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Energy Resources for the Future

"We want to consider scenarios in a 30-year perspective"

Programme Committee:

Arne Bjørlykke, Professor, NGU, Chairman
Knut Alfsen, Director of Research, CICERO
Kjell Bendiksen, Managing Director, IFE
Olav Bolland, Professor, NTNU
Arne Bredesen, Professor, NTNU
Einar Hope, Professor, NHH
Sverre Aam, President, SINTEF Energy
Hein Johnson, Secretary general, NTVA

Norwegian Academy of Technological Sciences

NTVA

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Aim of the Seminar

The Intergovernmental Panel of Climate Change (IPCC) published its four climate reports in 2007, and it seems that the world accepts that human activity constitutes a substantial contribution to climate change. Even though there is still some uncertainty regarding the climatic prognoses, we must face up to the consequences and reduce our greenhouse gas emissions. It is inevitable that there are some choices to be made to achieve this. We can reduce energy consumption or we can develop new energy without greenhouse gas emissions. The choice of energy system will among other factors be dependent on price, supply regularity, environmental requirements, resources and public opinion. How do we wish to cover our power demands in 2030, and how will technological developments influence this?

Based on the world's power demands as they appear today and are likely to be in the future, we will ask the experts to focus on the energy systems that have great potential for improvements regarding reduced environment impacts and price. We want to consider scenarios in a 30-year perspective. Such scenarios will also be useful regarding the development of strategies for energy research in Norway.

We will also ask for an evaluation of external non-technical limitations which can influence developments such as politics, environmental considerations and public opinion. When alternative energy systems are debated, various systems are usually contrasted based on today's technology. However, we must become better to analyse the possibilities in the technological development potential of energy systems. We must help people to understand the fact that technological development is a time-consuming effort.

The Seminar Report should be a useful contribution to the debate on energy systems for both specialists and the general public. It will also be a useful background document to help determine the priorities for energy policies and energy research in the future.

Arne Bjørlykke, Professor, NGU,
Chairman of Programme Committee

Seminar program 9 September 2008

10:00 – 10:10	Welcome to NTVA Technology Forum 2008	Professor Asbjørn Rolstadås, President of NTVA
10:10 – 10:50	Technological and Scientific Foresight of the Energy Demand of the World	Director of Programmes Elena Nekhaev, World Energy Council
10:50 – 11:20	Technology development - socio-economic aspects	Research Manager Gunnar Eskeland, Cicero
11:20 – 11:50	How can technology development produce results?	Senior Vice President Sverre Gotaas, Innovation, New Energy, Statkraft
11:50 – 12:50	Lunch	
12:50 – 13:20	Oil, gas, coal and CCS	Professor Olav Bolland, NTNU
13:20 – 13:50	Nuclear Power	Vice President Mikko Kara, VTT (Technical Research Centre of Finland)
13:50 – 14:20	Sun	Head of division Arve Holt, IFE
14:20 – 14:40	Break	
14:40 – 15:30	Other renewable energy resources - Wind (on land and offshore) - Wave power - Hydro power (small scale) - Geothermal power	 - Professor Geir Moe, NTNU - Project manager Tore Gulli, Fred. Olsen - Professor Hermod Brekke, NTNU - Professor Arne Bjørlykke, NGU
15:30 – 16:00	Transport sector and use of - battery - hydrogen - bio fuel	Research Manager Steffen Møller-Holst, SINTEF Materials and Chemistry
16:00 – 16:20	Break	
16:20 – 17:30	Summing up	Managing Director Kjell Bendiksen, IFE
20:00	Dinner, Lerchendal gård (Aperitif 19:30)	Hein Johnson

Energy saved is energy gained. Delft Railway Station, Holland
(Photo: Hein Johnson)

Content:

Global Energy Today and Tomorrow: Demand, Resources and Technologies

Elena Virkkala Nekhaev, Director of Programmes, World Energy Council

Introduction

The energy industry around the world is today undergoing major changes, increasingly opening up to the global energy imperatives and challenges of liberalisation, market, competition, security of supply and environment. At the same time, 1.6 billion people, a quarter of the world population, do not have access to electricity; and the need for energy infrastructure investment is huge. The most fundamental challenge facing the energy industry is meeting the rapidly growing demand for energy services in a sustainable way, at an affordable cost and in an environmentally acceptable manner.

Energy projects are among the most capital intensive and long-term infrastructure investments. Decisions made today will impact on our lives for decades, and it is important that these decisions are based on facts and a proper economic assessment of available options.

The energy challenges are not the same in all regions. While rapidly growing economies in the developing world are hungry for power, practically any power to support economic growth and provide basic energy services for their citizens, industrialised countries are focusing on securing electricity supplies in a competitive environment and in a publicly and environmentally acceptable way.

Energy Demand Outlook

Before looking into the future, it may be useful to review what has happened over the past ten years:

- World population has grown by 12 % and today over 60 % of all people live in East and South-East Asia.
- Consumption of primary energy has increased by 20 % and electricity consumption by 32 %.
- Oil price has jumped from 10 to nearly 150 dollars per barrel.
- These figures are considerably higher than in any high growth scenarios drawn 20 years ago.

Current “business as usual” scenarios paint a similar picture:

- Global energy demand is expected to double in the next 30-40 years with China and India alone accounting for over 40 % of that increase.
- Electricity demand is expected to triple over the same time period.
- Fossil fuels will remain the backbone of the energy supply, and their use will even increase in absolute terms, while their share in the energy mix will drop slightly.
- Global CO_2 emissions will rise by more than 50 %, and again two countries: China and India will together account for 60 % of the total emissions by 2050 or earlier, and EU’s emissions reductions will be dwarfed by the emissions growth in these two Asian Giants.

Resource Overview

The starting point for any discussion about energy is primary energy resources: coal, gas and oil, which, together with uranium and thorium, are finite, and renewables, which can be split into two broad categories: intermediate and perpetual. Peat and geothermal energy are considered to be intermediate resources, as they have both finite and perpetual qualities. Bioenergy, solar and wind are the principal perpetual resources, together with various marine energy resources, such as tidal and wave power and Ocean Thermal Energy Conversion (OTEC).

No other organisation is in a better position to cover energy resources than WEC. For over 70 years, WEC has been producing a triennial Survey of Energy Resources based on the research conducted using its member network, regional organisations and various other expert bodies. The WEC Survey is the most comprehensive collection of data and other relevant information about global energy reserves and resources. Electronic copies can be downloaded from the WEC website at www.worldenergy.org free of charge.

The main conclusions of the last WEC survey published at the end of 2007 indicate that the world's energy resources, in particular coal, will remain abundant and sufficient to meet the growing global demand for energy for many years.

Coal resources are abundant and widely distributed around the world. The proved coal reserves could last for nearly 200 years at the current production levels. More than 70 countries can economically produce coal. The energy sector is heavily dependent on this resource, around 40% of all electricity in the world is generated from coal, and both Asian Giants China and India have coal-based economies. Today, however, coal has a bad reputation, in particular in the OECD countries, because of its "poor" environmental record, but there are remedies in sight, clean coal technologies, carbon capture and storage, just to name a few.

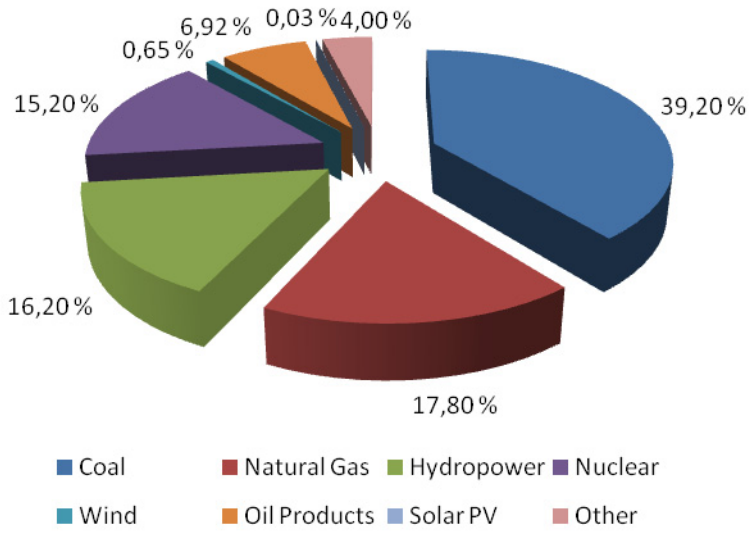

Figure 1: World Electricity Generation by Fuel
Source: WEC

Oil, on the other hand, could not be more different. The past couple of years have clearly demonstrated the volatile nature of oil and the world's continuing dependence on this leading energy resource. The recent steep rise in oil prices, however, has not been caused by dwindling oil reserves. On the contrary, WEC research demonstrates

that proved oil reserves have increased over the past three years and have reached 1 215 billion barrels at the end of 2005, i.e. approximately 117 billion barrels more than three years earlier. Concentration of the main oil resources in a few regions and long supply routes to the main markets are at the heart of the issue. The reserves to production ratio for oil have remained at approximately 40 years for more than three decades. Continuous improvements in exploration, processing, conversion and end-use technologies may extend the availability of oil for decades to come.

In addition to conventional oil, there also are complementary oil resources: ***Oil Shale*** and ***Natural Bitumen/Extra Heavy Oil***. Oil shale has been found in nearly 40 countries, and the total global resources are estimated at 2 800 billion barrels. Oil shale can be burnt directly as a fuel or it can be processed to produce various liquid fuels.

Natural Bitumen/Extra Heavy Oil (often referred to as tar or oil sands) is a dense substance with high viscosity and concentration of nitrogen, oxygen, sulphur and heavy metals. The total resource is estmated to be at least of the same magnitude as the original deposits of conventional oil.

Natural Gas reserves are even more concentrated than oil. Three countries: Russia, Iran and Qatar control over 50 % of all gas reserves in the world, whereby 20 % of the total global gas reserves are located in one huge field between Iran and Qatar. Natural gas is plentiful and currently yields a reserve to production ratio of nearly 60 years. It is widely assumed that there is much more gas to be yet discovered. However, the recent additions and some of the well-known large fields are located in remote regions with poor infrastructure, and developing these fields would be a huge challenge, not least due to the enormous investment requirement.

Uranium reserves on current assumptions can last for 40-70 years at current consumption levels. The leading producers of uranium are Canada, Australia, Kazakhstan and Russia. Secondary sources of uranium (from the dismantling of nuclear warheads) are playing an increasing role in the market and can affect the development of the leading production centres. Thorium ore is also a potential resource in the long-term.

Nuclear Energy plays a significant role in the global electricity supply, it accounts for over 15 % of total electricity production. At the end of 2007, there were 439 nuclear power plants (NPPs) in operation around the world, with the total of 371.7 GWe installed capacity. There also are 31 reactor units under construction with a total capacity 23.4 GWe. The ten countries with the highest reliance on nuclear power in 2006 were: France, 78.1 %; Lithuania, 72.3 %, Slovakia, 57.2 %, Belgium, 54.4 %; Sweden, 48.0 %, Ukraine, 47.5 %; Bulgaria, 43.6 %, Armenia, 42.0 %, Slovenia 40.3 % and Republic of Korea, 38.6 %. From 1975 through 2006 global nuclear electricity production increased from 326 to 2 661 TWh. Installed nuclear capacity rose from 72 to 369.7 GW(e) due to both new construction and increased output at existing facilities.

Renewable Energy today accounts for about 18 % of power generation, with nearly 90 % of this coming from hydropower, the largest source of renewable energy. Renewable energy power generation is not directly comparable to fossil-based production, since most renewable energies are intermittent and cannot easily be used for base-load electricity supply. However, they can play an important role in specific circumstances, in particular in remote off-grid areas.

Hydropower is the leading source of renewable energy. In Europe and North America about 70 % of all hydro resources have already been developed, compared to South America with 33 %, Asia with 22 % and Africa with only 7 %. Africa's hydro power potential is so enormous that it is not worth developing it now, since there is not enough demand within a reasonable distance, and building long transmission lines would be both long-term and high-cost.

Biomass is the second largest source of renewable energy, and in addition to electricity generation, it is also used in direct applications in households, for production of biofuels for transportation and in other applications and processes. Biomass can also substitute a fraction of coal in coal-fired boilers: co-firing is another solution.

Biomass includes various organic materials, such as wood by-products and agricultural wastes, which can be used to produce energy. Biomass can substitute some fossil fuels for the chemical industry and energy (biofuels for transport, heat and electricity). Electricity from biomass has enjoyed steady development.

In 1998, 98.8 TWh were produced from biomass throughout the world. In 2005, the world electricity production from biomass reached 183.4 TWh. Growth of biomass use is however limited by a number of factors but prospects for biomass are positive. Biomass was the second largest renewable sector with 5.6 % of the renewable origin electricity in 2005, behind hydro power (89.5 %) but ahead of wind energy (3.0 %). However, biomass actually delivered only 1 % of the global electricity, far behind fossil fuels (64 %), large hydro (16.2 %), and nuclear (15.2 %).

Europe and North America are the leaders in the use of biomass with almost 75 % of the global bioelectricity production, ahead of Asia (about 18 %). Africa today represents only 0.2 % of the total biomass-based electricity production.

Biomass energy offers an array of benefits:

- No greenhouse gas during the life cycle and less emissions than fossil-fuel plants
- Forest sustainability
- Contributes to energy independence and regional economy
- Proven technologies for combustion and co-firing
- Use of low-cost products

Biomass systems are most often fuelled by waste wood, from logging operations, forest thinning, low-grade wood or sawmill residues, which are far too frequently burnt in the open without pollution control. These systems create a commercial market for wood whose extraction benefits forest health, while also boosting the forest-product economy. Rather than depleting the forest resource, biomass energy, when sustainably supplied, strengthens the forest growth.

Biomass conversion to electricity has several major drawbacks:

- Seasonal availability
- Transport and processing require energy
- Pollution and emissions
- Required land area

The land area required for fuelling a biomass power plant is huge compared to other energies. The following table shows the land area required for operating a 1 GW renewable energy plant (average values):

Table 1: Land area requirement for electricity production

Energy Source	Wind	Solar (PV)	Biomass	Geothermal
Land area for a 1 GW plant	100 km²	30 km²	5 000 km²	200 km²

Sources: WEC and US DOE

The very long-range biomass electricity production potential is estimated at 11 000 TWh per year, i.e. more than 60% of the world-wide electricity production in

2005 (18 140 TWh). This potential is higher than that of other renewable energies: hydro (7 500 TWh), wind energy (around 4 500 TWh), solar energy (4 400 TWh).

Solar Energy is delivered by the sun, and thus depends on the day and time. At high noon on a cloudless day at the equator, the sun delivers about 1 kW/m² to the Earth's surface. However, this measure has to be adjusted to take into consideration clouds, latitudes and sunsets. Solar power is assessed by the irradiance, which is the average number of kWh per m² per year (or day). Typical irradiance ranges from 700 kWh/m²/year in northern regions (Northern Europe, Canada) to 2 200 kWh/m²/year in the sunniest areas (Africa, Southern Europe).

Theoretically solar energy has enormous potential. The total amount of solar energy reaching the Earth's surface is a thousand times greater than the world total energy consumption. The long-range solar electricity production potential (corresponding to a reasonable required area) is estimated at 4 400 TWh per year, i.e. more than 26 % of the world-wide electricity production in 2003 (16 570 TWh). This is lower than for biomass (11 000 TWh) and hydro (7 500 TWh), but almost identical to the wind energy potential (around 4 500 TWh).

In 1992, the total installed PV capacity in the world was 110 MWp. By the end of 2005, this figure was already 4 640 MWp, including 1 460 MWp added during the year, the growth rate of 34 %. Solar PV is today the fastest growing power generation technology.

Historically, Japan was one of the first countries to massively support PV energy. Its cumulative installed capacity in 2005 was 1 430 MWp, corresponding to 31 % of the world-wide PV energy installations. Over the past two years, Germany has become the largest market, representing 58 % of the new installations world-wide in 2005. The United States is the third largest market with 105 MWp installed in 2005 and a cumulative capacity of 465 MWp. Far behind Germany, Japan and the United States, come the two Asian giants India and China.

PV cells cannot fully convert sun power: typical solar panels have an average yield of 12 %, with the best available panels at about 20 %. Consequently, a production of about 1 kWh per m² PV panel on average can be expected every day in a good area after taking into account weather, latitude and yield. PV energy can be an ideal solution for alternative electricity supply but it has several drawbacks:

- Intermittence
- Grid integration
- Weather dependence
- Use of toxic materials

Over the past fifteen years, photovoltaic (PV) solar energy has grown exponentially. Initially leading-edge technology only used for satellites, PV cells is becoming more common.

Wind is often considered to be the most advanced of the renewables, after hydropower. The world's best wind sites are spread around the coastal regions. Offshore projects spur the development of ever larger machines and wind turbines of 5 MW and above are entering the market. At the same time, the electricity systems with a rapidly increasing share of wind power are facing new challenges. Experience in the countries with a high share of wind in their electricity production (20 % and above), demonstrates the difficulties of integrating an intermittent energy source into the grid and the implications this can have for the system performance.

Since the early 1990s, wind power has undergone a considerable level of development. In 1995, an installed capacity of 5 000 MW was achieved globally. 2005 was another record year for wind energy, with an installed capacity reaching

59 200 MW and 11 700 MW added during the year (i.e. a growth rate of 25 %). In 2006, the first statistics show a total capacity of 72 600 MW (13 400 MW installed during the year, i.e. 23 % growth rate).

Due to this development the wind power sector represented 3.0 % of the total renewable electricity in 2005, behind hydro power (89.5 %) and biomass (5.6 %). Wind energy delivered around 0.6 % of the global electricity generation (98.4 TWh), far behind coal (40 %), gas (19 %), large hydro (16 %), nuclear (15.5 %) and oil (7 %).

2006 was a great year for wind energy. Nevertheless the great majority of wind turbines were installed in Europe, despite Asia (+49 % in 2005, +30 % in 2006) and North America (+33 %) showing the highest growth rates, with India overtaking Denmark in absolute numbers. Europe maintained a leading position but new installations represented 57 % of the very latest installations, while in 2004 this figure was 71 %.

Few countries stand out. Germany is the leader with more than 20 600 MW installed in 2006 i.e. nearly one third of the world-wide wind power installation. Thereafter come Spain (11 615 MW installed), the United States (11 600 MW), India (6 050 MW) and Denmark (3 140 MW). These five countries account for nearly 75 % of the global capacity in 2006.

Offshore wind energy production is currently much more expensive than onshore. Initial investment is 50 to 100 % higher depending on site (depth, distance from shore, type of substratum). O&M costs are also 50 to 100 % higher depending on the site.

The kWh cost for onshore production is estimated between 5 and 12 c€/kWh depending on the turbine size and site, whereas offshore production cost is estimated between 8 and 20 c€/kWh. Thus onshore wind energy production can compete with coal, gas and nuclear electricity and other energies which cost between 3 and 6 c€/kWh, all the more as external costs (impact on human health, ecosystems and global warming) are not considered here. Wind energy, with low external and production costs is an attractive clean alternative to fossil fuels.

Table 2: Investment and production costs for different type of generating plant

Type of plant	Investment costs (€/kW)	Production costs (€/MWh)	External costs (€/MWh)
Nuclear	2000-3000	25 - 30	2.3 - 18.8
Coal	1000-1800	30 - 35	19 – 99.0
Gas	600-800	35 - 60	7 – 31.0
Large hydro	1000-2000	30 - 65	0.04 - 6.03
Geothermal	1500-2700	50 - 80	0.2 - 0.5
Biomass	1000-2800	40 - 110	2.0 – 50.0
Wind (onshore)	1000-2800	50 - 120	0.5 - 2.6
PV grid-connected	5000-9000	250 - 650	1.4 - 3.3

Source: WEC Performance of Generating Plant Committee

Technically, no major breakthroughs in further wind power development are expected soon and it is presumed that costs will gradually decrease with widening production and manufacturing improvements, unless raw material prices increase drastically.

Ultimately, incentive mechanisms are needed to locate new markets and accelerate expansion of the wind energy sector.

This clean and relatively cheap energy will represent the first step towards reduction of GHG emissions. However, due to its intermittent nature, wind energy alone will be unable to supply a major part of electricity demand. A clean energy mix, which would combine renewable energies (wind, solar, biomass, marine and geothermal) with nuclear, hydro and others depending on local and regional circumstances is absolutely necessary in order to achieve a balanced and sufficient electricity supply and significantly reduce GHG emissions.

Challenges and Issues

What is the most challenging issue facing the global energy sector today? Energy security emerged as one of the "hottest topics" on nearly everyone's agenda a couple of years ago thanks to high oil prices and the fear of supply disruptions. After a period of fairly low and stable oil prices and the ensuing complacency at the end of the 20th century, the world has finally began to understand the vital role of energy in our modern society.

Europe presents an extreme example of energy vulnerability, as a result of the "dash for gas" at the end of last decade. 80 % of all the new thermoelectric capacity built in the last 10 years is gas-fired, approximately half of all European homes use gas. 60% of all the gas used in the European Union (EU) is currently imported. EU's reliance on Russian gas is considerable. Russia currently supplies 100 % of gas imported into Finland, Slovakia, Lithuania, Latvia, Estonia, Bulgaria, Romania and Hungary. It also supplies 80 % of the gas imported into Austria, the Czech Republic, Poland and Greece, 40 % of the gas imported into Germany and 30 % of the gas imported into Italy and France. This situation is not going to change. In the short term, our dependence may even increase.

This should really be food for thought for all Europeans, politicians and the general public alike.

Electricity Sector Faces Tough Choices

The electricity sector has very long lead-times. The life time of a conventional power plant or an electrical substation is over 30 years. Permitting, siting, design, construction and operational life for nuclear plants can be nearly 100 years.

Electricity cannot be stored, so at any moment in time production should match demand. Demand can vary by up to 100 % depending on the time of the day, seasons and other variables. Therefore it is necessary to have an adequate mix of base-load plants and peaking units. Some technologies are suitable and economically viable only as base-load (e.g. nuclear), other as peaking units (single cycle gas turbines).

The speed of generating capacity growth around the world is staggering. It is driven by growing economic activities and also by the need to replace the old capacity. To meet this growth on the global level it would require the following generating capacity additions over the next two decades.

Table 3: Global Generating Capacity Addition Requirement. Annually between 2013 and 2030

Technology	Number of Additions	Capacity (each)
Coal -fired CCS	22 thermal generating plants	800 MW
Gas-fired CCS	20 thermal generating plants	500 MW
Nuclear	20 Reactors	1 000 MW
Hydropower	2 x Three Gorges Dams	18 000 MW
Biomass and waste	400 CHP plants	40 MW
Wind	17 000 wind turbines	3 MW

Source: IEA

In Europe today, more than 30 % of generating capacity is over 30 years old. By 2020 this figure will be 80 %. It is becoming urgent to define the future energy mix for Europe, as this window of opportunity will not last very long.

Taking into account the long life cycles of the energy sector technologies and the expected huge growth in demand for electricity, it is obvious that all energy resources and all technologies must be considered. The world does not have the luxury of choosing one technology over another, and costs of available solutions and incentives must be considered based on a full life-cycle assessment to allow each technology to find its appropriate niche.

This will help create a Sustainable Energy Technology Portfolio for every country and every region based on their specific circumstances.

Environment, and climate change in particular, have become the leading drivers in the energy sector, especially in the OECD countries. When it comes to total GHG emissions, the United States are clearly in the lead, but China is rapidly catching up.

Global GHG emissions are rising, and under the “business as usual” scenarios, they are expected to go on rising for decades to come.

The problem is not a lack of policies: thousands of policies have been introduced around the world. The fact is that these policies do not deliver – a new fresh approach is required. It might be more effective to treat emissions reductions in a broader context. After all, sustainable development is not only about the environment. Policies which do not contribute to economic and social development will themselves prove unsustainable. Sustainability will not be achieved at the cost of social development, especially for the 1.6 billion people who do not have access to modern energy services.

Power generation with 41 % of the total CO_2 emissions and transport sector with 21 % are the largest emitters of CO_2 but on the positive side, there is a high energy efficiency potential in each of these two sectors.

One of the positive impacts of globalisation is the convergence of energy intensities in industry around the world, although there still are large disparities between regions. The CIS countries still need three times as much energy as OECD Asia to produce one unit of GDP.

In terms of household per capita consumption, USA is in the league of its own. An average North American uses nearly three times as much electricity as an average European and more than ten times as much as an average Indian.

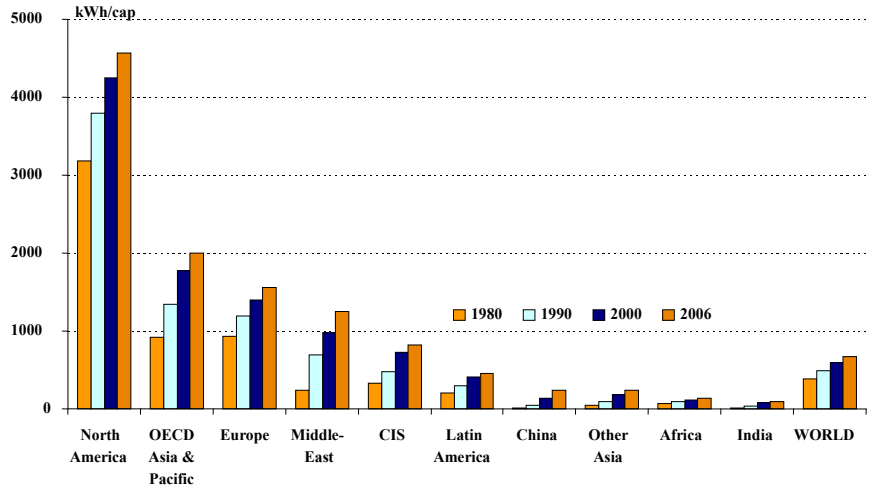

Figure 2: Household Electricity Consumption per capita
Source: WEC/ADEME Energy Efficiency Policies and Indicators Committee

Energy efficiency potential is huge and can be realised in a relatively short time. This slide demonstrates how buildings insulation and energy-efficient design can help significantly reduce the household heat consumption. Finland and Latvia have similar climates but Finnish homes use 50 % less energy for space heating than Latvians, and this was achieved over two decades by gradual improvement of insulation and better energy management.

The Way Forward: Cooperation and Inclusiveness

Current energy policies in most countries across the world leave a lot to desire. They are often short-term, lack focus and are outright confusing. A closer cooperation between all stakeholders is needed to develop adequate policies based on facts and not beliefs and assumptions and accepted and supported by all.

ALL energy sources will be needed. Only renewables or only fossil fuels will not make it, and no source of energy should be excluded from the available options.

ALL technologies will be needed, as different circumstances require different technological solutions. More important, a better use of existing technologies holds a great potential, and should be fully explored.

ALL stakeholders have a role to play. Neither governments, nor businesses can do it on their own. Partnership is the key word, and efficient partnerships for success are even more important.

Oil, gas, coal and CCS

Professor Olav Bolland
Norwegian University of Science and Technology,
NO-7491 Trondheim, Norway
Email: olav.bolland@tev.ntnu.no

Introduction

The Intergovernmental Panel on Climate Change (IPCC) Fourth Assessment Report states that it is very likely (>90 % probability) that human emissions of greenhouse gases are warming the planet surface. In order to reduce the man-made warming, concerted action to mitigate emissions of greenhouse gases is now needed. The main greenhouse gas generated by human activities is carbon dioxide (CO2). CO2 is produced mainly by the combustion of fossil fuels in the power sector, manufacturing industry and in the transport sector, but also in the production of energy carriers and services. Projections by the International Energy Agency indicate that fossil fuels will be the dominant source of energy until 2030 and most likely beyond then (IEA 2006). It is, therefore, becoming increasingly important that we develop and deploy mitigation technologies that can make significant reductions in CO2 emissions in all sectors.

It is generally agreed that the capture cost, and also to some extent the energy consumption, depend on the size (tonnes/day) of the capture process. When looking at the man-made sources of CO_2 above a certain rate, for example 0.1 Mt CO_2/year, it is evident that power generation is by far the most important emitter, followed by the cement industry, refineries and iron/steel industry. The current trend of increasing demand for power globally, indicates that power plants will be the primary targets for implementation of CO_2 capture. Other large-scale sources of CO_2 and in particular those with high partial pressure of CO_2, are also of primary interest in this respect.

CO_2 has been captured from industrial process streams for over 80 years, although most of the CO_2 that is captured is vented to the atmosphere because there is no incentive or requirement to store it away from the atmosphere. Current examples of CO_2 capture from process streams are purification of natural gas and production of hydrogen-containing synthesis gas for the manufacture of ammonia, alcohols and synthetic liquid fuels.

So what is the problem? Why can't we just capture a sufficient amount of CO_2 and store it underground? There are challenges with issues related to added cost of power, availability of technology, additional fuel consumption, safety of transport and storage, and a general uncertainty whether carbon dioxide capture and storage can actually make a difference.

There is an underlying basis given by the thermodynamics related to the formation of CO_2 and to the separation of CO_2 from gas mixtures, which dictates the size of components and the energy required. The paper presents a status for various technologies for the capture of CO_2 in power plants.

Fuels

The importance of the different fuels is shown in Figure 1. It is very clear that the fossil fuels play a major role in energy use. For electricity production, coal has a share of about 40%. Coal is by far the most abundant source of fossil fuel, and is expected to play a major role in future electricity production and maybe also for making transportation fuels.

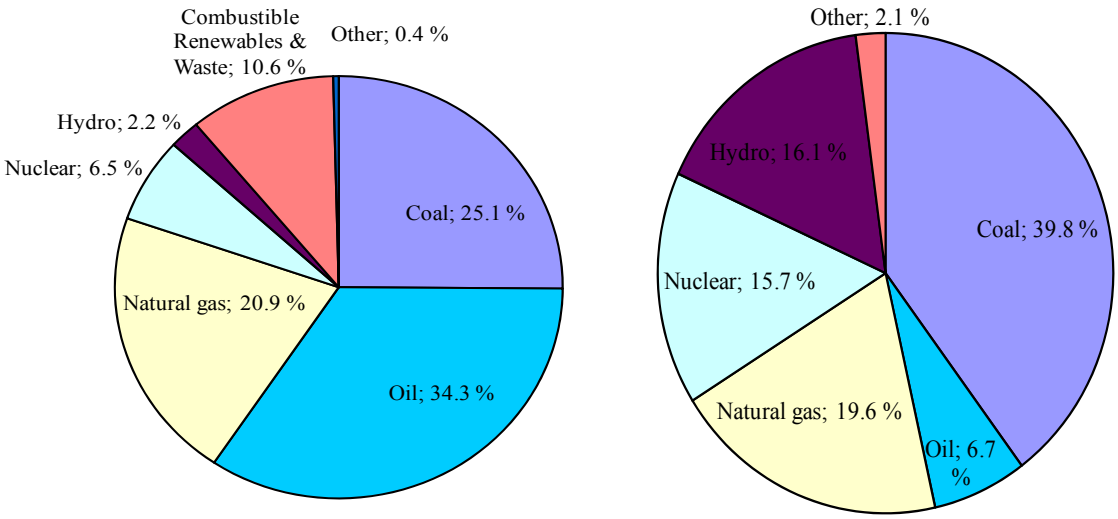

Figure 1: Total world primary energy consumption as % by fuel (left) and total world electricity generation as % by fuel or energy source (right) (WCI 2007)

Combustion is a chemical reaction between a fuel and an oxidant. In a power plant the oxidant is always oxygen. The fuel used in power plants consists of carbon and hydrogen as well as other components. Assuming that only hydrocarbons react with oxygen, a general combustion reaction can be written:

$$\begin{aligned} &C_nH_m + \lambda\left(n+\frac{m}{4}\right)(O_2+3.77N_2) \quad \rightarrow \\ &n\ CO_2 + \frac{m}{2}\ H_2O + (\lambda-1)\left(n+\frac{m}{4}\right)O_2 + \lambda\left(n+\frac{m}{4}\right)3.77N_2 \end{aligned} \tag{1}$$

The fuel molecule parameters *n* and *m* are:

- methane; m=4, n=1; hence m/n=4
- oil; m/n≈2
- coal; m/n≈1

For combustion with air a certain amount of nitrogen comes with the oxygen. The nitrogen does not take part in the chemical reactions related to the balance of the major species, as given in the reaction below. Nitrogen does take part in reactions related to like NO, NO_2 and N_2O, but these gases only occur in very small quantities in the overall mass balance. In real combustion processes there is an excess of oxygen. One reason for having more oxygen than strictly needed from the stoichiometry is obtain complete combustion which means that the fuel is fully oxidised. The mass transfer of oxygen, fuel molecules and a number of intermediate species in the flame zone is important in order to obtain complete combustion. The mass transfer relies on the mixing and residence time of the gases in the flame zone. In a gas turbine combustor the residence time is typically 5 ms, with a heat release that may be up to 300 MW/m^3. In a pulverised coal boiler the residence time in the combustion chamber may be about 2-3 seconds. If there is not sufficient oxygen present, some of the fuel will only be partially converted. Too little oxygen results in formation of hydrogen (H_2) and carbon monoxide (CO). In processes like reforming and gasification there is intentionally less oxidant (oxygen and/or steam) than needed for complete combustion. The quantification of excess air is normally done by the parameter λ - <u>excess air ratio</u>, which is defined as the ratio of oxygen in a combustion process to the stoichiometric amount of oxygen (*n+m/4*) needed for a specific fuel. Sometimes the term <u>equivalence ratio</u>, $1/\lambda$, is used

A gas turbine has an air excess ratio in the range λ=2.5-3, which results in about. 3-4% CO_2 (molar) in the flue gas by combustion of natural gas. A modern gas burner may have an air excess ratio down to λ=1.05. A pulverised coal power plant has typically an air excess ratio λ=1.2, which results in about 12-15% CO_2 in the flue gas.

The formation of CO_2 from the combustion depends on the composition of the fuel molecule; the *m*/*n*-ratio. We can distinguish between CO_2 formation caused by the composition of the fuel molecule and the efficiency of the power plant. This is depicted in **Feil! Fant ikke referansekilden.**.

Are we soon going to run out of fossil fuels? The answer is most likely no!

We are depleting the fossil fuel resources at an increasing rate. Still there are huge resources of particularly coal, but there are also still significant resources of oil and natural gas (Chu and Goldemberg 2007), (Freund and Kaarstad 2007), and (Brandt and Farrell 2007). A fraction of these resources is economic to produce today, the remaining is not. Both the amount of remaining resources and what is economic to produce have changed over time, and it is likely to be so in the future for a number of years. It is hard to predict for how long there will exist fossil fuel resources that are economic to produce. This depends mainly on fuel prices, cost of production and environmental limitations such as emissions of CO_2. Predictions vary in the range of 150-1500 years.

It should be noted that the technical challenge of producing fossil fuels is increasing. The resources which are easy and cheap to produce are the first to be exhausted, then comes the time of the more difficult ones. There is, however, no clear-cut transition between types of production, as one sees various kinds of on-going fossil fuel production. Examples of difficult resources to produce from are Canadian oil sand and Venezuelan heavy crude oil. The production of oil in these two examples requires a lot of expensive processing and use of energy before it can be fed to refineries. Other examples are oil shale, coal seams under seabed and natural gas hydrates. As the production on average becomes more difficult, there will be an increase in energy use and CO_2 emissions from the production of the fuels.

If proponents of Peak Oil[1] such as Laherrère, Campbell and Deffeyes (Swenson) are correct, the predicted peak in oil production takes place before 2020 (Al-Husseini 2006). It is very much disputed whether this is likely. Even if this will be the case, there are still so much fossil fuel resources left that we will probably see production of transportation fuels by coal-to-liquid conversion.

One very important conclusion is: The lack of fossil fuels <u>will not</u> cause a reduction of CO_2 emissions <u>soon enough</u> in order to avoid an unwanted high atmospheric concentration of CO_2. This implies that we cannot simply sit back and relax waiting for the fossil fuels to be exhausted, and by that have the problem with man-made climate change go away by itself.

[1] **Peak oil** is the point in time at which the maximum global oil production rate is reached, after which the rate of production starts to decline. Marion King Hubbert (1903-1989) first used the theory in 1956 to predict that US oil production would peak between 1965 and 1970. His model, the <u>Hubbert peak theory</u>, has since been used by some to predict the peak oil production globally.

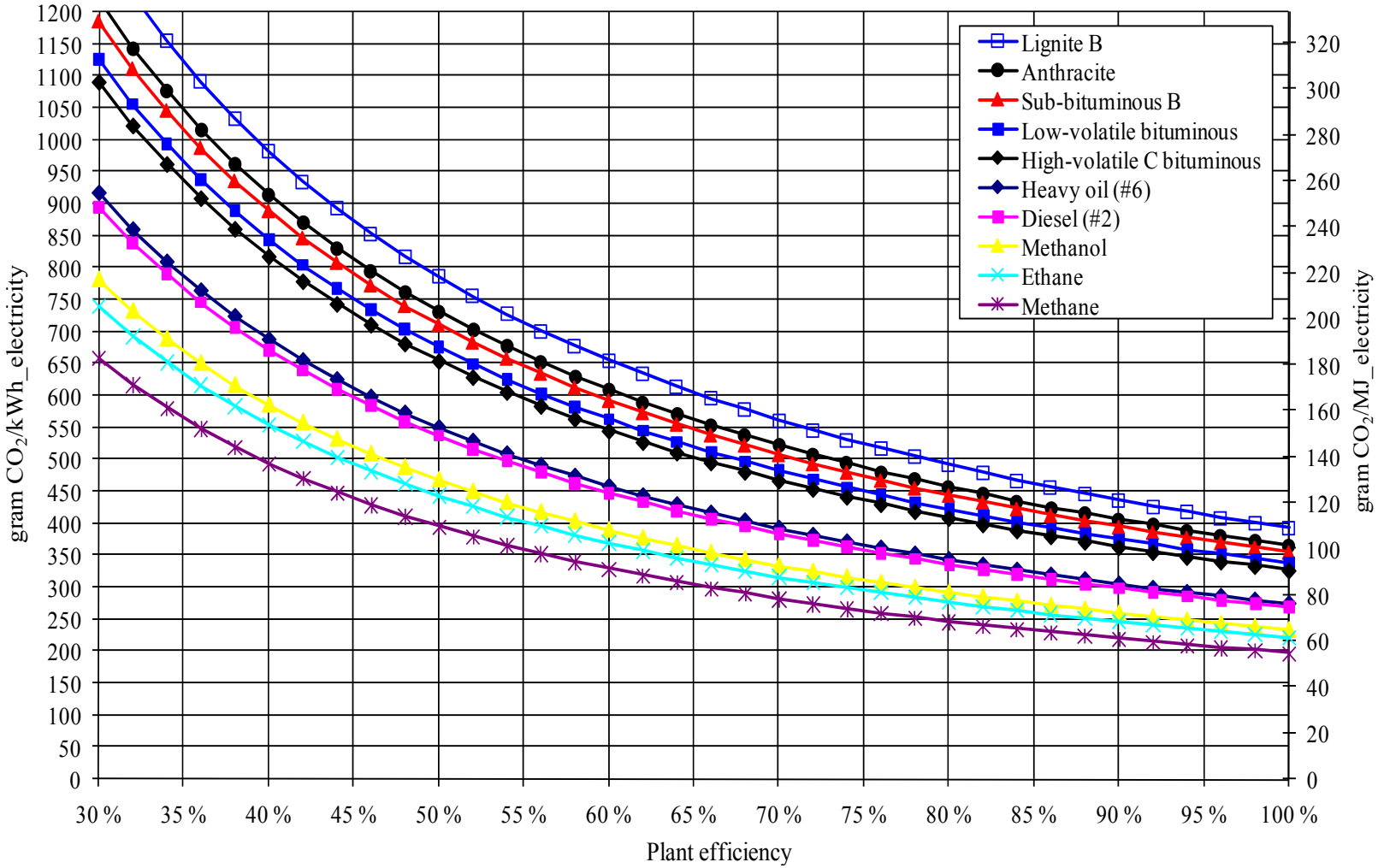

Figure 2: Formation of CO_2 from various fuels. On right-hand side ordinate (100% efficiency), the CO_2 formation per lower heating value is found. When moving along the abscissa (<100% efficiency), values for CO_2 formation are related to efficiency for converting the lower heating value into electricity.

