



2011 Technology Map of the European Strategic Energy Technology Plan (SET-Plan)

Technology Descriptions



EUR 24979 EN - 2011

The mission of the JRC-IET is to provide support to Community policies related to both nuclear and non-nuclear energy in order to ensure sustainable, secure and efficient energy production, distribution and use.

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2011 TECHNOLOGY MAP

of the European Strategic
Energy Technology Plan

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Preamble

The swift deployment on a large scale of technologies with a low-carbon footprint in the European energy system is a prerequisite for the transition to a low-carbon society - a key strategic objective of the European Union. A necessary condition for the timely market roll-out of these low-carbon energy technologies is an acceleration of their development and demonstration. This is catalysed by the European Strategic Energy Technology Plan (SET-Plan) through the streamlining and amplifying of the European human and financial resources dedicated to energy technology innovation. SETIS, the SET-Plan information system, has been supporting SET-Plan from its onset, providing referenced, timely and unbiased information and analyses on the technological and market status and the potential impact of deployment of low-carbon energy technologies, thereby assisting decision makers in identifying future R&D and demonstration priorities which could become focal areas for the SET-Plan.

The Technology Map is one of the principal regular deliverables of SETIS. It is prepared by JRC scientists in collaboration with colleagues from other services of the European Commission and with experts from industry, national authorities and academia, to provide:

- a concise and authoritative assessment of the state of the art of a wide portfolio of low-carbon energy technologies;
- their current and estimated future market penetration and the barriers to their large-scale deployment;
- the ongoing and planned R&D and demonstration efforts to overcome technological barriers; and,
- reference values for their operational and economic performance, which can be used for the modelling and analytical work performed in support of implementation of the SET-Plan.

This third edition of the Technology Map, i.e. the 2011 update, addresses 20 different technologies, covering the whole spectrum of the energy system, including both supply and demand technologies. The transport sector has however not been addressed, as this has been the focus of the European Strategic Transport Plan, which, at the time of writing, is under development.

Feedback from the previous editions has shown that the Technology Map has been used by national authorities for setting their own R&D and demonstration priorities; and by the research community as a source of authoritative information on energy technologies. We hope that this edition will continue to serve this purpose, whilst at the same time, serving as an invaluable tool for the ongoing implementation of the SET-Plan.

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1 Wind Power Generation

1.1. Introduction

Wind power is the renewable energy which has seen the widest and most successful deployment over the last two decades, from 3 GW to 200 GW of global cumulative capacity. In Europe, in 2010, five countries sourced more than 10 % of their electricity from wind and wind energy will provide at least 12 % of European electricity by 2020, therefore significantly contributing to the 20/20/20 goals of the European energy and climate policy.

1.2. Technological state of the art and anticipated developments

The kinetic energy of the wind is transformed into mechanical energy by the rotors of wind turbines and then into electricity that is injected into the grid. Wind speed is the most important factor affecting turbine performance because the power that can be extracted from the wind is proportional to the cube of the wind speed, e.g. an increase in the long-term mean wind speed from, for example, 6 to 10 m/s (67 %), causes a 134 % increase in production [EWEA, 2009]. Wind speed varies depending on the season, location, orography and surface obstacles and generally increases with height, creating the wind shear profile. Surface obstacles, such as forests and buildings, decrease the wind speed, which accelerates on the windward side of hills and slows down in valleys. Annual variations up to 20 % are normal.

A wind turbine starts to capture energy at cut-in speeds of around 3 m/s (11 km/h) and the energy extracted increases roughly proportionately to reach the turbine rated power at about 12 m/s (43 km/h), remaining constant until strong winds put at risk its mechanical stability, thereby forcing the turbine to stop at cut-out speeds of around 25 m/s (90 km/h).

Once stopped and secured turbines are designed to withstand high wind speeds of above 60 m/s (216 km/h). Generally, utility-scale wind power plants require minimum average wind speeds of 6 m/s.

