas price: US$8-12/MBtu, Coal price: US$80-130/tonne, Uranium price: €4-6/MWh, LF = 7000 hours
- Carbon price: €60/tCO_2e
- Variable operational costs: €2.5/MWh for CCGT; €3/MWh for coal-fired; €2.5/MWh for nuclear
- See more details on the input parameters in Appendix D.

Ad2. In addition, at a higher CO_2 price wind power would replace coal rather than gas, resulting in double the CO_2 emission reduction and would thus lower the cost of abated CO_2 emission from wind power.

Ad 3. Figure 6 suggest that at a CO_2 price of €60/tCO_2 onshore wind power would become competitive from an investor's perspective, based on the levelised cost of energy. For offshore wind a much higher CO_2 price would be necessary to make it competitive.

In addition, a higher CO_2 price could lead to a more active development of other low-carbon technologies, such as CCS and biomass (co-)firing. Figure 6 also illustrates the effect of CCS on levelised costs of electricity production. Applying CCS would not change the economic competitiveness between gas and coal: a gas-fired power plant with CCS has lower costs at the assumed fuel and CO_2 prices and emits less CO_2 than a coal-fired plant with CCS.

There is no exact break-even CO_2 price for Northwest Europe that would reverse coal-fired and gas-fired power in the merit order, nor is there a single CO_2 price at which wind power becomes competitive. Much depends on a wide range of factors including the fuel price settings, costs and efficiency of the conventional power plants, the operating costs and the costs of capital. Figures 5-9 show that under the cost and performance assumptions made in this study, a CO_2 price of €60/tCO_2 would in most cases already be sufficient.

[53] EGAF: Making the Green Journey Work (2011): If the load factor of gas plants in Europe were to increase from 45% to 65-70% and the load factor of coal-fired plants were to decrease from 60% to 20-25%, the CO_2 emission of the European power sector would decrease by 20-25%.

[54] MIT: The future of Natural Gas (2010): Displacement of coal generation with additional generation from existing natural gas CCGT capacity in the US could result in reductions in power sector CO_2 emissions on the order of 10%.

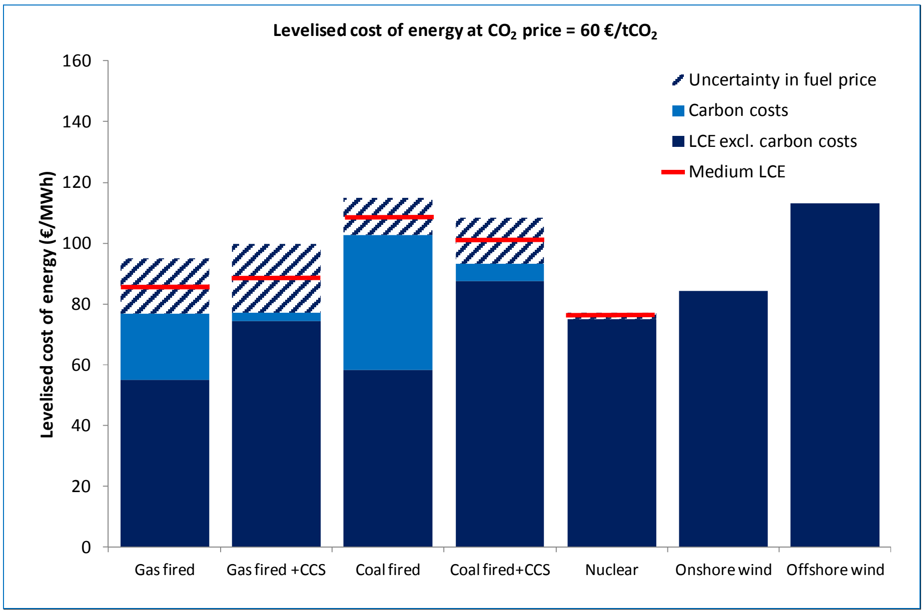


Figure 6: Levelised cost of energy of different power generation techniques

- Gas price: US$8-12/MBtu, Coal price: US$80-130/tonne, Uranium price: €4-6/MWh
- Carbon price: €60/tCO_2e
- LF: 7000 hours for gas-fired, coal-fired and nuclear, 2500 hours for onshore wind and 3500 hours for offshore wind
- See more details on the input parameters in Appendix D.

6.4 Designing a low-carbon energy system

In a design system, like in most Roadmap 2050 studies, costs are considered from the perspective of the total power generation system (societal costs) instead of the investor's perspective for one specific investment and are usually based on the levelised cost of energy.

When adding wind capacity to a power generation system, the capacity from other sources is needed in order to meet demand for periods of low wind supply. The costs of wind capacity will therefore essentially come on top of the costs of the base conventional system. From a societal perspective these extra investment costs are compensated in part or in full by avoided fuel and carbon costs.

Looking at the national ambitions[55] for NW Europe, the installed wind power capacity will more than double by the end of this decade to more than 100 GW. This means that around 70-80 GW of conventional power generation capacity has to be available as a back-up for wind. By complementing the variable wind power contribution to demand at any time, this back-up capacity will obviously run at a lower load factor than it would without wind. Figure 7 shows the stand-alone economics[56] of the various power generation techniques for a design system in baseload and in midload mode, both with and without CCS (for a future low-carbon energy system, the price of CO_2 emissions will be more substantial than it is today; therefore, for this analysis a CO_2 price of €60/tonne has been assumed). Gas-fired power plants are competitive with coal-fired in baseload and even more so in midload.

[55] National ambitions as of in 2010. .

[56] In the analysis of the levelised costs of energy the effects of reduced load factor on the efficiency of the conventional power plants has also been also taken into account (see Appendix I).