Coal power plants – the processes being used today

In general, a number of methods for large-scale coal-fired power generation are well established and widely used. Others are used only in a few plants. In Figure 3 these methods are depicted. Coal can either be combusted or gasified. The different methods are explained in the later. For more in-depth information on coal power plants, refer to (Miller 2005) and (Woodruff, Lammers et al. 2004).

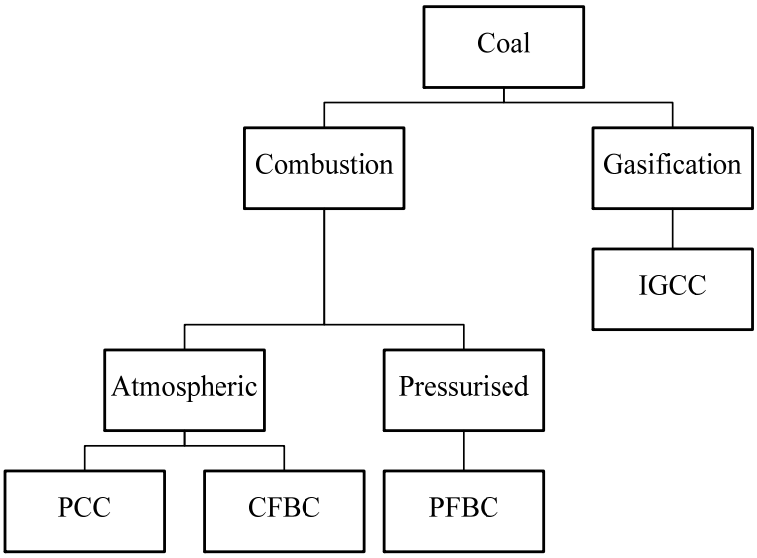

Figure 3: Coal conversion for power generation

Common for all coal fired power plant is a coal handling system. The coal is crushed, pulverised, sometimes dried, sometimes cleaned, and then fed to the combustion device.

Coal power plants show a very large range of efficiencies. The most advanced plants in operation today have about 45-47% net efficiency based on the lower heating value, while others have efficiencies around 30%. On a global basis the average efficiency for converting heating value of the coal into electricity is around 31-32% (Pacala and Socolow 2004), (Schilling 2005). The 1000 MW BoA unit of the Niederaussem power plant has probably the highest efficiency for lignite as fuel; 43.2% based on lower heating value, using a wet cooling tower (RWE 2008). For bituminous coal, the Danish power plant Nordjyllandsværket (unit 3) has probably the highest efficiency with about 47% based on lower heating value, using once-through open loop sea water cooling (Overgaard 2008). There is a huge potential to reduce CO_2 emissions just by increasing efficiency of coal power plants. A lot of new power plants built today have efficiencies far below what could be achieved using state-of-the-art technology. One important point regarding efficiency is that when capturing CO_2 from a coal power plant with the goal of a certain emission g CO_2/kWh, it is of outmost importance to minimise the amount of CO_2 to be captured by designing the power plant with high efficiency.

Pulverised Coal Combustion (PCC)

The most common process for coal-based power generation is Pulverised Coal Combustion (PCC) taking place at a pressure close to atmospheric. An illustration of a conventional steam cycle with coal combustion is given in **Feil! Fant ikke referansekilden.**. The technology is well developed, and there are thousands of units around the world, accounting for well over 90% of coal-fired capacity. PCC can be used to fire a wide variety of coals, although it is not always appropriate for coals with high ash content.

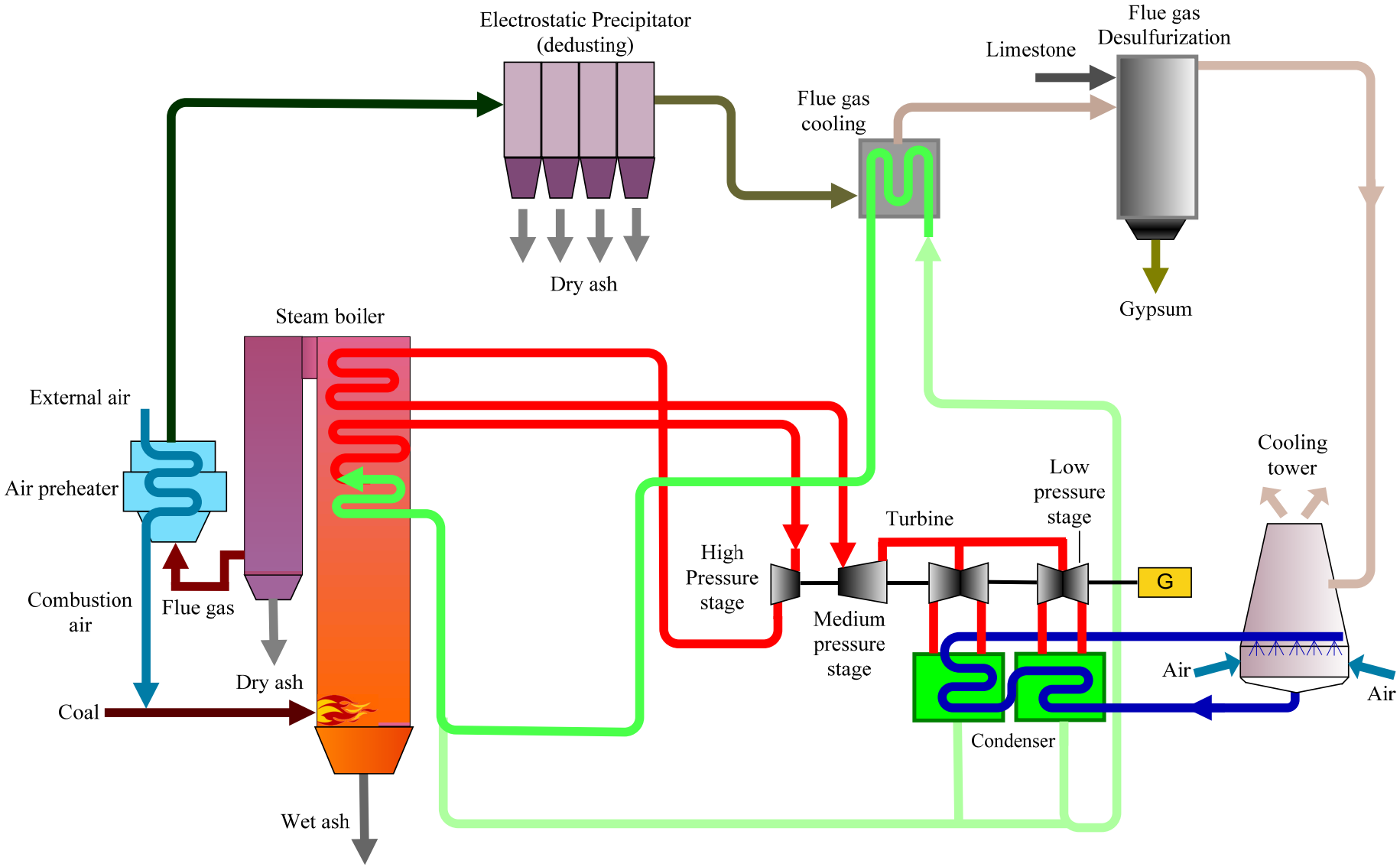

Figure 4 Coal-fired power plant with main components. The flue gas is rejected through the cooling tower.

Circulating Fluidised Bed Combustion (CFBC)

A Circulating Fluidised Bed Combustion (CFBC) plant for power generation consists of the following main equipment (Basu 1999), (Reh 1999):

1. A combustion chamber, or a so-called riser, in which combustion air is injected in the bottom flowing upwards and partially entraining solids; fuel and ash particles. The residence time for the solids in the riser is much longer than for the combustion air/flue gas(Reh 1999). The fuel is fed near the bottom of the riser as particles with diameter about 3 mm. Combustion takes place at temperatures from 800-900 °C. At the top of the riser, the air flows into a cyclone.
2. The cyclone separates the flue gas and the solids that were entrained by the gas flow in the riser. The solids fall down from the cyclone into a downcomer. The flue gas leaves from the top of the cyclone.
3. Solids are transported in the downcomer back to the bottom of the riser for another loop in the system. Depending upon size and density, the solids may recycle 10-50 times between the riser and the cyclone. In the downcomer, ash is removed from the system.

The rather large recycle flow of solids constitutes a very much higher heat capacity compared with the gas flow through the riser. This helps to smooth any temperature gradient and short-term temperature transients in the system. Consequently, combustion conditions are relatively uniform through the riser, although the bed is somewhat denser near the bottom. There is an extensive mixing, and residence time during one pass is very short.

CFBCs are designed for a particular coal to be used. CFBC is principally of value for low grade, high ash coals which are difficult to pulverise, and which may have variable combustion characteristics. It is also suitable for co-firing coal with low grade fuels, including some waste materials. The use of limestone injection into the riser is a well proven method for sulfur removal as an alternative to flue gas desulfurisation.

CFBCs are used in a number of units around 250-300 MWe size. A 460 MWe supercritical unit in Lagisza, Poland is as of 2008 the largest CFBC power plant (PEI 2006).

Pressurised Fluidised Bed Combustion (PFBC)

PFBC – Pressurised Fluidised Bed Combustion – is a method for combustion of mainly solid fuels (may in principle be any fuel) in a bubbling (or stationary) fluidised bed under pressurised condition. The combustion air needs to be pressurised before combustion and the hot gas downstream the combustion process is expanded. The most reasonable process design with respect to efficiency is to have this type of combustion process integrated in a gas turbine cycle. The exhaust from the gas turbine has the potential for heat recovery and additional power generation, and all the plants built so far are combined gas turbine and steam turbine cycles.

The stationary fluidised bed combustor is put inside a pressure vessel, where in addition to the fluidised bed itself there are cyclones, recycle downcomer for solids separated in the cyclone, ash cooler, ash removal, coal and sorbent feed systems.

The main reasons for pressurisation is to get more compact systems, increase in heat transfer due to lower gas volume and the possibility of utilising a gas turbine. The main advantages of the PFBC technology is the ability of handling fuels in different qualities, high energy efficiency, good environmental performance and potentially moderate specific investment.

After some smaller demonstration plants were built and operated, about nine PFBC plants have been built, though not in recent years. Some of these plants are still in operation.

It does not seem like PFBC technology has reached a maturity level where it competes with PCC. In the 1990s the PFBC technology gained a lot of interest, but considerable less now.

Integrated Gasification Combined Cycle (IGCC)

The power block of an IGCC plant is similar to that of a natural gas fired combined cycle plant which includes a gas turbine and a steam cycle. An IGCC plant also includes the major functions necessary to produce a gaseous fuel through gasification of coal, biomass, residual oil, pet coke or others. These are feedstock preparation, gasifier, cooling and heat recovery equipment, air separation (if oxygen-blown) and gas cleanup. A simple flow diagram is shown in Figure 5.

Various types of gasifiers are used. Gasifiers for coal used in IGCC are typically entrained flow slagging gasifiers which operate at around 40-70 bar and 1500 °C, well above the melting point of the ash to ensure that the molten ash (slag) has a sufficiently low viscosity to flow easily out of the gasifier. Sufficient oxygen (95 mole % purity) from an air separation unit (ASU) is fed to the gasifier which through partial oxidisation of the feedstock provides heat to achieve the desired operating temperature and converts the feedstock into a syngas mixture. When steam is required to ensure sufficient carbon conversion (avoid solid carbon product), this is bled from the power block's steam turbine.

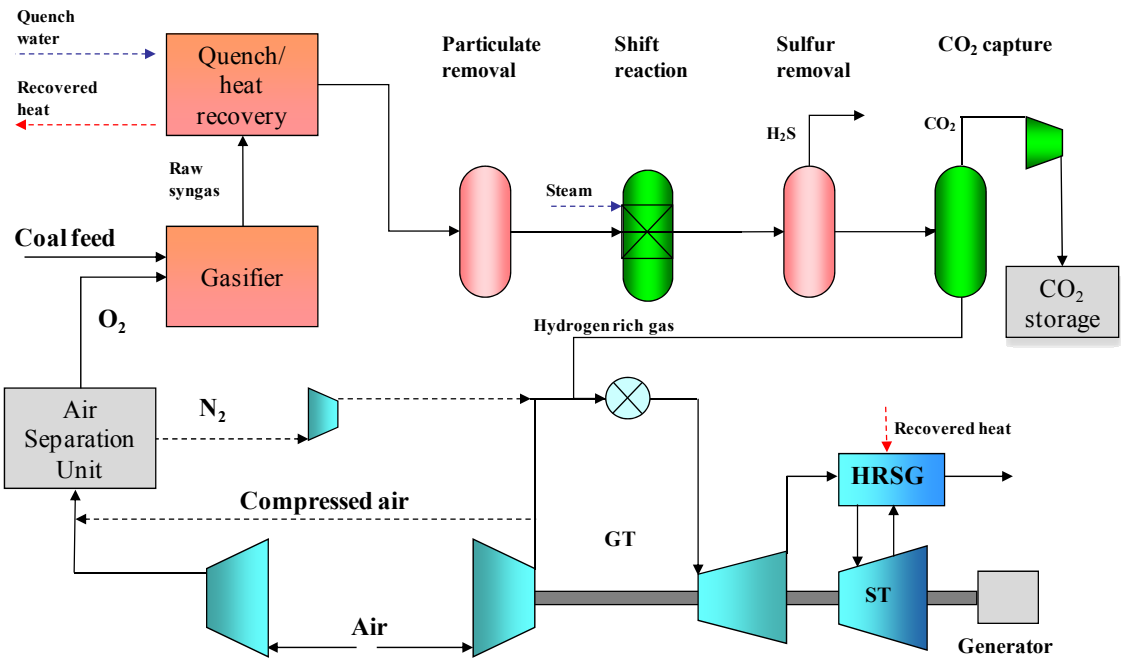

Figure 5: Integrated gasification combined cycle (IGCC) - flow diagram. The 'Shift reaction' and 'CO_2 capture' are only included for the capture of CO_2.

The hot raw syngas exiting the gasifier needs to be cooled down for "cold" gas cleanup (including removal of slag particles and different trace elements, sulfur and if relevant CO_2 capture). In case of CO_2 capture, a water-gas shift reaction step (where CO and H_2O exothermically react to CO_2 and H_2) is necessary to achieve CO_2 capture ratios

above approximately 60 %, and if the H_2O/CO mole ratio is less than 2, addition of steam generated in the shift and syngas coolers is required. Sulfur (as H_2S) and CO_2 may be removed by using as an example the Selexol process (physical absorption).

The remaining gas mixture after the gas cleanup is the fuel for the gas turbine (GT). The fuel consists mainly of CO and H_2. When CO_2 is captured, the fuel consists of mainly H_2. The fuel is moisturised, preheated and diluted with nitrogen from the ASU before combustion in the gas turbine's diffusion combustor. To achieve higher plant net power output and efficiency, some of the ASU air is bled from the GT's compressor discharge. To which extent compressor discharge air bleed is used to feed the ASU can vary in the range 0-70%. A minimum 30% air compression capacity in the ASU itself ensures that it can be started independently of the gas turbines. The heat recovery steam generator (HRSG) utilises the GT exhaust heat to produce superheated steam at different pressure levels which is fed to a steam turbine.

As of 2007 (GTW 2007), there are 16 IGCC plants in commercial operation using different feedstock including coal, pet coke, oil residues and biomass. Additionally, in Nakoso, Japan, a 250 MW IGCC with air-blown gasifier was started up in 2008. The total power output of these plants is more than 4000 MW.

Four of the earlier IGCC units Buggenum, Polk, Puertollano and Wabash, typically show typical time-availability around 70-80%. At the same time other gasification plants show time-availability in the range 96-98% (Laege and Pontow 2002), (Mook 2004). Over half of the unplanned unavailability in these four IGCC plants is caused by the power island, and actually not by the fuel and combustion systems, but rather a number of mature components (Higman, DellaVilla et al. 2006). Generally in industrial applications, Air Separation Units (ASU) provide a reliability of over 99% and an overall availability of over 98%. In an IGCC the ASU contributes with slightly more to unplanned unavailability compared to other uses of ASUs. The gasification reactor itself does not contribute much to the unplanned unavailability – although the refractory lined systems do require some planned maintenance and shutdown of the IGCC plant. The syngas cooler has typically been the major source of unplanned unavailability in the gasification part of the plant.

New IGCC plants will have net plant efficiency in the range of 39-48% (LHV). The wide range is explained by a number of factors; such as type of coal, gasification technology, degree of ASU integration, and technology level for the gas turbine.

Natural gas-fired power plants – Combined Cycles

Gas turbines are the machinery of choice for high power because of their continuous flow, steady torque and ability to operate at high RPM. When natural gas or distillate oil is to be the fuel the gas turbine, steam turbine and the combined cycle monopolize the field of power generation above about 20 MW.

The reciprocating Diesel or spark ignited (Otto) cycle engine is the preferred plant for small power plants (<5-20 MW).

The evolution of the gas turbine owes much to development of the jet engine for use in aircraft but its use for power generation preceded its use in aircraft. Single gas turbines are now in service with capacities of 330 MW. The gas turbine and it's combined cycle have evolved into the premier power plants for operation on clean gas and clean (distillate) oil. Gas turbines operating on coal or low grade fuels are being demonstrated but are not yet truly commercial.

For all but low load factor or when low cost gas fuel is available, gas turbines are combined with bottoming steam plants to create combined cycles. A gas turbine may convert 35-40 % of the fuel energy into power, mechanical electrical and heat losses

may account for 1% of the fuel input, leaving about 60-65% as heat passing to the bottoming plant in the exhaust of the gas turbine. The steam boiler, or Heat Recovery Steam Generator (HRSG), may capture 2/3 of the gas turbine exhaust heat for the bottoming steam cycle. The steam turbine may convert almost 20 % of the fuel input into power, incur about 2-3% losses and reject 21% of the fuel energy to the condenser. The combined gross power of gas and steam turbines then is about 53-60 % of the fuel energy.

A simplified flow diagram of a combined cycle is shown in Figure 6, while in Figure 7 a plant layout is shown for the same cycle.

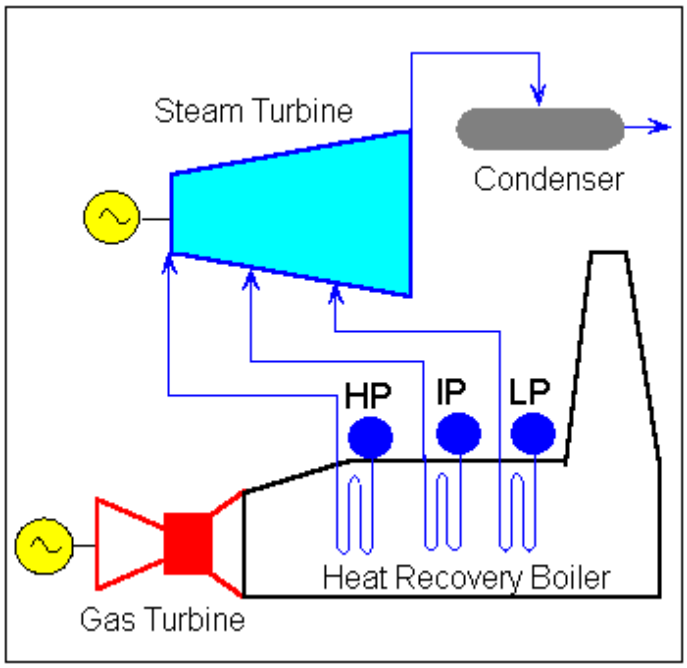

Figure 6: Natural gas-fired combined cycle (GTCC), simplified plant layout

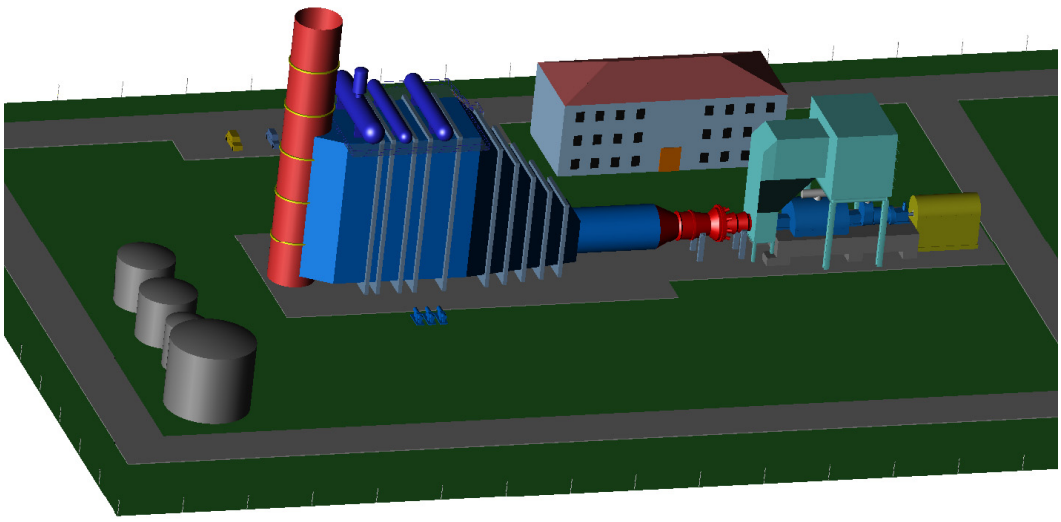

Figure 7: Natural gas-fired combined cycle (GTCC), simplified plant layout

Principles for combining power plants and CO_2 capture

There are three different principles for capturing CO_2 from use of fossil fuels in power plants, as is depicted in Figure 8. A fossil fuel is oxidised by which the fuel energy is converted to internal energy that can be converted into power to a certain extent. In a fuel cell the fuel energy is in principle directly converted to power. This oxidation may be a single step process as combustion, or it may include additional steps in which a fuel conversion takes place before combustion.

There are three basic principles for capturing CO_2 from fossil fuelled power plants:

- Post-combustion CO2 capture
- Pre-combustion CO_2 capture
- Oxy-combustion CO_2 capture

Post-combustion CO_2 capture: Capture of CO_2 from flue gases produced by combustion of fossil fuels and biomass in air is referred to as post-combustion capture. Instead of being discharged directly to the atmosphere, flue gas is passed through equipment which separates most of the CO_2.

Pre-combustion CO_2 capture: The fuel molecule is split by partial oxidation resulting in a syngas consisting of hydrogen (H_2) and carbon monoxide (CO). In presence of water vapour (H_2O) the equilibrium can be shifted towards H_2 and CO_2, which are subsequently separated. The idea is to form CO_2 while converting as much as possible of the fuel heating value into heating value of molecular hydrogen. The hydrogen can then be used as fuel in a power plant.

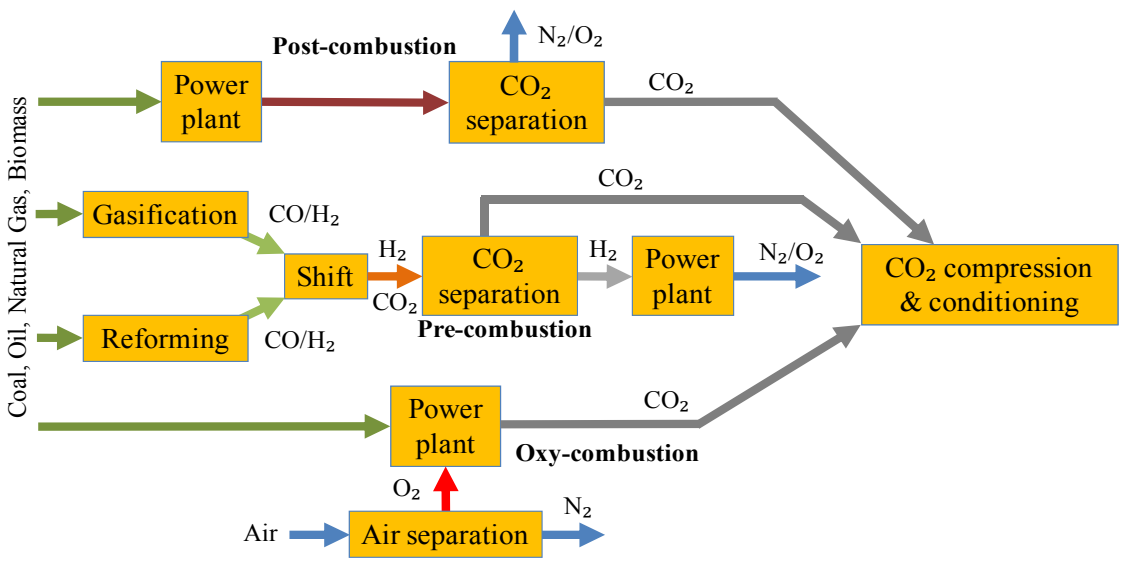

Figure 8: Principle methods for CO2 capture from power plants using carbonaceous fuels. From the top: post-combustion CO2 capture, pre-combustion CO2 capture, and oxy-combustion CO2 capture

In **oxy-combustion CO_2 capture** pure oxygen is used for combustion instead of air, resulting in a flue gas that, in the ideal case, consists of only CO_2 and water vapour (H_2O). An ideal case would be that: 1) the fuel consists of hydrogen, carbon and eventually oxygen, 2) combustion is complete with no excess of oxygen, and 3) the oxygen is 100% pure. If the fuel is burnt in high-purity oxygen, the flame temperature would be excessively high, so that either a non-adiabatic combustion process (heat removal) or recirculation of cooled combustion products is needed. Removing H_2O from

the CO_2 is considered an easy task because its condensing temperature is higher than the ambient temperature, unless for a very small partial pressure. In a real process the CO_2 is diluted also with other substances, not only H_2O, which, to various extents, are allowed or desirable to be present in the mixture with the CO_2 during transport and in the storage site. Oxy-combustion is about to have the major gas separation process (oxygen from air) upstream the combustion process, but in practice also a downstream separation is necessary in order to remove substances, present in small fractions, except for H_2O in some schemes, from a bulk stream of CO_2.

Post-combustion capture

Capture of CO_2 from flue gases produced by combustion of fossil fuels and biomass in air is referred to as post-combustion capture. Instead of being discharged directly to the atmosphere, flue gas is passed through equipment which separates most of the CO_2. The CO_2 is transported to a storage reservoir and the remaining flue gas is discharged to the atmosphere. A chemical absorption process, or amine absorption, would normally be used for CO_2 separation. Other techniques are also being considered, but these are not at such an advanced stage of development. Besides industrial applications, the main systems of reference for post-combustion capture are the current installed capacity of 2261 GWe of oil, coal and natural gas power plants [IEA WEO, 2004] and in particular, 155 GWe of supercritical pulverised coal fired plants [IEA CCC, 2005] and 339 GWe of natural gas combined cycle (NGCC) plants, both representing the types of high efficiency power plant technology where CO_2 capture can be best applied. Figure 9 shows classification of post-combustion power cycles based on the separation mechanism, capture process and desorption of CO_2 from the capture agent.

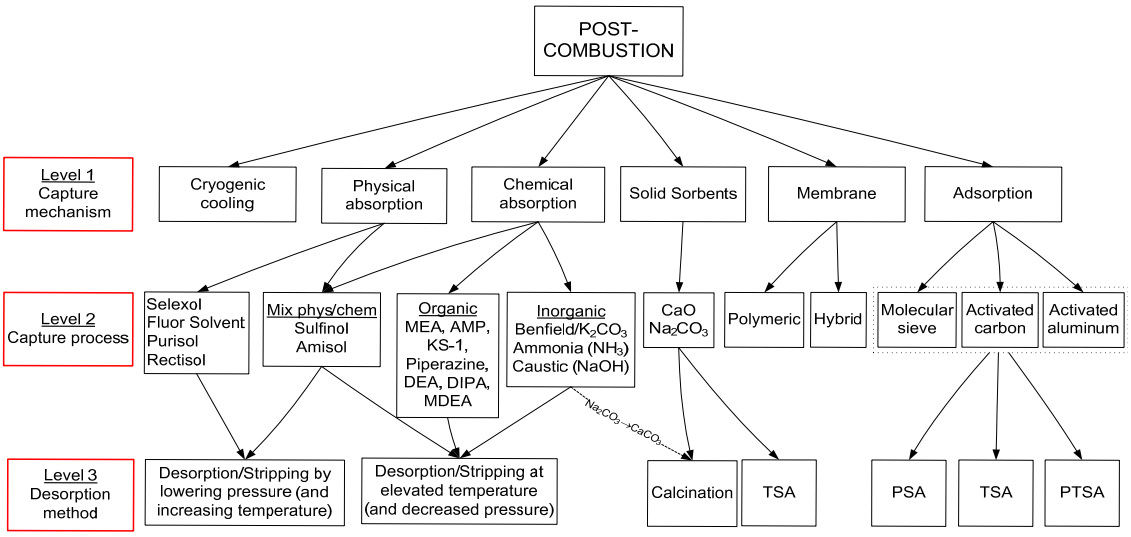

Figure 9: Classification of post-combustion methods for CO2 capture

Pre-combustion capture

Figure 10 shows classification of power cycles with pre-combustion CO_2 capture. The main criteria for the classification are type of fuel (level 1) and reforming/gasification method (level 2). For gasification, the methods are divided into air-blown and oxygen-blown gasifiers. There could have been a more detailed classification with respect to gasifier principle (entrained flow, fixed bed, slagging/non-slagging). For natural gas

there is on one side steam reforming (SR) with external supply of heat, and on the other hand auto-thermal reforming (ATR) and partial oxidation (POX) with internal generation of heat caused by the supply of oxygen. The heat generation for the reforming can further be classified as shown on Level 3.

After the reforming/gasification CO_2 capture depends on the use a water-gas shift converter, which enables hydrogen formation in order to keep hold of as much as possible of the initial fuel heating value, and the carbon to be converted into CO_2. The further step of CO_2 capture is to separate the hydrogen and the CO_2. This can either be done by separating hydrogen from the other product gases of the reforming/gasification/shift conversion, or to separate CO_2. The most common technology is to use absorption with a chemical or a physical solvent. Membrane technology may here develop to be competitive with absorption, but this depends on a technology development for membranes, and also a rather high partial pressure of CO_2. The generation of a CO_2/H_2 gas mixture can be regarded somewhat independent of the downstream CO_2 capture process. Another technology is to combine reforming/gasification with gas separation using a so-called membrane reactor.

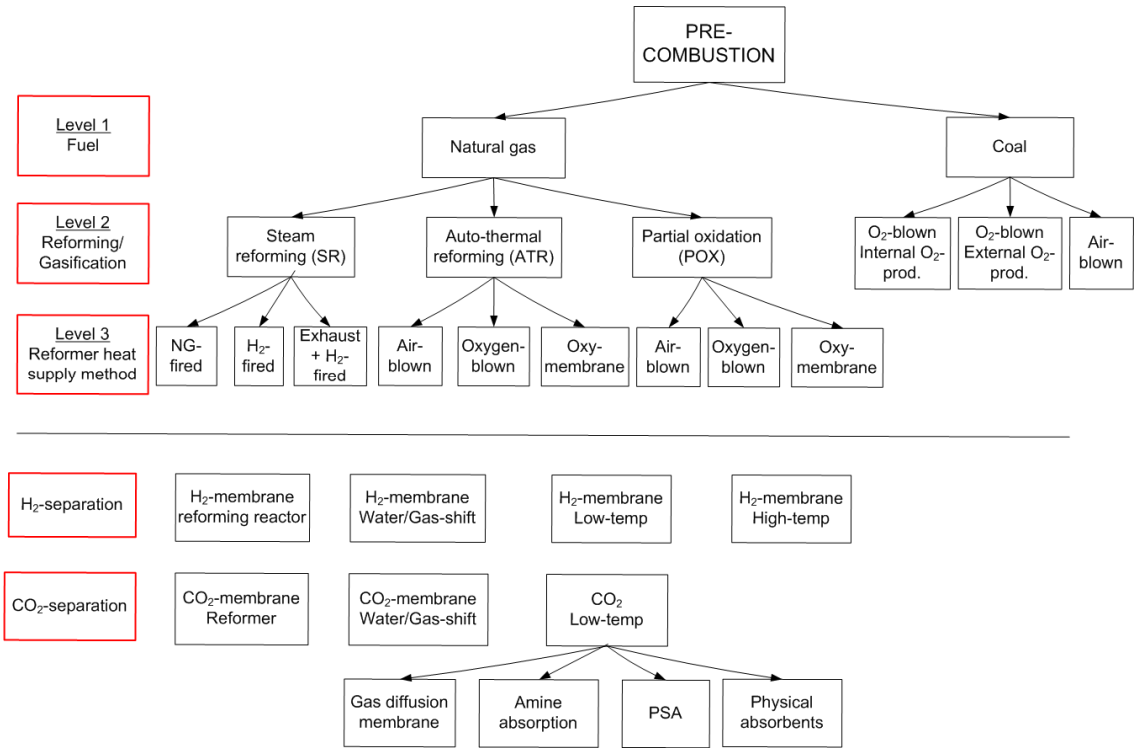

Figure 10: Classification of pre-combustion methods for CO2 capture

Oxy-combustion capture

The basic idea of oxy-combustion is to have combustion take place with pure or almost pure oxygen and to have very close to zero oxygen excess. Using oxygen in a pure form avoids the combustion products of being diluted with nitrogen. Further, having zero oxygen excess avoids the combustion products of being diluted with oxygen.

If the fuel is burnt in pure oxygen, the flame temperature is excessively high. To amend this, CO_2 and/or H_2O-rich flue gas can be recycled to the combustor to moderate the temperature. Oxygen is usually produced by low temperature (cryogenic) air separation. Novel techniques to supply oxygen to the fuel, such as membranes and

chemical looping cycles are being developed. The CO_2 purity from an oxy-combustion process is subject to variation. The sources of dilution may be:

- Nitrogen and other non-CO_2 gases originating from the fuel
- Impurities from air separation (argon, nitrogen)
- Oxygen excess in the combustion process
- In-leakage of air

The dilution may be so high that a separation process downstream the power plant has to be used anyway. This could, in some cases like in coal combustion plants, have significant implications on the design of the process with respect to O_2 purity from air separation, combustor design, measures for avoiding in-leakage of air, and safety measures by having slight suction.

Figure 11 shows classification of oxy-combustion power cycles based on integration of the air separation process and the power cycle.

In case of external air separation and supply, the oxygen is generated in an external air separation plant. The air separation technologies that are currently best suited for oxy-combustion power plants are the cryogenic air separation by distillation, membrane-based air separation and air separation using pressure swing adsorption. Cryogenic air separation is today the most readily available technology for large-scale production of oxygen.

When the air separation is done internally, the separation of oxygen involves a high degree of integration between air separation and power cycle. Technologies being investigated include using metal oxide as an oxygen carrier, such as in chemical looping combustion (CLC), or oxygen selective metal (the CAR-cycle) which are loaded and regenerated in a cyclic operation temperature swing process, or the oxygen is separated in a continuous operation using an oxygen transport membrane.

On the second level in Figure 11, the different cycles are divided into Brayton cycles and Rankine cycles. In Brayton cycles, known from conventional gas turbine cycles, the working fluid of the cycle is in gaseous state throughout the whole process comprising compression, heat addition, expansion, and heat rejection. In Rankine cycles, as found in conventional coal fired power plants, the working fluid switches between gaseous and liquid state in a closed loop with compression in the liquid state and expansion in the gaseous state. The working fluid in Rankine cycles is water, with only a few exceptions. The oxy-combustion cycles proposed in literature employs pure Brayton and Rankine cycles, a mixture of Brayton and Rankine cycles, and also the well known combined cycle approach used in conventional GTCC, with a high temperature gas turbine cycle and a conventional steam bottoming cycle.

On the third level it is convenient to separate different cycle concepts based on the composition of the recycled combustion products, which is necessary for controlling the combustion temperature and, in the case of a gas turbine cycle, controlling the turbine inlet temperature. Here it is chosen to differ between the internally fired power cycles where the combustion products are used as working fluid in the power cycle, and the externally fired power cycles where the heat of the combustion products is used to heat a separate working fluid. In both cases it is the combustion products, either mainly CO_2 or mainly H_2O, or a mixture of CO_2 and H_2O, that is used for recycling for the temperature controlling purpose.

Some of the different cycle configurations proposed in literature are given on level 4 in Figure 11.

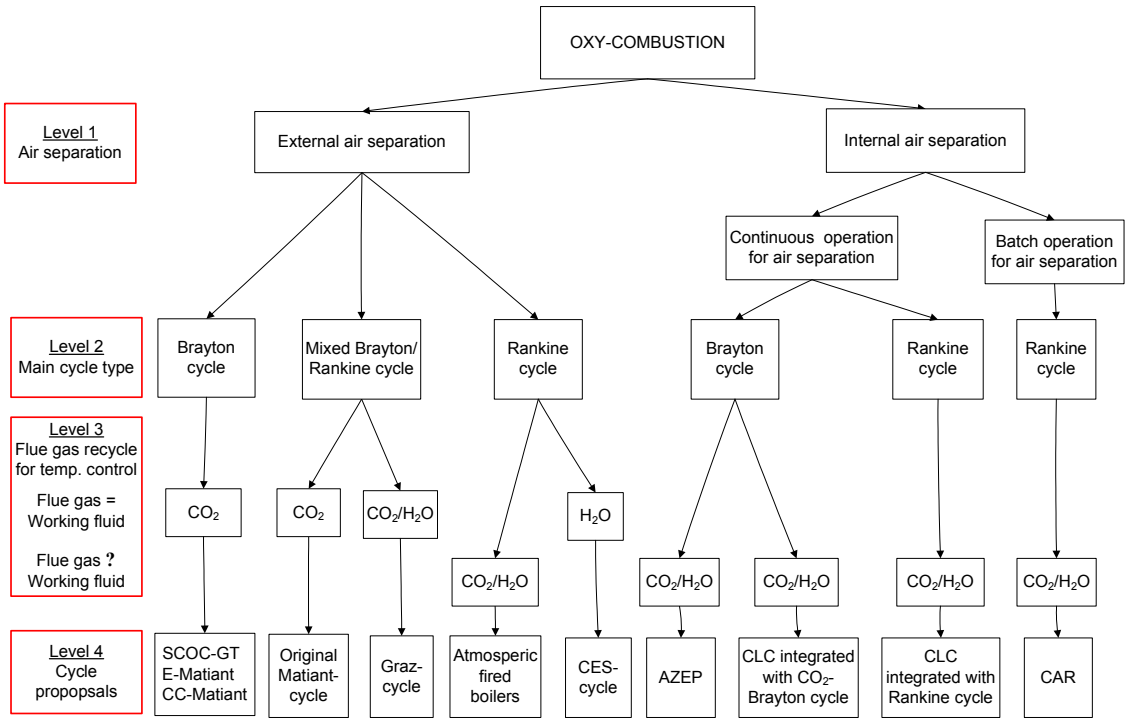

Figure 11: Classification of oxy-combustion methods for CO_2 capture

Efficiencies

In the following some power plant efficiencies for selected cases are presented, see Figure 12 and Figure 13. An overview of the cases are given in Table 1 (reference cases for natural gas both with and without CO_2 capture),

Table (natural gas-based oxy-fuel cycles),

Table 2 (natural gas-based pre-combustion cycles), lignite-fired cases in

Table 3 and IGCC-cases in

Table 4.