There are two main market sectors: onshore and offshore wind. The differences include complication of installation, working environment (saline and tougher at sea) and facility of access for installation and maintenance. In addition, as the wind is stronger and more stable at sea, wind turbine electricity production is higher offshore. Current onshore wind energy technology certainly has room for further improvement, e.g. locating in forests and facing extreme weather conditions, yet it is a mature technology. Offshore wind, however, still faces many challenges. There is a third sector, small turbines (up to 10 kW) for niche applications such as isolated dwellings, but this sector is unlikely to provide a significant share of the European electricity supply.

At the end of the last century, a wind turbine design (the three-bladed, horizontal-axis rotor) arose as the most cost-effective and efficient. The main technological characteristics of this design are: an upwind rotor with high blade and rotor efficiency, low acoustic noise, appropriate tip speed; active wind-speed pitch regulation; variable rotor speed with either a gearbox connected to a medium- or high-speed generator or direct rotor connection to a low-speed generator; and concrete, steel or mix towers.

An alternative design around a rotor with a vertical axis, e.g. Vertiwind [Technip] and Aerogenerator X,¹ is meant to have key advantages in particular for offshore wind farms. The equipment is placed just above sea level which enormously facilitates installation and maintenance. However turbines based on this concept are yet to be built commercially.

¹ <http://www.windpower.ltd.uk>

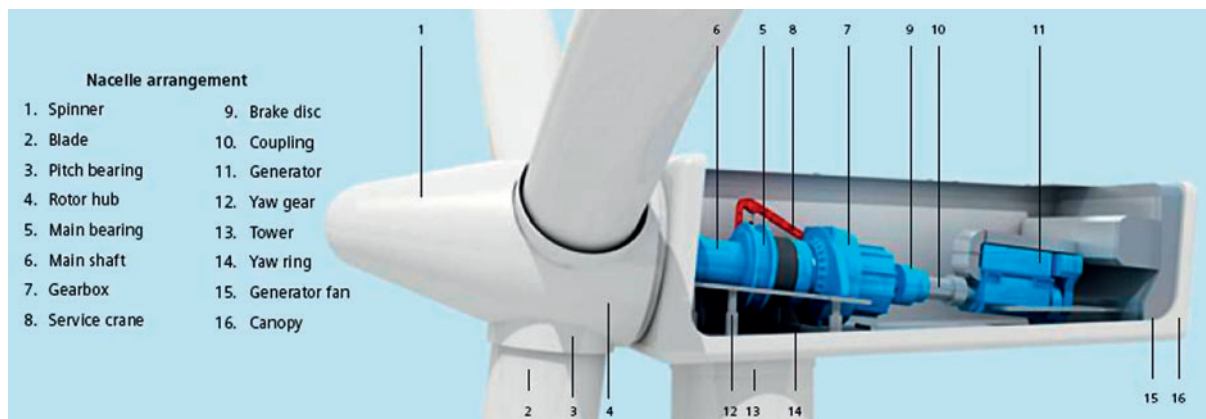


Figure 1.1: Geared wind turbine [Source: Siemens]

The main driver for developing wind technology is to minimise the cost of energy (CoE) production, for which efforts focus on minimising capital costs and maximising reliability. These drivers translate into: design adapted to the wind characteristics; grid compatibility; aerodynamic performance; and adaptation for offshore. Technical considerations that cover several of these goals include turbine weight reduction; larger rotors and advanced composite engineering leading to higher yields; and design for offshore installation, operation and maintenance.

Throughout the years the electricity grid codes in the EU-27 Member States (MS) have become stricter and now require that wind turbines highly support the grid by having, for example, fault ride-through capabilities, as well as a high-quality electricity output. The consequence is the evolution of wind turbine technology -as reflected by turbine configuration- from the initial machines' fixed rotor speed with stall control (type A) through minimal variable-speed drive introducing pitch control (type B), then the doubly-fed induction generator (DFIG, type C) allowing higher variable speed configuration, and type D which allows the rotor to freely adapt its speed to the wind (thus maximising energy uptake) while using full power electronics converters, to provide the best-quality electricity to the grid. The added market share of the last two configurations has increased from 44 % of installed capacity in 2000 to 84 % in 2009 [Llorente Iglesias et al., 2011].