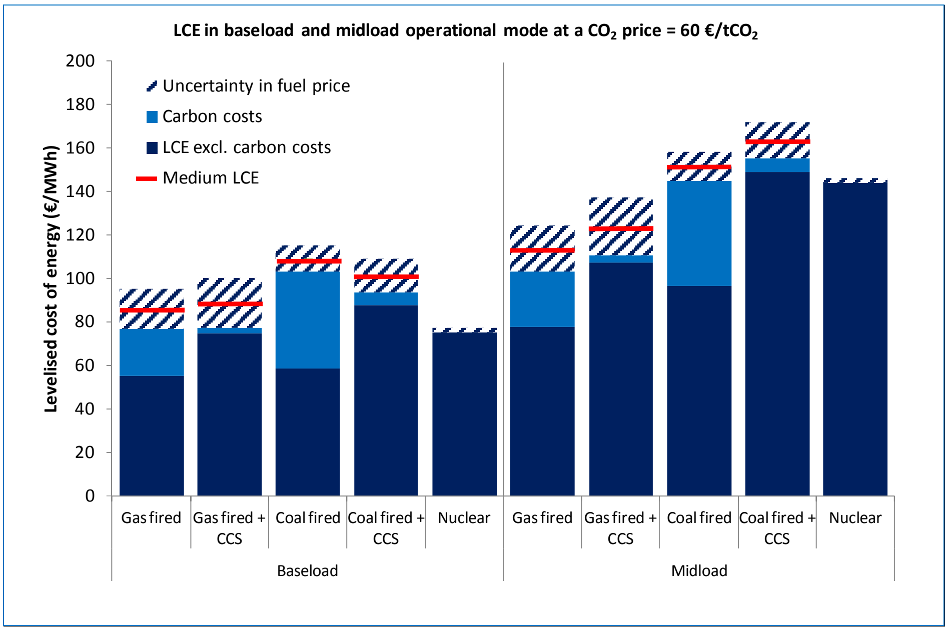


Figure 7: Levelised cost of energy in different operational mode

- Baseload: 7000 full load hours, Midload: 3500 full load hours
- Gas price: US$8-12/MBtu, Coal price: US$80-130/tonne, Uranium price: US$4-6/MWh
- Carbon price: €60/tCO_2
- See more details in Appendix D.

There are several options for "partnering" wind energy to fill the gaps created by reduced wind power (i.e., making up for reduced wind power to meet demand). From the perspective of CO_2 reduction, nuclear would be a good partner for wind energy with its zero CO_2 emission. However it is technically, economically and environmentally questionable whether nuclear plants should be built with the same capacity as installed wind power, only to provide back-up at a relatively low load factor. From the perspective of using wind energy to reduce CO_2 emission, displacing an electricity source which itself has near zero emissions of CO_2 will raise the cost of wind per ton of abated CO_2 to extremely high levels. Economically this makes no sense. Therefore, the option of nuclear power as partner to wind energy is not further investigated in this study.

Fossil-fired plants with or without CCS are technically feasible options to partner wind to achieve a reliable integrated energy supply. The economic and environmental impacts of these options are compared in Figure 8. For this analysis the assumption was made that CO_2 reduction targets will continue to be pursued by means of CO_2 pricing (ETS or otherwise). Therefore, the analysis was done at a CO_2 price of €60/tCO_2 instead of the current CO_2 price of less than €15/tCO_2. With this CO_2 price Figure 8 shows that gas-fired power generation is a better partner to wind power than coal-fired, both from the perspective of CO_2 emission reduction and from the perspective of power generation costs. From an environmental perspective the combined CO_2 emission is low, and it comes at lower cost than nuclear or coal.

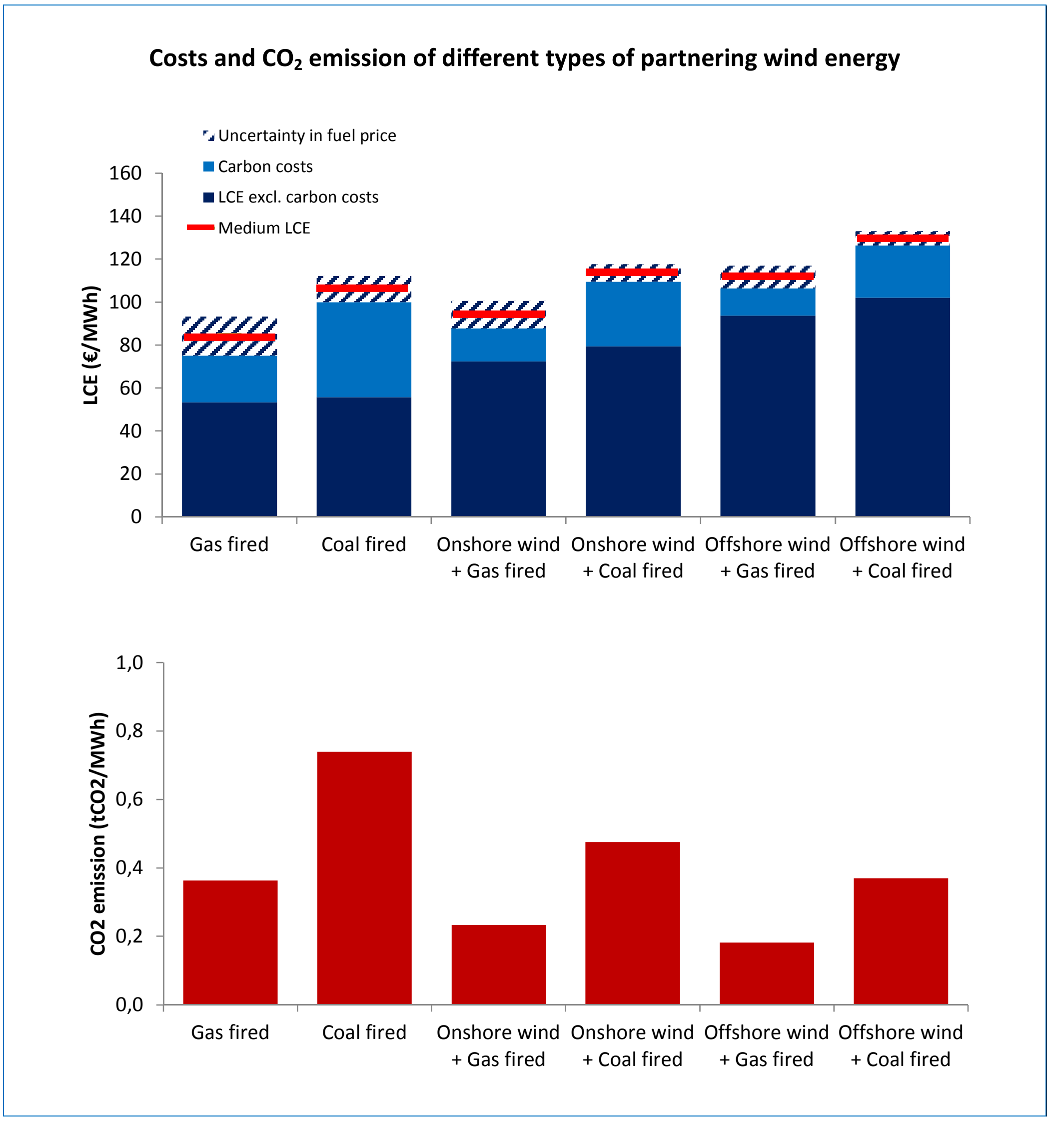


Figure 8: Levelised cost of energy and CO_2 emissions of various types of partnering wind energy

- Gas price: US$8-10/Mbtu, Coal price: US$80-130/tonne
- Carbon price: €60/tCO2
- Onshore wind: 2500 full load hours, Offshore wind: 3500 full load hours, Power demand: 7000 full load hours
- See more details in Appendix D.