Table 1: Overview of the reference processes; Combined Cycles with and without CO_2 capture.

GTCC	The generic cooled gas turbine model in combined cycle. HRSG with three pressure levels and single reheat. No CO_2 capture - reference
GTCC Post-combustion	Combined Cycle similar to GTCC, but here with 90% post-combustion CO_2 capture by amine absorption

Table 2: Overview of the natural gas-based Oxy-Fuel and Chemical Looping Combustion cycles

Water cycle	A reheat oxy-fuel cycle where liquid water is recirculated to the first combustion chamber for temperature control. Clean Energy Systems cycle.

S-Graz	An oxy-fuel cycle where both steam and CO_2 is recirculated to the combustion chamber for temperature control. More steam is recirculated than in the original Graz cycle.
SCOC-CC	A combined cycle semi-closed oxy-fuel gas turbine where most of the CO_2-rich gas from the condenser is recirculated to the gas turbine compressor. HRSG with two pressure levels and one reheat.
AZEP	This concept is based on a Combined Cycle in which the gas turbine combustor is replaced with a Mixed Conductive Membrane (MCM) reactor, enabling a fully selective separation of oxygen from nitrogen. There are two AZEP cases; one with almost 100% CO_2 capture and another with 90%. The latter includes natural gas combustion in front of the GT turbine in order to increase efficiency.

Table 2: Overview of the natural gas-based pre-combustion cycles

ATR-CC	Combined Cycle power plant tightly integrated (air, steam, heat) with an air-blown auto-thermal natural gas reformer (ATR), with subsequent shift reactors and CO_2 capture by absorption.
Siemens Cycle	Pre-combustion CO_2-capture combined cycle with ATR, CO shift / H_2 separation with an H_2 selective membrane and an absolute pressure drop over the membrane in an integrated membrane reactor; combustion of residual combustibles in the CO_2 rich stream with Oxygen and H_2O/CO_2 flue gas recirculation + utilization of released energy in a closed second gas turbine cycle
Hygensys – IFP	Pre-combustion cycle. The gas out of a first part of the turbine provides the heat to the steam-reforming reactor, before to be sent to the second part after reheat. The hydrogen gas produced by steam-reforming is the fuel of the gas turbine (after CO_2 capture).
NTNU - Cycle	Pre-combustion cycle with an ATR membrane reactor with an oxygen-permeable membrane (ceramic) with a higher total pressure on the permeate side of the membrane than on the retentate side. Water-gas-shift membrane reactor with a hydrogen-permeable membrane (Pd).

Table 3: Overview of the lignite-based cycles

AIR	Air fired lignite cycle <u>without</u> CO_2 capture (reference)
OXYFUEL	Oxy-fuel fired lignite cycle with CO_2 capture
OTM	Oxy-fuel fired lignite cycle with integrated gas turbine and OTM module

Table 4: Overview of the IGCC hard coal-based cycles

IGCC-Ref	A coal-fired integrated gasification combined cycle (IGCC) <u>without</u> CO_2 capture. No integration with the air separation unit (ASU). 100 % of the air for the ASU is delivered by an external compressor. The Shell gasifier is chosen for the gasification process.

IGCC-Ref ASU	IGCC-Ref but 100 % integration of the ASU into the gas turbine. All air for the ASU is extracted from the gas turbine compressor. The heat from the compressed air is used in the steam section of the combined cycle. Just as the IGCC-Ref cycle, without CO_2 capture.
IGCC-CAP	IGCC processes with CO_2 capture using physical absorption. Before the CO_2 separation a CO-shift reaction takes place. The gasification and the combined cycle is similar to IGCC-Ref. 100 % of the air for the ASU is delivered by an external compressor.
IGCC-CAP ASU	IGCC-CAP but 100 % integration of the ASU into the gas turbine. All air for the ASU is extracted from gas turbine compressor. The heat from the compressed air is used in the steam section of the combined cycle.
IGCC-OTM	Gasification and CO_2 capture identical to IGCC-CAP with an oxygen transport membrane (OTM) is integrated into the gas turbine cycle. Lower total pressure on the permeate side than on the retentate side.

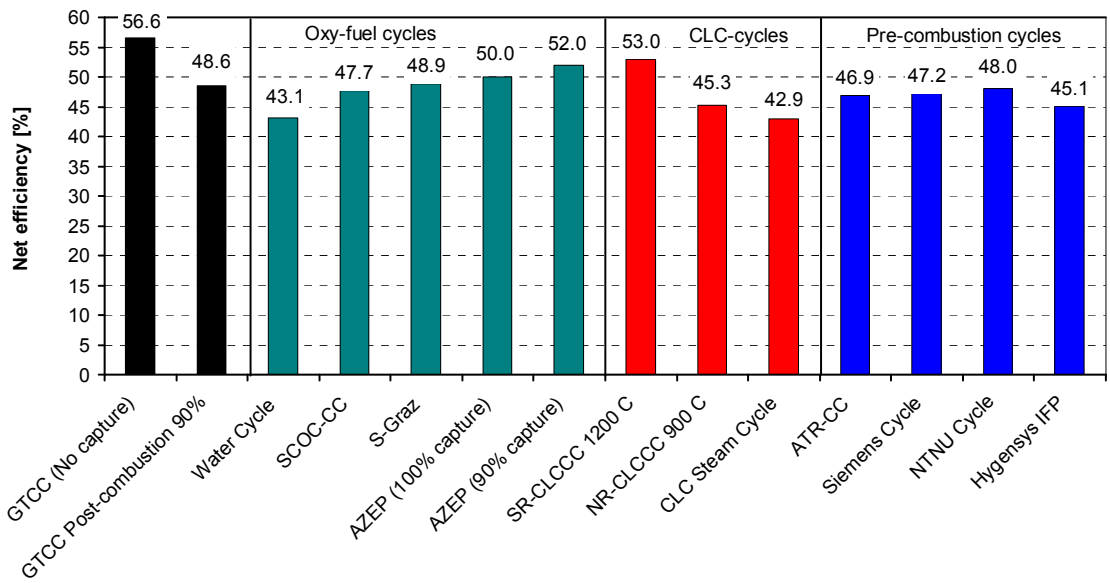

Figure 12: Net plant efficiencies of the natural gas-fired cycles

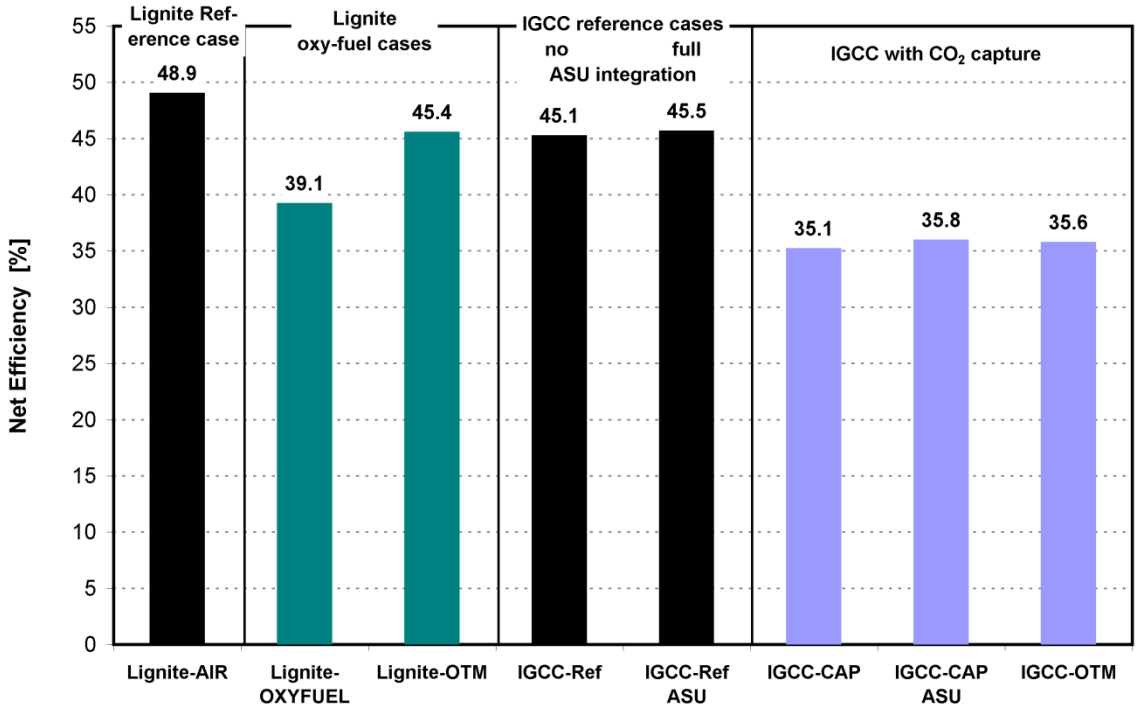

Figure 13: Net efficiencies of all coal-based cycles

The efficiency of natural gas-fired power plants is reduced with 8-14 %-points when the energy consumption for CO_2 capture and storage is included. A number of various cycle alternatives are possible, and there is no obvious "winner" among them, though there are a number of "looser" options with rather low efficiency and requiring development of new technology. On a short-term basis post-combustion with amine absorption seems like an obvious choice. Some of the other technologies, both oxy-combustion and pre-combustions concepts, do have the potential for high efficiency and low cost. Future R&D development and, maybe more important, construction and operation of large-scale plants with CCS will provide more basis for which of these concepts will be 'winners'.

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Prospects for Nuclear Power

By: Professor Mikko Kara, Biofuels project, VAPO and
Øivind Syversen, student, Department of Physics, NTNU

Introduction

Today, nuclear power makes up 16 percent of the electricity generated globally, but other factors such as uncertainty related to subsidising of renewable power, CO2-pricing and price of fossil fuel make it difficult to clearly see the future significance of nuclear power. In addition to economic factors, energy security and environmental issues will be of great importance. One major issue is the need for a credible waste disposal policy. This will be crucial for public and political acceptance, and therefore crucial for the future of nuclear power.

Nuclear Power Today

As of August 8th 2007 the number of operating nuclear reactors worldwide was 439. The United States, France and Japan are leading producers of nuclear power with 104, 59 and 55 reactors respectively [1]. Today more than 12 000 years of total operating experience have ensured high performance and availability [2]. The existing fleet of reactors can be improved by increasing capacity and extending lifetime. This can be done at relatively low cost, and so the interest in promoting investments is growing. Financial incentives such as the Energy Act [3] in the USA are also among the reasons that have encouraged several companies to start the licensing process of building new reactors.

It is likely that economics will be the main driver for nuclear power. One therefore needs to distinguish the existing fleet of plants from new investments. The latter means large investment costs and high financial risk compared to existing plants written-off years ago. Building new reactors involve many first-of-a-kind experiences due to years of stagnation in the nuclear industry, which result in delays and budget overruns. For instance the new EPR at Olkiluoto in Finland has been put back by over two years and has a budget overrun of 1 billion EUR [1].

Besides economics, considerations of importance for viable investments in new nuclear plants are public and political acceptance, effectiveness of new licensing processes and waste disposal policies.

Economy – The Main Driver

The linear trend of the system price in Figure 1 shows a long term gradual increase in the price of electricity, but on a small scale the fluctuations are huge.

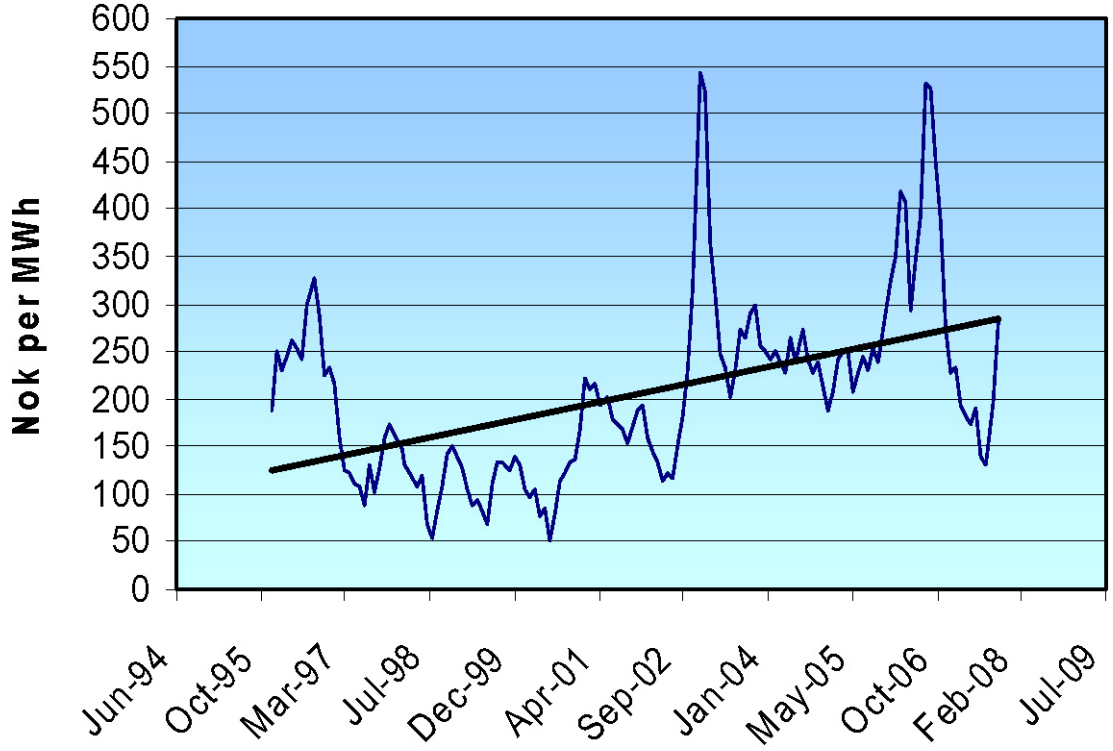

Figure 1: Electricity system price given in NOK per MWh. The straight line is a linear fit to the actual system price. (Source: [1]).

The same trend can be seen for the oil price in Figure 2, continually fluctuating. Similar behaviour is also seen for coal and gas prices. From early 2007 until mid 2008 the oil price soared and reached an all-time high close to 150 USD per barrel. Today the price of oil is below 50 USD per barrel.

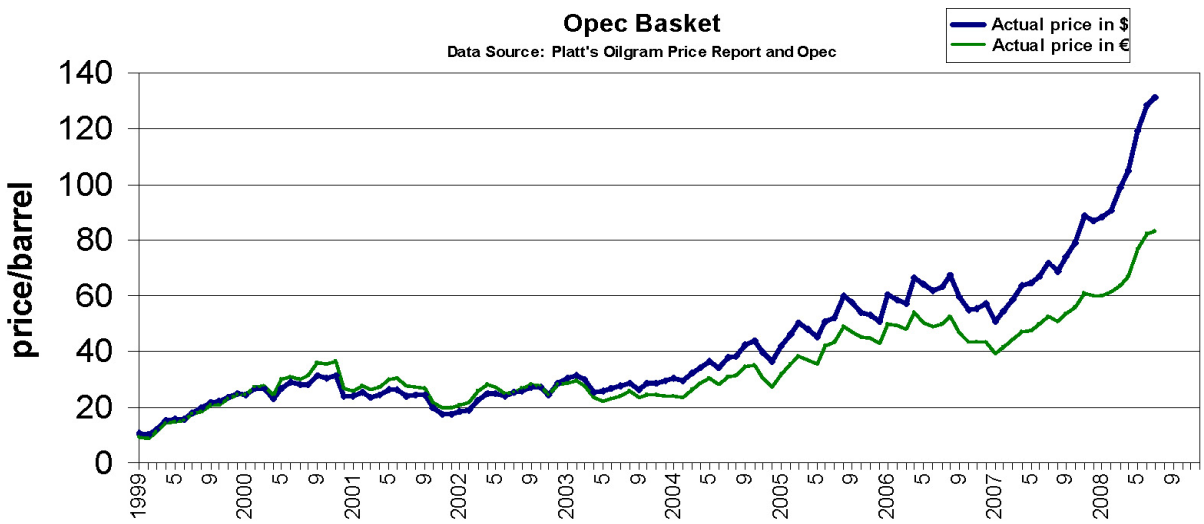

Figure 2: Price development of oil given in USD and EUR per barrel. (Source: [1]).

It is clear that the fossil fuel prices are unpredictable, but likely to go up due to energy demand growth. This unpredictability is reviving the interest in nuclear power in many countries. Especially developing countries may profit by investing in nuclear power plants that offer relatively predictable power generation costs compared to fossil fuelled power plants.

The World Energy Council raise this issue comparing power generation cost as result of a doubling of international prices of coal, natural gas and uranium [2]. In the case of coal-fired power plants one would see an increase in generation cost of about 35-45 %. Analogously, one would see an increase of 70-80 % for gas. A doubling of the uranium price on the other hand, only increases nuclear generation cost by about 5 %. For a developing country or a country dependent on foreign fossil fuel, the choice of fuel for power production is not just a question about economy, but might be of importance to a country's energy supply security. The nuclear expansion programmes of France and Japan in the wake of the 1970s oil shocks, was partly due to concerns about energy supply security [2].

Today the energy security of Eastern Europe is threatened as a result of disputes between Russia's state-owned gas company, Gazprom, and Ukraine regarding natural gas supplies and payment.

Pricing of CO2

After the Kyoto Protocol entered into force in early 2005, restrictions and taxes on greenhouse gas emissions have made nuclear power more attractive. This is because nuclear power plants produce far less greenhouse gas emissions than fossil fired power plants. The construction of a nuclear plant and the nuclear fuel cycle will undeniably cause emissions, but over the lifetime of the plant the emissions will be compareble to those of wind power and biomass conversion [2]. During 2006, CO_2 was traded at between 6 and 29 EUR per tonne in Europe. TheWorld Energy Council state that a charge of 20 EUR per tonne of CO_2 would improve a nuclear power plant's generation costs relative to those of a modern coal-fired plant by 10-20 % [2].

Existing Fleet of LWR

The performance and availability of the existing fleet of reactors have improved significantly over time. As an example the capacity factor of LWRs in the United States went from 55 % in 1973 to 89 % in 2005. The capacity factor is defined as the actual amount of energy produced divided by the maximum energy possible to produce, over a given time.

The existing fleet of plants is getting older, but at the same time the real operation and maintenance costs have declined. Compared to the market value of electricity in a going forward cost basis the existing fleet is very economical, and therefore life extension of existing fleet through licence renewals is typically economical. It is also feasible that a modest increase in capacity of some units will be economical.

Figure 3 confirms that the existing reactor fleet is getting old and it indicates that nuclear is experiencing a stagnation period. The number of reactors of one specific age in the figure gives a picture of how many reactors that were first connected to the grid that particular year. Looking at the number of reactors at an age of 20 and 28 years, one can see the effect of the Chernobyl accident on April 26th 1986 and the Three Mile Island accident on March 28th 1979. The immediate effect, a significant drop in the number of reactors connected to the grid the year of the accident, was seen in both cases. In the case of the Chernobyl the decline in grid connections did not stop the

year after. This disaster changed the public and political acceptance of nuclear power, and so the decline continued for many years. Even though it is more than 20 years since the Chernobyl accident today, this disaster is one of the reasons that nuclear power finds itself in a stagnation period.

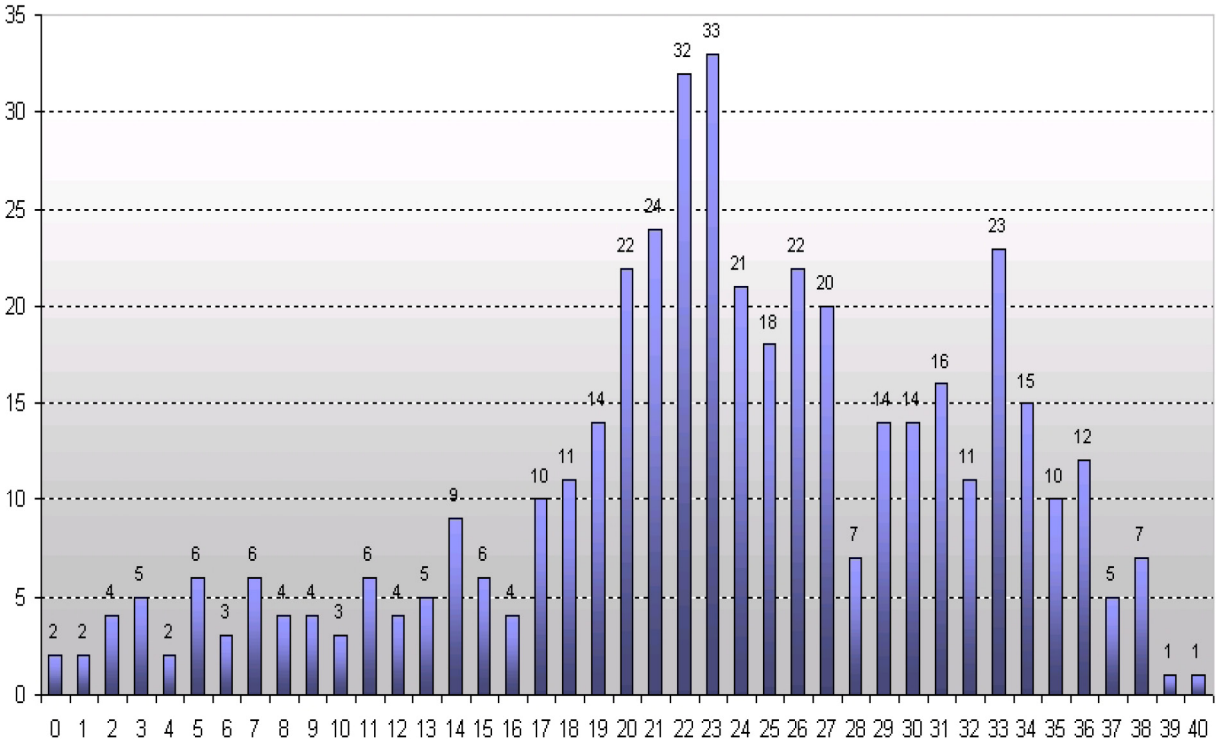

Figure 3: Number of operating reactors by age as of June 26th 2007. Note: Age of a reactor is determined by its first grid connection. (Source: [1]).

Investment in New Nuclear Plants

Because of the failing public and political acceptance of nuclear power seen after the Chernobyl accident, relatively few nuclear plants have been built in recent years. As mentioned, there are many factors of uncertainty related to new investments, for instance credible construction and cost data being limited due to years of stagnation.

This means that the best estimates are drawn from actual experience rather than engineering cost models. In fact, nobody has ever overestimated the construction cost of a nuclear power plant at the pre-construction stage.

Credible construction cost estimates should include costs such as engineering, construction management and owners' costs. For a nuclear power plant with a construction period of 5 years, an estimate of 1500 EUR per kW installed capacity is a good basis. This adds up to about 20 billion NOK in construction cost for a typical 1500 MW nuclear power plant.

Note that besides construction and cost data, the competitive, regulatory and contractual environment is very uncertain and varies widely across the world. For instance the United States as a whole has not yet adopted policies to place a price on CO_2 emissions.

The Evolution of Nuclear Power

The world's first nuclear reactor was called Chicago Pile-1 and was located at the University of Chicago. After Chicago Pile-1 first went critical on December 2nd 1942, almost twelve years passed before the world's first commercial nuclear reactor arrived. Today the total number of commercially operating reactors is 439 and about 30 new plants are under construction.

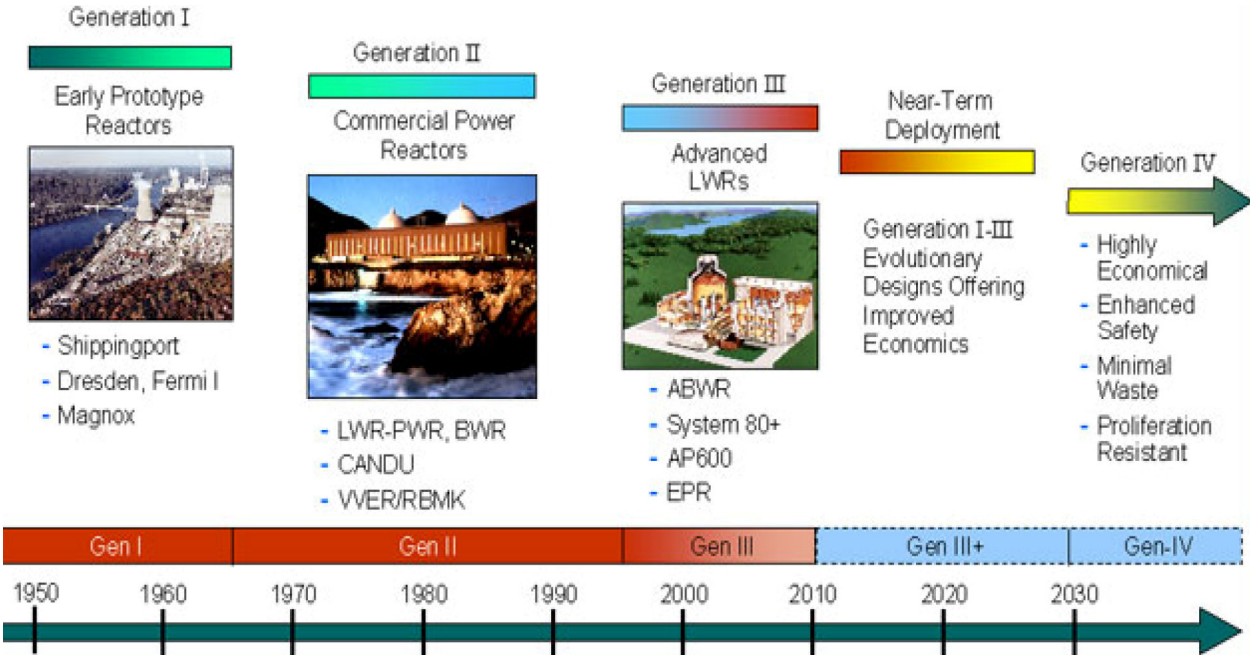

Figure 4: The Evolution of Nuclear Power. (Source: [1]).

Figure 4 shows how nuclear power has evolved. Combined with Figure 3 one can see that the majority of nuclear reactors are Generation II reactors. Actually about three quarters of the existing fleet of plants are more than 20 years old.

The typical lifetime of a nuclear reactor is 40 years plus potentially 20 more years with a licence renewal. This means that the world's nuclear capacity will decline quickly after 2030 without new investments.

Conclusions

The future prospects of nuclear power will be decided by numerous factors, but economy will be the main driver. The extent of subsidising of renewable power and the United States adopting policies to place a price on CO2 emissions will be of great significance. A worldwide CO2-pricing will enhance nuclear investment and keep the present fleet generating good windfall profit. This is because nuclear power plants over the lifetime of the plant produces far less CO2 then fossil-fired power plants. It is especially those nuclear power plants with a 20 year licence renewal that generate good windfall profit.

Credible and economic nuclear waste disposal policy is needed to maintain and strengthen public and political acceptance for nuclear power.

Finally, new investments in nuclear capacity are needed to avoid decline in the world's nuclear capacity after 2030, and energy supply security is likely to make the need for new investments even higher.

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Solar Energy

By Claude R. Olsen, Teknomedia AS, based on the presentation by Department Head Arve Holt, Solar Energy, Institute for Energy Technology (IFE)

Introduction

The sun is an inexhaustible source of energy for humankind. Our sun constantly produces 10^{26} W, of which 10^{17} W reaches the earth. This is equivalent to 10,000 times more total energy than earth's interior generates.

The wonderful thing about solar energy is that it is available to everyone at no cost. Today, there are still two billion people who are living without a trunk grid connection for electricity. For many of these, solar energy would be ideal for generating electric power. Solar energy is very well suited for distributed energy production because it is very easy to scale up or down. In outlying areas, small grids can be employed for local energy systems.

The challenge is that sunshine is not a continuous source. The solar radiation striking any given point on earth depends on the season, time of day, weather conditions and pollution factors.

Energy from the sun can be harnessed in two ways:

- *Solar thermal collectors* use the sun's rays to warm up water. Cool water circulates in a panel which absorbs the rays' energy and converts it to heat. For utilising the sun's energy in Norway, situated so far north, solar heating panels are just as applicable as solar cells.
- *Solar cells* use solar radiation to produce electricity. This articles deals with solar cells for the production of electricity, the area where there will be major market expansion.

Figure 1: Solar cells at a cabin. Photo: IFE

Solar cell installations

There are two main types of solar power installations: standalone (detached) and those connected to an electricity grid.

Figure 2: A solar cell-powered beacon. Photo: Olav H. Matvik/Kystverket

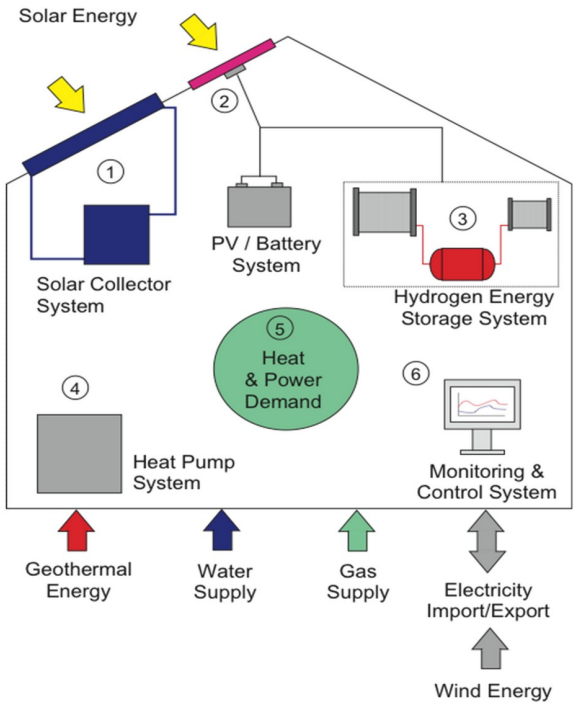


Figure 3: Solar energy system in a home. Illustration: IFE

In Norway alone, solar cell panels have been installed at over 100 000 cabins. With a panel, a charge controller and a battery pack, cabin owners can light up their lamps, watch TV and charge their mobile phones. These detached solar cell panels are also commonly used in lighthouses and pleasure boats. In other countries, such installations are used to run pumps and provide traffic sign lighting. Detached solar cell panels can supply electricity to nearly anything that requires it in small amounts.

Of the grid-connected installations, roof-mounted systems for residences and industrial buildings are growing the fastest. But now, large-scale solar cell facilities are being placed on pieces of land, allowing far greater output capacity. Future solar facilities are envisaged covering several square kilometres in the equatorial sunbelt; the electricity could be distributed to consumers via transmission cables stretching as far as 8,000 kilometres – with a transmission loss of less than 10 per cent.

With a solar radiation of 1 kW/m^2 and a solar cell efficiency of 15 per cent, an installation spanning one square kilometre would have a 150-MW capacity.

Market

The fastest-growing segment of solar cell installations are those connected to the grid, showing a growth of 40-60 per cent annually over the past five years.

Over the same period, detached installations have grown some 15 per cent annually. This is a low number when considering the two billion people not connected to any electrical grid. The challenge is in acquiring the capital to invest in solar cell installations – so the market, in order to truly take off, will require good financing solutions.

Japan, Germany, Spain, the USA and several other countries have encouraged the emergence of solar cell technology by introducing feed-in tariffs that provide payment to the owners of solar cell installations for the amount of electricity they feed into the grid at a guaranteed rate, and by offering direct investment subsidies. These measures have led to rapid growth in the Japanese and German solar cell industries; production capacity of solar cells has been doubling every year. Fortunately, Norwegian companies have been able to benefit from these developments by being part of the value chain. REC got an early start and has gained a strong position as one of the world's largest solar cell companies. REC invests several billion kroner annually in its plants in Glomfjord and Porsgrunn (Norway), Singapore, Sweden and the USA.

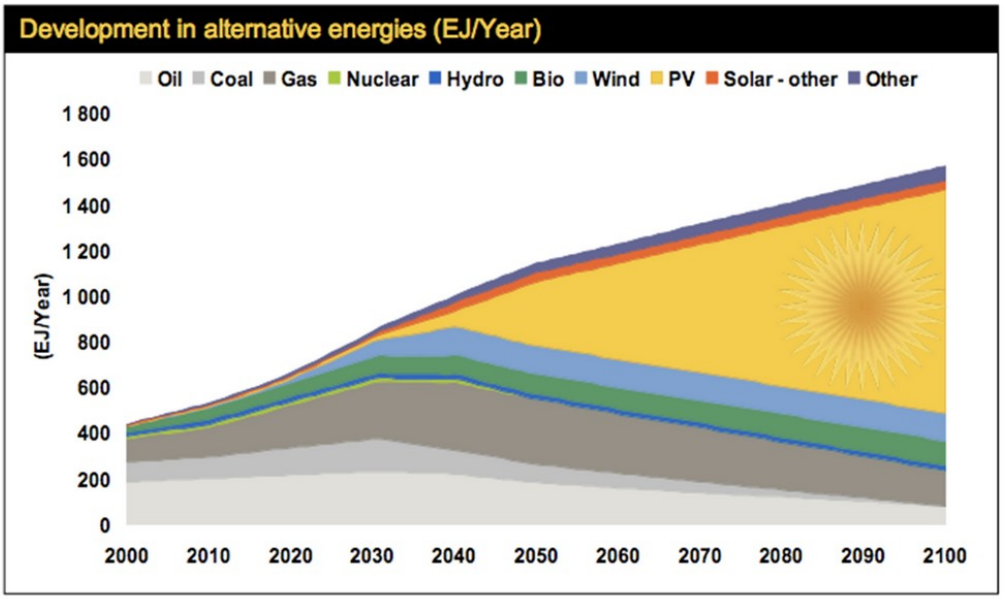
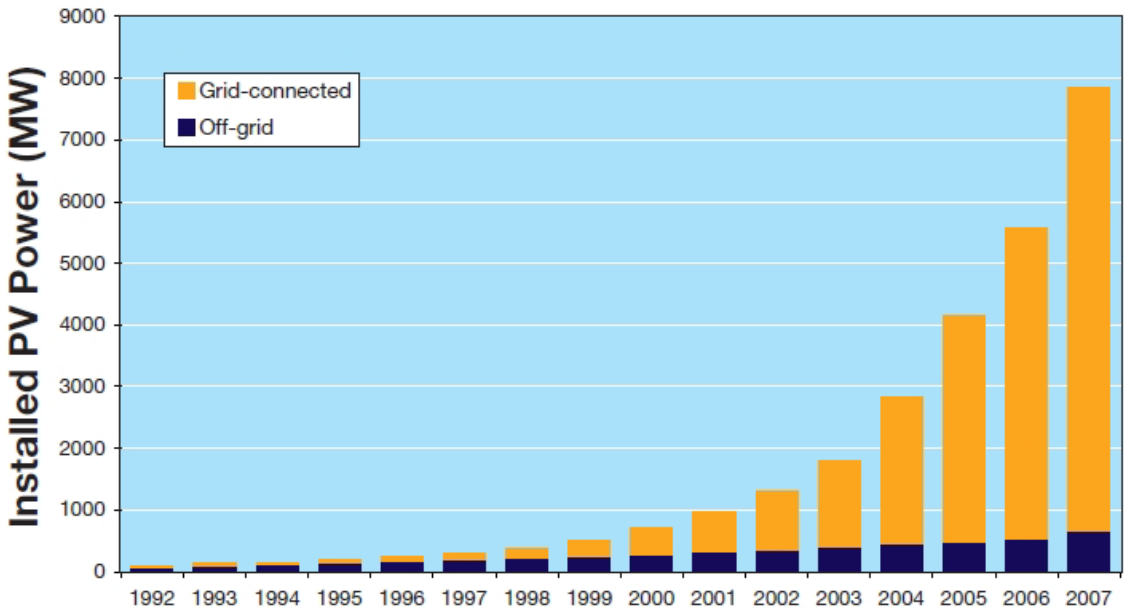


Figure 4: Market potential in alternative energies. Source: Solarwirtschaft.de

Several Norwegian companies are contributing to the rise in production capacity, such as NorSun of Årdal and Elkem Solar of Kristiansand. Some production facilities will be built in Norway, although the trend for both REC and NorSun has been to build most factories abroad. Many countries offer good incentives in the form of investment support, tax exemptions and free training of personnel.

The financial crisis is causing a dent in the growth curve, since funds are scarce for new installations, which leads to delayed construction starts. Banks are still wary of lending money to such higher-risk projects, but this will only be temporary. A small crisis may turn out to benefit the industry, since production costs have been halved over the last five years, while sales prices have not dropped. The market needs a price reduction, and the best companies will survive. The stock market gold rush is over, and the solar cell industry will normalise.

The energy market is enormous, estimated at a value four times that of the world's combined gross national product. Today, solar energy accounts for only a fraction of a per cent. It is believed that within 50 years, however, 10-20 per cent of all energy production will come from solar cells. An annual growth of 25-30 per cent would accomplish this.



Cumulative installed grid-connected and off-grid PV power in the reporting countries

Figure 5: Installed photovoltaic power worldwide. Source: IEA

Norway's theoretical potential output of solar power is 900 kWh/m^2 per year, while the world's prime locations could produce 2,500 kWh/m^2 per year. Compared to Norway, it is almost three times cheaper (over an installation's lifespan) to produce solar electricity in Perth, Australia, due to the higher solar radiation. The total cost in Oslo is around NOK 1.50/kWh, compared to approximately NOK 0.60/kWh in Perth.

The costs of producing silicon of solar-cell quality will be further reduced when companies such as REC switch from the energy-intensive Siemens process to making silicon with fluidised bed technology, which requires only a fraction as much energy. Other ways of cutting costs are by using less materials, more efficient processes, and better process equipment. Price reductions of 50-70 per cent can be expected within the next 10 years.