The production of the magnetic field in wind turbine electricity generators is the object of another key technological evolution, from electromagnets to permanent magnets. The former included simple squirrel-cage (SCIG) and then wound-rotor (WRIG) induction generators, then compact DFIG and full-size, low-speed electromagnet generators (LS-EMG) in a turbine without a gearbox. New designs are substituting electromagnets with permanent magnets (PMG) on the grounds of increased reliability, higher partial-load efficiency, and more flexibility of integration with compact gearboxes or power electronics. However, this change is not without problems because of supply/demand unbalances of the basic raw materials needed for permanent magnets (rare earth elements) which lately have triggered escalating prices, and because the main world supplier, China, has set up tight export quotas. Last but not least, ores of rare earths are often found mixed with radioactive materials and its mining and the disposal of its waste presents additional environmental challenges.

Key issues for offshore wind include: reducing maintenance stops; safe access for staff when the sea is rough (the technological evolution of the access vessels determines how rough a sea they can withstand and thus the number of days that they can guarantee access to turbines); improving the design of the coupling between foundation/installation vessels to reduce installation time and to increase the number of working days; cost-effective foundations/installation for deeper waters and further-offshore sites; and reducing the cost of interconnection, currently about 20–25 % of the CapEx. Interwoven with those issues is the reliability of offshore wind turbines: the more reliable they are the less access is needed for corrective maintenance. In addition, the development of floating foundations is accelerating and the first deep-water wind farm could be envisaged for 2015.

The trend towards ever larger wind turbines, which slowed in recent years, has resumed. The largest wind turbine now in commercial operation has a capacity of 7.5 MW, and most manufacturers have introduced designs of turbines in the 4.5 – 10 MW range (up to a total of 42 different designs) mostly for offshore use. Table 1.1 includes a sample of current or recently-presented large turbines, whilst 10 MW designs have been presented by Sway (Norway), Clipper (US) and AMSC Windtec (US-AT). Both industry and academia see even larger turbines (10 – 20 MW) as the future of offshore machines [TPWind, 2010].

Rotor diameters which, in general stabilised since 2004 at around 100 m, have, during the last two years, started to grow again and nowadays a significant number of turbine designs include rotors greater than 110 m. In Figure 1.2, it can be seen that for rotor sizes between, for example, 115-120 m diameter, a very wide range of turbine electrical capacity from 2 to 6.5 MW is offered. The main reasons are commercial and the adaptation to local wind conditions.

Tip speed is limited by acoustic noise and turbines might be requested to operate at reduced speed in noise-sensitive areas. However, offshore, the tip speed can increase to above 80 m/s thus increasing electricity production. Pitch control is the technology of choice for controlling rotor speed, coupled with variable-speed regulation. Drive trains tend to reduce their weight and offshore turbines tend to stabilise hub heights at 80 - 100 m. This is because offshore wind shear is lower and there is a trade-off between taller towers yielding slightly higher production but needing heavier, increased foundation loads involving higher tower and foundation costs [EWEA, 2009]. Offshore foundations for deeper waters

Manufacturer	Model	Capacity (MW)	Technology	Status
Vestas	V164-7.0	7.0	MS-PMG	Prototype expected for 2014
Sinovel	SL5000	5.0	HS-DFIG	Prototype installed in 2010
Sinovel	SL6000	6.0	HS-SCIG	Prototype installed in 2011
GE Energy	4.1-113	4.1	LS-PMG	Prototype expected for H2, 2011
Goldwind/Vensys	GW5000	5.0		Prototype in 2010
Goldwind/Vensys	GW6000	6.0	LS-PMG	Prototype expected for late 2011
Enercon	E126-7.5	7.5	LS-EMG	Commercially available
REpower	5M	5.0	HS-DFIG	Commercially available
REpower	6M	6.15	HS-DFIG	Commercially available
Nordex	N150/6000	6.0	LS-PMG	Prototype expected for 2012
XEMC-Darwind	XD115	5.0	LS-PMG	Prototype installed in 2011
Siemens	SWT-6.0-120	6.0	LS-PMG	Prototype installed in 2011
Alstom Wind		6.0	LS-PMG	Prototype expected for 2012
Areva Multibrid	M5000	5.0	MS-PMG	Commercially available