Figure 9 shows that adding CCS to gas- and coal-fired power plants further reduces their CO_2 emissions, while gas-fired remains economically more attractive than coal-fired. It should be noted, however, that a combination of wind power and conventional power generation with CCS raises new questions of feasibility, partly because of the higher costs when operating at low load factor (see figure 7) and partly because of concerns surrounding reduced flexibility of power plants in combination with CCS.

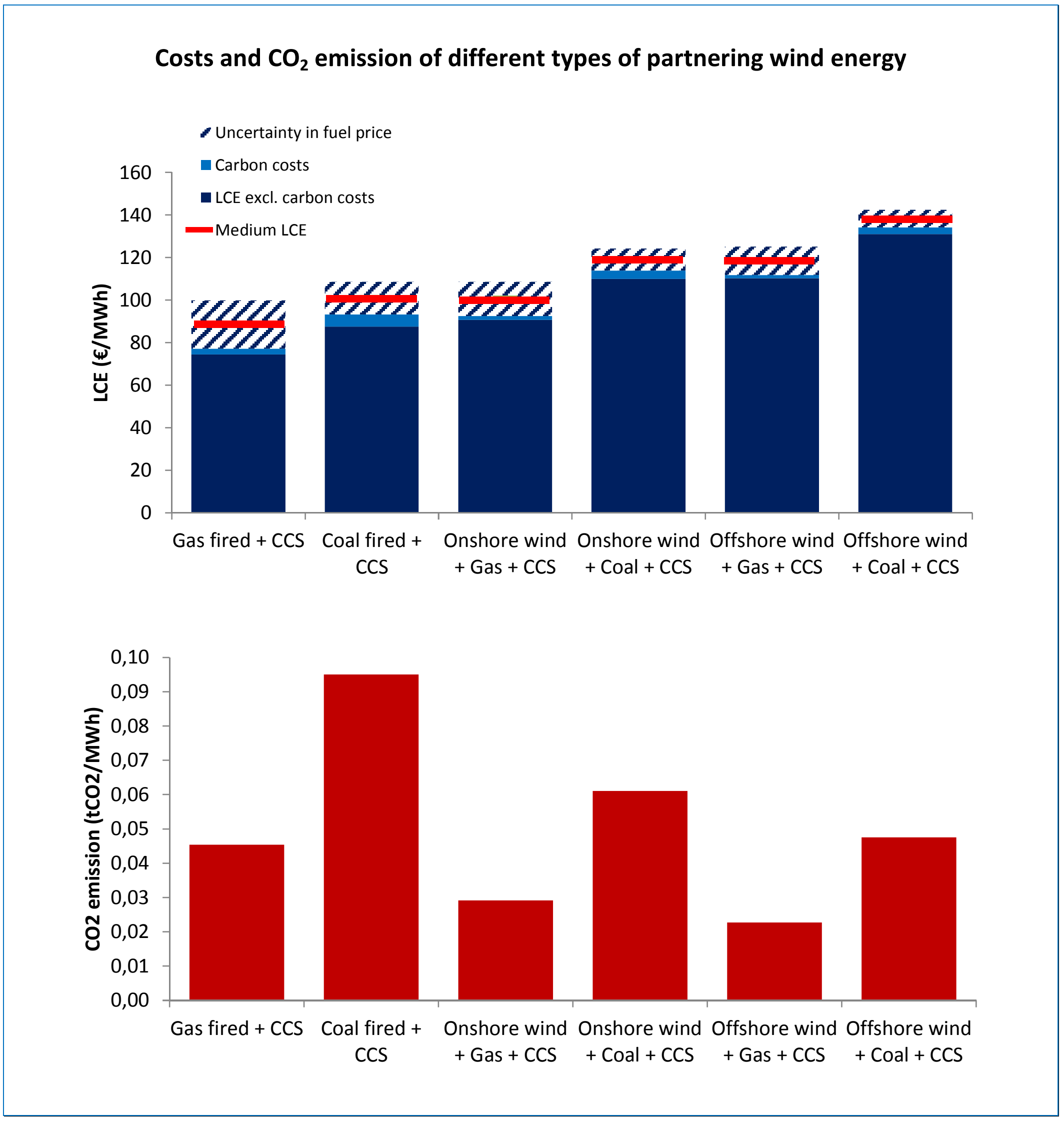


Figure 9: Levelised cost of energy and CO_2 emissions of various types of partnering wind energy with CCS

- Gas price: US$8-10/Mbtu, Coal price: US$80-130/tonne
- Carbon price: €60/tCO2
- Onshore wind: 2500 full load hours, Offshore wind: 3500 full load hours, Power demand: 7000 full load hours
- See more details in Appendix D.

6.5 Impact of partnering

Due to their relatively high flexibility[57], gas-fired power plants are often involved as providers of short-term flexibility. Sections 6.3 and 6.4 show that gas-fired power is also the most attractive option as a long-term back-up partner for wind energy. However, partnering with wind has operational and economic impacts on the performance of gas power plants, on gas supply and on the gas infrastructure.

i. Operation of gas-fired plants

[57] See Appendix H.

More flexibility could imply that gas-fired power plants will be operated at a lower load factor, leading to reduced efficiency[58,59]. Lower efficiency of the back-up gas-fired plant enhances its operational costs, raises its CO_2 emission and thus reduces the positive effect on CO_2 emission from combining wind and gas. More flexibility requirements probably also reduce the expected lifetime of the power plant and increase its operational costs. In this study these latter two effects were not included in the quantifications due to the lack of robust data on this subject. It should also be noted that in a (design) system in which a number of gas-fired power plants provide the support to wind power, it is unlikely that the flexibility requirement will be evenly allocated to all gas-fired plants. More probably, there will be a process of portfolio optimisation in play, in which some plants will be less affected by variability than others. This could reduce the impact on plant efficiency and operation.