Materials

The market for solar cell materials is dominated by silicon, a component in some 95 per cent of solar cell systems currently being produced. Other solar cells are based on thin-film technology, using layers just one micron thick. By comparison, silicon wafers are typically 150-200 microns thick.

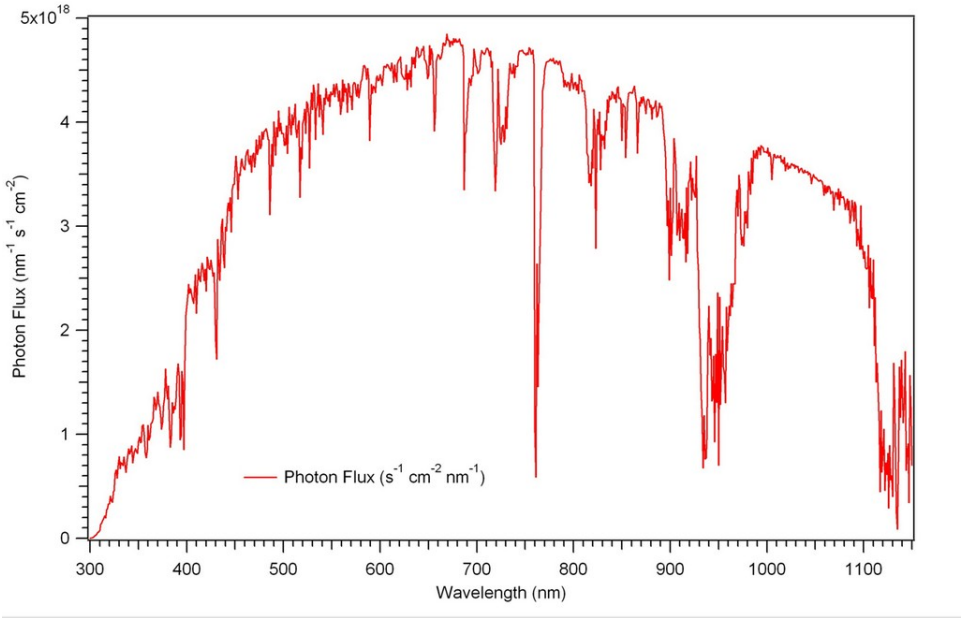


Figure 6: Silicon utilises the photons in sunlight within the wavelength range of 400 to 1100 nm. Illustration: IFE

While the efficiency of today's thin-film solar cells is 5-10 per cent, solar cells of silicon achieve 14-20 per cent.

Most thin-film solar cells consist of cadmium telluride (CdTe) cells, produced by the company First Solar, and the compound CIGS ($Cu(In_xGa_{1-x})Se_2$), which several companies produce. Both achieve a 10-12 per cent efficiency but have the potential to become as efficient as silicon.

Thin-film cells of CdTe will never be mass-produced due to the scarcity of tellurium. Furthermore, cadmium is an environmentally hazardous material. Using CIGS has the disadvantage that indium is expensive and of limited quantity. Nevertheless, production capacity for both types could approach a few GW per year.

There are other types of solar cell materials, such as gallium arsenide, but they are very expensive. Solar cells based on organic materials face stability problems.

For solar cells, there is currently no real material to compete with silicon, which is found worldwide. Thirty per cent of the earth's crust consists of materials containing silicon in some form. For the large-scale facilities producing solar power, which require a lifespan of at least 50 years, it is hard to beat silicon, a highly stable material with a low probability of degradation.

Silicon's efficiency in a single solar cell structure is theoretically limited to 30 per cent, since silicon absorbs only the 400-1100-nanometre wavelength range of the sunray. The best silicon solar cells on the market today achieve 22 per cent efficiency, while commercial multicrystalline cells manage about 15 per cent and monocrystalline cells 20 per cent.

Of all the world's solar cells, about 45 per cent are multicrystalline cells of silicon, about 45 per cent are monocrystalline, and some 5 per cent are thin-film. Multicrystalline cells are cheaper to produce but are prone to impurities entering the cells and lowering their efficiency.

By stacking layer upon layer of solar cells that are customised for different wavelength ranges of sunlight, solar cells can achieve efficiencies of 50 per cent, meaning half the solar energy that strikes the installation is converted to electrical current.

At IFE, we investigate materials that can improve solar cells to a theoretical limit exceeding 60 per cent. In practical solar cell installations, we aim for 30 per cent efficiency. Systems like these could be commercialised within 10-20 years.

The value chain

Solar cells make up a long value chain, from production of silicon to completely installed solar energy systems.

Quartz is the starting point. By adding carbon, the silicon is separated out. (In this process, Elkem has been a world leader for many years.) Next, a purification process grows solar-grade silicon crystals. REC has two production facilities in the USA that are among the world's largest, while Elkem has just opened a major facility using alternative technology for purifying silicon. FESIL is also working with this.

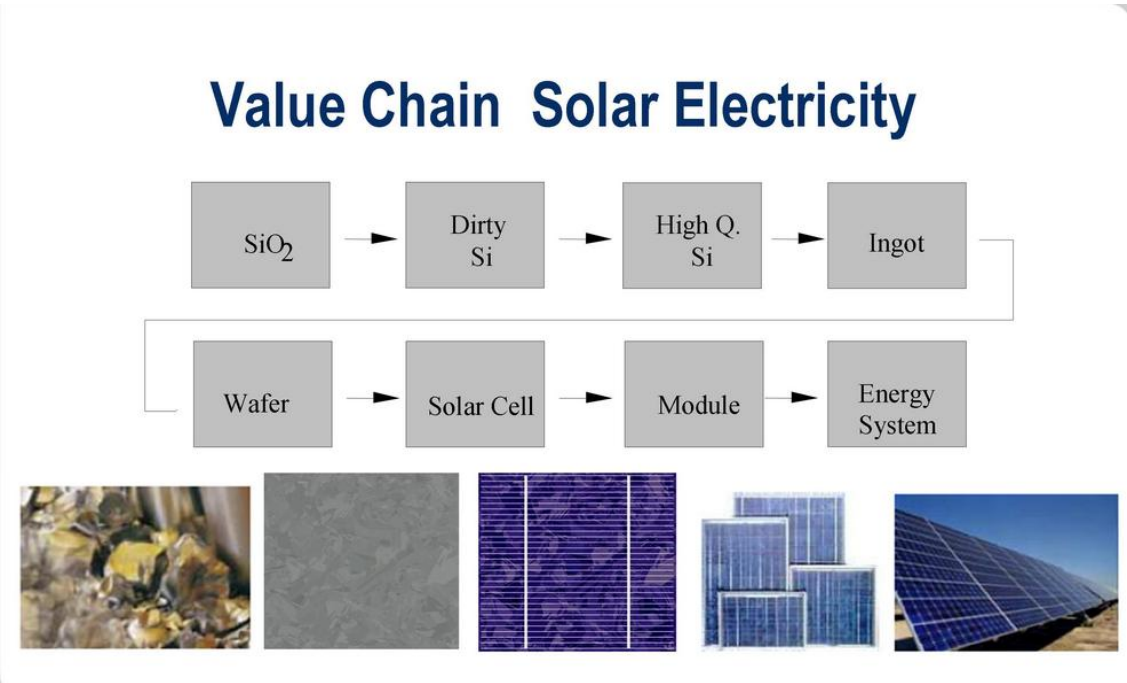


Figure 7: Value chain for solar electricity. Illustration: IFE

Norwegian companies involved in the value chain are:

- *Feedstock:* Elkem Solar, REC Silicon, NorSun, Hydro Solar, FESIL.
- Other pilot projects: SilanSil, NSR, Swirl process (IFE), IsoSilicon (IFE)
- *Crystallisation:* REC ScanWafer, REC Sitech, NorSun
- *Wafering*: REC ScanWafer, NorSun
- Solar cell production: REC ScanCell
- Module production: REC ScanModule AB
- *Energy systems:* REC Solar Vision, Solkraft AS
- *Sub-suppliers:* Orkla Exolon, Metallkraft, Vetro Solar, CruSiN

A number of sub-suppliers have sprung up around the solar cell industry. Orkla Exolon produces silicon carbide used in the sawing of silicon blocks into wafers. Metallkraft recycles the silicon carbide from the sawing waste. Vetro Solar plans to manufacture glass for solar cell panels, and CruSiN produces melting pots for purifying the silicon. There is also an array of Norwegian companies that work with automation or the construction of production facilities.

Globally in 2008, some 8 GW of solar cells were produced.

Conclusion

Within 50 years, solar electricity can potentially constitute some 10-20 per cent of total global electricity production.

A price drop of 50-70 per cent is expected over the next 10 years.

Although other materials will find niches, solar electricity installations will predominantly be comprised of solar cells made of silicon.

Norwegian companies are well-positioned in the global market, with high potential for further industrial development. REC, Elkem Solar and NorSun currently have production units for solar cell wafers in Norway.

The prospects for offshore wind energy in Norway in a 25 year perspective

By Geir Moe, Professor ScD

Introduction

The future prospects for offshore wind energy depends on which sources of energy that will be available, and on the relative merits of offshore wind energy compared to the other sources. It makes little sense to discuss offshore wind energy, unless this context is kept in mind. For instance: If global warming was of no concerns and oil and gas would be available in nearly unlimited quantities, then there would be no reason to develop offshore wind energy. On the other hand if the destruction of the living conditions on our planet due to global warming is considered to be of overriding importance, or if oil costs say 300 $ per barrel and gas 10 $ per m^3, then electricity from offshore wind would probably be quite attractive, even at a cost of 1 NOK (or more) per kWh.

Today very few people with insight in climate matters doubt that (i) a global warming is taking place and (ii) that it is mostly manmade. Also rather few of them argue that it would be too expensive and/or too difficult to alleviate the problem. Information on this matter is reasonably well known, so in this paper the conclusions from the IPCC (The Intergovernmental Panel on Climate Change) will be accepted as a premise, without any further justification.

In the sequel info concerning the reserves of oil, natural gas and coal will be summarized, since public knowledge in this field is limited. It will be claimed that the production of the fossil fuels that has provided most of the world's energy supply up to now will reach its maximum capacity within a few decades, followed by a decline. The current price increases on oil, natural gas and coal are symptoms on this trend. This is another very important reason why alternative energy sources must be developed.

Fossil fuels – Reserves and availability

The industrialization and the improvement in the living conditions that have been taking place in the developed word during the last 200 years or so, has been based on the use of cheap, abundant energy. The word population has grown from about 1 billion 200 years ago to 6.7 billions today. That translates to an average growth rate of about 1.8 % per year. From a maximum around 1960 the population growth has slackened somewhat to about 1.14 % now. This large population has depleted the resources of our planet at an increasing rate and now production is struggling to keep pace with demand in some areas, notably for oil and gas.

There exists a theory about the production rates of oil from a given geographical area, usually referred to as 'peak oil', or 'Hubbert's peak theory' after its originator, see e.g.[1]. It suggests that production from a limited resource follows a bell shaped curve and that the curve's parameters can be determined on the basis of discovery rates, production rates

[1] http://en.wikipedia.org/wiki/Hubbert_peak_theory

and cumulative production levels, even at a point fairly early in the cycle. The theory can be said to be making predictions as regards 'easy oil' only, thus production from oil tar and oil synthesized from coal is not included. This theory is in disagreement with the more common economist viewpoint that a (moderate) price increase will result in more exploration and therefore in (significantly) more finds. Then, the traditional economist argue, production can be increased and if necessary also more refining capacity can be built, so that production can be increased. Hubbert pointed out that for a limited resource as oil the best prospect will be found and exploited first, and at a certain time it will be a practical impossibility to discover and exploit enough small fields to increase the production level, and later even to maintain it. Several of the 'peak oil' proponents claim that the world is now near to 'peak oil', i.e. that the maximum production rates is about to be reached. Some facts seem to support this viewpoint. Thus the 14 largest oil fields that provide 20 % of today's oil output are on an average 48 years old, the youngest being the 23 year old offshore Brazil Marlin field. It is also worth noting that 2.5 % of the producing 2500 oil fields yield half of today's energy output. Thus if small fields only are discovered it will be very hard to keep the production level up when the production from the giant fields are falling off. A prediction of when the peak in the word oil production would occur was made by Hubbert himself in 1956, and he said 'in about a half century'. However average reservoir recovery rates have increased from 22 % then to about 35 %, so a delay of occurrence of peak oil should be expected. Also, since large quantities of oil is available in a relatively small number of countries political decisions such as those reached in OPEC will influence production rates and price levels. Also speculators can for a while influence the oil price considerably. *Still, indications are that increasing demands and stagnating production levels of oil have led to the current high prices on oil and gas, and that the prices will stay high permanently, even though short-term fluctuations will occur.*

It has been widely believed that coal is an abundant source of energy. However two recent reports draw startlingly different conclusions, see a short résumé in [2] or the full report to the German federal government in [3]. There it is pointed out that until quite recently estimates of coal reserves have been significantly too high, and that in these estimates coal quality and suitability for production have not been considered. One of these studies predicts that 'peak coal' may occur in as little as 15 years. Further they predict that the peak production will be 30 % higher than today, and that this production rate can be maintained for some time, after which it will decrease. The second study is in general agreement with the first, even though it does not use the concept 'peak coal'. Since it takes several years to plan and build a coal plant and it is built for a 30 year life, concerns about the long-term price development for coal is more than an academic exercise.

Table 1: The world energy usage in 2006 in per cent. From 4

Oil	Natural gas	Coal	Nuclear	Hydropower	Biomass	Remaining
37	23	25	6	4	3	1

Adding oil, gas and coal it is seen that carbon based fuels provide 85 % of the total energy supply. Also it is seen that if coal is to replace say 30 % of the oil and gas then a 67 %

[2] http://gristmill.grist.org/story/2007/4/11/0950/93002

[3] http://www.energywatchgroup.org/fileadmin/global/pdf/EWG_Report_Coal_10-07-2007ms.pdf

[4] http://en.wikipedia.org/wiki/Energy_consumption#Consumption.

increase in the coal production rates is needed. Wind energy in 2006 provides 0.3 % of the total energy and photovoltaic solar 0.04 %. Many economic studies predict that the world energy usage will increase by 50 % by 2030 - but this may be a practical impossibility.

Worldwide electric energy constitutes only about 15 % of the total energy usage, thus wind energy produced about 2 % of the words electricity in 2006. In Europe the percentage is larger, however, in Denmark as high as 20 % and even in the large, densely populated Germany about 7 %.

CO_2 emissions to the atmosphere by different energy generating technologies

To assess the amount of CO_2 emitted when energy is produced by a given technology a life cycle analysis should be used, i.e. the construction, production and demolition phases of the generating system must be taken into account. (Commonly called 'carbon footprint'.) Coal based power plants emits roughly 1000 g per kWh, while combined cycle natural gas plants (NGCC) emit roughly half that amount, see [5]. Using Carbon Capture and Storage (CCS) techniques 80-90 % reduction is expected, i.e. 100-200 g CO_2 per kWh produced will be emitted from coal plants and half of that from natural gas plants. Emissions for renewable energy and nuclear energy are given in figure 1.

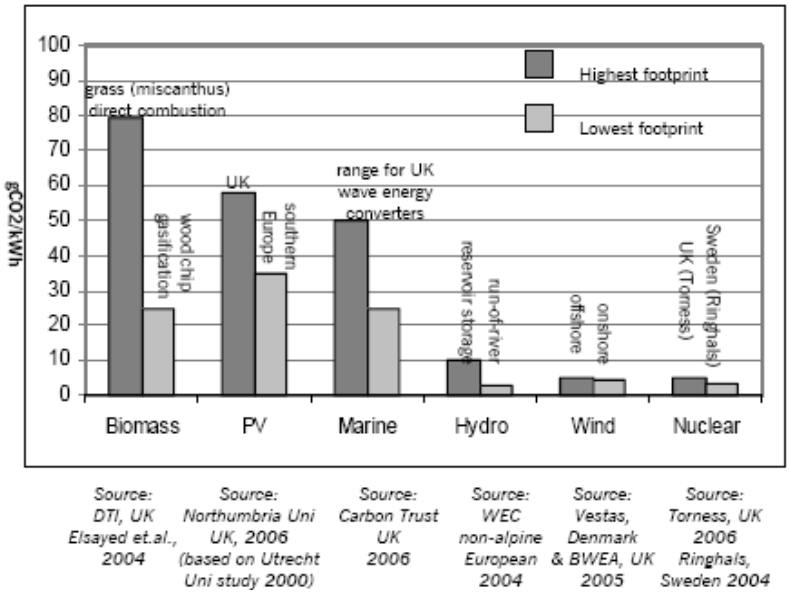


Figure 1: Range of carbon footprints for UK & European 'low carbon' technologies from [6]

It is seen that even with CCS coal and natural gas have a much higher greenhouse effect than the 'low carbon' technologies, indeed for natural gas with CCS a factor of at least 10

[5] http://www.parliament.uk/documents/upload/postpn268.pdf
[6] http://www.parliament.uk/documents/upload/postpn268.pdf

higher than hydro, wind and nuclear technologies and at least 20 for coal with CCS. Without CCS the ratio of the carbon footprints of gas versus wind is roughly 100.

End of cheap energy

Fossil fuel combustion accounts for 80 % of the greenhouse gas emissions generated by humans, and can hardly be replaced in the near future. Hence policies must be implemented to ensure that Carbon Capture and Storage (CCS) is implemented, which is expected to increase the price of the generated electricity by 30-60 %, see [7]

Electricity generated by oil or natural gas will at the present price levels be expensive. Thus at a gas price of 4 NOK per standard m^3 the electricity will cost about 0.80 NOK/kWh. With CCS the price must be expected to reach 1.05-1.25 NOK/kWh. It is difficult to predict what the price of electricity from new coal power plants will be in light of the present drastic price increases for coal and considering the claim that coal resources are relatively limited. Anyway, the key issue is not present coal prices but what they will be during the life of the coal power plant, i.e. during the next 30 years.

It seems unlikely that a severe energy crisis can be avoided. Part of the solution may be to use much more nuclear energy. However the required uranium isotope (U235) exists in very limited amounts and nuclear power also has grave implications for security as regards terrorism and also as regards long term storage of wastes. If switching to other uranium isotopes then plutonium will have to be dealt with, sharply magnifying the terrorism aspects. Thorium has been suggested, but is as of now a completely untried technology, and can therefore in any event not be implemented in the near future. For a more detailed presentation about the uranium resources, see [8].

Land based wind energy will in the next 5 years cost about half of electricity from natural gas, and has as just mentioned less than a 10 % as large carbon footprint as a gas power plant **with CCS**. Later the price ratio must be expected to become even more favorable due to increasing gas prices. In Norway considerable areas with good wind exists along our coast. Thus there are about 20000 km^2 with more than 8 m/s average yearly wind, as measured at 100 m altitude, and if 20 % of this area is used about 120 TWh could be produced, i.e. roughly the same as the current Norwegian electricity production. Such an ambitious development of wind energy would use about 1.2 % of our land area and is for the time being quite unrealistic, considering the attitudes toward wind turbines expressed in the media, and the lack of political leadership evident so far in our oil-rich nation.

Current status and plans for European offshore wind parks

EU has made a “binding commitment” that 20 % of the total energy supply shall come from renewable sources by 2020. Accordingly, in February 2007, offshore wind energy development was given high priority [9]. The target is to reach 50 GW of offshore wind

[7] http://en.wikipedia.org/wiki/Carbon_capture_and_storage

[8] http://en.wikipedia.org/wiki/Peak_uranium

[9] Chair of the European Policy Workshop on Offshore Wind Energy Deployment, Berlin Declaration, Conclusions of the Chair, Berlin, February 2007.

energy by 2020. This amounts to a rate of growth during the next 13 years that matches the growth seen in the onshore sector during the last 13 years [10].

At the end of 2006, Europe had operating wind farms in Denmark (398 MW), United Kingdom (304 MW), Ireland (25 MW), Sweden (23.3 MW) and the Netherlands (136 MW). That represented 3.3% of the wind energy production [11]. Fig. 2 shows a map of the existing and planned offshore wind turbines in North West Europe, where the development has been concentrated up to now.

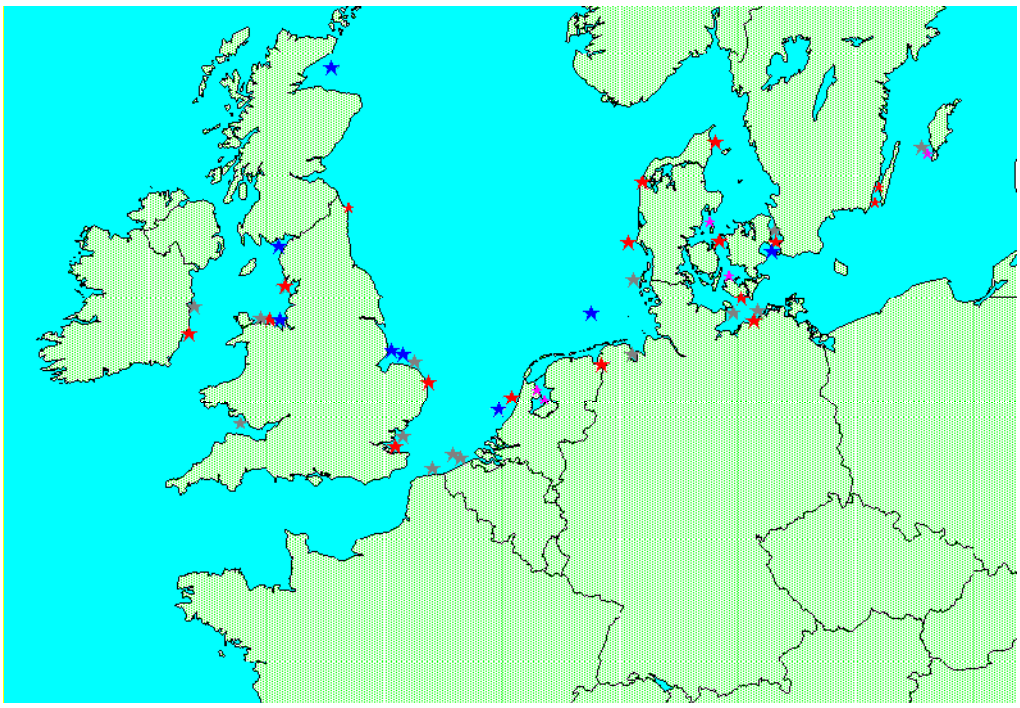


Figure 2: Map of existing and planned wind farms in North-West Europe, June 2007 [12]. Red = (built MW wind turbines), purple=(built small wind turbines), blue=(under construction), grey=(planned)

The leading offshore wind countries have up to now been Denmark and the UK. Denmark was the pioneer in this field as it built the first offshore wind farm in the world in Vindeby in

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[10] European Wind Energy Association, EWEA's response to the European Commission's Green Paper "COM(2006)275 Final) "Towards a future Maritime Policy for the Union: A European vision for the oceans and seas", Brussels, June 2007.

[11] European Wind Energy Association, EWEA's response to the European Commission's Green Paper "COM(2006)275 Final "Towards a future Maritime Policy for the Union: A European vision for the oceans and seas", Brussels, June 2007.

[12] www.offshorewindenergy.org

1991. It has now eight operating wind farms, including the biggest one in the world, located at Horns Rev in the North sea (Fig. 3), composed of 80 2MW turbines that generate enough power to meet the demand of 150 000 Danish Homes. Wind conditions in this area is exceptional, as this wind farm is in production between 40 and 50% of the year [13]

Figure 3: Horns Rev offshore wind farm [14]

Two upcoming farms of a capacity of 200 MW each, Horns Rev II and Rødsand, expected to be commissioned 2009/2010, will generate enough energy for 350 000 to 400 000 Danish homes, or 4 % of the Danish electricity consumption. Wind energy is planned to produce more than 50 % of the Danish electricity needs by 2025, and most of the new parks are expected to be located offshore [15]. The UK has five operating wind farms. The development plans are huge, and as of now, leases have been allocated for parks totalling 7200 MW, corresponding to 7% of UK's electricity supply [16]. The UK has also built the demonstration farm Beatrice, in a water depth of 45 m, making it the deepest wind turbine site in the world. Germany has no operating wind farm yet, but it is expected to be a major player in the years to come, as official projections claim a target of 1100 MW by 2010, and from 12000 to 15500 MW by 2020 [17]. Further developments are planned or under construction off the coasts of the Netherlands, Belgium, France and Spain, where Spain

[13] Danish Energy Agency, Offshore Wind Farms and the Environment, Danish Experiences from Horns Rev and Nysted, Copenhagen, November 2006.

[14] http://www.bwea.com/images/media/HornsRev-Denmark.jpg

[15] Danish Energy Agency, Offshore Wind Farms and the Environment, Danish Experiences from Horns Rev and Nysted, Copenhagen, November 2006.

[16] Global Wind Energy Council, Global Wind 2006 Report, Brussels, 2007

[17] Greenpeace, Global Wind Energy Council, Global Wind Energy Outlook 2006, Brussels, September 2006.

recently made an important move by allowing the construction of offshore parks bigger than 50 MW [18].

The very fast development of offshore parks has not been without technical problems. One aspect is simply that the production apparatus is strained because of increased production rates, and that the challenges posed by the offshore environment have not been sufficiently accounted for by the wind industry. The stronger offshore winds may simply not have been properly designed for, and also excessive corrosion due to salty air is rumored to have occurred. The offshore oil industry handles this by filtering of the air entering machinery rooms. Similarly corrosion of structural members is handled by sacrificial anodes and specialized paints. Exactly which problems have occurred in offshore wind, and why, are not yet in the public domain, and therefore detailed discussions on these matters cannot not be given. But based on what is known now the undersigned believes that the technology used by the offshore oil industry could be adapted to offshore wind too.

In the future electrical energy mix in the EU the varying production from wind energy due to varying mean wind speed on timescales hours or more creates a need for 'balancing power'. The required amount of balancing power is quite large because the lion's share of wind energy will be produced in and around the North Sea, and over this area the wind climate is strongly correlated. Hydroelectric power is an especially valuable source of balancing power, since hydroelectric power can be regulated over short time intervals, while coal or gas fired plants preferably run at constant or slowly varying power. Norway has about half the hydroelectric electricity production in Europe and is therefore being connected to our neighbors to the south or west by underwater power cables. It has been said that these quite expensive cables can be paid for by the price differences between day and night power in the EU. To increase the balancing capability more generating capacity must be added to our hydroelectric stations and it is also considered to extend the capacity further by pumping water back into the reservoirs when wind is plentiful.

A new type of high voltage direct current cables, so-called HVDC light, has been introduced about 10 years ago, see for example [19] and is used to connect the Troll Offshore platform to the Norwegian land based net, see [20]. Recently also the energy company E.ON has chosen HVDC light for the 400 MW German wind park Borkum 2 which is situated 130 km from the shore.

Potential and plans for offshore wind energy in Norway

The potential for development of offshore wind energy in Norwegian waters is huge. Beyond 20 km from shore and in less than 60 m water depth it is theoretically possible to develop a production of 786 TWh per year, or about 6.5 times the current electricity production in Norway, while the areas where the water depth is less than 300 m could theoretically yield an enormous 13700 TWh a year. Of course nobody is suggesting that these areas could be filled up with turbines. "Filled up" is not a good term, however, since e.g. with 5 MW wind turbine the distance between neighboring turbines will be nearly 1 km.

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[18] http://www.renewableenergyaccess.com/rea/news/story?id=49530

[19] http://www.offshore-mag.com/Articles/Article_Display.cfm?Article_ID=173948

[20] http://www.abb.ca/cawp/gad02181/c1256d71001e0037c1256c17002dabad.aspx

(This distance depends on how large wake losses one will accept.) Pleasure crafts can easily travel through such a wind park, but for safety reasons ships must be kept out.

Table 2: Estimated wind resource in Norwegian economic zone. The NVE estimates uses 0-20 m and 20-50 m. 'Utenfor 20 km' means 'Beyond 20 km (from the shore)' 'Kystnært' is less than 20 km from the shore. From Sweco Grømer "Potensialstudie av havenergi" 21

Område	Vanndyp	Potensial offshore [TWh]		
		Utenfor 20 km	NVE-estimat, kystnært*	Total
Sør for Lat 61°N	0 – 30 m	0	6,8	6,8
	30 – 60 m	324	9,7	334
	60 – 300 m	2 320	n.d.	2 320
	Totalt	2 644	16,5	2 660
Mellom Lat 61°N og Lat 67,5°N	0 – 30 m	0,1	100	100
	30 – 60 m	3	48	51
	60 – 300 m	3 740	n.d.	3 740
	Totalt	3 743	148	3 890
Nord for Lat 67,5°N	0 – 30 m	10	7,6	17,6
	30 – 60 m	459	27	486
	60 – 300 m	6 910	n.d.	6 910
	Totalt	7 380	35	7 420
Sum	**0 – 30 m**	**11**	**114**	**125**
	30 – 60 m	**786**	**85**	**871**
	60 – 300 m	**12 970**	**n.d.**	**12 970**
	Total	**13 767**	**199**	**13 970**

From the table is seen that the most attractive case of more than 20 km from shore and less than 30 m of waterdepth only occurs north of 67.5 degrees latitude, i.e. far away from the large population centers. However there is a potential for 324 TWh for the case more than 20 km from shore and in less than 60 m of waterdepth in the southern part of the North Sea. Then a wind park can be located on a cable between Norway and Denmark, Germany, the Netherlands or UK, and could under good wind conditions transport energy to both sides. Thus for a 700 MW cable up to 1400 MW can be transported, so that such a park may produce in the order of 5 TWh per year.

There are no wind park in Norwegian waters, and only one commercial park has received a concession from the Norwegian regulatory body NVE, namely the 350 MW installed

[21] http://www.enova.no/minas27/publicationdetails.aspx?publicationID=266

capacity Havsul I [22]. The distance to the nearest houses is 6 km, and the park is expected to provide 1 TWh to an area which is in need of extra generating capacity. In view of the difficulties experienced with wind turbines on land, additional offshore parks close to the shore will probably have problems getting concession. Thus the other parks in the near-shore Havsul suite have either not been given concession, viz. Havsul II, (800 MW) and Havsul IV (350 MW), or put on wait, viz. Havsul III (350 MW). Only one more offshore concession that has been granted, nemely to Statoil Hydro's prototype 3 MW floating test turbine 'Hywind demo' near to Karmøy [23].

NVE reports on no more applications for concession to install offshore wind parks, while the earlier step in this process, a so-called 'melding' (literal translation: "message") has been given for 9 parks. (Idunn (999 MW), Aegir (999 MW), Fosen Offshore (600 MW), Gimsøy Offshore (250 MW), Sevær (450 MW), Siragrunnen (200 MW), Statwind (999 MW), 'Sørlige Nordsjø (999 MW), and Utsira (300 MW). This relative large number, involving large size parks can be taken as an expression of interest among Norwegian companies, but for these plans to be realized national politics must be favorable and also a positive interaction with neighboring countries or directly with EU must occur.

What is the optimum size for an offshore wind turbine?

Higher structural expenditures must be expected if the size of a wind turbine is increased. Simply put, one is harvesting energy from an area, while building a volume, and if one assumes that all dimensions increase in the same proportion ('geometric similarity') then the structural volumes increase as length scale cubed, while the rotor area increase as length scale squared. The assumption that all dimensions should increase in the same proportion is correct as long as the wind loading on the rotor is the dominating force, but when the dominant loading is self weight the growth of weight as a function of length scale will be even faster, see e.g. Moe [24]. A mitigating effect is that the mean wind velocity increases with height, so that a taller wind turbine will experience stronger wind. The simplest model for wind profiles, which unfortunately is rather inaccurate, says that the mean wind velocity increases as height to the power 1/7 = 0.14, so that the increase of power production with length scale *s* will be

$$s^2\left(s^{0.14}\right)^3 = s^{2.42}$$

The wind profiles at the location of the rotor of large wind turbines will usually be considerably steeper than this, however. Thus data collected by Garrad Hassan, and published by EWEA (2004) indicate that the average increase of power production as a function of length scale is proportional to $\boldsymbol{s^{2.23}}$ for the larger wind turbines. This means that the turbine weight per kWh depends on the length scale as

$$s^3 / s^{2.23} = s^{0.77}$$

[22] http://www.nve.no/modules/module_111/netbasNVE.asp?iCategoryID=1403&script=9&objid=-46581

[23] http://www.nve.no/modules/module_111/netbasNVE.asp?iCategoryID=1403&script=9&objid=-54949

[24] G Moe , "What is the optimum size of a wind turbine?", proceedings OMAE 2007

i.e. this ratio increases as length scale to the power 0.77. For example by doubling the turbine height the weight per kWh will increase by a factor of $2^{2.23} = 1.70$. Or, more realistically, if the length scale is increased by 20 % then the turbine weight per produced kWh will increase by 15 %. If focus is shifted to a wind park, then the power production per unit area is to the first approximation the same: the distances in both directions in the horizontal plane must increase in proportion to the length scale. For the Horns Rev wind park a distance of 7 rotor diameters in both directions has been used [25]. That resulted in power production of about 88 % of what would be the case if there were no wake effects, i.e. if there were no reduction of the incoming flow due to upstream turbines. (A good approximation is that the wake loss is equal to the inverse of the length measured in rotor diameters.) Again, for a given park area, large wind turbines will produce more, since the rotor will be at a higher altitude, and according to the above this will amount to $s^{0.23}$, i.e. by a doubling of the height the power production will increase by about 17 %. Or more realistically, a 20 % larger length scale yields about 4.3 % more power for a given park area. In addition, the fact that there are fewer turbines for a given park size will diminish the loss due to park wake effects, but probably only by a tiny amount, unless the number of turbines in each row in the wind direction is small.

Another negative effect of increasing size is that the angular velocity of the rotor decreases. To a first approximation the velocity at the tip of the blades will be the same for all rotors, while the length of the periphery of the rotor disc of course increases linearly with length scale. Thus the angular velocity of the rotor and (low-speed) shaft will be proportional to the inverse of the length scale, so that the necessary gearing ratio will increase linearly with turbine length scale.

The size drawback can be offset by other factors. Thus larger turbines means fewer units to transport and install, and also less maintenance and less cabling at the field for a given electricity production.

[25] T Soerensen, P Nielsen, M L Thoegersen, "Recalibrating wind turbine wake model parameters – Validating the wake model performance for large offshore wind farms", proceedings of EWEC, Athens 2006

Concepts for bottom-fixed offshore turbines

Figure 4: The OWEC tower (Copyright OWEC tower)

Bottom-fixed turbines have been built in considerable numbers in shallow water, say in water depth of less than 20 m, and then solutions very similar to those used for the land based turbines have been employed. It seems that when land based solutions proved to be feasible in shallow water, they were selected during the short planning periods available for the first offshore parks, even though they might not be optimal under the new circumstances. The Beatrice wind farm demonstrator project is in 45 m water depth, which is the deepest wind turbines site yet. It has 2 units each with a REpower 5MW turbine, and has a tubular upper part of the tower, and an extension downwards to the sea floor by a specially designed unit, tentatively named 'a substructure'. Time will show whether this split between the tower itself (as designed for onshore sites) and a 'substructure' extending from the bottom of the tubular tower to the seafloor will be maintained, or whether both components will be integrated into a unified offshore tower. For the Beatrice substructure two Tripod designs and an OWEC jacket quatropod (see figure 1) were considered, and the quatropod was chosen. Its designers in the firm OWEC Tower drew on their background from the offshore petroleum activities on the Norwegian continental shelf. In Seidel and Foss 26 a fairly detailed comparison of the dynamics of the three alternatives is given. Additional information can be found on 27, from which also the mentioned Seidel and Foss paper can be downloaded. One advantage of the quatropod is that the wave loading on its slender members is lower. Another advantage is that the tower substructure unit is somewhat stiffer, so that for this turbine the dynamic amplification effects were reduced. It is also interesting to see that vibrations at one of the natural frequencies of the blades excited a group of braces in the quatropod at resonance, giving large local motions and stresses. The authors concluded that a detailed integrated dynamic analysis of the full wind turbine was necessary, in order to find such local dynamic problems and remedy them by a slight design change. For the Beatrice wind turbines also a specially designed Emergency Response Intervention Craft (ERIC) has been developed to transfer people to and from the turbine, see 28. The turbines are built adjacent to an oil production platform, which can be used as a base for maintenance and repair personnel. The owner will run the demonstrator turbines for a test period of five years. Then an evaluation will be made, which may lead to a dismantling of the two turbines, or an expansion to a full commercial park of up to 200 turbines

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[26] M Seidel, G Foss, "Impact of different substructures on turbine loading and dynamic behaviour for the DOWNVInD Project in 45m water depth", Proceedings of EWEC, Athens 2006

[27] www.owectower.no

[28] www.beatricewind.co.uk

One interesting concept for a 5MW offshore wind turbine is presented by the Multibrid development company. Here a hybrid solution is used to achieve the desired AC frequency, namely a small, one stage gearbox and a generator with considerably fewer poles than for a direct drive generator. The nacelle weight of 200 tonnes is quite low for a 5MW machine. Their use of a glass fibre reinforced plastic sandwich nacelle casing also contributes to the weight reduction. The Multibrid tower consists of a 70 m tall tubular steel tower, continued by a nearly 30 m tall tubular concrete substructure fastened to a base plate, through which 36 concrete piles are driven. For further information see [29].

One possible new solution for an offshore turbine would be to use a truss type structure for the entire tower, see Moe et al. [30]. A preliminary study was made comparing with the 5 MW Baseline Wind Turbine Model having a tubular tower, as defined by NREL. Fig. 5 shows the model used for the truss tower. The natural frequencies, static stresses, and buckling were verified and found to be satisfactory. The tower was found to be relatively soft in torsion, which could be handled by pitching the blades individually. This preliminary study showed that the weight of the truss tower was 50% of that of the tubular tower, making the former a promising new solution that should be studied further. However it is realized that the manufacturing costs for a tubular truss will be higher than for a tubular tower, so that more efficient manufacturing procedures must be found.