[PMG = permanent magnets; EMG = electromagnets and LS/MS/HS=low/medium/high speed; LS is necessarily a direct-drive machine, HS involves a 3-stage, conventional gearbox and MS is a hybrid]

Table 1.1: A sample of large wind turbines in the market or being introduced

(30-60m) are expected to diversify away from monopile steel into multi-member (jackets, tripods) and innovative designs such as *tribucket*, twisted jacket, suction bucket monopile and even concrete-based structures [CT, 2011].

Figure 1.2: rotor diameter vs. power in 500+ wind turbines [Source: JRC]

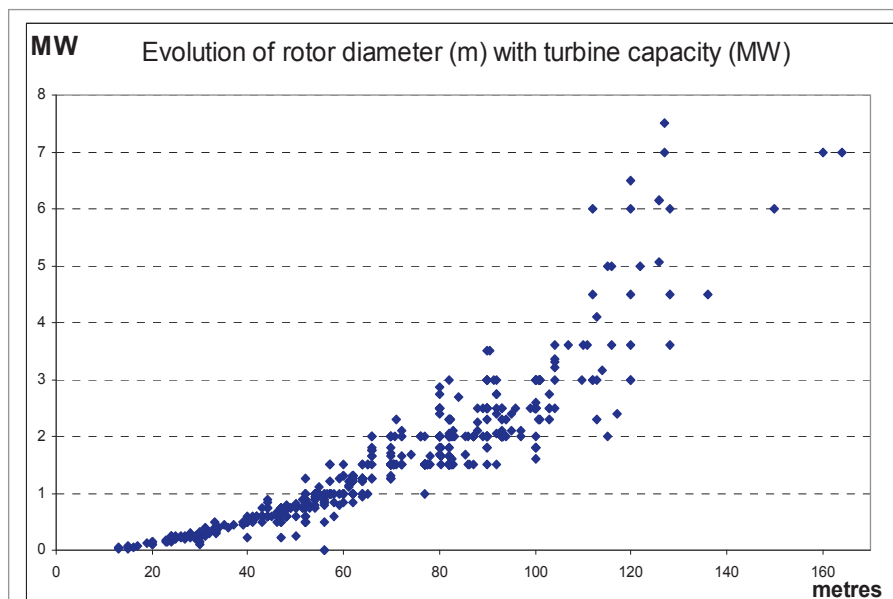


Figure 1.2: rotor diameter vs. power in 500+ wind turbines [Source: JRC]

The cost of wind energy depends on the cost of raw materials; technology fundamentals; supply bottlenecks (e.g. limited competition in offshore cable supply); market supply/demand balance; administrative barriers (permit process etc., including those caused by NIMBYism); payments for wind electricity, e.g. feed-in tariffs (FiT), FiT premium, market + premium, competitive tender, cash grant, etc.; and on risks and uncertainties impacting on the investors and lenders.

Upto 2004, turbine prices declined, influenced by technology learning and the increasing volumes of production. Supply/demand imbalances and the increase of raw material and component prices pushed up onshore turbine prices to around €1 150/kW in 2009, when the reduction in raw materials costs caused by the financial crisis, manufacturing overcapacity and

increasing competition pushed down prices to around €950/kW by mid-2011, with the Spanish and Italian markets showing the lowest prices [BNEF, 2011b]. Beyond Europe, the US at €790/kW (at 1 EUR = 1.4 USD) and China at €438/kW (at 1 EUR = 9.2 CNY) showed lower prices [BNEF, 2011a, 2011b]. Price quotes include transport to the site but not installation. The high price of turbines did not turn into high profits for their manufacturers, as European wind turbine manufacturers published 2010 EBIT in the range of 4-7 %, whilst Chinese ones did much better at 14-16 % [BNEF, 2011a]. Offshore turbine prices are in the range of €1500/kW [MML, 2011].