ii. Investments in gas-fired power plants

Flexibly-operated gas-fired power plants providing back-up for wind energy will run at a relatively low load factor[60]. As a result, the economics of such back-up power generation will become less attractive (see also Figure 7)[61]. This is reinforced by the application of CCS. Its capital charge for limited operating hours will be high. To ensure that sufficient amount of back-up generation capacity is available, the market conditions might have to be adjusted. The introduction of a capacity/capability market has been mentioned in this context. Further study on the implications of increasing the share of wind energy on the economics of gas-fired power plants is necessary.

iii. Flexibility requirements of gas supply

Flexible operation of gas fired plants also requires flexible gas supply. Different flexibility requirements of the gas supply can be identified:

- Short-term flexibility of gas supply to deal with the short-term variations of wind supply. Accommodation of this need for additional flexibility should be found in or very near to the market for economic reasons and may require additional investments in storage (e.g. multi-cycle caverns).
- Seasonal flexibility of gas supply.
  Generally there is more wind in winter than in summer. This could reduce the seasonal flexibility requirements for the total gas supply. However, during a very cold winter there may be less wind than normal, so wind power will not offer much relief for demand for gas during very cold spells.
- Year-to-year variations of wind supply
  The annual total wind supply can vary as much as 10-20 % from year to year. If gas-fired power is used to fill up the gap, it could introduce an uncertainty of the NW European gas demand on the order of 5-10 bcm by 2020.

The implications for the gas infrastructure of increasing the share of wind energy need to be further studied. Nevertheless, none of the increasing flexibility requirements described above is unsolvable. However, a large share of wind energy could increase the total cost of power generation.

[58] See Appendix I.
[59] Modern gas turbines are already designed with a focus on flexible operation, and therefore the effect of flexibility on power plants probably will reduce in the future.
[60] At a 30-50% load factor (equal to 2600-4400 full load hours).
[61] Another effect which could further reduce the utilisation rate of gas-fired plants is the increasing share of solar power in NW Europe (especially in Germany). Although solar PV currently has a load factor of around 10%, if the same gas-fired power plants are also used as back-up for solar as they are for wind, the economics of gas-fired power plants could further worsen.

7.

Conclusion

Wind power has a low capacity credit (in NW Europe). This means that wind power does not significantly replace other generating capacity; alternative power sources need to be in place, together with new installed wind capacity for at least 80% of installed wind capacity, to ensure that there is sufficient back-up to meet market demand at times of reduced wind power supply. Most of this will have to come from conventional power plants. If hydro capacity from Norway is available, this back-up capacity could be reduced to approximately 70%.

Wind capacity will thus essentially be “surplus” to the necessary dispatchable system capacity, and thus costs of wind capacity will essentially come on top of the costs of the base conventional capacity. The extra costs of wind capacity can be reduced or compensated by the abated fuel and carbon costs from conventional generation.

The effectiveness of wind power to reduce CO_2 emissions is directly related to the level of CO_2 prices. In today’s energy market with low CO_2 prices, new installed wind power tends primarily to replace gas-fired power, resulting in limited CO_2 reduction, and thus becomes an expensive and less effective way of reducing CO_2 emissions.

Sufficiently high CO_2 prices would reverse the position of gas and coal in the merit order (irrespective of wind), reducing CO_2 emissions by around 10-25 %. Other or complementary ways to achieve CO_2 emission reduction (for example, the use of an Emission Performance Standard) were not analysed in this paper.

With higher CO_2 prices, wind would replace coal-fired power, further reducing CO_2 emissions and significantly improving the effectiveness and costs of wind in reducing CO_2 emissions.

In a conceptual design for a future low-carbon energy system in which wind plays a prominent role in reducing CO_2 emissions, gas-fired power is the most suitable and economic partner, as long as other renewable options remain unproven, technically limited and/or uneconomical.

A high CO_2 price would be a tool for forcing additional low carbon measures, such as CCS. With CCS, gas fired generation remains more competitive than coal with CCS and offers an attractive and competitive low CO_2 option, in its own right, as well as in combination with wind.

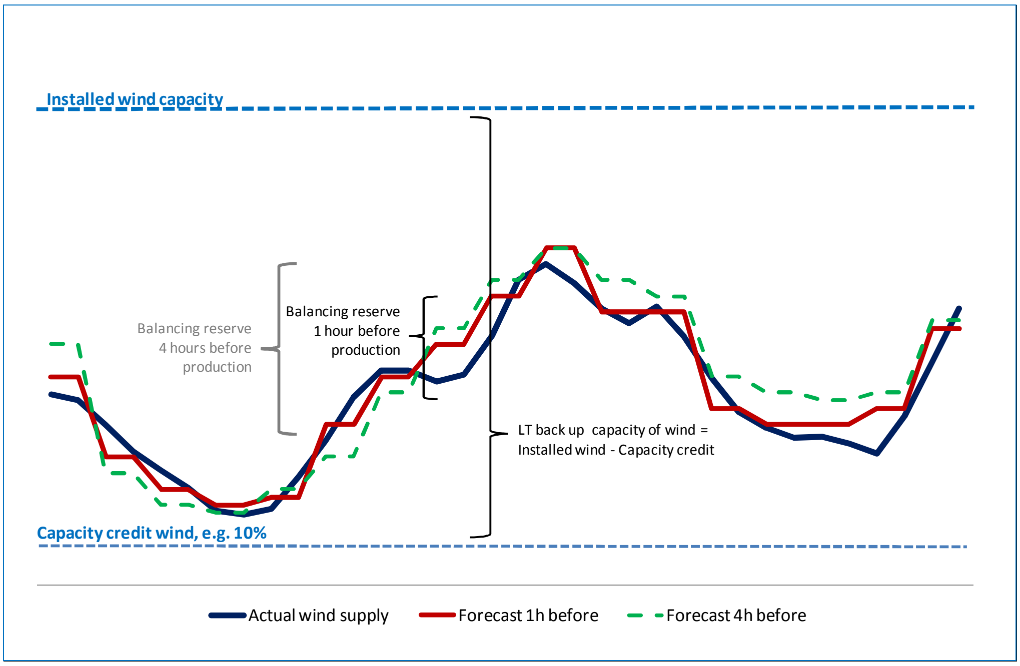
An additional question which arises is whether the present market model for organising and dispatching electricity is appropriate and effective in an environment with a significant share of wind power. In this context there are implications of large-scale partnering with wind power for the performance and economic viability of gas-fired power plants (with or without CCS) as well as for the gas supply. These will need to be further examined to ensure that the gas and power industries are ready to become secure partners.

Appendix A

Short-term back-up capacity of wind: balancing the electricity grid

The challenge of keeping a power system in balance is to correct for the *predictable* and *unpredictable* variations of the electricity supply and demand. The balancing reserves in the electricity system are usually divided into two groups: short-term back-up and long-term back-up. Here the short term refers to a time period of minutes up to four hours, while long term refers to periods longer than that.