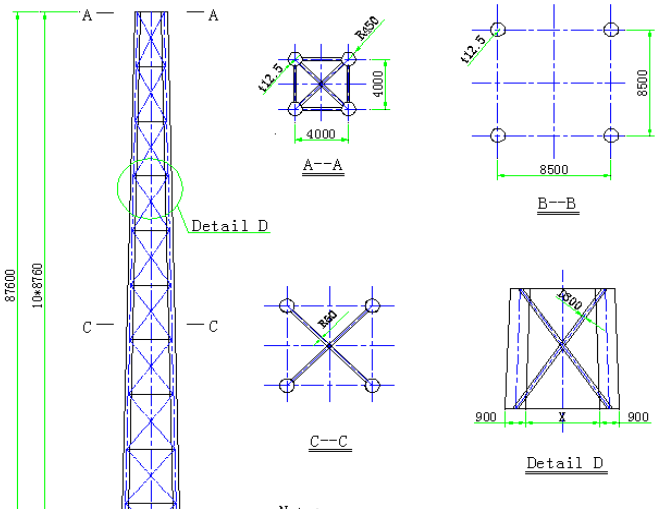

Figure 5: Layout of truss tower

Foundations for bottom-fixed turbines

The foundations of fixed turbines typically cost about 20-25 % of the total. The foundations for bottom-fixed offshore turbines depend on turbine size, water depth and soil conditions, to mention what probably are the most important parameters. In [31] a list of alternatives is given, A slightly modified version of this list of foundation solutions is as follows:

[29] http://www.multibrid.com/download/Info_Errection_M5000_191104.pdf

[30] Moe, G., Niedzwecki, J.M., Long, H., Lubbad, R., Breton, S.P., Technology for offshore wind turbines, Fluid Structure Interaction, The New Forest, UK, 2007

[31] B W Byrne, G T Houlsby, "Assessing novel foundation options for offshore wind turbines", World Maritime Technology Conference, London March 2006, http://www-civil.eng.ox.ac.uk/people/bwb/papers/MAREC011_paper.pdf

- Monopile
- Gravity foundation
- Suction caisson
- Piles
- Suction piles
- Tension piles

The monopile foundation has almost the same diameter as the tubular tower that it supports, and is therefore quite wide and can be difficult to drive or drill to a satisfactory depth. After installation the monopile foundation will usually not be perfectly vertical, but using a pile-sleeve connection with a sufficiently large annulus, the monotower can be adjusted to a vertical position and then fixed there by grouting in the annulus. The strength of grouting connections has been studied extensively and is reported to be satisfactory for such applications.

The gravity foundations at the shallow water Middelgrunden wind park consist of a 17 m wide concrete base kept in place by gravitation forces and protected from scour by extensive rock fill around the periphery. The base and the lower part of the structure is in one concrete piece, reinforced with tension cables, and have the form of a candlestick into which the turbine tower is mounted by grouting. Gravity foundations for large volume *offshore oil structures* are equipped with a skirt that may penetrate rather deep into the seafloor, and penetration is often assisted by underpressure under the bottom of the structure. During installation this may thus be considered as a 'suction caisson', in the terminology introduced herein. In a patented solution for wind turbine offshore foundations water jets of carefully controlled strength at the pile rim are used to facilitate soil penetration in hard sediments. Suction caissons are suction buckets representing a single cylindrical volume to which underpressure is applied. That means that the moment from the thrust force must be carried by shear stresses along the cylinder walls, assisted by penetration resistance on the downwind side of the cylinder.

Piles or suction piles can be used in the same way as for offshore oil structures if the lower part of the tower has several legs (tripods, jackets, or similar). However the thrust force on the turbine rotor creates a large static moment at the tower base, and hence the suction piles will experience pull-up forces with a rather large mean component for as long as a strong wind blows from the same direction.

Floating offshore turbines

There are as of now no floating offshore wind turbines that are ready for mass production, but the stage of prototype testing may be getting close.

Jonkman & Sclavounos [32] and Wayman & Al [33] present 3 types of floating offshore turbines, see figure 6. Professor Sclavounos recommends the second alternative in this figure, the tension leg platform (TLP) with suction piles, as the preferable alternative. In

[32] J M Jonkman, P D Sclavounos, "Development of fully coupled aeroelastic and hydrodynamic models of offshore wind turbines",http://www.nrel.gov/docs/fy06osti/39066.pdf

[33] E N Wayman, P D Sclavounos, S. Butterfield, J Jonkman, W Museal, "Coupled dynamic modeling of floating wind turbine systems", Paper no. OTC 18287, Offshore Technology Conference 2006

general one can say that the purpose of the tower and foundation of a Horizontal Axis Wind Turbine (HAWT) is to support the rotor in a nearly fixed position in space at a point some 100 m above the ground, and to resist the loading that is generated. Therefore minimum structural weight and manufacturing costs are sought and then the first alternative in figure 6, a slender tower, appears to be attractive. Hywind (see later) is based on this concept, while Sway (see later) has the same geometrical characteristics, but having one taut mooring it may also be considered as a special case of a TLP. A company called Blue H has built a small prototype of a TLP carrying 1 wind turbine, i.e. alternative 2 above. A fourth concept, "WindSea", developed by Force technologies, is a wind-vaning platform with 3 turbines, see [34]. Since caternary moorings to a swivel is used this is a so-called semisubmersible, i.e. an alternative not included in figure 6. The third alternative in figure 6, buoyancy stabilized floating turbines, is expected to be viable in sheltered locations only, because otherwise the waves will make the pitch motions too large.

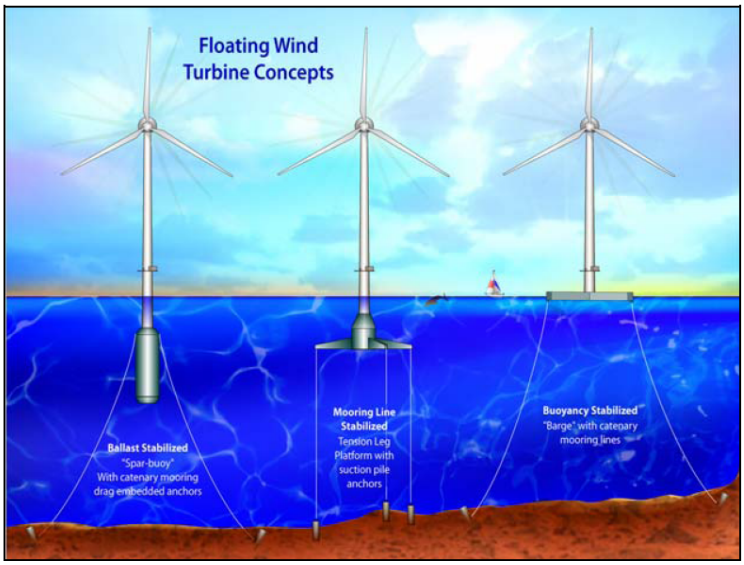

Figure 6: Types of floating wind turbines. From Jonkman & Sclavounos [32]

The rotor is on the upwind side on most existing horizontal axis wind turbines (HAWT), to minimize the influence of the tower on the wind field at the rotor. Then the rotor blades must be made stiff, to avoid collisions with the tower. To help in this respect, the rotor is often mounted on an inclined shaft so that the lower part of the rotor slopes away from the tower. Also the rotating blades usually trace a cone into the wind and often also the blades are given a curvature away from the tower, but as a result the centrifugal forces then introduce a bending moment at the root of the blade that adds to the moment from the thrust force. For floaters the problem of keeping the rotor facing the wind becomes somewhat more difficult, since the mooring lines usually will provide insufficient stiffness for rotations about a vertical axis. Therefore for floaters downwind rotors appear attractive, since they are stable in irregular wind, and it is argued that a much smaller yawing

[34] http://www.forcetechnology.com/NR/rdonlyres/FEC86579-4643-4D02-BD63-DEE1A88222A6/1688/30731en.pdf

mechanism is needed. However Hywind (see later) uses an upwind rotor and mooring by three lines that split in two parts near the turbine, so called 'crow legs'.

A major consideration for a floating wind turbine is hydrostatic stability. This is especially true if the tower is a slender tube, because then the metacenter will be at the position of the buoyancy center, since the effect of the waterplane area will be negligible. To get the center of gravity below the center of buoyancy is a severe requirement, considering that the nacelle, hub and rotor are positioned at least 150m above the center of buoyancy and in present 5MW designs typically weigh 350 tonnes or more. Reducing the top weight would accordingly be extremely valuable for this type of floaters. One promising concept for reduction of top weight by roughly 50% is presented by the small Norwegian firm ChapDrive AS, which uses hydraulic power transmission. Then the shaft in the nacelle drives a pump, which via a hydraulic line drives a hydraulic motor at the bottom of the tower. Small scale experiments indicate that the efficiency for this system is as high as for a mechanical gear box. Patents are pending and large scale testing is in progress. Also non-metallic direct drive generators may be a good alternative.

Figure 7. The Hywind floater

StatoilHydro has designed a version of the first alternative in figure 6, the ballast stabilized turbine, see [35]. They have conducted tests in the Marintek ocean basin in Trondheim, and are planning to start a demonstration project in 2009. The lower part of their structure is a 120 m tall cylinder in concrete or steel. The wind turbine is planned to be completed near land and towed to the site where it will be moored by three caternary cables. During production active pitch control will be used to minimize motions, and in the process also, indirectly, to harvest energy from the waves. Transportation of a complete unit in vertical position requires considerable water depth, say 100 m or more, everywhere on the route from the construction site to the place of operation. This is not a problem in Norway, but may be prohibitive on many of the sandy coasts of the world. The tension leg (TLP) or semisubmersible alternatives will have much lower draft, and the TLPs are planned to be kept stable during tow by suitable ballasting procedures.

[35] http://www.statoilhydro.com/en/NewsAndMedia/News/2008/Pages/hywind_fullscale.aspx

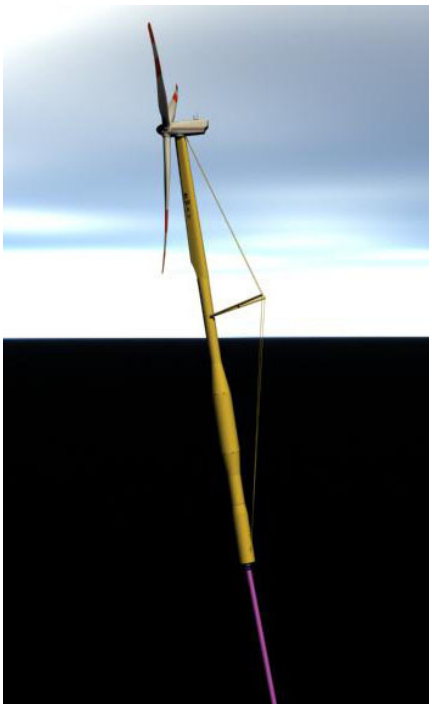

Figure 8. The Sway floating wind turbin
(Copyright Sway AS)

A third floater alternative is presented by Sway [36], see figure 8. Here the upper part of the tower is streamlined to minimize the disturbance of the wind acting on the downwind rotor. The advantages of a downwind rotor have been commented on earlier. Further the slender tower is stiffened by the taut cable arrangement on the upwind side of the tower. The thrust force is carried by a component of the mooring force, thus there is no moment acting at the base of the structure, and instead the thrust force, the buoyancy force and the mooring force must be in equilibrium.

Sway plans to start construction of a one quarter size prototype in 2008, and tentatively plans to build the first full scale prototype in 2010.

Conclusive remarks

- A brief summary is given of the case for renewable energy, namely that it is needed to alleviate the global warming threat and to help solve the coming energy shortage. It is also mentioned that landbased wind energy in Norway could generate the same amount of electricity as our present, very large hydroelectric based production does, by using wind turbines on 1.2 % of the land area of Norway. But it is also stated that to implement even 10 % of that would at present be a political impossibility.
- A brief review is given of the extremely ambitious plans for development of European offshore wind energy, and it is mentioned that Norwegian hydroelectric power will be very valuable as 'balancing power' in this context.
- It is stated that the potential for offshore wind energy is almost unlimited in Norwegian waters. In most of these areas floating wind turbines would be required, but bottom-fixed turbines could be used in less than 60 m waterdepth, and more than 20 km from the shore there are enough areas in less than 60 m in Norwegian waters that one could 6.5 times the present Norwegian electricity output could be produced. At 20 km distance the turbines would be visible from land in good weather, but only as soft, hairline-thick forms.

[36] http://sway.no/index.php?id=15

- A fair number of offshore bottom-fixed turbines have been built, all but one in water depths less than about 20 m. The concepts chosen have with few exceptions been adapted with small changes from landbased solutions, and the costs for the produced energy have been roughly twice the costs from landbased turbines. It is believed that considerably more efficient solutions can be developed.
- Floating offshore wind turbines are yet in the conceptual stage. However if energy production at sufficiently low prices can be achieved by floaters, then considering the enormous areas available, this may become an essential contribution to the energy supply of future generations.
- **Thus offshore wind energy in Norway can become the 3rd energy era for our energy-blessed nation. The hydroelectric power will remain, becoming increasingly valuable as energy becomes a scarce commodity, and when the oil and gas output is gradually decreased Norwegian wind power (landbased and/or offshore) may be substituted.**
- **A strong development of our wind resources will not come automatically, but will require political planning and support, and also concentrated efforts in research, development and manufacturing.**

Wave power development at FRED OLSEN

Gaute Tjensvoll
Department Manager, Wave Energy, Fred Olsen Ltd. Fred Olsens gate 2, 0152 Oslo
E-mail: gaute.tjensvoll@fredolsen.no

Introduction

Extraction of energy from ocean waves involves several areas of technology and widely differing concepts of power conversion. Despite a fairly long development history wave power for a number of reasons has seen limited commercial success so far. Because of its complexity in commercialization, it is not receiving the level of attention of solar- or wind power, however the wide availability and energy density in ocean waves mean this particular source of renewable energy has vast unused potential.

At Fred Olsen the FO3 wave power project since 2000 is working on advancing wave power towards commercialization. Extensive scale-model testing has been performed both in a wave tank and at sea, employing platform-based point absorbers and a hydraulic system of conversion from wave to electricity. While significant hurdles remain to be tackled, progress is steady.

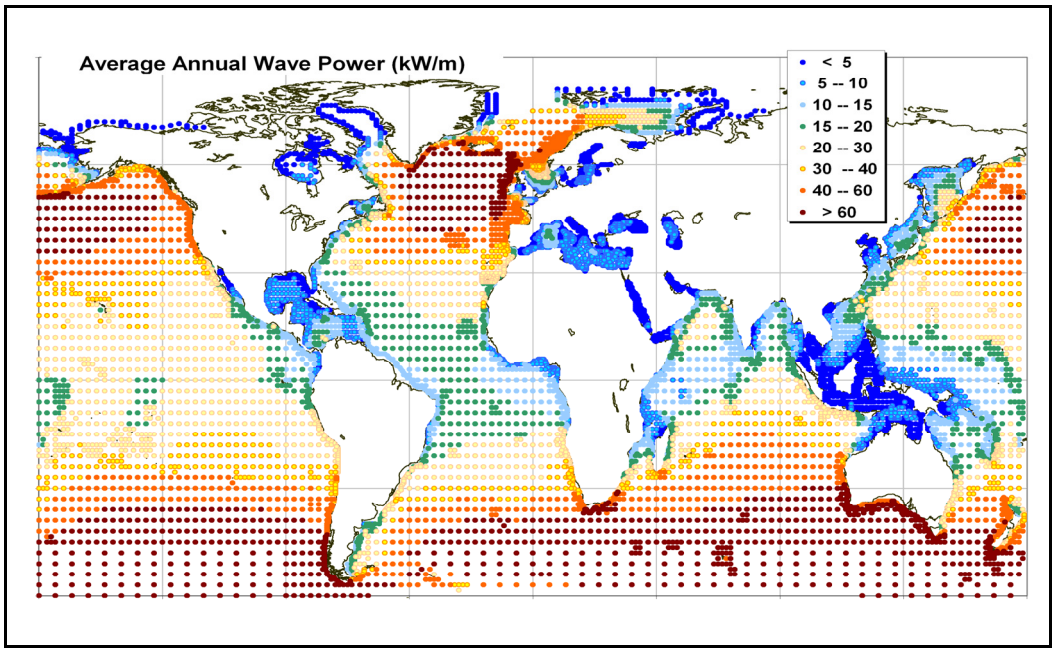

Figure 1: World wave energy map. [1] Wave energy has vast potential.

The why and which of renewable energy sources

We are currently seeing a surge in the demand for renewable energy that looks set to continue for a long time to come. The twin needs of having to curb greenhouse gas emissions while securing energy supply under increasing electricity consumption makes a strong case for renewables. The EU has set ambitious targets for increasing production of energy from renewable sources towards 2020. Looking towards 2040-2050 the transition to increased use of renewable sources of energy is expected to further intensify. Whereas improving energy efficiency as well as introducing carbon capture and storage technologies to fossil power production are both important measures to contain climate change, renewable energy will be the key to long term, sustainable power production. In a 30-year perspective, there is every reason to believe fossil energy sources will be increasingly scarce and expensive, leaving a substantial gap that needs to be filled by renewable energy sources.

Especially in electricity generation it is a matter of some urgency to replace fossil energy sources with renewable ones. In effect electricity generation needs to increase substantially, not only to cope with the world's increasing energy demand for existing uses, but also to accommodate the expected transition from fossil fuels to electricity as the source of energy for cars and other means of transportation. The question therefore is not which technology to choose for electricity generation among the new renewables - solar, wind or ocean energies like wave or tidal power. We are going to need *all* of these new sources of renewable energy, together with hydro power, biomass - and other renewable energy sources not yet commercially available.

Hurdles to overcome for wave power

The obstacles to wave power have proved both numerous and difficult to overcome. The efficiency of conversion from wave energy to electricity is a key issue and a big challenge. Especially the goal of developing control strategies for wave energy converters to increase power output at or near resonance frequencies in irregular seas has proven difficult. Another challenge linked to power output follows from the nature of the energy source with immense variations in energy levels over short periods of time. This large peak-to-average ratio can to some extent be levelled out in a big wave farm installation, but there is also a need to use energy storage or other ways of levelling power output. Studies show, however, that the power production profile from wave power may prove beneficial in combination with other variable-output energy sources like wind power.

Another major hurdle is making sure wave power conversion units survive over time in the harsh sea environment. The major problems here are periods of exceptionally high waves and extreme weather conditions. The extreme resulting forces pose engineering challenges and represent the major downside to the huge energy potential of ocean waves. Cost issues are what make this so difficult, since building very robust technology is also very expensive. Cost-effective technology with efficient energy conversion and good survivability is what all wave power projects are aiming for. Operations and maintenance costs are another important factor here as these tend to be high for ocean energy production, in particular in cases where physical intervention by personnel and the use of support vessels are required.

Overall however, wave power should be cost-competitive with other emerging renewable energy technologies. Solving the technological challenges while keeping costs down will probably still be a time consuming process and one that will need continued considerable investments before wave power units will be ready for broad commercial deployment.

Grid connection and power transmission issues are central to most kinds of power production, but the high cost of offshore transmission cables and the potentially long transmission distances make this especially true for any type of ocean energy. To make wave power commercial large installations will likely be needed. The large investments needed for such deployments mean the big players in the energy industry need to be involved. Still the issue of grid connection for wave power must be resolved in conjunction with other sources of ocean energy. Possible synergies with offshore wind farms or even existing fossil fuel power plants are interesting ideas for wave power. Sharing infrastructure and grid connection with a wind turbine could significantly increase the cost efficiency of a wave power installation. Independent enabling technologies facilitating cost-effective grid connection will be critical to success.

There are also other, non-technological hurdles to wave power. A supportive political and regulatory environment that is conducive to the development and introduction of new energy technologies is very important. History has often demonstrated lengthy application processes and significant regulatory risks. Different countries have very different merits in this context. Existing solar and wind power installations demonstrate that not only the availability of the resource, but also politics play a major role in deciding in which countries new technologies are introduced. Wave power may materialize not in the country with the best wave climate, but in the one with the more supportive regulatory environment and the better grid connection possibilities.

Wave power 30 years from now

Predictions concerning wave power have several times proved overly optimistic, so a certain level of caution would seem appropriate when predicting its future. Still, with several types of wave power technologies today in demonstration and pre-commercialization phases, it seems fair to predict that electricity production from conversion of ocean wave power will become commercially significant within this time frame. Much depends however on the choices that will be made by energy developers and governments going forward. These should see wave power as a promising emerging source of energy, and one that should be deployed in combination with other sources of energy. The technological advances resulting from RD&D (research, development & demonstration) work within this industry will have benefits not only for the wider marine renewables business, but also beyond that.

Commercialization of wave power will still need a long time to develop and mature, as is normally the case with any new technology in the field of energy supply and distribution. Small and mid-sized systems, initially not grid-connected, will need to be tested before installation of larger wave energy power plants. We must expect that along the way there will be disappointments and failures, and the final results might be significantly different from what we see today. Also, costs are likely to be higher than we calculate today. This has historically been the case with major technological developments, and wave power is unlikely to be different in this respect.

The technology development processes for capital intensive production systems are normally lengthy and expensive, and the homogeneous nature of electricity makes the chances of an early return on investments rather small.

Wave power development and testing at Fred Olsen

FO3 is the acronym for Fred Olsen's wave energy project. FO3 has been through a speedy and thorough development process. The development started in 2000 with concept design, basic modelling and 1:20 scale test in a wave tank.

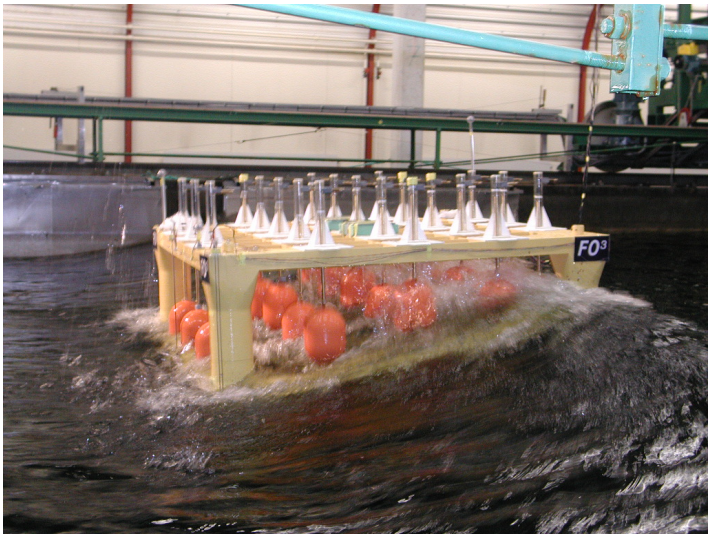

Figure 2: 1:20 scale test in wave tank

In 2004 the development continued with a 1:3 scale system test with power production in wave tank. The FO3 test system was based on multiple point absorbers on rods. The power take off system was hydraulic with a common motor/generator serving several producers.

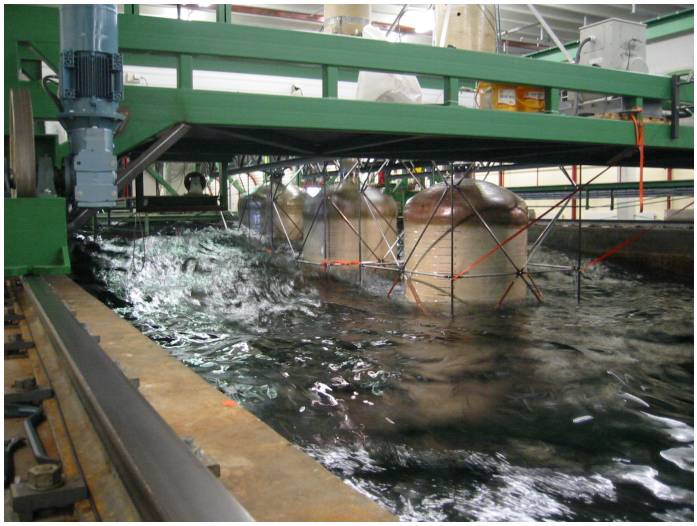

Figure 3: Point absorber 1:3 scale system wave tank testing

In 2005 the point absorber test system was moved to a small semi submersible platform, Buldra, to test the concept offshore. The offshore testing with Buldra has generated approx 2900 10-minute data sets. Each data set contains 61 channels where 10 channels are derived time series for velocities and accelerations for all point

absorbers in addition to calculated energy output and total pack box and bearing forces.

Figure 4: Platform Buldra at sea outside Jomfruland in Norway

An important part of the point absorber system development and testing at Fred Olsen has been to find an efficient way to regulate the point absorber damping force to achieve a high energy production. To get increased energy absorption from the waves it is important to achieve a phase shift between the wave position and absorber position. One technique to achieve this phase shift is called latching [5]. This technique includes latching (holding) the point absorber position until an incoming wave has submerged the absorber. When the absorber is submerged, the absorber is generating buoyant force to the power take off system. When this force reaches a preset value the absorber is released. Point absorber energy simulations shows that a point absorber control with latching technique shall be able to produce more energy then an absorber just following the waves. Latching techniques among other controls has been tested at Buldra.

The major findings and conclusions from the testing where as follows:

- Test platform Buldra survived severe sea states with waves above 9 meters, and proved itself a realistic concept for wave energy production.
- Latching techniques are demanding for the power take off system and difficult to control and optimize. The test did not prove significant power production gains with the latching used at Buldra.
- A portion of the available wave energy is lost due to the movements of the test platform. The capture ratio was lower than expected and did also decrease with higher wave states.
- An efficient point absorber power take off system requires a high efficiency on a broad band of wave frequencies and wave heights.
- On a platform with several point absorbers it would be beneficial to be able to control each point absorber individually. This would enable a more efficient system considering point absorber interactions, like shadow effects and diffraction.
- All in all, the lessons and experience from the tests have been significant for further development.

Figure 5: Pictures of the Løkstad test rig. Left picture: rig being put in position by test personnel. Right picture: plain side view of the rig in small waves.

In parallel with the test platform Buldra, Fred Olsen has also been doing wave energy testing on a land based test rig, at a test site named Løkstad. The Løkstad test rig is based on a single point absorber on rod system with both a hydraulic and an electric direct driven power take off system. The electric direct drive system allows damping with velocity and acceleration proportional damping force. This damping method gives less shock and stresses in the power take off system. It can also increase energy production through running the absorber towards resonance with the waves.

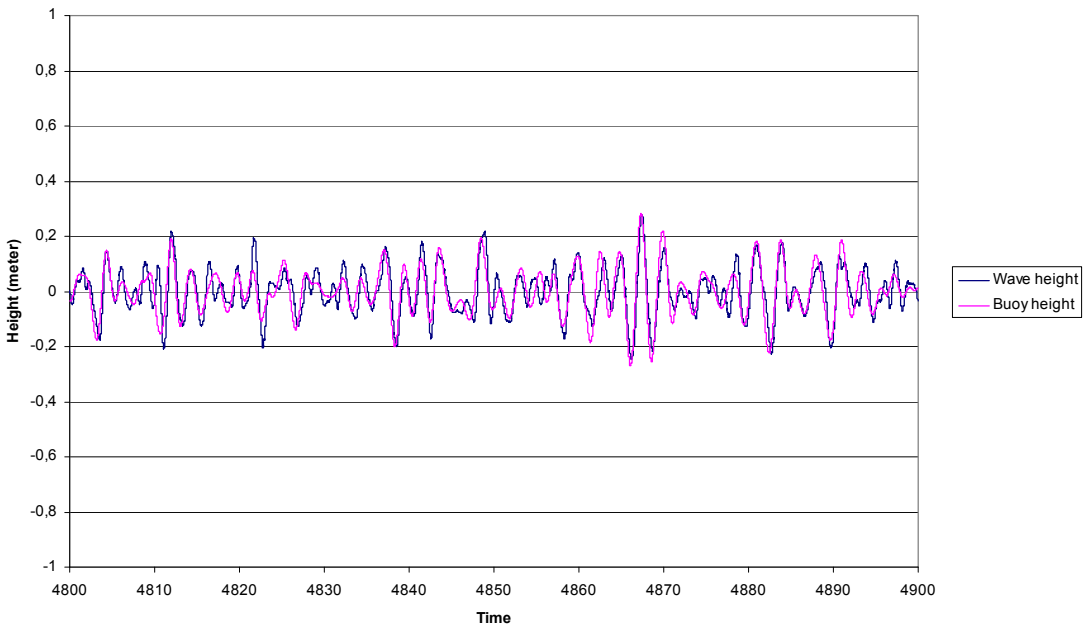

Figure 6: The plot shows a 100-second time series from a point absorber (buoy) test. The blue line shows the wave height and the pink line shows the buoy position. In some areas the buoy is traveling higher and deeper then the wave even though the point buoy travel is damped with a high damping force. The plot does not show a phase shift between the buoy and wave due to an offset between the wave sensor and point absorber.

Being smaller and providing easier access by personnel, the land based test rig has been subject to more updates and optimization work than Buldra test platform. This and other factors have made the Løkstad test rig more efficient than the Buldra take off system. The point absorber power take off system with acceleration control has shown signs of resonance effects, and high capture ratios.

Testing at the Løkstad test rig has been going on from 2006 to also include the summer of 2008. The major findings and experience from the testing are as follows:

- It is possible to reach high capture ratios for point absorber systems in irregular sea with sophisticated control.
- There is a correlation between theoretical wave energy models and energy produced on the rig. For more details about the used simulation model please consult the work of Ottar Skjervheim [2], Håvard Eidsmoen [3] and Bernt Sørby [4].
- The peak power production is up to 10-20 times higher than the average power production in an unlimited system. This is illustrated in the figure below.
- The smaller land based system is efficient for testing out various damping control techniques and power take-off components.

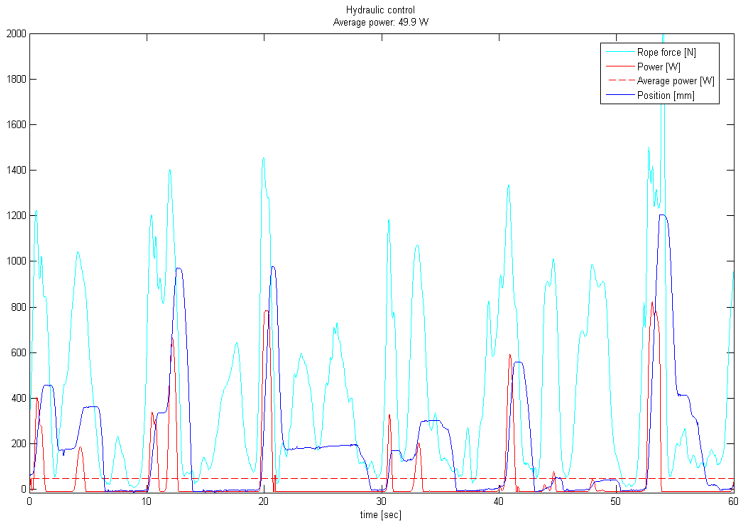

Figure 7: The plot shows a 60-second time series from a point absorber test. The dotted line shows the average power production. The red line is the power production, and the point absorber position is shown by the blue line. The point absorber position is scaled.

In parallel with the test activities described above, Fred Olsen has engineered a full scale platform at 36 by 36 meters in size and containing 21 point absorbers. This platform has been the subject of a pan-European research project supported by the EU 6th Framework Programme. Fred Olsen is the head partner of this research project called SEEWEC (Sustainable Economically Efficient Wave Energy Converter). The research project objective is to investigate the second generation wave energy platform and operational aspects related to wave energy production. The following picture shows an illustration of a potential future wave farm with the Fred Olsen platform.

Figure 8: Artistic illustration of a wave farm with four full scale platforms.

The challenge in the further development work at Fred Olsen is to implement, deploy and efficiently control an offshore system. The valuable experience from the test systems, the SEEWEC project and other development activities means Fred Olsen is well positioned to reach this objective.

Conclusion

Conversion of energy from ocean waves to electricity is one of the most promising sources of renewable energy that has not yet been commercialized. Although many competent groups of researchers are searching for it, no one has yet discovered the "holy grail" of wave energy. Clearly it is not easy to find. When it is found however, it will be a major contribution to world energy supply. Therefore we must continue searching and researching.

Wave energy development will still need time, and practical experience is vitally important to understand the challenges wave energy devices will need to meet. Theoretical models of the energy absorption potential for a point absorber show that significant amounts of energy can be absorbed, and test systems exist to prove the models. The main challenges involve designing effective controls and devices with components that can handle the harsh sea environment and the irregular nature of wave energy.

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Turbine design for small hydro versus large hydro

Hermod Brekke
Professor Emeritus, NTNU, Consultant, Litavegen 8, NO 7026, Trondheim, Norway
hermod.brekke@ntnu.no

Introduction

Norway has one of the smallest populations in Europa, but has the largest annual hydropower production of 120 TWh. Turbines for small hydropower stations have been traditionally made by small work shops. Later during development of the electric furnace industry and an increasing private consume, larger turbines were needed. A company, Kværner Brug, started around 1918 developing turbines with a workshop for production of large units using the laboratories established at the Norwegian University of Science and Technology (NTNU) for development of reliable high efficiency turbines. However, up to present time still numerous small manufacturers are producing small hydro normally from 50-100 kW up to around 5 000 kW.

Farmers are usually looking for the cheapest buy, often financed by local banks that are also interesting in the cheapest buy instead of buying reliable turbines with high efficiency. However, some farmers are buying more expensive high efficiency turbines which in the long run are the best economical choice as described later in this paper. Small hydro plants are often run of the river type, and impulse turbine types such as Pelton- and Turgo turbines are chosen for heads above 100 m.

For the lowest heads, reaction turbines like Kaplan Turbines, Bulb Turbines or S-Turbines could be chosen, but due to expensive double regulating systems, start-stop operation of 2-3 or more propeller type turbines are often chosen instead. For heads above 10 m, Francis turbines or simplified turbines with fixed guide vanes or pumps in reverse operation mode have been used.

In any case know how based on basic turbine theory and knowledge about structural design and material quality are required for a successful design also for small hydro and this knowledge is often missing for many of the cheapest turbine manufacturers. Further, efficiency tests are normally not made during commissioning of small turbines and even a simplified index test for verification of the relative efficiency that only requires a manometer with high resolution, are missing during commissioning of the units. As long as the rated power is achieved during flood with sufficient flow, the costumer is often satisfied, even if the efficiency is low and the power production is low at reduced flow in the river. An economic study of the loss in production caused by low efficiency is normally not made, but such analysis will be presented in this paper.

In addition to loss of production, brake down of the units is now and then reported, caused by broken buckets on Pelton turbines or cracked blades in reaction turbines. Sometimes stationary parts are also damaged by cavitation or fractures. Further the knowledge on pressure surges affected by the turbine characteristics is missing by many small turbine manufacturers and fractured pipes have also been reported. The development and choice of machinery for small hydro are discussed this paper. Sand erosion is a serious problem in countries in Asia and South America. An interesting test made at the Norwegian University of Science and Technology (NTNU) on flow analysis and sand separation will be presented. The test is proving that small hydro turbines and also larger units at low load may be seriously damaged even with a small sand content in the water.

Historical background in Norway

Small hydro in Norway can be traced back more than 1000 years where flour mills were driven by water wheels and built by local carpenters and black smiths and sometimes by the farmer himself who owned and operated the mill. Later also saw mills were built and operated by the owners. The Water wheels were in principle impulse turbines driven by the water velocity in open flumes where additional speed from increased pressure could not be utilized and then the head was limited to steps of about 5 m. In figure 1 the arrangement of a system of such mills is illustrated.

Figure 1: Water driven flour mills in cascade. (Restored old flour mills.)

When the electric power was developed, many small hydropower plants were built with turbines from many small hydro turbine manufacturers in Norway and other countries in Europe and the heads were now increased to the allowable penstock pressure allowing for heads of more than 100 m. Still the owners were farmers and small communities utilizing the waterpower for small industry and also saw mills and flour mills. The power of each hydropower plant was still small and the reservoirs were also small with a reduced production in winter time.

As late as 1943, 2000 small hydropower stations were in operation in Norway. Of the total installed number of turbines 73% was smaller than 100 kW and only 2.2% of the units were larger than 10 000 kW, but these large units produced 73% of the hydropower energy. Later, after World War II, the boom in hydropower started and from 1945 to around 1995 the total hydropower installation increased from about 3000 MW to around 28 000 MW, with an annual power production of about 115 TWh in years with normal rain and snow fall. The strong resistance from the environmentalists against building dams and reservoirs almost stopped the development of large projects in Norway after 1995.

Figure 2: Scenery in a Norwegian Fjord suitable for small hydro power projects as additional income for the owners of small farmers.

However, small hydro power units in run of the river projects have been accepted in general and a boom of projects owned by farmers or a group of farmers has grown up. An advantage of this development is that the owners are small farmers who cannot get an income sufficient for a family, without another income besides farming. Thus small hydro development may save the nice scenery in the Norwegian fjords with small farms up in the steep mountains or at the bottom of the mountains that drops down from around 1000 m to the fjords. This is because small hydro power plants of 500-5000 kW will not be visible when the buried small penstocks are hidden by grown up bushes within 10-15 years.

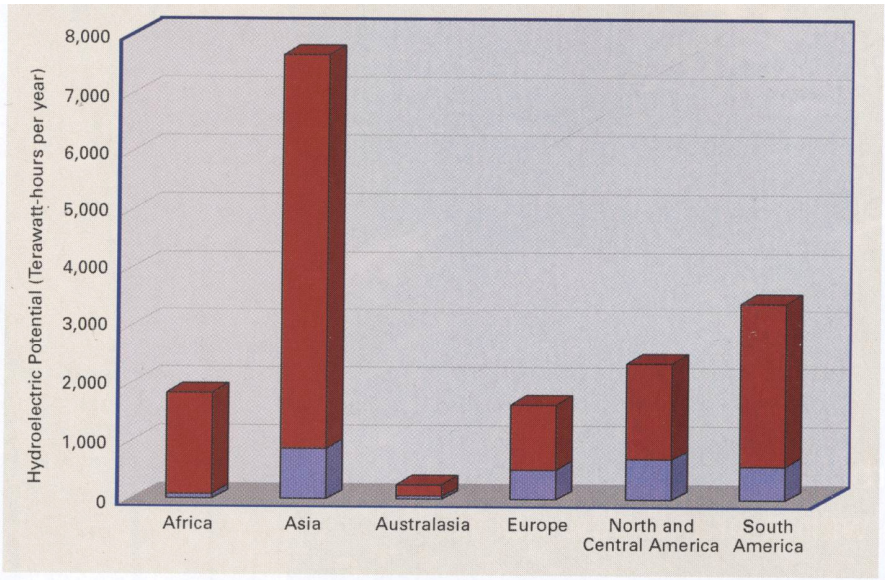
In figure 2 typical scenery of a Norwegian fjord is shown with possibility for many small hydro plants. In the fjords in Western Norway there is a capacity of about 15 TWh from economical feasible small hydropower plants, suitable for economical development. However, this paper is focusing on the choice of equipment for small hydro and possible general problems valid also for large units such as fatigue, safety, life time and erosion. Environmental problems will not be discussed.

The market for small turbines

This chapter describes the hydropower market aimed at owners of small rivers and streams with relatively high head, suitable for developing small hydro. The owners are often farmers with little or no knowledge about hydropower. On the sellers side of small hydropower equipment the situation is as described in the following:

- Many different companies are producing turbines with a wide range of price and quality.
- Cheap turbines are offered, but often with low efficiency and low reliability and references or documentation of efficiency. Several break downs have also been reported of such turbines.(Broken Pelton buckets, not fulfilling guaranteed power, vibrations and noise and leaking valves after short time in operation etc.)

- Also broken penstocks have been reported, caused by incorrect fitted joints or water hammer problems due to lack of knowledge about calculation of pressure oscillation.
- The owners are often using cheap local consultants with little or no experience in turbine design. A thorough analysis of turbine efficiency versus price of the mechanical equipment is often missing.
- Manufacturers of large turbines with experienced engineers, or small turbine manufacturers with skilled staff and high technical standard, are often expensive and are not recommended by the local consultants.
- Local banks that are financing small hydropower projects are also often in favour of the cheapest buy, and do not evaluate price versus loss in production caused by low efficiency.