Similarly, European capital investment (CapEx) for onshore projects showed a reduction to €1 000/kW in 2003/4, and then climbed to reach its peak in 2008, then down to around €1 250/kW in 2010 [EU, 2011]. In the USA, the DoE suggests for a CapEx level around €1 600/kW [DoE, 2011]. Offshore CapEx have been even more affected by supply-chain limitations and the difficulties of working offshore, and showed strong price increases from €2 200/kW in 2007 to €3 000-4 200/kW in 2011 with the upper end covered by farther offshore, deep-water wind farms [JRC]. MML [2011] suggests that raw material costs are not that significant but instead prices of offshore wind include a market premium in the order of 20 %. This is notably higher than for onshore wind due to significant risks related to both construction and operation.

Onshore operation and maintenance (O&M) costs are estimated at €21/MWh (or €47/kW/yr at a 25 % capacity factor) and, over a 20-year operation period, constitute 35-45 % of total costs. They have presented a declining trend from the €35/MWh for the old 55 kW wind turbines [EWEA, 2009]. Offshore O&M costs are in the €25-40/MWh (or €106/kW/yr at a 40 % capacity factor) range with a European average of €30/MWh [EU, 2011] and towards the upper range for farther offshore installations.² The cause of these high costs is mainly the high fixed cost of getting access to the turbines, even when the higher production partly compensates for the difference. Offshore insurance costs, on top of O&M, can be as high as €5-12/MWh.²

The technology learning effect is presented in terms of a turbine-cost progress ratio (PR), and a PR of 90 % caused cost reductions up to 2003 [NEEDS, 2006; Junginger, 2007], but then this learning effect was overcome by market factors causing prices to increase. It is very difficult to estimate the technology learning effect in offshore technology because market and project aspects (e.g. farther offshore

wind farms) have had a much higher influence in turbine prices and project costs. Offshore wind experienced a period of fierce competition (2000 - 2004) which reflected in neutral PR and, since 2005, a PR above 100 % showed the continuous increase of capital costs [GH, 2009] in what can be seen as negating technology learning. During the last six years, offshore technology R&D has focused on increasing the reliability of turbines which brought about an increase in capital cost - although the cost of energy benefited from the increased reliability.²

The expected capital investment trend is for onshore capital costs to reduce further due to non-technological factors - such as the entry into the competition of Chinese turbine suppliers and the increasing size of turbine blades - playing a significant role, and then to stabilise. Without doubt technology will continue to progress but, as wind turbines are viewed as some kind of commodity, it is likely that non-technological factors will have a stronger influence in the onshore turbine price. Offshore wind is expected to maintain high costs until 2015 but it has more room for factors including technology improvements (e.g. to reduce foundation and installation costs), learning-by-doing, improved supply chain and more competition which could lead to a reduction of 28 % by 2020 [MML, 2011].

The integration of wind energy into the electricity grid can occasionally involve other costs including the reinforcement of grids, the need for additional balancing power and ancillary services. The first two items have been evaluated in Denmark, per MWh of wind electricity, at €0.1-5 (for 30 % wind share) and €1-4 (20 % wind share), respectively [Krohn et al., 2009]. A range of studies in the US shows that costs for wind energy integration of up to 40 % are below €7.5/MWh, and often below €3.8/MWh [DoE, 2011]. These costs can be reduced through creating larger balancing areas, reducing the wholesale market gate-closure times to 4 - 6 hours, more frequent intra-day markets, intra-hour scheduling (e.g. 5-minute scheduling) and better forecasting used by system operators. There is also room for low-cost improvement by optimising the grid operational procedures [DoE, 2011].

² Personal communication with leading European turbine manufacturers, developers, and industrial intelligence companies during the course of the summer of 2011, in the context of [EU, 2011].