The figure below gives an illustration of the short- and long-term back-up capacity for wind:



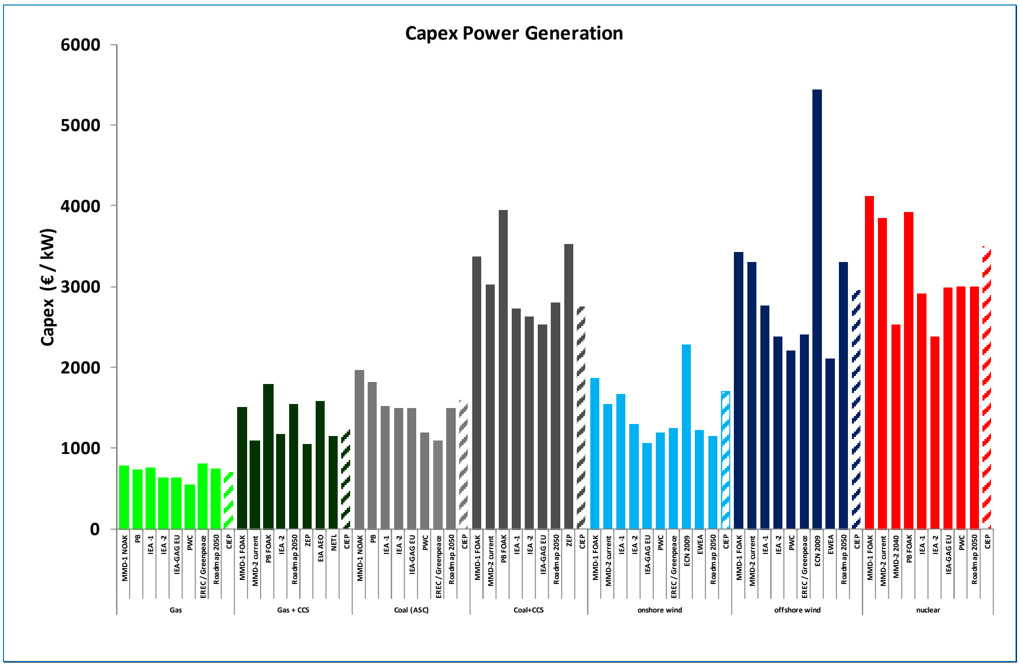
Source: CIEP

The wind-induced increase of the necessary short-term balancing reserves of a power generation system is not part of this study. The "IEA Wind Task 25" study gives an overview of several works of the past decade on this subject. The estimated increase in short-term reserve requirements in the studies summarised by the IEA has a large range: at wind penetrations of 10% of gross demand the increase in short-term reserve requirement is around 1-4% of installed wind capacity. At 20% wind penetration level the increase of balancing requirements is about 4-8% of the installed wind capacity. The costs of the extra balancing reserves are limited, as existing conventional power plants can usually offer the extra balancing reserves.

Appendix B

Literature overview on the investment costs

In this study the levelised cost of energy was calculated based on input parameters found in the literature. The figure below shows the wide range of assumptions regarding the investment costs of power generation techniques in the different studies. For this report mid-range capital cost figures were chosen, as shown in the shaded columns. Appendix D gives an overview on these and other input parameters used for the LCE calculations.



Composed by CIEP

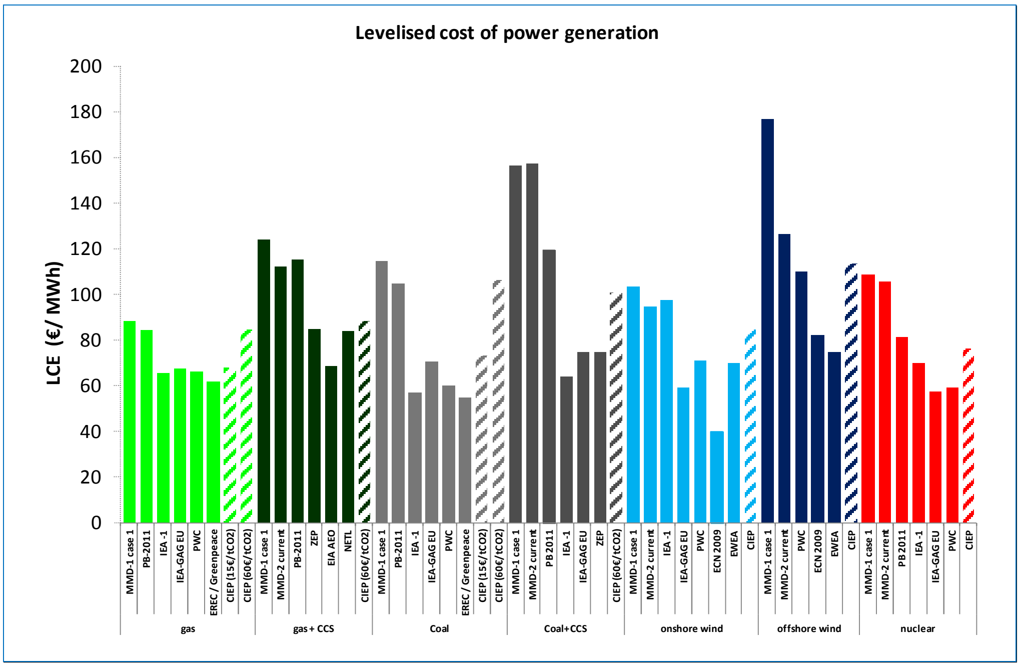
The following literature was used:

- Mott Mac Donald (1): UK Electricity Generation Costs Update (2010)
- Mott MacDonald (2): Costs of Low-Carbon Generation Technologies (2011)
- Parsons Brinckerhoff: Electricity Generation Cost Model - 2011 Update
- IEA: Projected Costs of Generating Electricity (2010)
- IEA GAG: Are We Entering a Golden Age of Gas? WEO-2011 (2011)
- PWC: 100% Renewable Electricity (2010)
- EREC / Greenpeace: Energy [R]evolution: Towards a Fully Renewable Energy Supply in the EU-27
- ECN: Current Developments in Wind (2009)
- EWEA : The Economics of Wind Energy (2009)
- ZEP: The Costs of CO_2 Capture, Transport and Storage
- NETL: Cost and Performance Baseline for Fossil Energy Plants
- EIA: Annual Energy Outlook 2011

Appendix C

Literature overview on Levelised Cost of Energy

The figure below shows the wide range of levelised cost of energy that can be found in the literature. The costs of power generation in the different studies can vary more than €50/MWh. These results are often difficult to compare, as the input parameters are not always clearly communicated. A slight change in the assumptions about, for example, the efficiency of a power plant, the length of the building period, the investment costs or the fuel- and carbon prices can result in a significantly different LCE. Especially the assumptions about the (expected) CO_2 price and investment costs tend to differ strongly in the studies below.