Worldwide, the technically feasible undeveloped hydroelectric potential (red) is highest in Asia, South America, and Africa. The developed quantity of each region is shown in blue.

Figure 3: Worldwide undeveloped hydropower. On this market small turbine will be built especially on the country side in developing countries in order to supply remote areas with electricity.(HRW Volume 15, Nov 2007/Ref. 1/

The largest technical feasible undeveloped hydro power worldwide we find in Asia, South America and Africa. /Chris Head**, Ref. 1**/. A large part of this potential is located in remote areas with spread population and not fully developed infrastructure with available power lines. Then small hydro will be the best choice for needed electric power for villages and farmers. In such case it is important to establish a reliable system with reliable machinery.

During my work as professor in hydraulic machinery at the Norwegian University of Science and Technology (NTNU), I received many calls from owners of small hydro power plants due to break down of equipment or reduced power production caused by bad performance of the installed equipment. Further problems with erosion from filthy water have been reported especially from foreign countries. Some examples of these problems will be discussed in the following chapters in this paper.

Basic turbine design

Reaction turbines

In the following, examples of possible simplifications of the large complex high efficiency turbines will be given:

Large Francis turbines are very complex, but with an efficiency exceeding 95% for high head turbines (H > 350 m) and 96% for medium and low head turbines (75m<H< 150m). For outputs below or around 50 MW, simplified design has been made in order to reduce production cost. In figure 4 an example of a simplified large high efficiency Francis turbine is shown.

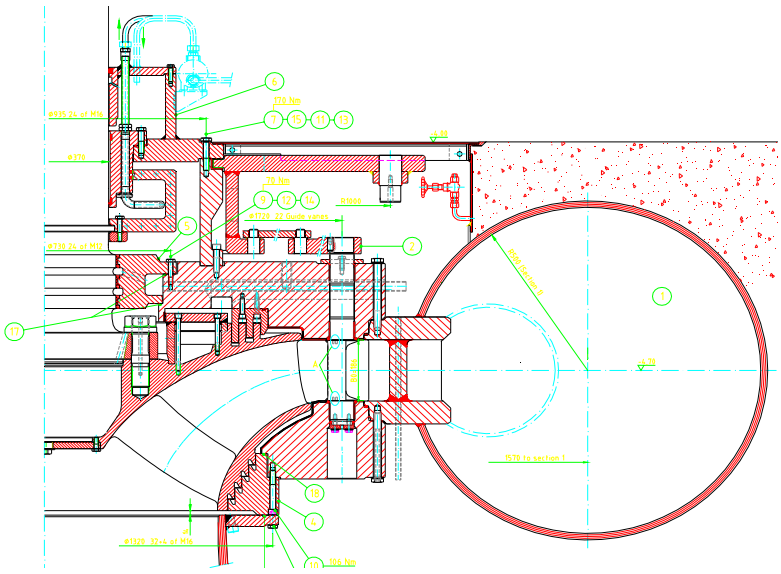


Figure 4: Simplified design of a Francis turbine to save work hours. (Courtesy Kvaerner Hydro.)

For small hydro further simplifications have been made by removing the regulating ring, using the generator bearing as turbine bearing and simplifying the spiral casing by reducing the number of sections. However, some efficiency has been lost in this process, but the costumers are often looking more at the price than on the efficiency and this fact is governing the market at present time. In figure 5 is shown a simplified small Francis turbine, suitable for outputs 1-15 MW depending on head.

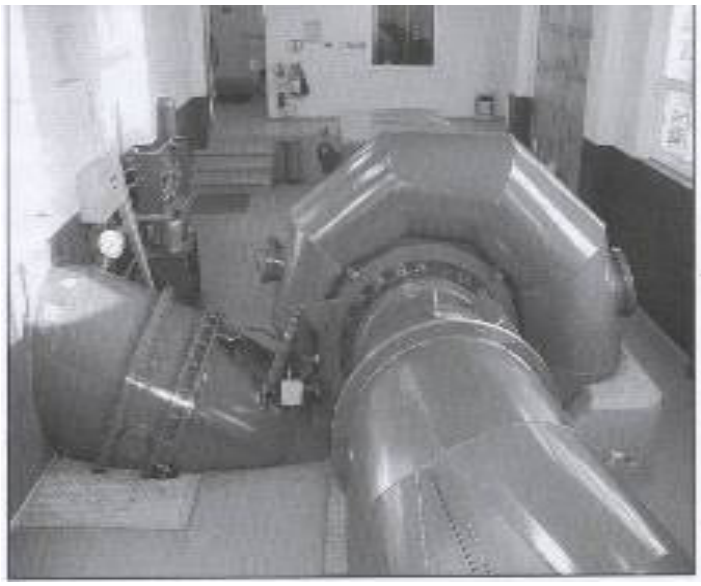


Figure 5: A Francis turbine in a small hydropower plant.

Experience in turbine design is required, especially for high specific speed Francis turbines and axial turbines, and the costumer should be warned about low price turbines from manufacturers without references from successful design. Several reports of unsuccessful operation of cheap reaction turbines exist as a warning. Low price cannot substitute for quality in the long run.

Of axial turbines the S-shape turbines represent a typical design normally used for small hydro. In order to limit the size of this paper a description of this turbine type is not given.

Another possibility, for a cheap installation in a small run of the river hydro plants, is to install 3 standard pumps for reverse operation. In this case the smallest unit should have a capacity of approximately 1/7 of the maximum flow, the second 2/7, and the third 4/7 of the total capacity. Then the run of the river can be utilized in steps of ($Q_{max}/7$) as illustrated in figure 6.

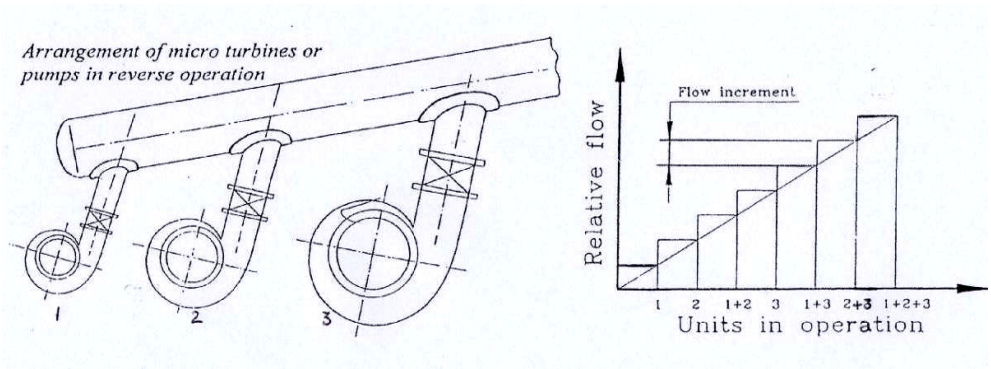


Figure 6: Three pumps in reverse operation for on-off control of the flow in a run of the river plant.

However, it is important to have the knowledge about pump theory and turbine theory because the operating point of a pump in turbine mode has a lower head than the pumping head. Expertise is needed to calculate the optimum operation point of a pump in turbine mode. Further, only low specific speed centrifugal pumps without wing profiled blades should be used and the blades at the pump impeller inlet and outlet should be

reshaped for turbine operation. Reports also show that not successful pumps in reversed operation have been installed. By installing unsuitable pumps or pumps operating at incorrect head, a cheap buy of pumps for turbine operation may give a bad economically result.

Impulse turbines

Impulse turbines such as Pelton turbines and Turgo turbines are suitable for high head installations. The Turgo turbine is an axial flow version of a Pelton turbine with a possible efficiency on the same level as for a Pelton turbine. The Cross Flow turbines are normally designed for lower heads and for small hydro only. The advantage of this turbine type is a low price, but the draw back is a low efficiency. Even if the water level in the outlet pipe has been lifted up to be close to the runner by a vacuum arrangement, the efficiency will not be higher than around 75%. This was proven by tests made during a student work at the Waterpower laboratory at NTNU 50 years ago and also at a test later at the Laboratory at EPEL-LMH Lausanne according to verbal contact between the author and Professor Avellan at EPEL in Switzerland.

The reason for this may be found in splashing and incorrect directed flow across the runner in a mixture of water and air. However, the cost for producing Cross flow turbines is low and if such turbines have been installed in rivers using only a small part of the total flow with no limitation, only the capacity of the turbine will be the limitation for power. But in small streams where the power production is depending on a restricted flow with claims of bypassed water flow, the loss of production due to low efficiency will not make the buy of turbines with low efficiency economical.

Large multi nozzle Pelton turbines have proven efficiencies exceeding 92% and model turbines operated at 100-200 m net head have proven efficiencies close to 93%. The droplet circulation in the turbine casing of Pelton turbines increases with the head and size, and this fact may explain the reason for a negative scale effect from model to prototype for Pelton turbines probably caused by increased windage loss.

However, small cheap Pelton turbines are often made by local manufacturers with little experience and theoretical background on Pelton turbine design.

The reason for numerous manufacturers of low efficiency Pelton turbines, may be found in the fact that the principle of Pelton turbines is very simple. However, the flow analysis of Pelton turbines is a most complex task compared with the analysis of other turbine types.

The weak part in a not successful design may be found in one or all of the following points

- The jet. (Skew velocity profile or rotating flow towards the nozzles)
- The buckets. (Bad shape creating large outlet losses and creating outlet water hitting the next jet in a vertical multi jet turbine)
- The turbine casing. (Incorrect shape creating outlet water plashing back onto the runner.)

In figure 7 is shown an example of a design of a small vertical Pelton turbine with sharp corners in the inflow bifurcations and sharp bends from the main ring formed conduit. Such design gives a simple cheap turbine, but the general rule that “bends in two planes will create swirl flow and should be avoided”, has also been broken in this case. The reason is that a swirl flow towards the nozzles creates spreading of the jets which gives a poor efficiency and may create pitting in the buckets and on the nozzles.

Figure 7: An unfavourable design of a small vertical Pelton turbine with sharp bifurcations changing flow direction creating swirl flow.

However, lost production caused by poor efficiency makes a cheap buy expensive. By making over dimensioned nozzles the guaranteed power is normally achieved, but the production in the low flow period where all available water is used, will be reduced.

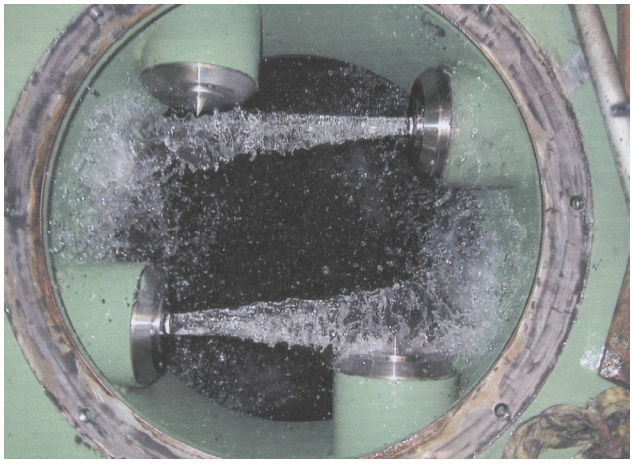


Figure 8: Jet test with two jets in a turbine with skewed velocity profiles and swirl flow in front of the nozzles.

In fig. 8 is shown the jets of a vertical Pelton turbine with bad inflow towards the nozzles creating split jets and a low efficiency. In figure 9 is illustrated erosion pitting on the nozzles of a multi jet Pelton turbine. Such pitting proves bad velocity profile in the jets and/or bad shape of the buckets creating high speed water passing through the runner.

A general additional error in the design of Pelton turbines is obstructions for the outlet water from the runner leading to water splashing reaching the runner and thus making an obstruction for the outlet water. This problem is increasing with increasing operational head and is also a reason for a lower efficiency of the prototype than of the model turbine also for well designed turbines. The reason can be found in the difference in operating head of models which is normally 100 –

However, a parameterized turbine built on standardized parts gives contribution to a reduced price even if the cost will be higher than for the examples shown in fig. 7, 8 and 9. 200 m compared to the operating at head of the prototype of 700-1200 or higher which increases the water droplet circulation.

Figure 9: Droplet pitting on the nozzles of a Pelton turbine caused by incorrect design. This turbine design is different from the design in fig 7 and fig. 8.

An optimum design of a small Pelton turbine must be based on the same principle as used for large turbines.

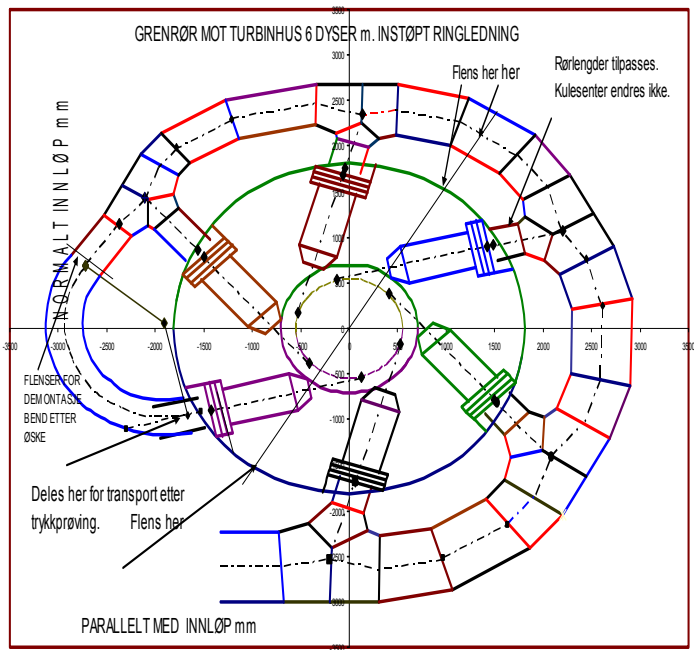


Figure 10: Manifold and injectors for a small medium size Pelton turbine designed for high efficiency .(Courtesy: BREKKE TURBINES: ENERGI-TEKNIKK LTD)

In the turbine shown in fig. 10 the inflow conditions towards the nozzles is good and reduces rotation and skew velocity profiles which leads to a uniform jet.

Evaluation of efficiency

An analysis of the influence from the efficiency on the economy for a small run of the river project is illustrated in figure 11, where a typical shape of the flow-duration curve for a stream in a Norwegian fjord has been used. The additional income for an efficiency difference of 3% will make the best choice to buy a more expensive turbine even if the turbine price is double in some cases. Such evaluation is depending on the price of electricity and the interest for the loan in the bank. In addition to the evaluation of the efficiency, the reliability and life time of the turbines should be studied.

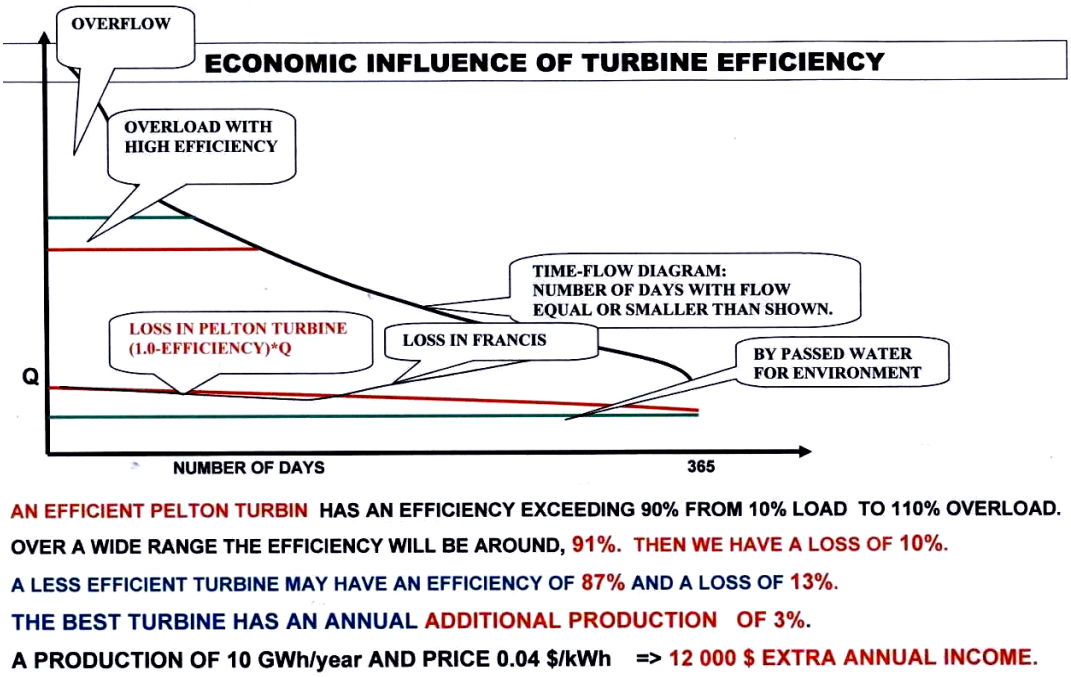


Figure 11: An economic analysis proves the advantage of buying a high efficiency multi-jet turbine for a typical run of the river project

Reliability and life time

Fatigue problems

In addition to pitting and low efficiency, fatigue problems may also occur. The basic theory of high cycle fatigue problems is based on material tests and stress analyses of the Pelton buckets with pulsating load from the jets, and similar analyses on reaction turbines where high cycle stress amplitudes on the blades are caused by the blade passing pressure pulsations and draft tube surges. However, some small turbine manufacturers do not have the necessary knowledge of this basic theory. Then fractures may occur and a low price cannot substitute for a brake down of a turbine runner.

From material tests the well known **Paris Law** has been established for high cycle fatigue. Further a threshold value of the stress intensity factor $=\Delta K_{th}$ where no crack propagation occurs, has been found. Based on the material tests made by Sulzer and presented by Dr. Herbert Grain **/Ref 2/**, the value $\Delta K_{th}=72$ (N $mm^{-3/2}$) for $R=(\sigma_{min}/\sigma_{max})=0.5$ has been proven for a 13.4 CrNi cast steel. (The equation for the threshold value yields: $\Delta K_{th}=(\sigma_{max}-\sigma_{min})_{th}\sqrt{a_{th}}*\Theta$.

(Here Θ is the geometry constant which is found to be $\Theta=1.25$ at the root of a Pelton bucket.**/Ref 2/).**

The depth of a defect =$\mathbf{a_{th}}$ that will not grow with cyclic stresses $\Delta\sigma_{th}=(\sigma_{max}-\sigma_{min})_{th}=45$ N/mm^2, will then be **1.64 mm** according to **/Ref 2/** with a length of **3.28 mm** for a surface crack. The corresponding value for a sub-surface crack will be and **3.28x3.28** mm.

Also in Francis turbines blade cracking may occur. The reason for this is high cycle pressure pulses on the runner blades passing of the wakes behind the guide vanes and residual stresses from welding or unfavourable geometry of the runner. Cracking of short bolts of high strength class, have also occurred in runners and in places affected by high frequency pressure pulsations from rotating parts and also in low cycle pressure loaded parts.

A thorough knowledge of material qualities and fatigue theory is required and not all manufacturers of small hydro have this knowledge. This is because an official quality insurance system is not always applied for small hydro. A rupture in a small hydro plant will be a big accident, but normally not a catastrophe as for a large hydropower plant and this is the main reason for a more strict control of large hydro turbines. **/H. Brekke Ref. 3**/

Cavitation and sand erosion

Cavitation

Also for small hydro incorrect design leads to cavitation pitting both for Impulse turbines and Reaction turbines even if the specific speed is moderate versus operational head. Because it is possible to build these turbines free of cavitation, no measurable pitting depth at all should be allowed in the guarantee for small hydro turbines. This is because the small thickness of the blades and buckets does not allow for measurable pitting depths as described in the IEC standards.

Sand erosion problems, a study of sand separation, flow analysis and experiments

It should also be noted that sand erosion will increase with decreasing radii of the curvature of blades or buckets i.e. small hydro turbines will then get more severe erosion than large hydro turbines operating at the same head.

The reason for this statement can be found by studying the balance between the centrifugal forces in outward direction driven by the tangential flow component and the drag force affected by the radial component of the flow velocity in direction towards the centre of the turbine.

The centrifugal force in outwards direction yields:

$$F_c= (\rho_{st}-\rho_w)* (\pi*d^3/6)*C_u^2/R$$

Here ρ_{st}=density of stone, ρ_w= density of water, **d** = diameter of a spherical stone, C_u= tangential flow velocity component and **R**=radius of runner inlet.

The equation for the drag force yields:

$$Fd= CD*\rho w*(\pi d2/4)*Cu2/2$$

The sand grains equal to or bigger than the diameter, found by combining the two equations, will rotate between runner and guide vanes until the sand grains are crushed by numerous collisions with the guide vanes and then the smaller parts are flushed through the runner. /Brekke **Ref.4**/

The critical diameter = **d** of a sand grain that will not go through the runner yields:

$$d=3/4CD(\rho w/(\rho st-\rho w))(Cw/Cu)2R=Cd(\rho w/(\rho st-\rho w)TAN2(\alpha)R$$

The drag coefficient C_D in the cross flow where $\alpha=(C_w/C_u)$ = flow angle from the guide vanes, was found during a research work made at the Norwegian University of Science and Technology (NTNU) by a PhD student Bhola Thapa from Nepal during the authors last years as professor guiding PhD students in 2002. /Bhola Thapa **Ref. 5**/

In figure 12 an illustration is given of the forces acting on a particle in the swirl flow towards the runner inlet in a Francis turbine.

In order to make a thoroughly study on the forces acting on the sand grains at the runner inlet in a Francis turbines, a test rig was built at NTNU in 2002.

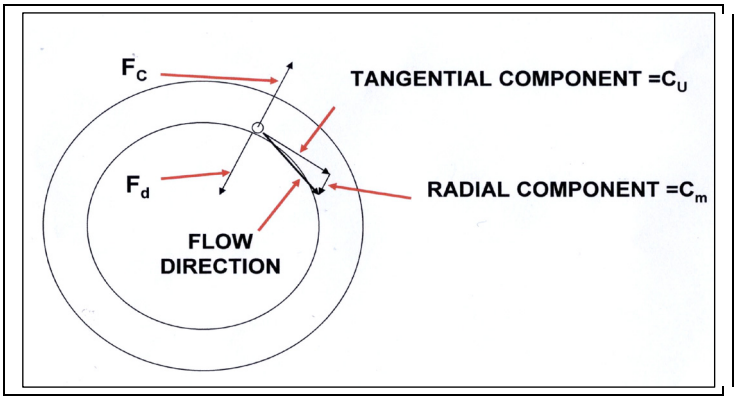


Figure 12: Illustration of the forces on a sand particle in the swirl flow from the guide vanes towards the runner.

The test rig for the study of sand separation consisted of a cylinder with a vane cascade creating a rotational flow in a spiral towards a centre hole. Sand particles and spherical glass balls and steel balls were fed into the rotating flow field. The particles in question were circling in radii (orbits) depending on the density and the size (diameter) of the particle. Different particle shapes were also tested, but the volume was transferred into diameters depending on the volume. Except for shapes very different from spheres, the differences from the behaviour of spheres were small. The particle paths were traced by means of a high speed camera. In figure 13 the test rig is shown with a sand particle.

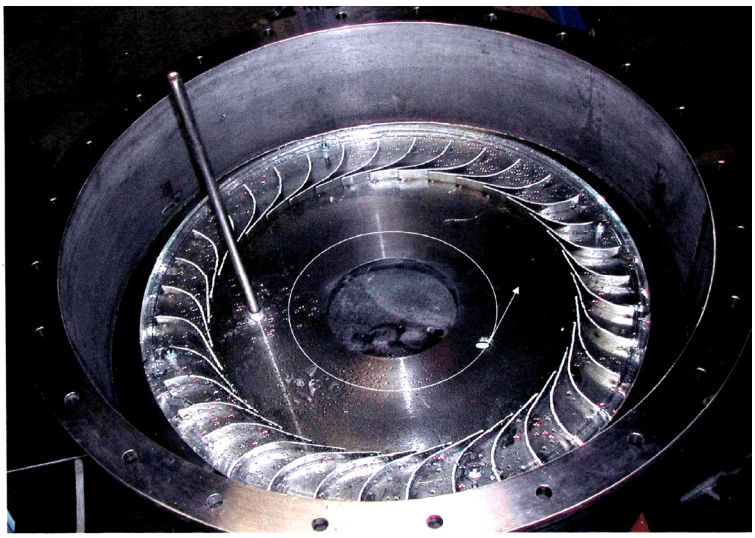


Figure 13: The test rig with a particle in rotation observed by means of a high speed camera.

The drag force coefficient found experimentally for the cross flow in the test rig, showed very good agreement with the drag force found in the literature for parallel flow..

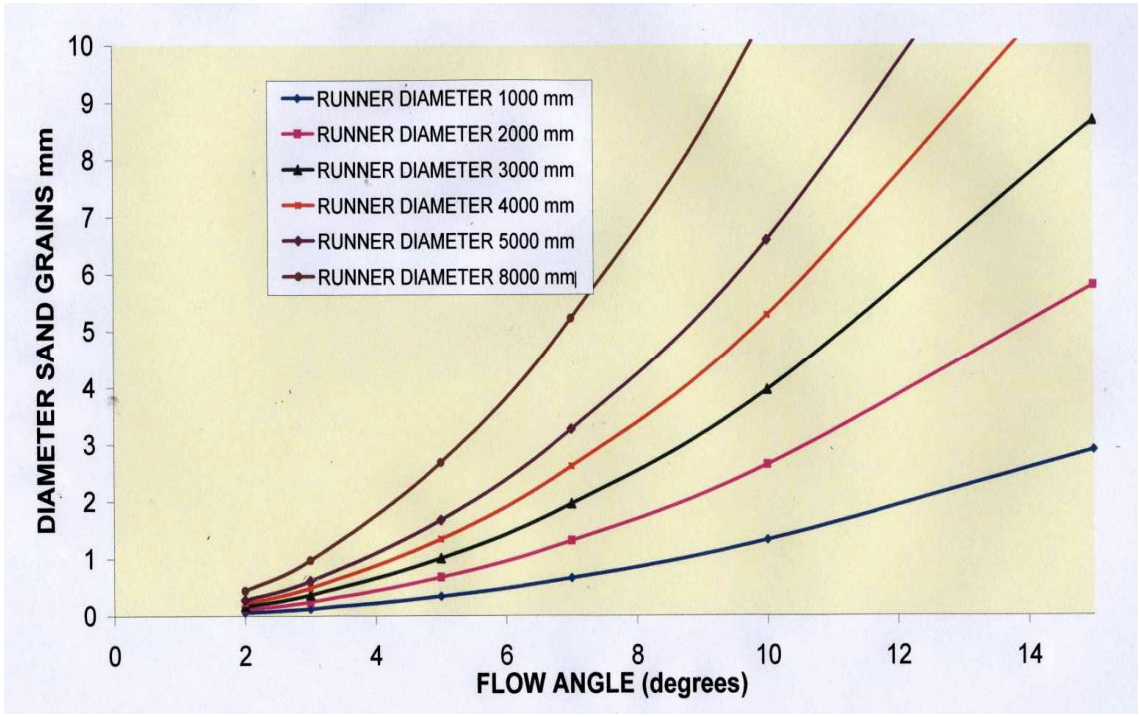


Figure 14: Grain size diameter (d) versus flow angle (α≈guide vane angle) as function of runner diameter. Result from test rig experiments. The drag coefficient was found to be C_D=0.1 during the test. (Test rig shown in figure13.)

In figure 14 the test result is illustrated by means if the a diagram showing the diameter of the smallest sand grain that will rotate outside the runner inlet of a Francis turbine as function of the flow angle with the runner diameter used as parameter. It is clearly demonstrated that the sizes of sand grains that will rotate outside the runner inlet, will be proportional to the runner diameter. Thus in small hydro turbines at low load, all sand grains with diameters down to a size 0.1 mm at a guide vane angle of 4° will not pass through the runner before they are crushed to dust after having given a contribution to the sand erosion on the guide vanes and runner inlet.

An indication of the influence of the flow direction can be found by studying the difference in flow angle from the guide vane cascade towards the runner between the crown and the band. It has been proven by CFD analysis and measurements in models that the meridian component is much larger at the band than at the crown in traditional high specific speed runners caused by the curvature of band and crown. Then silt will stay in rotation on the crown side between the runner and the guide vanes especially at low load of low head turbines of traditional design.

In figure 15 is shown severe sand erosion on the guide vanes, in a high specific speed turbine.

The sand erosion of the turbine in question was observed at Unit II at the Fourth Stage Power station on the **Mao Tiao He River** in China /Li Xue-Zong **Ref 6**/. The turbine had been in operation in 5000 hours often at part load and also in synchronous condenser operation and no other parts of the turbine had been damaged. This indicates that relatively fine grain sand and silt were trapped by the small inwards directed drag force compared to the centrifugal force in the upper region of the guide vanes near the crown.

At very low load and no load, also outward flow might have occurred near the crown. (See figure 15 Right.)

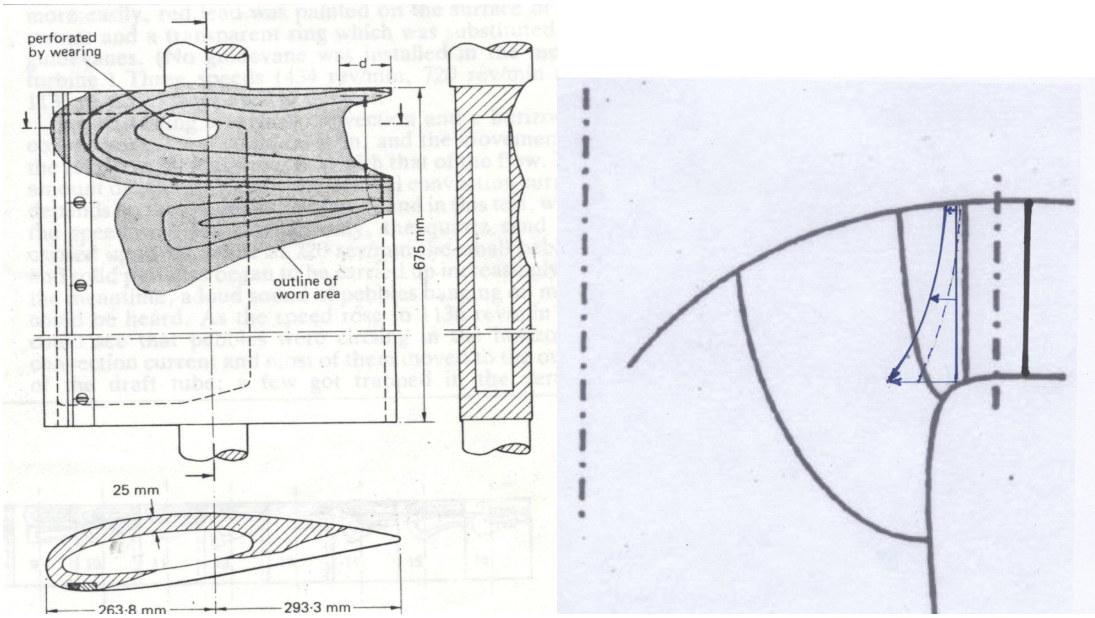


Figure 15: Left: Severe sand erosion on guide vanes of a high specific speed runner /Ref. 6/.Right: Schematic illustration of radial velocity distribution at runner inlet of a high specific speed runner with traditional design at full load (full line) and at part load.(dotted line).

It should be noted that a properly made X-Blade runner, like the runners for Three Gorges Power Plant, will increase the inward flow velocity near the crown of the runner and thus reduce the sand erosion.

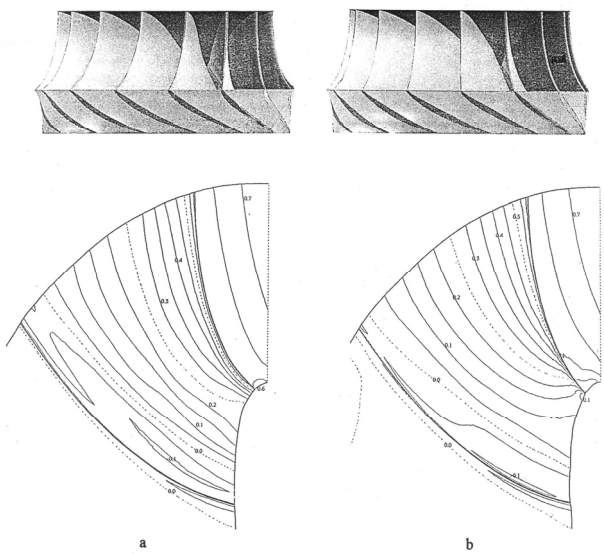


Figure 16: Illustration of the difference in the pressure distribution at the band near the blade inlet of a X-Blade runner (left) compared with a traditional runner (right).

It should also be noted that the aim of the design of the so called X-BLADE runners for Three Gorges in China designed at KVAERNER HYDRO (based on the idea of the author in 1995), was to increase the pressure on the runner at the band in order to reduce the meridian velocity. This was obtained by introducing a negative blade lean at the inlet of the blades and balancing the blade lean angle towards the outlet of the blades. Then the difference in the radial flow component between the band and the crown would be reduced and the sand erosion would be decreased. However, the main purpose of this design was to obtain a stable operation at part load with reduced pressure pulsations and highest possible efficiency.

Sand erosion in Pelton turbines

In Pelton turbines all sand grains will pass through the turbine so re-circulation of sand as described at the inlet of Francis runners does not occur. However, because of the high velocities, sand erosion has been observed on the needles in Pelton turbines probably caused by the turbulence in the boundary layers making very fine grain silt “to dance with the turbulence movements” and thus create fine ring formed groves on needles.

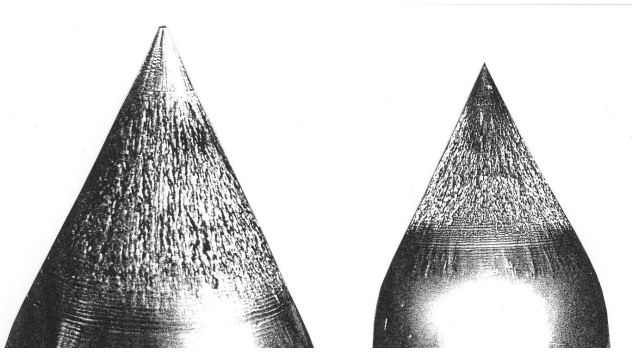


Figure 17: Sand eroded ring formed groves on the needle tips at Mel Power Plant in Norway causing severe damaged by cavitation.

At Mel Power plant in Norway fine concentric ring groves were caused by hard fine grain silt where 98.8%, was smaller than 0.125 mm and 90% was smaller than 0.060 mm. These circular rings then caused cavitation damage on the needle tips as shown in figure 17 after 600-700 hours in operation. This damage occurred when the reservoir downstream of a glacier was drained down the first year in operation causing silt laden water for the turbine.

However, also the buckets in a Pelton turbine will be damaged by sand, but in the buckets, coarse sand is more destructive than fine silt. The reason for this is that even if the centrifugal force is very high in the bucket flow, the drag force on silt is also high and most of silt grains do not to reach the steel surface in the short period of time before the water has passed the buckets.

In a high head large Pelton bucket the acceleration may be as high as 2500 g or 25 000 m/s^2. However, in a small Pelton turbines of size 1/5 of the large turbine and operating at the same head the acceleration will be 5 times higher i.e. 12500 g or 125 000 m/s^2 and then more silt will hit the surface in the buckets in small turbines than in large turbines. This means that a sand grain of 1.0 gram will be pushed against the surface with 5 times the pressure that occurs in a large turbine in the first touch on the surface. Further a smaller hydraulic radius is causing more sand in contact to the surface./**Ref. 4**/.

Figure 18. Sand eroded Pelton buckets from a small turbine in Nepal. High acceleration causes severe destruction.

Control of water hammer pressure surges

The knowledge of analysis of water hammer pressure surges is vital during commissioning of small turbines connected to long penstocks. This is to avoid dangerous pressure shocks that may cause ruptures of pipes and in worst cases turbine parts inside the powerhouse. The fast increasing rotational, speed during shut down of low specific speed Francis turbines connected to generators with small inertia masses, also increases water the hammer pressure peaks in the penstock. Knowledge about this problem is vital for the turbine manufacturer. However, some small turbine manufacturers do not have qualifications in this field and that may lead to dangerous ruptures of penstocks and turbines.

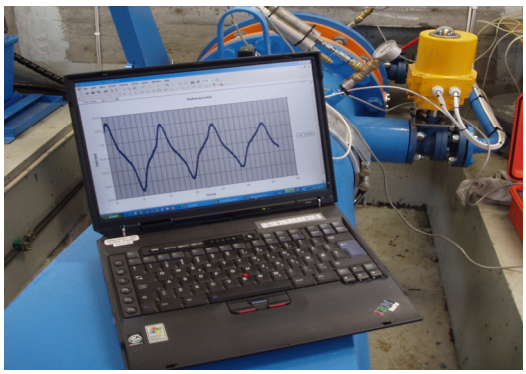


Figure 19: Recording of pressure oscillation by closing a bypass valve in order to find the reflection time=2L/a.

The closing time must be determined based on water hammer analyses as follows. From a registration as shown in figure19, the wave speed of the pressure waves in the penstock can be found using the time from bottom to top of the pressure oscillations =Δ**T=2L/a**. When the length of the penstock**=L,** is known the average wave speed **=a** can be found. Then the closing time of needles in a Pelton turbine can be found based on the guaranteed pressure rise =Δ**H=a**Δ**C/g** where Δ**C** is the water velocity reduction during the time Δ**T=2L/a**. If the full load velocity = **C,** the closing time will be $\mathbf{T_{cl}}$**=**Δ**T*C/**Δ**C**. In addition nonlinearity of the closing history of the needles for Pelton turbines or the guide vanes including the influence of the runaway speed for Francis turbines must be taken into consideration.

Conclusion

The same knowledge is needed for buying and producing small hydro as for large turbines.

First of all simplification of a turbine design without loosing efficiency requires a thoroughly knowledge of hydraulic design of both impulse turbines and reaction turbines. A thoroughly knowledge of structural design and fracture mechanic theory is also needed for the safety.

The mechanism of sand erosion and the influence from the curvatures must be known. Attention should be paid on the smaller radii of small turbines which increase sand erosion which is of importance for the life time that may be short for small units. Finally the background of water hammer in the conduit system and its influence on the governing stability is required also for small turbines especially when operation on isolated grid is required.

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Geothermal energy and ground source heat

Arne Bjørlykke and Christophe Pascal
Geological Survey of Norway (NGU), 7491 Trondheim, Norway

Introduction

Determination of the thermal state in the crust/lithosphere has a wide range of applications spanning from the use of geothermal energy to estimation of maturation conditions of hydrocarbons in the subsurface or characterisation of the quality of the natural reservoirs hosting them. In addition to these economic and societal aspects, geothermal research has a strong academic potential on fundamental issues related to Earth dynamics including tectonic deformation and climate change.