Curtailed is a problem of increasing impact. Curtailment is the forced stopping of wind electricity generation following instructions from grid operators. This happens mostly in two cases, either there is excess (overall) electricity production compared to the existing demand (e.g. on a windy Saturday night), or the local wind generation is larger than what can be absorbed by the transmission lines to the centres of demand. Curtailment is not regularly quantified in Europe, and it is expected to remain limited, but elsewhere curtailment is having a strong impact: 17 % in Texas in 2009 reduced to 8 % in 2010 after a new line was built [DoE, 2011], as well as 17 % in Inner Mongolia in China [CCBIS, 2011].

The discussion on costs of generating wind energy often overlooks the fact that this energy is sold in wholesale markets where all electricity negotiated receives the price conceded to the marginal supplier, i.e. the most expensive supplier accepted to generate. In this context, zero-fuel-cost technologies, such as wind, displace fuel-dependent, expensive technologies and therefore reduce the marginal price applied to all electricity traded (and not just for wind power). In periods of high fossil fuel prices, the resulting multiplying effect overcompensates for any subsidy that wind might receive. Calculations in Denmark quantified the related savings, over the period 2004 - 2007, at an average of €3.3/MWh of traded electricity. This figure, due to a 20 % wind share, is equivalent to a saving of €16.5/MWh for (only) wind-generated electricity [Krohn et al., 2009]. These benefits do not take into account the increased security of supply, reduction in price volatility and the oil-GDP effect, nor the cost of purchasing carbon under the European Trading Scheme.

The system availability of European onshore wind turbines is above 97 %, among the best of the electricity generation technologies [EWEA, 2009], although because malfunctions occur most when the wind is blowing strong this 3 % unavailability translates into a higher lost production of maybe 5 %.² The typical capacity factors onshore are 1 800 – 2 200 full-load hours equivalent (in which a wind turbine produces at full capacity), and 3 000 – 3 800

offshore, for a European global average of 1 960 hours.³ Technology progress tends to increase these figures but best sites onshore have already been taken and new wind farms are built at lower wind speed sites.

1.3. Market and industry status and potential

The global installed wind capacity grew at a 29 % annual average between 2000 and 2009, and added 39.4 GW in 2010 to total 199 GW (+24.7 %) [BTM, 2011]. The offshore sector grew by 52 % in 2010 to 1 100 MW [JRC], including shoreline and intertidal installations, although it still contributes no more than 1.6 % of global installed capacity. In the EU-27, wind installations increased 9.3 GW to reach 84.3 GW (+12.4 %) [GWEC, 2011], and offshore made up 11 % of these new installations. With an annual increase of 18.9 GW, China moved to first place in the ranking of cumulative installed capacity at 44.7 GW [CWEA, 2011a], ahead of the US which installed 5.11 GW for a cumulative 40.2 GW. However, in terms of operational, i.e. grid-connected capacity, the US is still the world leader as it was estimated that around 34 % of Chinese installed capacity (15 GW) was not connected to the grid at the end of 2010 [ChinaDaily, 2011]. The status of the EU as the major world market is now part of history since 2004, when 70 % of newly installed capacity took place in the EU, this figure was reduced to 24 % over the succeeding six years. During 2010 wind installations accounted for 16.7 % of new electricity plant in the EU [EWEA, 2011] and 25 % in the US [DoE, 2011].

Consequently with this trend, top European turbine manufacturers suffered a reduction of their global market share from 67 % in 2007 [EWEA, 2009] to 40 % in 2010 [BTM-JRC, 2011], a trend that will continue this year as Chinese manufacturers continue to take advantage of their stronger market. The Top-10 manufacturers in 2010 included four Chinese (Sinovel, Goldwind, Dongfang and United Power), Vestas and Siemens (DK), Gamesa (ES), Enercon (DE), GE Wind (US) and Suzlon (IN).

³ Author's calculations based on the historical wind energy capacity factor (CF) from Eurostat data on generation and installed capacity (21.2 %), and assuming that end-of-2010 installed wind capacity (from [GWEC, 2011]), averaged over the year, generated at 21.2 % CF. 2010 gross electricity inland consumption was estimated at 3 300 TWh short of Eurostat statistics. World wind electricity generation estimated from mid-point of capacity at the beginning and end 2010 (158 – 199 GW respectively) and a CF of 2000 hours. Data on country share of wind electricity is based on diverse country publications and [GWEC, 2011]. Data on projections of energy consumption from "Energy trends to 2030".