Composed by CIEP.

The following literature was used:

- Mott Mac Donald (1): UK Electricity Generation Costs Update (2010)
- Mott MacDonald (2): Costs of Low-Carbon Generation Technologies (2011)
- Parsons Brinckerhoff: Electricity Generation Cost Model - 2011 Update
- IEA: Projected Costs of Generating Electricity (2010)
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- ECN: Current Developments in Wind (2009)
- EWEA : The Economics of Wind Energy (2009)
- ZEP: The Costs of CO_2 Capture, Transport and Storage
- NETL: Cost and Performance Baseline for Fossil Energy Plants
- EIA: Annual Energy Outlook 2011

Appendix D

Input parameters for the calculation of levelised cost of energy

Capex values were derived from the costs found in literature, shown in Appendix B. For each technique a value was taken in the mid range of the cost figures. Construction period, efficiency, non fuel operational costs, and lifetime were based on the study of Mott MacDonald: "UK Electricity Generation Costs Update" and on experts' opinion. The fairly wide spread of capex values in appendix B indicates the high level of uncertainty around these costs, in which time and location are among the factors influencing the cost levels. The cost data chosen for this report do not pretend to be more accurate than any other in absolute terms, but are reasonably consistent in relative terms (for gas and coal techniques). It should also be noted that CCS has not been applied commercially. Possible new technological developments that could in future reduce the costs of techniques which are immature today (such as CCS techniques and offshore wind) were not taken into account.

For these reasons, the LCE calculated in this study should be regarded as not more than as illustration of competitiveness.

Power generation source	**Capex (€/kW)**	**Construction period (yrs)**	**Efficiency* At LF = 90%**	**Non fuel operational costs**	**Lifetime (yrs)**
Gas	800	3	60%	€ 16.500 /MW/yr + € 2,5 /MWh	25
Gas + CCS	1200	3	48%	€ 30.000 €/MW/yr + € 4 /MWh	25
Coal	1750	5	45%	€ 45.000 /MW/yr + € 3 /MWh	35
Coal + CCS	2700	5	38%	€ 70.000 /MW/yr + € 4,5 /MWh	35
Nuclear	3500	5	100% **	€ 50.000 /MW/yr + € 2,5 /MWh	50
Onshore wind	1700	2	100%	€ 25.000 /MW/yr	25
Offshore wind	2950	2	100%	€ 56.000 /MW/yr	25

CO_2 removal of CCS: 90%

Discount factor: 10% (sensitivity with 7%)

Fuel price:
Gas: 8 - 12 $/Mbtu
Coal: 80 - 130 $/tonne
Uranium: 4 - 6 €/MWh

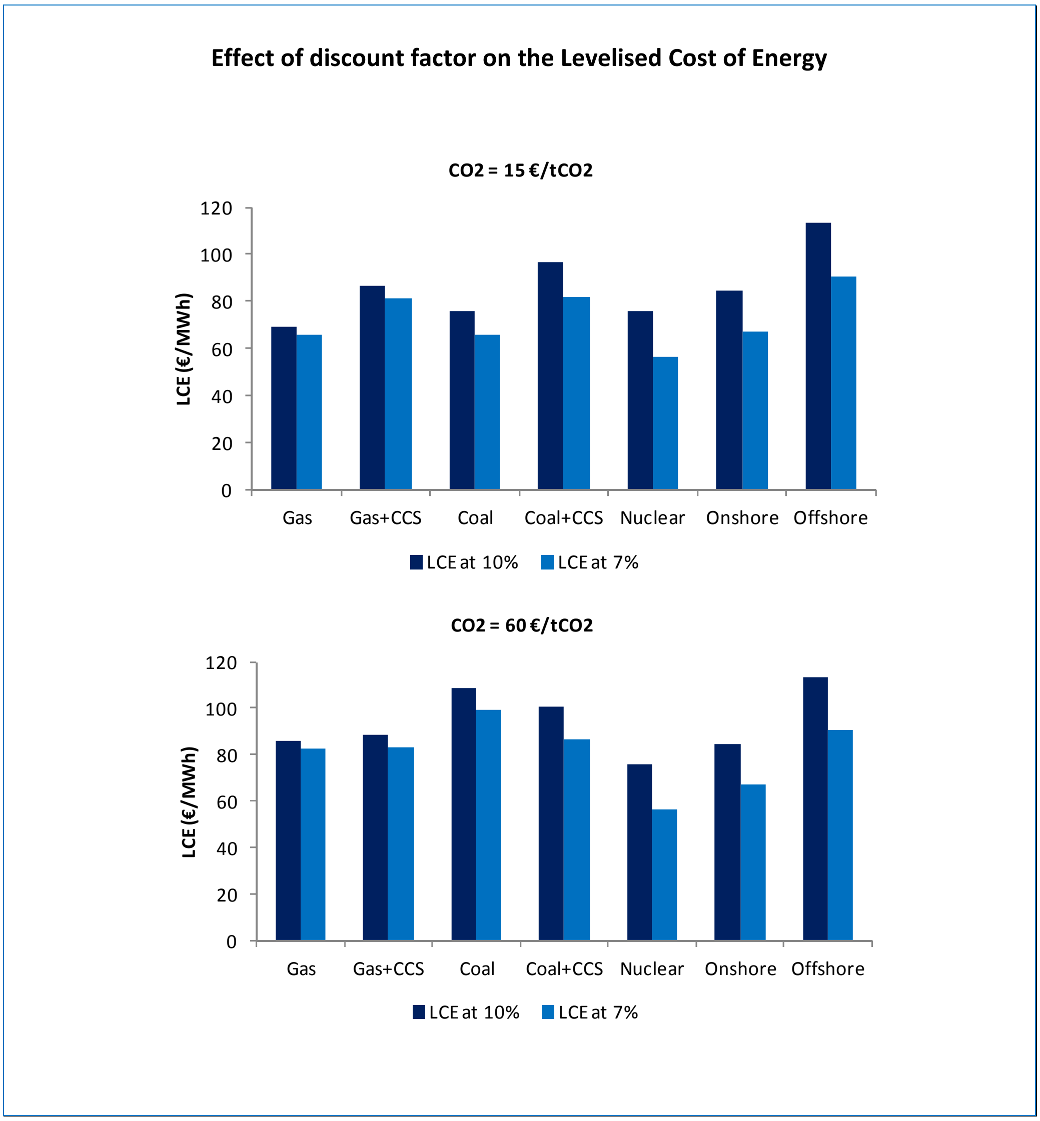
Carbon price:
0 - 100 €/tCO_2e

* Efficiency reduction of power plants due at low load factor operation is desrcibed in Appendix G
** Efficiency loss of nuclear power plants is taken into account as part of the fuel price