Geothermal energy comes from the decay of naturally occurring radioactive isotopes of uranium, thorium and potassium. On continents, half of the heat flowing to the surface originates in the crust, the second half in the deep mantle (i.e. below ~40 km depth). In a normal granitic rock the three radiogenic elements are contributing with approximately one third of the energy each. The average continental heat flow to the surface is 60 mW m^{-2} ± 20 depending on rock composition and to a lesser extent on rock age. The temperature at the surface of the Earth is therefore dominated by heat from the sun and the temperature of the uppermost 10s of meters of the ground is approximately the yearly temperature average. Typical thermal gradients for continental crust generally range between 20 and 40˚C km^{-1}, the lowest values being associated with basement rocks with relatively high thermal conductivities whereas the highest ones are most often observed in sediments with low thermal conductivities. Therefore thermal gradients can vary from 20˚C km^{-1} in the 12 km deep borehole on the Kola Peninsula, 30-40˚C km^{-1} in the mid-Norwegian continental shelf and up to 100˚C km^{-1} beneath the Kravla volcano in Iceland.

The energy technology is dependent on the temperature of your energy source. The use of ground source heat requires heat pump technology. The increased demand for cooling of houses and offices has opened a new market for heat pumps and the possibility for storage of energy from the summer season to the winter.

Temperatures in hot springs and deep boreholes down to 2 and 3 km reach 40 to 100˚C: heat energy that can be used to heat homes, greenhouses and other buildings. In Denmark there are10 large projects of this kind in operation, one providing hot water for parts of Copenhagen.

Energy sources with temperatures above 100˚C can also be used for production of electricity and hydrogen. Such high heat anomalies can be found along tectonic plate boundaries due to vertical heat transport by magmas and the convection of water. Spreading ridges like on Iceland are particularly interesting as geothermal energy sources.

Ground source (Geothermal) heat pumps (GHP)

Ground source heat pumping is one of the fastest growing ways of utilising renewable energy, with an annual increase of 10 % (Lund et al., 2008). Sweden is a global leader with 350,000 units installed with a total output of 12 TWh per year, exceeded only by the output of GHP technology in the US. Norway has 15 000 units in operation with a collective output of 1.5 TWh per year. The two largest systems for extracting heat from the ground using boreholes in Europe, are located in Norway (Midtømme et al., 2008).

The average yearly temperature is the most important factor for heat production. The local heat production in the rock has a minimal influence and the variation of the thermal conductivity in different rock types is also of restricted importance. Locally groundwater flow may play an important role for the heat capacity and the thickness of the overburden is of economic significance during the drilling face (Slagstad et al, 2008).

An energy well in bedrock with a closed collector is the most common form of ground source heat extraction. Usually these systems consist of a 100-250 m deep borehole containing a plastic collector hose filled with anti-freeze liquid (Gehlin, 2002; Ramstad & Midtømme, 2008).

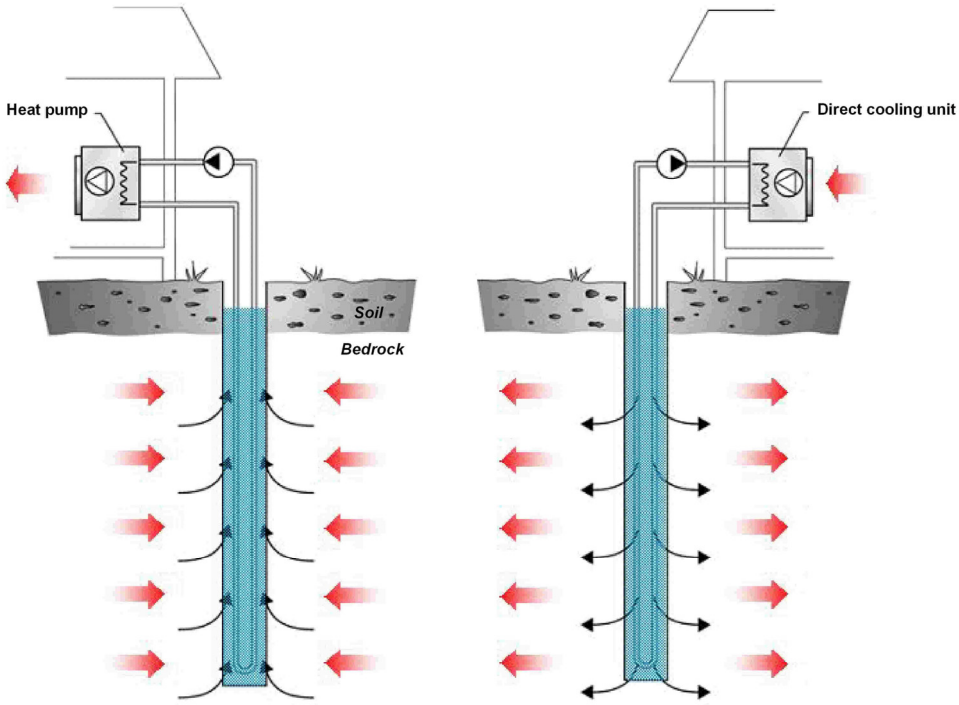

Figure 1: (Gehlin, 2002)

The ground may also be used for storage of heat, contributing to the cooling of buildings in the summer and heating in the winter; a technology called "Underground Thermal Energy Storage (UTES) "(Midtømme et al., 2008). Both boreholes in bedrock and groundwater aquifers can be used for UTES. Norway's largest bedrock-based UTES installation is in operation at Akershus University Hospital near Oslo where 220 boreholes penetrate bedrock to a depth of 200 m. An additional 150 boreholes are planned. The expected payback time for this investment is approximately 12 years dependent on future fluctuations in the cost of energy.

The largest groundwater based UTES in Norway is at Oslos Gardermoen International Airport. The system has been in operation since 1998 and comprises an 8 MW heat pump array coupled to 18 wells of 45 m depth, 9 for extraction of groundwater and 9 for re-injection. The system covers the total need for cooling of the airport and offers a typical heat production of 11GWh. The system paid for itself through reduced energy costs in 4 years.

Ground source heat pumps based on extracting groundwater represent an ideal solution for energy storage and extraction (Ramstad & Midttømme, 2008).

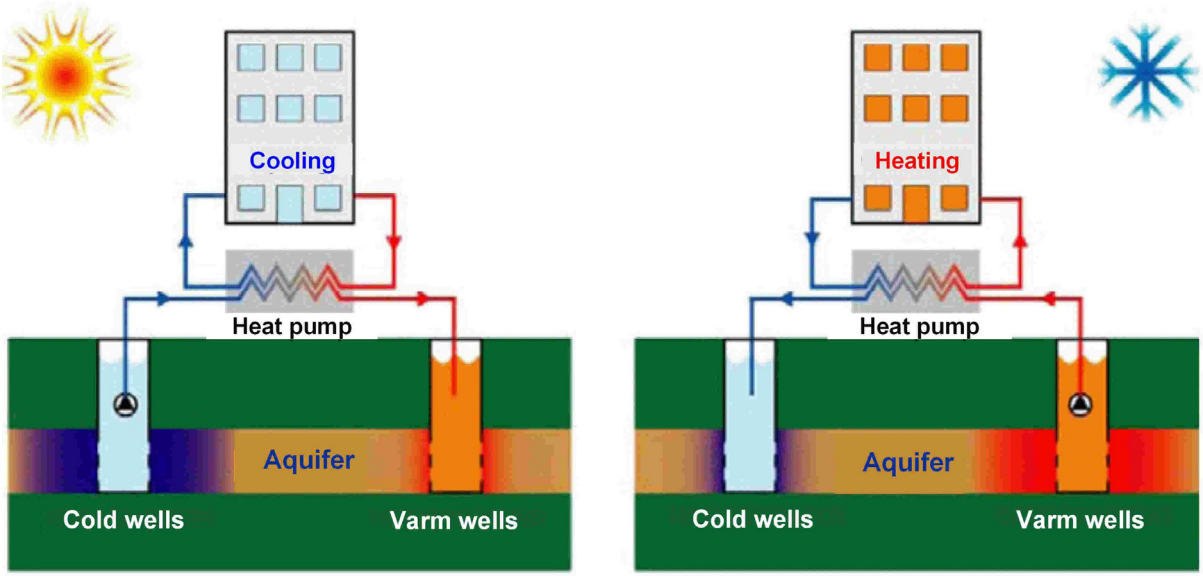

Figure 2: Illustration: IEA Heat pump centre.

Geothermal hot water for heating

Hot springs have been used for thousands of years for bathing and heating dwellings. Today the direct use of hot water also includes agricultural applications and in industrial processes. The most important users of hot geothermal water are shown in Table II.(Illustration: IEA Heat pump centre.)

Most hot springs are related to volcanic activity. Otherwise, high heat producing granites can drive convection of groundwater and the formation of hot springs. Over the last 20 years 1 to 3 km deep aquifers in sedimentary basins have been developed for the production of hot water. One recent example is from Copenhagen where two 2.3 km deep wells were drilled into Triassic sandstone and hot water (82-83˚C) from the wells is now used for heating purposes in the city (Knutsson, 2008).

There have been several attempts to produce hot water from aquifers in fractured crystalline rocks. Problems with control of the groundwater flow in fracture zones and reduction of permeability due to alteration of the crystalline rock has made many of these projects unsuccessful.

Modern drilling technology developed for the petroleum industry opens for directional drilling and thereby enables the construction of geometrically complex heat exchange system to depths of 3 or 4 km. Future utilisation of this technology will bring geothermal water to a far larger portion of the world than was previously thought practical.

Electric power generation from geothermal energy

In order to produce electricity or hydrogen from geothermal water one needs water of more than 100 ˚C and only Iceland of the Nordic countries can produce electricity from geothermal water. Iceland has developed plants that distribute both hot water and electricity generated from hot water. The electricity is cheap at about 2 eurocent per KWh.

The highest geothermal gradients are found at tectonic plate boundaries and where major rifts thin continental crust. The spreading ridge traversing Iceland provides optimal conditions for water heating and convection due to the high thermal gradient and an extensional tectonic regime. In Iceland the thermal gradient and low pressure in the ground results in boiling of the geothermal water in one or more boiling zones. At spreading ridges in deep oceans, geothermal water sourced from seawater reaches the seafloor without boiling and

precipitates sulphides and other minerals. The temperature of the fluids is 300 to 400 ˚C and they have high concentration of copper and zinc, which precipitates as sphalerite and chalcopyrite on the seafloor due to the drop in temperature,

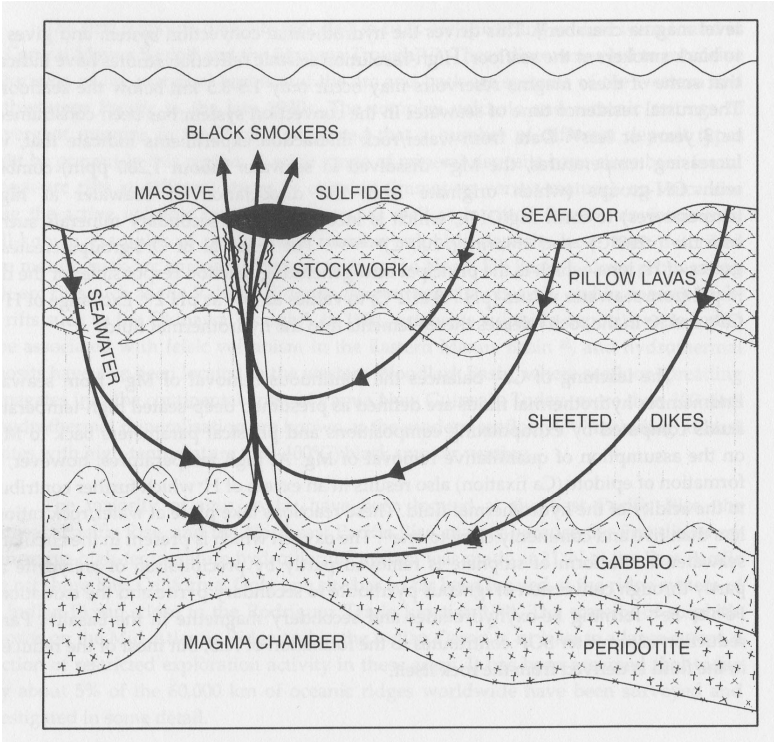

Figure 3: Model showing a seawater hydrothermal convection system above a sub axial magma chamber at an oceanic spreading centre. Radius of a typical convection cell is about 3-5 km. Dept of the magma chamber usually varies fro 1,5-3,5 km

The high cost of energy has made geothermal energy very profitable, and in 2000 Iceland established the Iceland Deep Drilling Project with the support of the International Continental Drilling Program. The main goal of the ongoing project is to drill into high temperatures supercritical fluids below the boiling zones. A borehole 5 km deep is planned at the Kravla volcano in the northern part of Iceland they expect to tap fluids at approximately 500˚C (Lund et al., 2008). Supercritical fluids are expected to have high contents of copper and zinc, similar to the fluids forming the black smokers on the seabed. There are several technological challenges related to production of energy and metals from these fluids. One major problem is to avoid plugging of pipes through precipitation of minerals and another is drilling at such high temperatures.

If the Deep Drilling Project is successful in Iceland, there is a large potential for energy extraction from spreading ridges globally. Some spreading ridges are close to continents like on the western part of Mexico and west of Canada and USA and they may be used for energy supply, electricity or hydrogen from large offshore installations. In Norway there is a good potential for extracting geothermal energy and metals from supercritical fluids beneath Jan Mayen; several black smokers with sulphides have been discovered on the seafloor close to the island.

Conclusions

The use of geothermal and ground source heat is increasing rapidly in the Nordic countries and internationally, and cost is very competitive in the world energy market. The use of heat pumps based on ground source heat is a flexible energy source for buildings of all sizes.

New technology promises to provide two new geothermal energy concepts:

Improved drilling technology will permit heat exchange systems using complex boreholes reaching 4 km. depth. This technology can provide water at 100 ˚C for use in urban areas. This concept can be used almost anywhere.

Utilisation of supercritical fluids at 400 to 600˚C in volcanic areas including oceanic spreading ridges. This method has a large energy potential and a large potential for metal production. The transport and processing of supercritical fluids is challenging and the energy source is geographically restricted.

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Road transportation – from crude oil to renewables

By: Dr. Steffen Møller-Holst & Dr. Ann Mari Svensson, SINTEF

The transportation sector's contribution to GHG emissions

The transportation sector contributes by 26 % to the overall global Greenhouse Gas (GHG) emissions [Chapman 2007], the second largest share, next to stationary power generation. Among the various forms of transportation; automotive, aviation, maritime and rail, road transport takes by far the largest share of around 75 % [WWF 2008].

The picture is similar, but somewhat skewed in Norway, where the transportation sector contributes by as much as 37 % to the emission of GHGs, as illustrated in Figure 1.1. This is primarily due to massive Norwegian coastal traffic and stationary power generation in Norway being fully (99,4 %) covered by hydroelectric sources. Road transportation alone contributes by 23 % of the total domestic GHG emissions, and both road and maritime transport have experienced a significant growth over the last decade. The distribution of emissions from various modes of transport in Norway is shown in Figure 1.2.

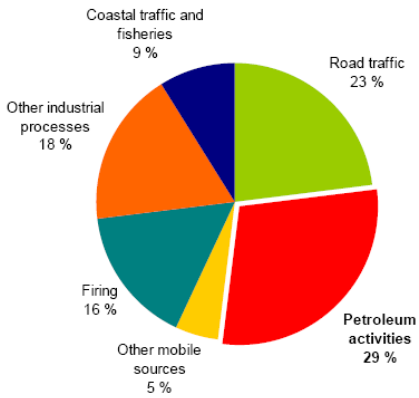

Figure 1.1: Contributions to GHG emissions in Norway from the various sectors, showing that transportation contributes by 37 % to the domestic emissions (sum of Road traffic (23 %), Coastal traffic and Fisheries (9 %) and Other mobile sources (5 %)) [Facts 2006].

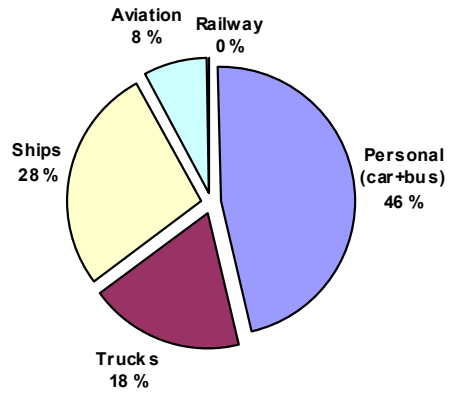

Figure 1.2: Distribution of sources of GHG emissions within the Norwegian transportation sector [SSB 2005-26]. Road transportation takes a 64 % share of the total emissions (Personal + Trucks).

Personal transportation (car + bus) by far dominates domestic transport related GHG emissions, but maritime transport and road transportation of goods (by trucks) also contribute significantly (Figure 1.2). The GHG emission from domestic aviation takes an 8 % share whereas railway's contribution is negligible (0.3 %, due to high degree of

electrification and hydroelectric power generation). Road transportation is representing the largest segment of transportation taking a 64 % share of the domestic GHG emissions. In this paper, we will focus on road transport.

Approach to reduce GHG emissions from road transportation

The two main drivers in the strive for reducing GHG emissions from transportation are; i) the highly debated global warming issues, ii) the dwindling crude oil resources fuelling the growing transportation sector. According to Oman [Oman 2003] petroleum resources will be near exhaustion within 50 years. And as oil prices increase, more energy demanding and less environmentally benign sources like oil sand, extra heavy crude, or oil shales are being exploited, exacerbating the problem. Clearly there is a delicate balance between economical interests and ecologically acceptable solutions. On this arena, political engagement and intervention is needed, and strong political incentives and regulations may direct the development in the right direction (ref section 8). It is unlikely that technological innovation constitutes the sole answer to the climate change problem. Behavioural changes brought about by policy will also be required [Chapman 2007].

The technical approach

The technical approach to reducing GHG emissions from road transportation includes the following three basic elements:

1. Increase efficiency in existing technologies
2. Introduce new technologies as well as reduce weight/size of vehicles
3. Utilize more environmentally sound fuels

Figures from Statistics Norway show that road transport increased by around 60 % from 1990 to 2003, while the fuel consumption (and emissions) increased by 34 %. Continued incremental energy efficiency increase of conventional propulsion technologies has, thus, not been sufficient to compensate for the increasing transportation demand over the years. So, expecting that efficiency increase alone will solve the problem, is far too optimistic.

Introduction of new technologies is potentially a much more powerful measure, but require changes to production lines and challenges large investments. The internal combustion engine (ICE) has been subject to more than 100 years of development, and is provided to the market at low cost due to mass production. The transition to new propulsion technologies is therefore highly challenging in view of the immature state of these technologies. Reducing weight and size of vehicles will in any case be beneficial.

Substitution of conventional crude oil based fuels with alternatives like biofuels utilising ICEs also constitutes a viable option. The low efficiency of ICEs and limited availability of biomass resources, however, underlines that introducing biofuels alone will not solve the problem we are facing.

To address the challenge of global warming and dwindling crude oil reserves, all three elements listed above should be pursued in parallel.

As we imagine, there are numerous options for GHG emission reduction from road transportation. The urgency of stabilising and reducing the CO_2-concentration in the atmosphere demand stronger measures than incremental improvements of existing technologies.

Global warming scenarios and dwindling crude oil reserves call for revolutionizing the whole transportation sector by decarbonising it completely.

Are we heading for the "Hydrogen Society"?

A pre-requisite in order to succeed in global warming abatement is that sustainable technologies and fuels are identified. Only those options which are "future-proof" i.e., compatible with the zero emission energy system of the future, should be developed and pursued. Investments in intermediate and non-"future-proof" solutions should be minimized [TES 2007].

Substantial discrepancies and controversy is experienced in literature studies evaluating various technologies and alternative fuels and their respective potential to reduce GHG emissions from transportation. There is furthermore disagreement whether hydrogen will become a key energy carrier in the future. Whereas some even claim that hydrogen may become the principal energy carrier because it provides better energy storage solutions than electricity [Converse 2006], others point at hydrogen being a dead-end-track [WWF 2008]. European energy and automotive companies have in their recently published Transport Energy Strategy [TES 2007] screened a high number of potential fuels and technologies and come to the conclusion that 2nd generation biofuels and hydrogen represent the two most promising options.

The term "Hydrogen society" is misleading. Hydrogen will never constitute the sole energy carrier in a future energy system. This would waste a lot of energy.

In general there are three major and frequently used arguments against introducing hydrogen as energy carrier for transportation. One is the energy losses or inefficiency encountered from production to end use, the second is the hydrogen storage problem and third; the cost of building a hydrogen infrastructure. The potential for zero-emission and the flexibility with respect to energy source, however, constitute the key rational for utilising hydrogen as energy carrier for transportation applications. In the future renewable energy sources (RES) will take an increasing share of the stationary power generation, causing the need for energy storage to rise dramatically. The additional functionality as an energy storage medium renders introducing hydrogen highly advantageous. It is furthermore concluded by Ruijven et al [Ruijven 2007] that an energy system that includes hydrogen is much more flexible in responding to climate policy.

The potential GHG emission reduction by introducing hydrogen is highly dependent on the source of energy utilised for the production. When generating hydrogen based on RES, GHG emissions are close to zero. Producing hydrogen from biomass may generate CO_2-emissions related to the energy demanding production process and transportation of the biomass. Reforming of natural gas provides hydrogen with CO_2-emission reductions proportional to the retention potential of Carbon Capture and Storage (CCS) for the production process, which is typical in the order of 80-85 %.

We conclude that hydrogen is needed to make the energy system of the future more robust by adding substantial energy storage capacity and providing fuel for transportation. However, electricity will remain our principal energy carrier, due to its superiority in energy efficiency.

This paper will focus on the potentials to reduce national GHG emissions from road transport, by assessing and discussing the contribution from the three technological options:

Electrical, hydrogen as well as bio-fuelled vehicles.

A long term prospective for CO_2-free road transport

A prospective for the next 60 years illustrating how the most promising candidates for a renewable transportation sector; electricity, biofuels and hydrogen, may substitute crude oil based fuels (gasoline and diesel) is shown in Figure 2.1.

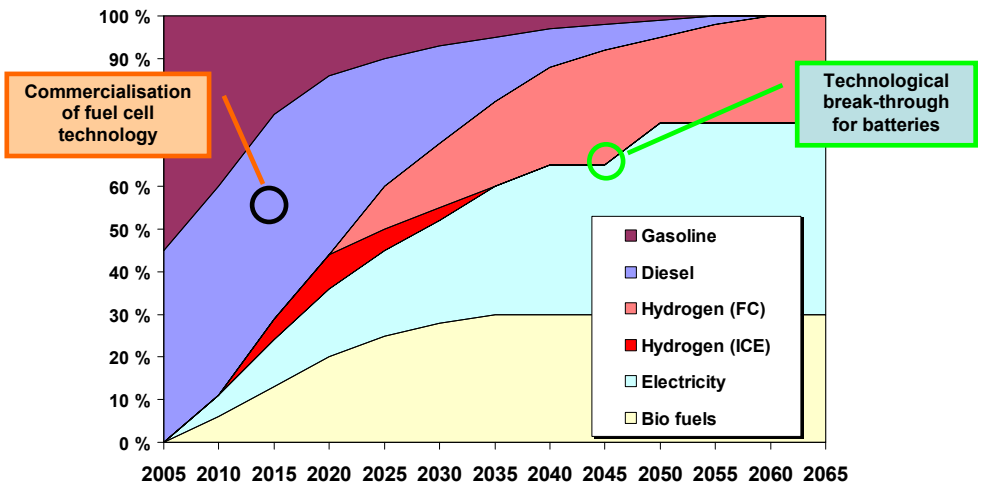

Figure 2.1: In a long time-frame perspective, electricity, biomass and hydrogen each may cover roughly one third of the global energy demand for transportation.

Electric vehicles are available today, but their application is limited due to the low energy density of current battery technology. Higher shares of electric vehicles as well as biofuels could be realized in a short timeframe. The contribution from biofuels is, however, limited by the availability of resources. A substantial improvement in battery technology is needed to reach the depicted share of electricity in transportation from 2010 towards 2030. Hydrogen powered ICE vehicles (section 3.2) are expected to take a minor share in an interim period between 2010 and 2030. Characteristic breaks in the curves (Figure 2.1) are reflecting technology breakthroughs. The first indicates commercialisation of fuel cell vehicles assumed to become available from 2020. A second break-through in battery technology development is indicated, resulting in an even larger share of electrical vehicles post 2045. It should be stressed that Figure 2.1 represents one possible and robust pathway towards a fossil free transportation. Substantial regional variations are expected, depending on resources' availability. Nations which possess large biomass resources[1] would consequently utilise a higher share of biofuels, whereas nations rich in hydropower would prefer electrical vehicles.

Outline of this paper

The complexity of this topic and the format of this paper does not allow for an in depth treatment of all alternative fuels and technology options. In the next section, state of the art for the above selected vehicle technologies is described. Section 4 deals with two

[1] Brazil already covers 40% of its domestic demand for fuel by sugar-cane derived bio ethanol.

scenarios for introduction of alternative fuels and new propulsion technologies in Norwegian road transportation. Certain limiting factors for the desired development are discussed in section 5. Some unused potentials facilitating the desired development are pin-pointed in Section 6. The required R&D-activities to address these limiting factors are listed in Section 7 and finally, Section 8 provides recommendations for Norwegian politicians for actions needed to be taken domestically, compatible with solving problems of global warming and dwindling crude oil reserves.

State of the art for vehicle technologies and "fuels"

In this section, a state of the art description for electrical and hydrogen fuelled vehicles is provided. In addition the domestic biofuel potential is discussed.

Electrical vehicles

Electric propulsion technologies are superior to conventional internal combustion engines (ICEs) with respect to energy efficiency[2]. In this section we will shortly describe state of the art for three classes of electrical vehicles; the Battery Electric Vehicles (BEV), the Hybrid Electric Vehicle (HEV), and the Plug-in Hybrid Electric Vehicle (PHEV). All these types of vehicles could contribute to significant emission reductions, and their introduction should be encouraged where feasible. However, the low energy density and high cost of present battery technology limits the market for BEVs in particular, but also HEVs and PHEVs. Battery technology is subject to intensive R&D and is expected to improve both with respect to energy density and cost. Fuel Cell vehicles also utilise an electrical drive train (see section 3.2).

Battery Electrical Vehicles (BEV)

Battery Electric Vehicles (BEVs) are commercially available (at close to competitive prices when subject to tax exemption in Norway), both as electrified versions of small, conventional ICE cars, and as small cars which have been designed and developed from scratch as BEVs.

The typical drive range for BEVs is 50-150 km. Even if this is sufficient for a significant fraction of trips made by cars (83 % of all trips are shorter than 20 km, which again corresponds to 48 % of vehicle km [Mobility TØI]), the share of electric vehicles is still very low. By January 1st 2007 there were 1,667 electric (mostly small city-) cars registered in Norway [Elbil]. The number has probably passed 2000 by now.

Major obstacles for obtaining massive market shares include the small size of the BEVs (some with only two seats), as well as the time needed for recharging (typically several hours). Fast charging is possible, but on the expense of battery lifetime. Car manufacturers indicate that next generation Li-ion batteries can be charged up to 80 % within 15 minutes. Improvements are expected for the battery technology, and the drive range is expected to increase over the coming years. Still, there are challenges related to cost and lifetime/durability of the battery packs, and the fact that the energy density is too low for batteries to be utilized in medium to large cars for average drive cycles (city + highway driving). These obstacles render the BEV a real alternative for 2 car households only, for many years to come.

There are two Norwegian manufacturers of electric vehicles, ElBil Norge, which produces the small electric car Kewet Buddy, and Th!nk, which have developed small electric vehicles, and soon will start series production.

[2] A WtW efficiency of 69 % is estimated, if electricity is based on RES, including charging & discharging of batteries and losses in the electric motors and electricity grid [WWF 2008].

Chinese BEV production ramps up from 20.000/year in 2009 to 200.000 in 2010. The Chinese market for electrical bikes is already substantial, due to legislation of petrol-driven scooters being outlawed in many Chinese cities including Beijing and Shanghai, due to severe air pollution. In 2005 9 million electrical bikes were sold, and this market alone is expected grow to 30 million in 2010 [WWF 2008].

The Hybrid electrical vehicle (HEV)

By combining a conventional ICE with an electric drive-train and small battery pack, the HEVs may reduce fuel consumption significantly for city driving at varying load. Kinetic energy recovery regenerative braking constitutes part of these savings.

Figure 3.1: Toyota Prius Hybrid; by May 2007 accumulated sales numbers for this HEV passed 1 million.

The downsized ICE in these vehicles is started and operates at high load and close to optimal conditions to charge the batteries. During acceleration it also assists the electric motor to provide adequate power. The gain in efficiency upon hybridization varies widely and depends on the drive cycle. For pure city driving, the reduction of fuel consumption varies from 18 to 40 % [Markel 2006] depending on vehicle model. In this paper a 25 % saving in fuel is assumed for mixed driving (ref. Figure 3.4).

Since Toyota launched their Toyota Prius Hybrid in 1997 (Figure 3.1), accumulated sales numbers passed 1 million in May 2007.

Hybridization is expected to eventually become an integral part of all propulsion systems designed to operate in urban areas, thus subject to frequent starts and stops (Figure 3.2).

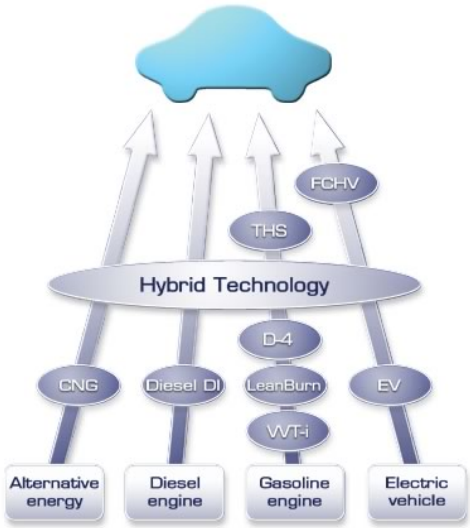

Figure 3.2: Toyota foresees that hybrid technology will become an integral part of all propulsion systems.

The Plug-in Hybrid Electrical Vehicle (PHEV)

PHEVs are given the additional functionality over HEVs that they may be re-charged externally (from the electricity grid). Several auto manufacturers have recently shown PHEV prototypes which are expected to be available in the market within the next 2-3 years. Toyota has announced that Prius PHEV will be commercially available from 2010, with a battery range of 7 miles (11 km) [Toyota ORB]. Significant further improvements are required before PHEVs can be successfully spread in the market [Toyota]. GM's Chevrolet Volt was presented at the Detroit auto show in spring 2006, expected to have a range of 20 miles (32 km) on electric energy (stored in the batteries) when ready for the market in 2010. The targeted price is $30.000 [WWF 2008]. It is expected that PHEVs with improved range will be available in the future. Estimated annual gasoline consumption savings for the PHEVs are depicted in Figure 3.4, as reported by Electric Power Research Institute (EPRI) [EPRI], assuming mixed driving i.e.

Figure 3.3: Two examples of Plug-in Hybrid Electric Vehicles: The Chineses built BYD and GM's Chevrolet Volt.

combination of city and highway drive cycles for average US road traffic.

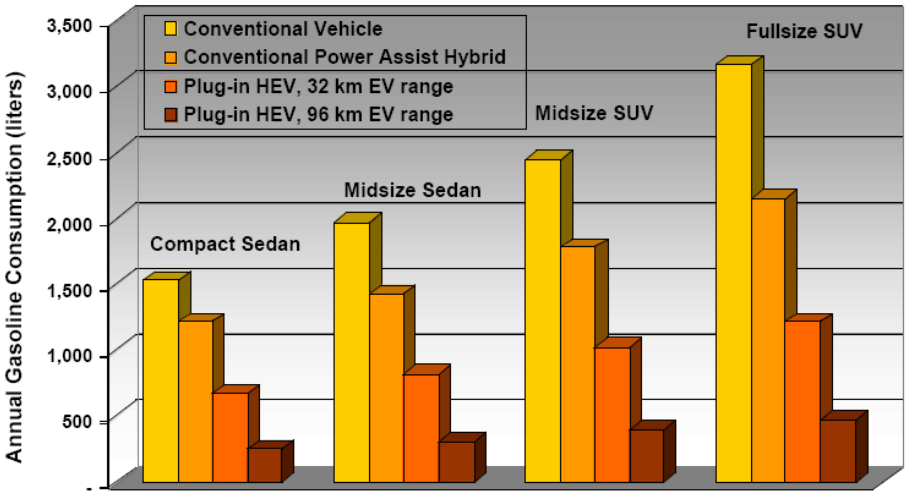

Figure 3.4: Annual Gas consumption for various PHEVs for a mixed drive cycle (source: Electric Power Research Institute, 2003 [EPRI].

As shown in Figure 3.4 the emission reduction of PHEVs depends strongly on the battery capacity (EV range). For an EV range of 32 km the saving for mixed driving is 57 %. Moreover, in a well to wheel perspective the CO_2-emission depend strongly on the electricity mix from which the batteries are charged (ref. example section 5.2). For Norwegian hydropower, the above fuel savings coincide with the emission reductions.

Hydrogen powered vehicles

Hydrogen may be produced from nearly any energy source, either by splitting water utilising electricity generated from renewable energy such as hydro-, wind-, solar-, wave- or tidal energy, from gasification of biomass or from fossil fuels e.g., by reforming of natural gas. Technologies for hydrogen production are commercially available, both based on natural gas reforming and water electrolysis, and hydrogen is handled regularly in industrial processes at large scale. Energy efficiency for hydrogen production is in the range of 50-85 % (HHV) [Ruijven 2007] depending on the source.

Hydrogen may be utilised both in internal combustion engines (ICEs) and fuel cells (FCs). Conventional ICEs converted from gasoline to hydrogen typically provide 20-30 % less power than the original gasoline vehicles (e.g. Toyota Prius, Mazda RX8 and BMW 7-series as shown in Figure 3.5). The reason for losing power is linked to the lower specific volumetric energy content of hydrogen vs. gasoline. It is common to turbo-charge these engines to regain some of the power. Hybrid vehicles for hydrogen (rebuilt Toyota Prius by Quantum, Figure 3.5) are semi-commercially available, and currently sold for around 800 kNOK (~100 k€) per vehicle.

Toyota Prius Hydrogen

Mazda RX8

BMW 7-series

Figure 3.5: Three hydrogen powered vehicles utilising internal combustion engines. Toyota Prius Hydrogen is rebuilt by Quantum (classes A and B below).

Three classes of hydrogen powered vehicles exist:

Class A vehicles either utilise ICEs converted from gasoline to hydrogen, or custom made ICEs for hydrogen. The typical engine configuration is a conventional four-stroke Otto-Engine (BMW, Ford), but Wankel-engines[3] are also being developed (Mazda).

Figure 3.6: Hydrogen vehicle from Th!nk Global with a PEM fuel cell extending the range from 125 to 250 km.

Class B constitutes the hybrid hydrogen vehicles like the hydrogen version of the Toyota Prius (Figure 3.5). Plug-in versions are expected to be developed in the future.

Class C vehicles all utilise fuel cell technology, but at various levels of hybridization.

a) Vehicles which are primarily BEV (e.g., Th!nk, Figure 3.6) equipped with a small fuel cell which charges the battery pack, and extends the range typically by a factor 2.
b) Full size fuel cell vehicles like the OPEL Zafira HydroGen 2 (ADAM OPEL GmbH (a part of the GM group)), which is purely powered by a PEM fuel cell, thus representing no hybridization.
c) Fuel cell vehicle prototypes utilising a strong hybrid configurations such as Toyota FCHV (Figure 3.7) and Honda FCX, both utilising relatively large battery packs.

Efficiency-wise fuel cells are by far superior to ICEs, but significantly less efficient than BEVs if based on renewable electricity. In a Tank to Wheel (TtW) perspective the efficiency of FC powered vehicles are reported to be 30-60 % [Ruijven 2007]. The Well to Wheel (WtW) efficiency suffers due to energy losses from hydrogen production and storage. An estimate of the WtW efficiency is 28 % [WWF 2008].

Figure 3.7: Toyota FCHV, a hybridized PEM fuel cell prototype vehicle with 830 km driving range.

Fuel cell powered vehicles however, exhibit ranges which by far exceeds those for conventional BEVs. Toyota recently announced[4] their latest FCHV concept vehicle, providing a range of 830 km (Figure 3.7).

Fuel cell vehicles are not yet commercially available. These are expected to become available at acceptable cost by about 2015 and at competitive prices around

[3] The Wankel rotary engine is a type of internal combustion engine, invented by German engineer F. Wankel, which uses a rotor instead of reciprocating pistons.
[4] http://www.toyota.co.jp/en/news/08/0606_2.html

2020 according to EC's strategic documents [EC IP 2006].

Hydrogen is expected to find its prime market as fuel for passenger vehicles and buses in urban areas. For heavy duty vehicle (truck) applications the drive cycle (high load over long distances) does not fit fuel cell technology and efficiency characteristics very well, and biofuels are thus expected to be the preferred solution in this market segment.

Biofuels

The recent renaissance of biofuels reminds us of the fuels once used at the birth of the Internal Combustion Engine; More than a century ago Henry Ford's first car ran on alcohol and Rudolf Diesel fired his namesake engine with peanut oil.

Today, biofuels as bio-diesel and bio-ethanol are available as transportation fuels in most European countries (as such, or in blends) and is converted in slightly modified conventional Internal Combustion Engines (ICEs), like in SAAB 9-5 BioPower (Figure 3.8). These so-called ***first generation biofuels*** are made from plants (seeds or sugar). The production of bio-ethanol ranges from what is claimed to be sustainable from sugar cane in Brazil to what is characterized as highly questionable corn-based ethanol produced in the US, giving rise to GHG emissions which may exceed those of conventional fuels.

Forest and waste can be utilized for production of synthetic fuels (biomass-to-liquid (BTL) fuel), so-called ***second generation biofuels*** which, however, is still at an early stage of development. The aim of the EC (Directive 2003/30/EC) is a replacement of 5.75 % of fossil fuels by biofuels by 2010, whereas alternative fuels in total should replace more than 20 % of the petroleum based fuels within 2020. The potential for production of biofuels within the EU is assumed to be maximum 25-30 % of the annual consumption, but there are large uncertainties related to such estimates. One challenge with respect to large scale utilization of biomass for biofuel production is the competition with other products based on biomass resources, in particular food, heat or chemicals synthesis.

Figure 3.8: GM's SAAB 9-5 BioPower utilises E85 in a slightly modified conventional ICE.

The availability of biofuels is increasing in Norway, either as imported fuels, or based on the conversion of imported plant oils. Due to the low growth rates at these northern latitudes, utilization of plants/farmed land for production of biofuels is not considered feasible in Norway, and a domestic production of biofuels is foreseen to be based on forest/waste wood, agricultural waste and landfill gas. Fuel production from algae has recently also attracted attention. These conversion technologies are, however, still not commercially available, and major technological developments are required. Recently, a national roadmap for the establishment of domestic biofuel production [Bioroadmap] was launched, which provides suggestions for priorities in order to realise large scale biofuel production in Norway. Here, the potential for increased utilization of biomass for fuel purposes is estimated to around 20 TWh annually, with a possible increase of 5 TWh if animal by-product (manure) is also utilised. It is further estimated that in a 10-20 year perspective, domestic supply of biofuels could account for around 20-30 % of the fuel consumption for transportation. The roadmap focuses primarily on the production of various routes for bio-ethanol from ligno-cellulose, and the production of synthetic bio-diesel by gasification of biomass, and further synthesis to Fischer Tropsch (FT)-liquids.