In the EU-27 in 2010, the wind energy generation, estimated at the European average of 21.2 % load factor, was 148 TWh or 4.5 % of the estimated 3 300 TWh of EU electricity demand. Worldwide wind supplied 357 TWh.³ The countries with the highest wind share in the electricity mix in 2010 included Denmark (22 %), Portugal (17.1 %), Spain (16.6 %), Ireland (10 %) and Germany (6.2 %).³ The integration of 50 % wind power into an electricity system is seen as technically possible [EA, 2007].

Achieving the 2020 EU industry target of 230 GW, of which 40 GW is offshore, remains a realistic scenario. Electricity production would be 520 TWh, between 13 and 15 % of EU electricity demand [EWEA, 2011].³ The 2030 potential is 350 GW, of which 150 GW offshore, and would produce 880 TWh, between 21 and 24 % of EU demand.³ The economically competitive potential of 12 200 TWh by 2020 and 30 400 TWh by 2030 [EEA, 2009] is beyond reach. In the EU, in the long run, offshore wind should reach 50 % of wind installed capacity.

According to the International Energy Agency, global onshore cumulative capacity could reach 670 GW by 2020, of which 109 GW is offshore, with 215 GW in China and 115 GW in the US. By 2030 global installed capacity could reach 1 024 GW of which 194 GW offshore, 270 GW in China, and 210 in the US, and generate 7 % of the then estimated world consumption of 32 700 TWh [IEA, 2010a, 2010b].

Wind is already competitive with fossil-fuel generation in high-wind sites such as Scotland. The expected rise in fossil fuel prices, along with wind technology improvements - fuelled by initiatives such as the SET-Plan [European Commission, 2007] - will make that at more and more sites, wind generates cheaper electricity than fossil fuels. Wind power is thus an insurance against fluctuating (and rising) energy prices in addition to creating security of supply and protection against unstable sources of fossil fuels.

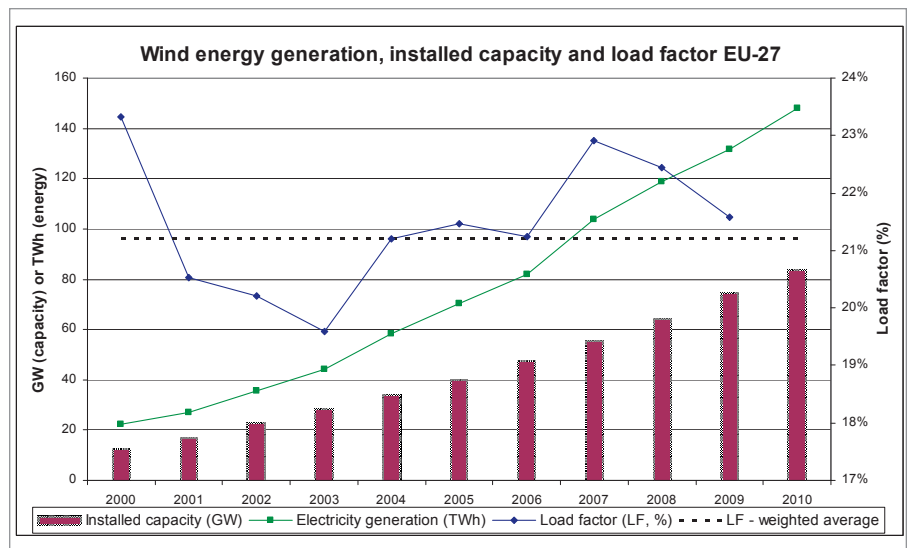


Figure 1.3: The evolution of annual capacity factor compared to installed capacity, 2000-2010. [Source: JRC based in Eurostat and own data]

1.4. Barriers to large-scale deployment

The main barriers preventing wind energy development have not changed much since the 2009 Technology Map [JRC, 2009], namely: a high-levelised cost of electricity (CoE) caused mainly by high capital costs and, especially offshore, high O&M costs; administrative barriers (lengthy permit process, etc.), social acceptance (often after individual visual perceptions mixed up with the NIMBY syndrome) or the lack of trained, experienced staff, in particular for the expected offshore development in the 2014 – 2020 period.