Appendix E

Effect of the discount factor on the Levelised Cost of Energy

The levelised cost of energy in this study is calculated at a discount factor of 10% (similar to most studies discussed in Appendix C). The figure below shows a sensitivity analysis of the LCE calculations based on a discount factor of 7%. Especially the LCE of capital-intensive generation techniques is significantly reduced compared to the base case with a 10% discount rate. Based on the assumptions of Appendix D, the application of a discount factor of 7% suggests that onshore wind power is a competitive option from an investor perspective.



Appendix F

Costs of CO_2 reduction

When wind power is added to a system to reduce CO_2 emission, the cost of abated CO_2 is:

$$Cost\ of\ CO_2\ abated\ (€/tCO_2) = \frac{LCE\ (wind)\left(\frac{€}{MWh}\right) - \ Marginal\ costs\ of\ abated\ fuel\left(\frac{€}{MWh}\right)}{CO_2 emission\ of\ abated\ fuel\left(\frac{tCO_2}{MWh}\right)}$$

In a design system, from the perspective of the *total* costs and CO_2 emission of power generation the cost of abated CO_2 emission per each MWh of generated power is:

$$\frac{Costs\ of\ power\ generation\ (backup + wind)\left(\frac{€}{MWh}\right) - \ Costs\ of\ power\ generation\ backup\left(\frac{€}{MWh}\right)}{CO_2 emission\ backup\left(\frac{tCO_2}{MWh}\right) - CO_2 emission\ (backup + wind)\ \left(\frac{tCO_2}{MWh}\right)}$$

where the cost of power generation including wind energy is (in the case of 7000 full load hours of demand and 2500 of full load hours of onshore wind):

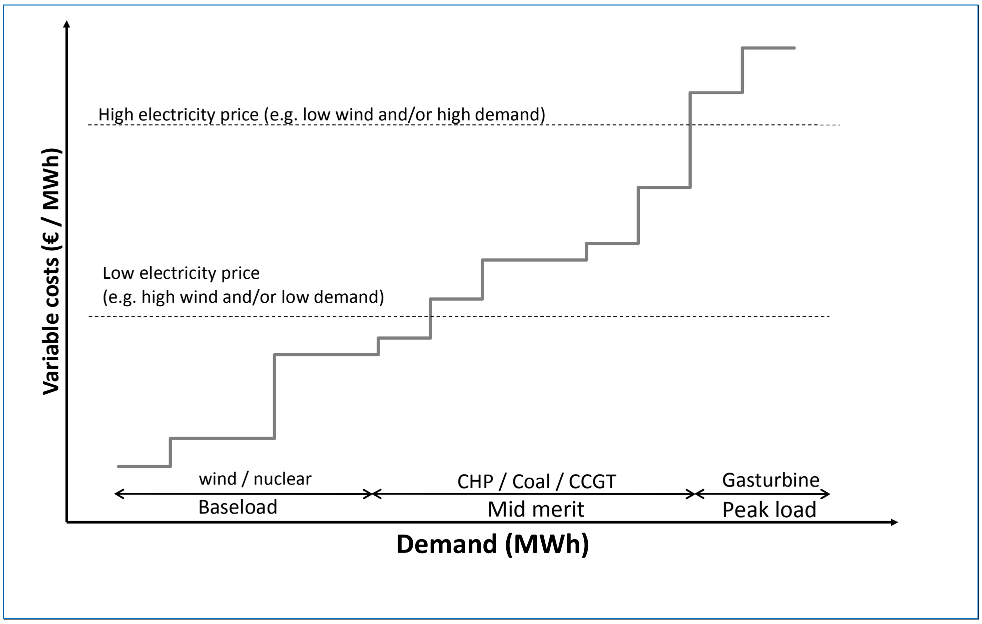
$$Costs\ of\ power\ generation\left(\frac{€}{MWh}\right) = \frac{2500\ (h) * LCE_{wind}\left(\frac{€}{MWh}\right) + \ 4500\ (h) * LCE_{backup}\ \left(\frac{€}{MWh}\right)}{7000\ (h)}$$

Appendix G

The merit order

The merit order is a way of ranking available sources of energy, especially electrical generation, in ascending order of their short-run variable costs of production, so that those with the lowest variable costs are the first ones to be brought online to meet demand, and the plants with the highest variable costs are the last to be brought on line. The merit order curve (see figure below for illustration) starts with the least expensive unit, moving towards the most expensive units, presenting the costs and capacities of al generators. Each power generation unit in the figure is shown as a step in the curve. The merit order curve shows the variable costs (fuel costs, CO_2 tax, operational and maintenance costs, etc.) and is not influenced by the investment costs of the different power generation units.

Wind power has low variable costs (no fuel- or CO_2 costs) and therefore enters at the left side of the merit order curve, “pushing” the other generating techniques towards the right side (towards mid merit). Another effect of wind on the merit order curve is that the electricity price is generally expected to be lower during periods with high wind supply than in periods with lower wind supply (the “merit order effect”).



Source: CIEP. Figure is only for illustration

Appendix H

Characteristics of conventional power plants

The most important characteristics of a power plant are the costs (capex, fuel costs, CO_2 tax, operation and maintenance costs), efficiency, emissions (CO_2, NO_x, SO_x), the nameplate capacity and the flexibility of the plant. Efficiency is indirectly also included in the fuel costs and emissions (higher efficiency leads to lower fuel costs and emissions). These parameters define the choice of an energy mix for power generation (excluding strategic decisions).