Large scale production plants of at least 400 MWth will be required for this conversion process to become profitable as concluded in the work of Tijmensen *et al.* [Tijmensen]. Biomass feedstock costs are assumed to be constant here, whereas in practice, biomass costs could significantly increase for larger scales due to higher logistics costs, which is likely to be the case for Norwegian conditions. In general, the cost of biomass is governed by the demand also for other applications. It is assumed that these results are applicable also for Norway. Assuming an overall LHV efficiency of around 40 %, and an annual operational time of 8,000 h, this corresponds to an annual consumption of around 8 TWh biomass.

Bio-ethanol from ligno-cellulose could potentially be produced economically at smaller scale [Bioroadmap], but at somewhat lower energy efficiency. In this study, a LHV conversion efficiency of 35 % is assumed. The Concawe EUCAR-study [Concawe WtW] from 2006 of a large number of biofuels, show clearly that fabrication of biofuels is relatively energy demanding.

In the Scenarios in section 4 the following assumptions apply for domestically produced biofuels: First full scale production site for synthetic diesel in 2012, production of synthetic diesel, from a total of 8 TWh biomass. From 2016, production of ethanol in smaller production facilities, total of 4 TWh biomass utilised. From 2022, production of synthetic diesel in another 400 MW production site (8 TWh raw materials). Assuming 40 % conversion efficiency for the production of synthetic diesel, and 35 % for the production of ethanol from wood, this implies that the biofuel available on the market is:

- 12 PJ synthetic diesel from 2012
- 12 PJ synthetic diesel and 5 PJ ethanol from 2016
- 25 PJ synthetic diesel and 5 PJ ethanol from 2022

Combustion of biomass is considered CO_2 neutral, but overall GHG emissions from combustion of biofuels depend on production methods. Furthermore combustion of biofuels also gives rise to emissions of NO_x, SO_x, particles etc. and specifically N_2O [Concawe WtW].

There are no environmental benefits related to the utilization of imported biofuels as long as there is a general shortage of supply within the European countries. Import could, however, facilitate later use of domestically produced biofuels. Rough estimates indicate that an increase in CO_2 emissions related to transportation of rape seed oil/bio-crude, or the product biofuel, over long distance (1,000-2,000 km) by truck would typically be in the order of 2-6 %. Transportation of raw material (biomass or waste) across similar distances, would lead to a significant increase in the CO_2 emissions of the product fuel, typically in the order of 30-50 %, due to the low energy density of the raw material.

The results from the Concawe WtW study are assumed to be representative also for Norway, although it seems reasonable to believe that due to more energy intensive forestry and generally longer distances to a production plant, the numbers are likely to represent the “lower bounds” of what can possibly be achieved in Norway with respect to GHG emission reduction. Still, with wood or wood waste as raw materials, the reduction of GHG emissions by substituting gasoline and diesel by biofuels can be significant. Scenarios for road transportation in Norway in a 2050 perspective

Targeted emission reductions from road transportation

Today close to 800 million road vehicles are expected to double within 2030 [WWF 2008]. A corresponding dramatic increase in crude oil demand and global GHG emissions from transportation is foreseen. The majority of this growth is expected to take place in the fast growing economies of China and India with their huge

populations. For global energy demand forecasts of various energy sectors, we refer to the paper by Dr. Gerald Doucet, entitled *"Technological and Scientific Foresight on the Energy Demand of the World"*.

To ensure the relevance of this paper for Norwegian stakeholders, we will focus on discussing scenarios for domestic road transportation. By addressing alternatives compatible with meeting challenges of global warming as well as dwindling fossil energy resources, robust and adequate recommendations for Norwegian politicians are provided (section 8). It should be emphasized, however, that premises for future transportation solutions, in particular in terms of availability of vehicles, are set internationally.

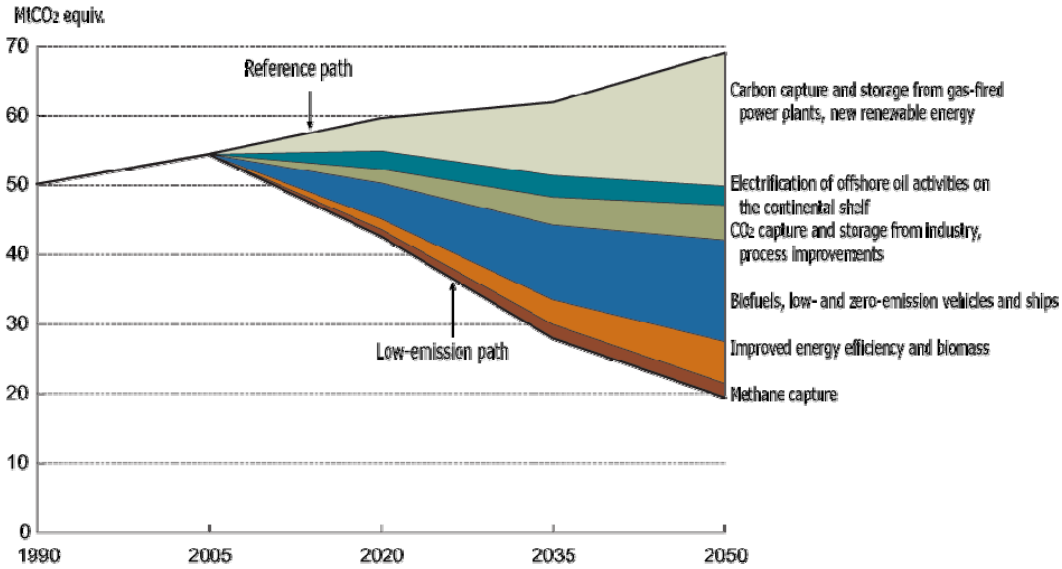

Figure 4.1: Recommendations for reduction of GHG emissions for various sectors from the Norwegian Commission on Low Emissions [NOU 2006: 18].

The Norwegian Commission on Low Emissions [NOU 2006:18] has made predictions for an overall GHG emission reduction of 50-80 % by 2050, based on the requirement that the level of CO_2 in the atmosphere should be stabilized at around 450 ppmv (ca 550 ppmv CO_2 equiv.), Figure 4.1. The Norwegian Minister of Finance has recently announced that half to 2/3 of the emission reductions will be realised domestically[5].

Major reductions in emissions from transportation are foreseen, and road transportation emissions are predicted to be reduced by around 90 % by 2050. Modest emission reductions are envisaged for the maritime sector, whereas emissions from aviation are predicted to remain stable.

Scenarios for Norwegian road transportation

In order to elucidate on possible emission reduction pathways for road transportation in Norway, two scenarios have been developed:

[5] Minister of Finance, K.Halvorsen: http://www.zero.no/klima/finansminister-kristin-halvorsen.pdf

- **Scenario A** relying on massive introduction of available BEVs as well as HEVs for private passenger transport and replacement of diesel by biofuels for heavy duty vehicles. Extra savings by introducing PHEVs are also considered.
- **Scenario B** assuming massive introduction of hydrogen powered fuel cell hybrid electric vehicles (FCHEV) after the year 2020.

The scenarios are based on Well to Wheel (WtW)-calculations, and not complete Life Cycle Assessment (LCA). Of the total CO_2 emission from an average car 76 % stems from operation, 9% from manufacturing the vehicle and a further 15% from emissions and losses in the fuel supply system [Potter 2003]. WtW-analysis thus includes 91% of the total emissions and is, hence, considered an adequate approach, although this percentage differs somewhat between types of vehicles. All results presented in this paper are based on the standard European drive cycle (Euro 3/Euro 4), representative for city driving.

Norway has the lowest share of public transport in Europe [SSB 2005-26] and due to demography this share is expected to remain low [Nasjonal Transportplan], although subject to significant political debate. Compared to 440.000 heavy duty trucks operating on Norwegian roads, emissions from ~30.000 Norwegian buses are minor. We include trucks but exclude buses from the scenario evaluations.

Direct use of natural gas (NG) is expected to take shares of the fuel supply in certain sectors such as maritime transport and within public transportation replacing diesel. CO_2-emission reduction by replacing conventional fuels with NG is limited to a maximum of 10-15% (utilising conventional ICE technologies). As this paper focuses on de-carbonizing road transportation, NG is not included in the scenarios.

Increasing political awareness and strong incentives for introduction of biofuels in transportation have triggered a growing global market for this commodity. It is in this context crucial to realise that moving biomass over long distances for utilisation in another region or continent reduces the potential CO_2-benefit of this valuable resource. To safeguard optimum utilisation and maximize global CO_2-emission reductions, local production and utilisation should be encouraged (ref. section 2.4). Therefore, for the scenarios in this paper, we consider utilisation of domestic biomass resources converted into biofuel by 2nd generation technologies. Due to the lack of other viable fuel alternatives for long distance heavy duty vehicles (trucks), this biofuel is reserved for this transportation segment and converted in conventional ICEs. Calculations show that estimates for the domestic potential for biofuels of 20 TWh correspond to 62% of the fuel demand for trucks in 2050.

These scenarios are based on available public demand forecasts for the transportation sector [Nasjonal Transportplan], knowledge of the status of technologies, expectations for technology development, available information on the car pool, distribution of length of trips, average number of passengers in each vehicle etc [SSB 2005-26]. Fuel economy is assumed to increase by 30 % for all technologies in the given timeframe (2005-2050). HEVs are saving 25% whereas PHEVs are saving 60% of the fossil fuel over a mixed drive cycle, compared to conventional ICEVs (Figure 3.4).

Scenario A: Utilization of domestic Electricity and Biofuels

In this scenario massive introduction of battery electric vehicles (BEVs) as well as hybrid electrical vehicles (HEVs) is foreseen. The driving range of the BEVs is not significantly increased from today's 100-150km. The upper limit for the penetration of BEVs is limited to one car per Norwegian household having 2 or more cars (39 % of households) [Mobility TØI]. The assumed rate of substitution of Scenario A, expressed as shares of new cars sold, is depicted in Figure 4.2.

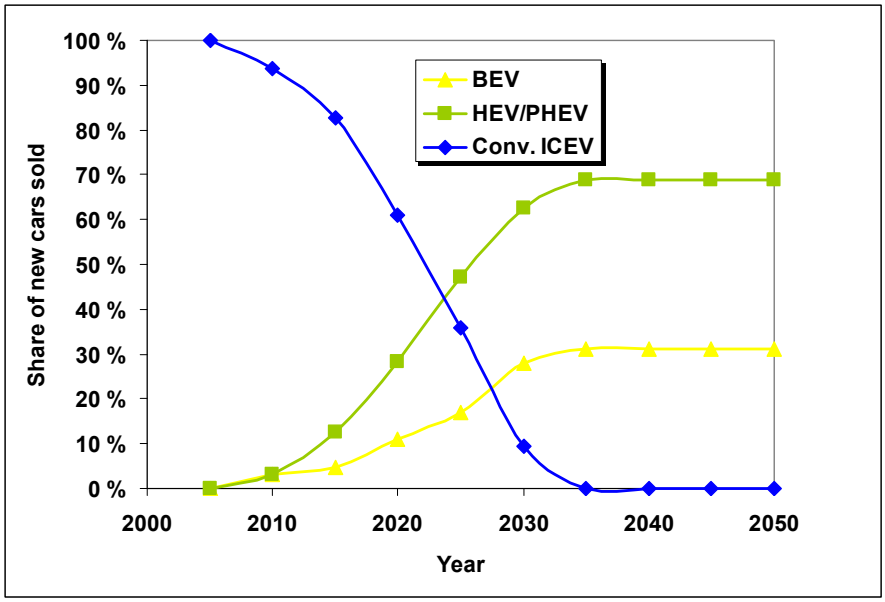

Figure 4.2: Share of new vehicles sold for Scenario A showing a massive substitution of BEVs and HEV/PHEVs for conventional ICE vehicles (based on fossil fuels) in the personal cars transportation segment.

The shares of BEVs and HEV/PHEVs shown in Figure 4.2 reach 3 % of all new cars sold already in 2010, corresponding to around 3,000 new vehicles in each category. By 2020 the sale of non-conventional vehicles sold has grown dramatically to almost 40%.

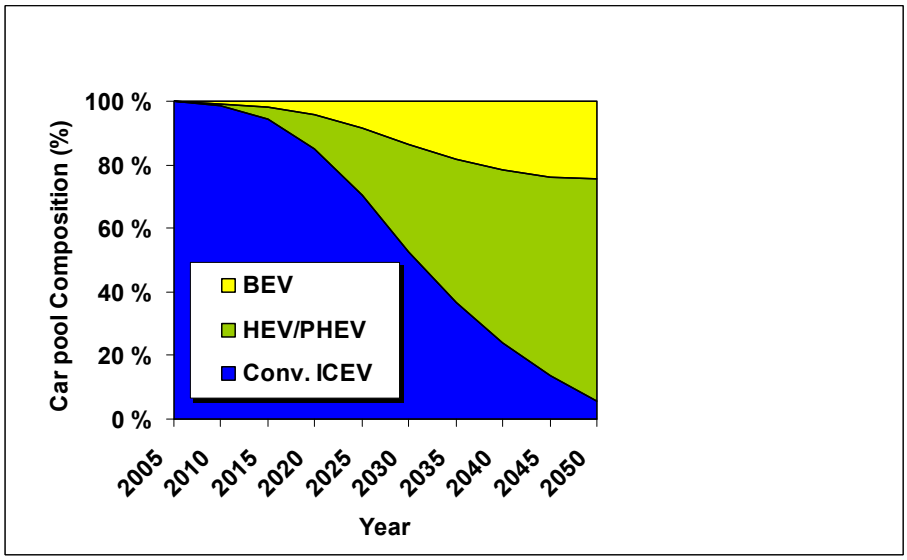

Figure 4.3: Calculated shares of BEV, fossil fuelled HEVs and conventional ICE vehicles following the shares of new vehicles sold shown in Figure 4.2.

The resulting evolution of the composition of the passenger car pool is shown in Figure 4.3, assuming an average vehicle lifetime of 20 years[6]. Although less than 10 % of new cars sold in 2030 are conventional ICE vehicles, the share is still more than 50% of the car pool the same year. ***It is essential to take this "delay" into account when considering the effect of political measures aiming at reducing GHG emissions.***

The CO_2 emission reduction related to Scenario A is given in Figure 4.4. The contribution from introduction of domestically produced biofuels reflects establishment of two biofuel production plants (ref Section 3.3). Introduction of BEVs and HEVs are by 2050 contributing an additional 1 and 2 million tons CO_2-reduction, respectively.

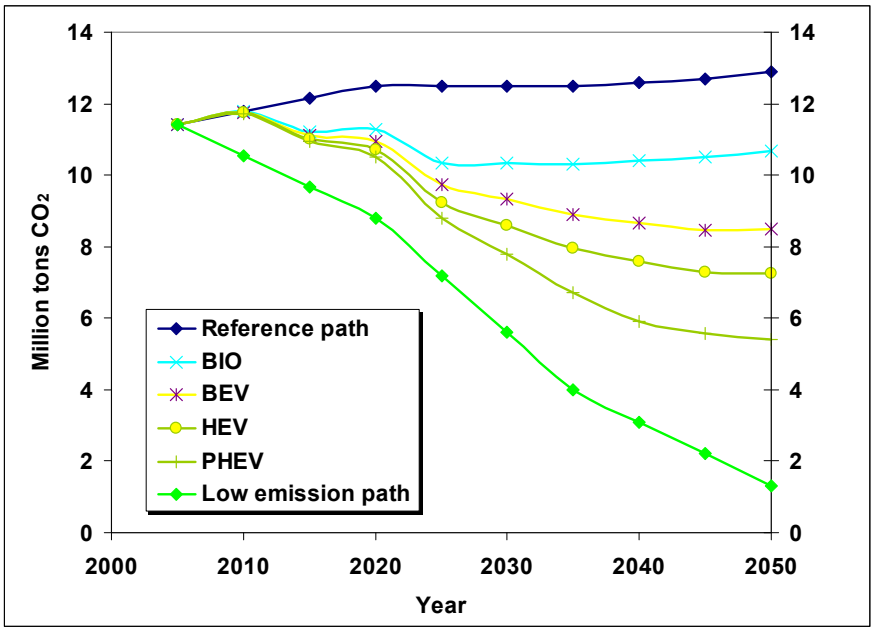

Figure 4.4: Contribution to emission reductions for Scenario A, given the composition of vehicles shown in Figure 4.3. Biofuels are reserved for heavy duty vehicles and alone reduce emissions by ~ 2 mill. tons/year, by covering 62% of their fuel demand in 2050.

PHEV replacing of HEV in Scenario A

Plug-in Hybrid Electric Vehicles (PHEVs) may contribute to increase the penetration of electricity into road transportation, as PHEVs emit far less CO_2 than HEVs for comparable drive cycles (Section 3.1). In this scenario, an all-electrical range of PHEVs of 32 km (20 miles) is assumed. This makes the PHEV the customer's first choice for a family car, given that electricity prices give substantial lower operation costs. Assuming the same penetration rate for PHEVs as for HEVs (Figure 4.2), an additional reduction in CO_2-emission of between 1.5 and 2 mill tons in 2050 is estimated. The large uncertainty in this number is due to the lack of detailed information on the drive pattern (distribution of vehicle distance travelled) for Norwegian transportation.

[6] Current average lifetime of Norwegian private cars is 19.7 years (2006). This implies that around 5% of the car pool is exchanged every year. Several factors may alter this figure dramatically, including increasing the scrap vehicle cash-back, very high cost of conventional fuels etc.

As can be concluded from Figure 4.4, the predicted Low emission path for road transportation cannot be reached by the massive introduction of low-emission vehicle technologies such as BEVs and HEVs/PHEVs in the private car segment alone, supplemented by utilising domestic biomass as fuel source for heavy duty vehicles.

Scenario B: Massive introduction of hydrogen vehicles from 2020

In agreement with expectations for commercialisation of fuel cell (FC) technology [EC IP 2006], a massive introduction of hydrogen FC hybrid electric vehicles (FCHEV) is assumed from 2020 in Scenario B. The shares of new cars are depicted in Figure 4.5. In an interim period of about 30 years PHEVs are foreseen to take a dominating share of the new low emission cars' market. Battery Electric Vehicles are introduced like in Scenario A. The corresponding car pool composition is shown in Figure 4.6.

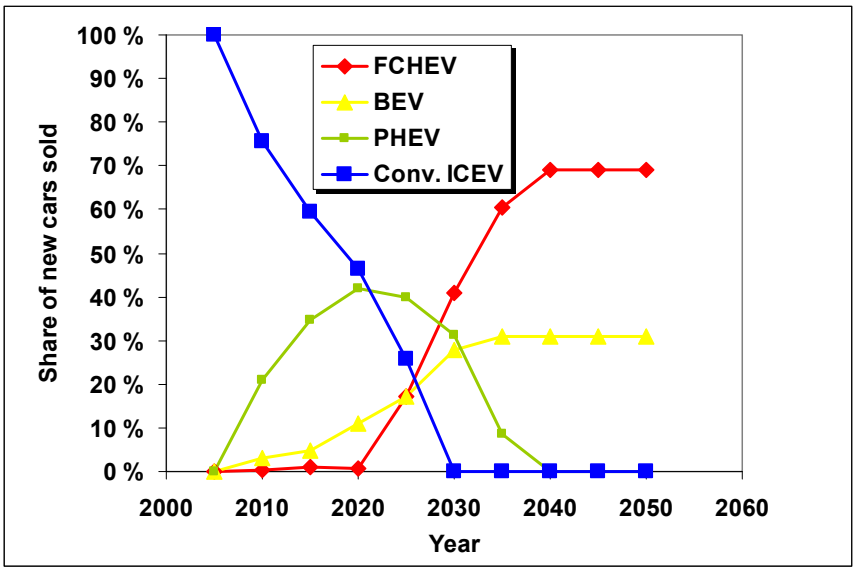

Figure 4.5: Share of new cars sold in Scenario B, expecting a massive introduction of hydrogen powered FCHEVs from 2020 and sales of Conventional ICEVs being banned after 2030.

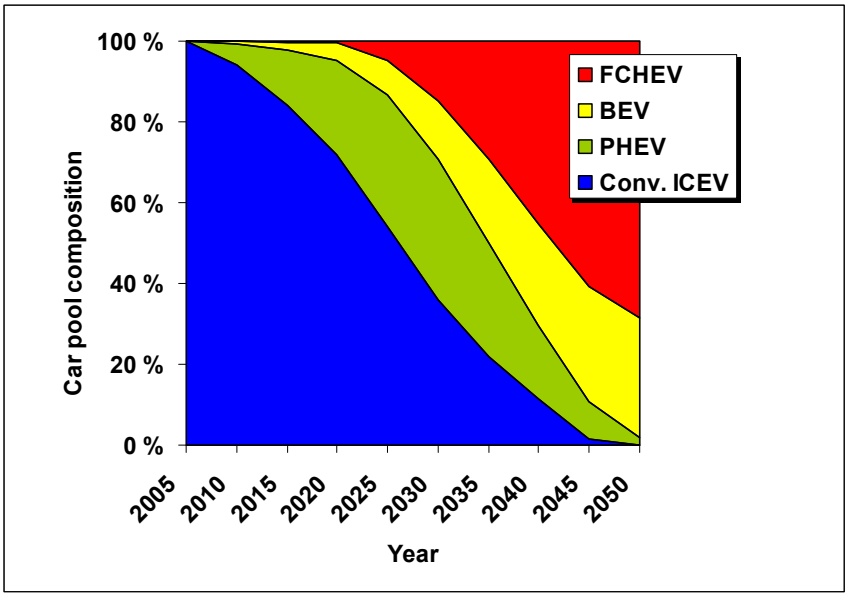

Figure 4.6: Estimated shares of vehicles in car pool when vehicles are introduced according to Scenario B (Figure 4.5).

The emission reductions for Scenario B are depicted in Figure 4.7. The reduction obtained still does not fully comply with the Low emission path. Comparison of Figures 4.4 and 4.7, however, shows that replacing fossil fuelled PHEVs with hydrogen powered FCHEVs contributes by another 2 million tons of CO_2 emission reduction.

The Well to Wheel (WtW) emission from hydrogen vehicles depends on the source for hydrogen production. In this scenario hydrogen is assumed produced from natural gas (NG) and renewable electricity (by water electrolysis (ELY)) is considered. When based on NG, 85% of the carbon is taken care of by the Carbon Capture and Storage (CCS)-process. Hence the emission reduction from utilising hydrogen vehicles in both cases is substantial as shown by the two red curves in Figure 4.7.

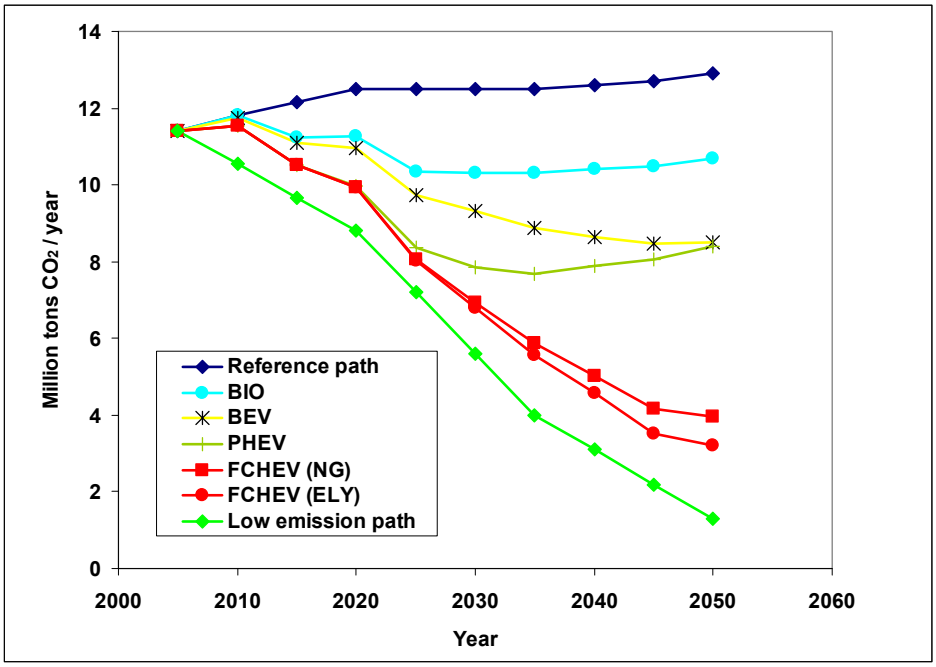

Figure 4.7: Contributions by various vehicles to emission reductions for Scenario B, following the introduction of low emission vehicles as given in Figure 4.6.

The extensive hydrogen vehicle introduction of Scenario B requires a corresponding expensive infrastructure development (Section 5.5).

Conclusions from scenarios

Scenario B indicate that the Low emission path is within reach taking into account that additional reductions would be achievable from

1. Hybridization of public transport (buses) not included in the scenarios
2. Importing and substituting biofuels for the remaining fossil fuel demand for heavy duty vehicles not covered by domestic biofuel production

Scenario A shows that Plug-in Hybrid Electric Vehicles takes us 2/3rd down the road, but Scenario B reveals that fuel cell vehicles powered by hydrogen based on RES or natural gas with CCS are required to comply with the prediction of the Commission of Low Emissions [NoU 2006:18].

It should be stressed that hydrogen production from fossil sources without CCS or the failure of FCHEV commercialization by 2020 would alter these conclusions dramatically. Assuming another electricity mix than the Norwegian (which is dominated by hydropower) would also give a very different picture. The figures obtained here are thus not generally valid given other assumptions and energy system characteristics.

Limiting factors for the desired development

Rising crude oil prices

Liquid hydrocarbon fuels derived from crude oil provide ninety-five percent of the primary energy consumed in the transport sector worldwide. There is no other sector which is so utterly reliant on a single source of primary energy, and this fuel specificity represents a unique threat to both the environment and global security [WWF].

Inherently one may argue that renewable alternatives to crude oil would benefit from high oil prices. As oil prices climb to ever new top notations, however, alternative, less accessible sources for increased oil production such as oil sand may become economically profitable to exploit (ref. section 2). Preference for investing in such fossil source exploitation at the sacrifice of investments in renewable energy sources is seen.

High share of fossil energy in stationary power production

Sources for electricity vary dramatically from region to region. The substantial share of fossil fuel in the average global electricity mix dramatically hampers the benefit of introducing electrical vehicles such as BEVs and PHEVs. Availability and development of Renewable Energy Sources (RES) for fuel production is required to fully take the advantage of these promising propulsion technologies.

An example to illustrate this point:

A Battery Electric Vehicle (BEV) charged from the electricity grid in Indiana, US, would release 20 % more CO_2 than a conventional diesel powered ICE vehicle, due to the high share of coal and low efficiency of power in the electricity mix [WWF 2008]. On the contrary, a BEV based on Norwegian electricity mix be truly zero emission. Substantial introduction of BEVs and PHEVs in Norway must be seen in relation the fact that there is currently a shortage in electricity production in dry years, resulting in import of electricity from Europe.

Limited energy storage capacity in energy systems

As intermittent Renewable Energy Sources (RES) are introduced into the energy system, a substantial deviation/discrepancy between RES-production and energy demand will result, requiring large-scale energy storage. Introduction of substantial numbers of PHEVs represents viable energy storage capacity, by e.g., allocating 10% of the battery capacity of all PHEVs for such storage. For short time storage this may cover a certain percentage of the energy storage requirements. For longer time storage, hydropower magazines represent substantial storage capacity. For large scale seasonal storage of energy, however, electrochemical energy storage is needed. Electrochemical flow batteries may represent interesting solutions, but with the additional feature of being a true zero emission fuel for transportation, hydrogen is foreseen as the optimal energy storage medium.

Availability, cost and performance of new alternative technologies

Several technological limitations are encountered, potentially hampering the transition to the emission free transportation scenario. Technology break-through is needed both for battery and fuel cell technologies. For battery technology, energy density, cost and charging time are limiting factors for widely use of BEVs and PHEVs. The all electric range depends on successful development of the Li-based battery technologies (ref section 3.1). Fuel cell technology exhibit adequate performance, but suffers from high cost and limited durability. Especially the limited availability of Platinum used as

catalyst material in PEM fuel cells constitutes a major obstacle. These technological limitations coincide with the R&D-requirements listed in section 7.

Infrastructure for hydrogen as well as charging spots for BEV and PHEVs

Electricity and hydrogen are only energy carriers and their production must be based on various energy sources. The first public charging spots for electrical powered vehicles (BEVs and PHEVs) are currently being built in Oslo. Expenses are expected to be acceptable, but as the numbers of EVs increase, especially in larger cities, the grid capacity is may need a capacity upgrade causing substantial investments.

Currently there are around 300 hydrogen refuelling stations world-wide [H2-stations]. In Norway only two refuelling stations provide hydrogen (Stavanger and Porsgrunn), two more being financed recently. The cost of establishing a fully developed world-wide infrastructure for hydrogen has been estimated by IEA to be US $ 2.5 trillion [IEA 2005]. Figures for the US are in the range of $ 200 billion corresponding to approximately 1,5 % of US' GDP (13.3 Trillion in 2006). Recent estimates for Norway indicate an investment of € 1,2 Billion (~10 Billion NOK) [NorWays].

Large investments in existing technologies' and fuels' production

Heavy industrial engagement from energy as well as automotive companies represents a lock-in effect. New alternative fuels and power trains tend to be more expensive than conventional Internal Combustion Engines (ICEs), inducing a certain risk for auto manufacturers to invest in new technologies and heading for future markets with uncertain sales numbers. Long term and foreseeable political framework would facilitate increase industrial investments in alternative fuels and technologies.

Lack of coordinated political incentives and strategies

Political commitment to international agreements on emission reductions is currently strengthened. Still there are numerous examples of national political incentives resulting in sub-optimal solutions. One example is the substantial feed in tariffs incentive for introduction of RES in Germany, which have resulted in installation of wind mills. A better coordinated European energy policy would assure that these numerous wind mills be installed in areas with far higher average wind speeds, e.g., in Norway.

China's pledge from 2006 of allocating 10% of the GDP to development of renewable energy sources [WWF 2008] represents a strong political commitment to solving global problems as well as meeting dramatically growing national energy needs.

Adequate funding of R&D as well as demonstration projects

The levels of funding for introduction of RES, alternative fuels and new propulsion technologies have been far too low to facilitate and sustain an adequate R&D activity within the recommendations areas given in section 7. In Norway at least 1% of the income from vehicle and fuel taxation (~50 billion NOK/year) should be allocated to alternative fuels and new propulsion technologies. Totalling 500 mill. NOK/year, 300 million should be allocated to demonstration and infrastructure development, whereas 200kNOK should be earmarked R&D activities in this area (ref. sections 7 and 8).

Unused potentials

Off-peak and peak power for transportation

Production and grid capacity is dimensioned to cope with peak demand. Thus, off-peak power from existing stationary power generation plants represents a substantial potential for charging BEVs as well as PHEVs. The benefit of utilising off-peak power naturally varies with the characteristics of the energy system. In this respect the Norwegian electricity production dominated by hydro-power differs significantly from e.g., European or US electricity generation.

Peak power from intermittent RES also constitutes a significant source for both charging electricity vehicles but also for hydrogen production. Typical situations would be utilising peak power from a wind park when the electricity demand or grid capacity is lower than the available RES production capacity.

Synergies between stationary power and fuel production

The transportation sector cannot be seen as isolated from stationary power generation, simply because the energy resources are shared between the two sectors. Simultaneous assessment of utilising energy resources across stationary and transportation reveal substantial synergetic effects; For an electric vehicle travelling 12.000km/year the total electricity demand is estimated at approximately 2000kWh[7]. In search for available electricity for this purpose, knowing that we in dry years import electricity from Europe, one should look at alternatives such as:

- Installing more heat pumps in residential buildings:
  A heat pump may save 3-5000kWh for an average single family house, enough to power 2 electrical vehicles!
- Install solar cells on the roof, even in Norway:
  Assuming a conservative 100kWh output/year, 20 m^2 (or 4x5meter) would generate 2000kWh, enough to power one electrical vehicle!

Biomass

Norway has compared to e.g., Sweden and Finland, utilised a far lower share of the available biomass resources. However, to fully utilise the energy content, biomass should preferably be reserved for stationary Combined Heat and Power (CHP) generation giving a far better total energy utilisation. If utilised for transportation, biofuels should be reserved for certain transport segments such as heavy duty vehicles, and the aviation and maritime sectors where other viable alternatives are hard to find. Co-firing with gasified biomass in natural gas power plants utilising CCS-technology may actually represent a sink for CO_2, providing a negative CO_2-foot-print.

Natural gas with CCS for hydrogen production and export

European energy and automotive companies have concluded that hydrogen will be a preferred fuel of the future [TES 2007]. In a recent paper we have assessed the potential export of hydrogen as fuel for the European market produced from natural gas (NG) and wind power. It was concluded that H_2 production in the GW-scale may well represent a commercially interesting option for increasing the value of Norwegian NG and meet the predicted demand for hydrogen in the European transportation sector [Stiller et al 2008]. The topic was also addressed by Andreassen [Andreassen 1993].

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[7] Information from CalCar developing the Prius+ PHEV, measuring 6,2 km/kWh [WWF 2008].

R&D required to reach sustainable road transportation

Fostering the introduction of renewable energy sources replacing crude oil as the primary energy source for transportation require increased R&D in a wide range of areas such as:

Renewable energy technologies

Further development of Renewable energy technologies including

- Improved efficiency for existing hydropower plants,
- New materials and processes for more efficient and low cost solar cells,
- Development of off-shore wind turbines,
- New concepts for harvesting wave and tidal energy,
- Bio-fuel production by 2nd generation technologies utilizing ligno-celluloses in advanced bio-refineries

Hydrogen technologies

- Hydrogen-production from
  - Renewable energy sources by water electrolysis
    Alkaline as well as PEM water electrolysis technologies
  - Natural gas with Carbon Capture and Storage
    linked to development of pre-combustion solutions
- Hydrogen Storage and Distribution
  - Focus on development of storage solutions compatible with requirements for automotive applications
  - Components and new concepts for H_2 refuelling stations
- Hydrogen end use technologies
  - Fuel Cells
  - Combustion technologies

Biomass exploitation and utilisation for CHP and biofuels

For R&D requirements in this area, please refer to bio-roadmap [Bioroadmap] and elements from Bio-strategy [BioStrat 2008].

Energy System analysis for optimum resource utilisation

- Assessment of energy production and use across stationary power generation and transportation for identification of synergies between the sectors.
- Grid-related issues linked to introduction of EVs (bi-directional energy flow)
- Optimal development of infrastructure for el and H_2-vehicles

Societal and socio-economic issues

- Behavioural change
  - Studies of how behavioural change may be promoted by policy measures which enhance the attractiveness of alternatives to private car use.
  - Identification of economical thresholds for customers to alter travel habits
- Development of adequate regulatory measures and taxation for promoting sales of more environmentally sound vehicles.
- Assessment of how a combination of taxes and regulations may facilitate introduction of improved technology altogether may alter travel habits
- Establishment of methodology for quantification of the effect of various measures.

Recommendations to Norwegian politicians:

Recently, Norwegian politicians have devoted significant attention to the problems related to global warming. This spring (2008) the political parties came to a National climate agreement (Klimaforliket) and allocated a significant amount of funds to address the challenge of global warming.

Transportation has, however, neither before nor after this agreement received adequate attention. The establishment of TRANSNOVA as part of Klimaforliket, represents the exception. This new public body belonging to the Ministry for Transportation & Communication will administer 50 million NOK/year from 2009-2011.

The following concrete actions are recommended to Norwegian politicians for the transportation sector in their climate change abatement:

- **Follow up on the strategies and recommendations given through the**
  - Report from the Commission of Low Emissions [NoU 2006:18]
  - Bio-road map [Bioroadmap] and the Biomass strategy [BioStrat 2008]
  - Action Plan for 2007-2010 from the National Hydrogen Council [HHP]
- **Develop, strengthen and actively use TRANSNOVA**
  The establishment of TRANSNOVA represents a unique political opportunity to address the significant challenges imposed by emissions from transportation. By developing a robust public body and allocating the required funds to demonstrate alternative fuels and new propulsion technologies for transportation, TRANSNOVA will constitute a key to solving emission problems.
- **Implement Public Purchasing of best available technologies**
  to facilitate introduction of improved vehicle technologies and alternative fuels.
- **Develop strong political incentives for purchasing low emission vehicles**
  Follow up and further shift taxes towards vehicle emissions to facilitate the transition to a more environmentally sound transportation sector. Preferably also reduce the average age of vehicles on Norwegian roads from 19.7 years.
- **Transfer transport of goods to low emission sectors**
  primarily from road to maritime and rail by applying strong political incentives
- **Establish and implement technology-neutral standards**
  Setting of technology-neutral standards is generally favoured over technology-specific mandates. In practice, the outcome will be that certain options are automatically excluded by the setting of standards, but this is essentially weeding out the losers, which is not the same as *'picking winners'* [WWF2008].
- **Raise funding for R&D and demo to an adequate level of 500 mill NOK/year**
  Until 2006 The Norwegian ministry of Transportation and Communications allocated a total of ~ 23 mill NOK to alternative fuels, a mere 0.1 % of the Ministries' total budget. Compared to the income from vehicle taxes (approx. 50 billion NOK in 2007, Ministry of Finance) the increase through the establishment of TRANSNOVA to 50 million NOK/year is marginal. This reflects the lack of political commitment to changing transportation to a more environmental sound sector. By increasing the funding to 1% of the vehicle tax income (500mill NOK/year) it will be possible to address the challenge adequately by:
  - Demonstrating and facilitating introduction of best available technologies through TRANSNOVA (300 mill NOK/year) and
  - supporting R&D for next generation and improved technologies through the Research Council of Norway (200mill NOK/year).

List of Abbreviations and Acronyms:

BEV	Battery Electric Vehicle
BTL	Biomass to Liquid
CCS	Carbon Capture and Storage
CHP	Combined Heat and Power
EV	Electric Vehicle
FCHEV	Fuel Cell Hybrid Electric Vehicle
GDP	Gross Domestic Product
GHG	Greenhouse Gas
HEV	Hybrid Electric Vehicle
HHV	Higher Heating Value
IEA	International Energy Agency
ICE	Internal Combustion Engine
ICEV	Internal Combustion Engine Vehicle
IPCC	Intergovernmental Panel on Climate Change
kWh	Kilowatt-hour (unit of measure: energy)
LHV	Lower Heating Value
PEM	Proton Exchange Membrane (fuel cell)
PHEV	Plug-in Hybrid Electric Vehicle
TtW	Tank to Wheel
WtW	Well to Wheel
WWF	World Wide Fund for Nature (formerly World Wildlife Fund)
ZEV	Zero-emissions Vehicle

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