The flexibility of the plant is described by the start-up time and the ramp-rate of the plant. Different types of power plants have different technical limitations to operating in a flexible way. Gas turbines (GT) are the most flexible, but have low efficiency (30-35%) and thus relatively high fuel costs and high CO_2 emission, and as such are usually only used during peak demand. In combined cycle gas turbines (CCGT) a gas turbine is combined with a steam turbine, leading to higher efficiency (60%) and therefore lower fuel costs and CO_2 emissions, but also lower flexibility. Coal-fired plants are generally less efficient (40-48%) and less flexible than CCGT plants. Nuclear power plants are often assumed to run only in a baseload mode. However, technically most nuclear power plants can be operated flexibly to a certain extent (with a load decrease from 100% to about 30% of the nominal power and a maximum of two cycles a day. New nuclear power plants can technically offer more flexibility). The table below provides an overview of the technical parameters of different types of power plants.

	Typical efficiency*	Start up time (min)	Max ramp rate
Gas turbine	30-35 %	10-20	20 %/min
Gas plant (CCGT)	58-60 %	30-120	3-10 %/min
Coal plant	40-48 %	60-600	1-5 %/min
Nuclear	100%		1-5 %/min

Source: CIEP, based on Vuorinen and the TU Delft.
*"Typical" efficiency is the efficiency of a typical plant under ideal conditions (stable run).

The flexibility of a power plant determines its potential contribution to the short-term balancing of the electricity grid. For the long-term back-up this is mainly determined by the costs.

Appendix I

Impact of intermittency on fossil fuel-powered plants

When a large amount of the power generation source is wind and therefore intermittent, the rest of the power generation source (or at least a part of it) has to run in a more flexible way than at a low wind penetration level.

Flexible operation of a power plant affects efficiency in two different ways. Due to the flexibility, the average load factor of the plant decreases, leading to lower efficiency and thus higher costs and higher emissions. At a 40% load factor, for example, an average coal-fired power plant loses about 10% of its efficiency, while efficiency of a CCGT plant is reduced by about 15%. Another effect is that especially during fast ramp-up periods efficiency decreases temporarily. According to experts this latter effect can be neglected.

Composed by CIEP, based on Vuorinen, TUHH and Tauschitz.

Besides the technical and economical limitations of operating a plant in a flexible way, flexible operation reduces the lifetime and the efficiency of the plant while maintenance increases. It is difficult to quantify the exact effects of flexible operation on the lifetime and on the maintenance costs; therefore it is not taken quantitatively into account in this study. However, the hidden costs of reduced lifetime and increased operational costs can be significant and should be studied in more detail.

Appendix J

Available hydropower from Norway

Hydropower from Norway is already a part of the solution to balance the electricity grid of NW Europe; however, it is limited by interconnection capacity. Norway has a total generation capacity of 31.3 GW, of which 29.6 GW is hydropower capacity (including 1.3 GW pumped hydro)[62]. Assuming that about 80%[63] of the installed hydro capacity is available during the winter peak demand and considering a peak demand of 23.8 GW[64], theoretically 1.5 GW of electricity could be transported "as firm" to NW Europe during winter peak times[65]. Most of the time more capacity from Norway would be available. However, not more than 1.5 GW can be taken into account as "firm" (that is, about 3% of the current installed wind capacity in NW Europe).

There is still about 37 TWh of reservoir potential that can technically[66] be exploited, mostly small-scale projects at home and pumped storage[67]. Assuming that 80% of the hydro capacity is available in the winter, a maximum of about 11 GW of generation capacity could be considered as firm back-up capacity for NW Europe, about 10% of the total potential planned wind power capacity in 2020. However, that would mean that more than 9 GW of new interconnection capacity should be realised between Norway and NW Europe (there are now plans in place for about 4 GW in total).

[62] IEA Country Review 2011 on Norway
[63] IEA Country Review 2011 on Norway
[64] Statnett estimates peak demand of 23.8 GW in Norway with temperatures corresponding to a one in ten years' winter day.
[65] The current interconnection capacity between Norway and the Netherlands is 0.7 GW; between Norway and Germany it is 0.7 GW.
[66] Consideration of the environmental effect of hydro energy is not taken into account in this technical potential.
[67] www.statkraft.com

Appendix K

Onshore and offshore wind turbines

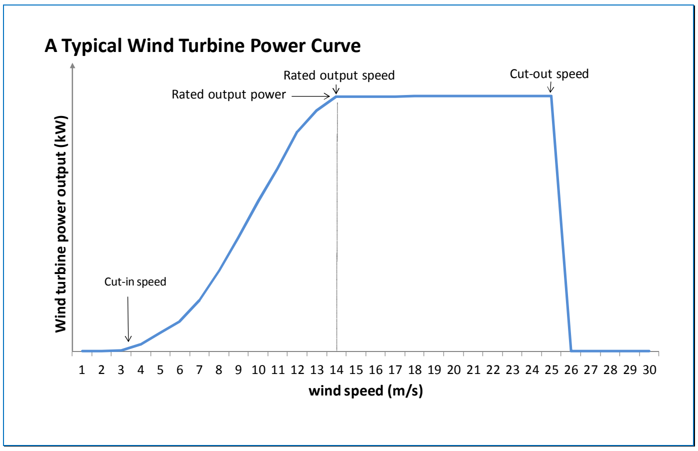
The amount of electricity produced by a wind turbine strongly depends on the turbine's nominal power, its type, hub height, power curve and the location of the wind turbine. The location of the turbine and the hub height determine the available wind energy, while the characteristics of the turbine itself (maximum capacity and power curve) determine how much of the wind energy can be converted into power.

The same wind turbine gives very different results, depending on its location. Onshore locations are often easier to access than offshore, resulting in lower installation and maintenance costs. Also, the availability of onshore wind turbines is on average higher than that of offshore turbines, as offshore locations need to be able to withstand higher stress due to stronger wind, high waves and corrosive sea air and has longer repair time due to bad weather conditions (e.g. strong wind, high waves, fog). Offshore locations, however, usually have a higher average wind speed, resulting in a higher average full load hours. The North Sea is one of the most attractive locations in Europe for wind parks, due to its average number of hours with high wind speed. Here the average wind speed is about 9 m/s, compared to around 4 m/s onshore.

The table below gives an overview of the characteristics of onshore and offshore windmills.

	Capex (€/kW)	Average full load hours	Average avaiability
Onshore	1500 – 1900	2300 – 2600	97 – 98 %
Offshore	2500 - 3500	3400 - 3900	90 – 95 %

The figure below shows a typical power curve for an offshore windmill. Wind turbines start to operate above a certain wind speed value (usually around 4 m/s). At high wind speed the turbine shuts down to protect the windmill from damage.



Offshore wind turbines usually have a higher nameplate capacity (5-6 MW, as compared to 2-3 MW onshore) in locations with high wind speed and therefore give higher average power output efficiency than onshore locations. Despite this, they are less economical due to the higher investment and maintenance costs.