The group of economic barriers include: relatively high raw material (steel, concrete, copper, rare earths), component and turbine prices; low competition among second- and third-tier suppliers (drive shaft, brakes, drive-train bearings, etc.); high grid-connection costs; limited grid transmission capability that is reinforced only slowly; scarcer sites with good resources and, since the financial crisis, very tight financing conditions. Higher wind penetration is also prevented by lack of adequate interconnections, including international links, which are necessary also for the easing of balancing requirements that would be the result of a larger balancing area [EWEA, 2009]. Financing issues have somehow eased during 2011 in that there are now more institutional actors (e.g. pension funds) ready to finance debt. However, the financial stakeholders expect high internal rate of returns (IRR) for offshore wind which is causing a further increase in CoE, this high premium could be reduced through clear and long-term policy commitments as well as a structured effort to reduce risks and barriers faced by investors.²

Entry barriers to offshore wind have eased with regards to wind turbines, even if there are still only two clear market leaders, as nearly all manufacturers have commercialised or presented offshore turbines. Entry barriers remain for cabling manufacture though (HVAC/HVDC subsea cables), with few actors able to manufacture cable connections to the onshore grid, and – to a lesser extent – cable-laying and foundation-installation vessels.

Onshore grid expansion plans are disappointing [European Commission, 2011a]. In 2010, ENTSO-E prepared a pilot ten-year network development plan under the assumption of only a 25 % renewable energy penetration by 2020, when even the National Renewable Energy Action plans estimate more than 37 %. One of the greatest challenges remains the connection (both on- and offshore) of the very large offshore potential.

Finally, the group of administrative barriers include lengthy procedures, too many authorities involved, inexperienced civil servants, non-homogenous application of regulations, and an unclear administrative framework, among others [European Commission, 2011a].

1.5. RD&D priorities and current initiatives

The engine behind European RD&D is the European Wind Initiative (EWI) of the SET-Plan, composed of industry, EU Member States and the European Commission. The EWI has an estimated investment of EUR 6 billion shared between industry and public funding. Its steering group has approved the following R&D priorities suggested by the Wind Technology Platform [TPWind, 2010]: new turbines and components for on- and offshore deployment, large turbines, testing facilities; development and testing of new offshore foundations, and its mass-manufacturing; grid integration including long-distance HVDCs, connections offshore to at least two countries and multi-terminal solutions; and resource assessment including a new European wind atlas and spatial planning instruments. While R&D programmes run by the European Commission are already adapting to these priorities, Member States are expected as well to align their R&D funding in the near future.

Public bodies could possibly have the largest impact in cost reduction if they focused in reducing the risks and uncertainties existing in the different phases of a wind farm project. Examples include identifying

and reducing the uncertainty of wind energy yield calculations (which would result in lower risks for financial institutions providing debt); and reducing the risks of the permit process, e.g. through streamlining the permit schemes, public planning of preferred wind deployment areas, etc. Identifying why financial institutions require such a high IRR for offshore wind and subsequently taking action would help to ease the pressure on offshore CoE.

Wind energy depends on other sectors including: the electricity grid which is a fundamental enabler for higher wind penetration and is currently underdeveloped in particular regarding international interconnections; electricity storage (pumped or reservoir hydropower, compressed air, etc.); and manufacture of subsea HVAC/HVDC cables. The European installed capacity of hydro-pumping storage, currently at 40 GW, should be increased in order to allow for more system flexibility. More reservoir-hydro capacity would contribute to grid support and this would enable more wind and other non-firm renewables into the system.

The European society is still not aware of the full extent of the climate change problem and of the impact of wind energy to alleviate this problem. There is a need for the EU and individual Member States to raise awareness that reduce the “not in my back yard” syndrome toward wind farms and their required grid connections. Last but not least, there is a need for better cooperation among the European wind industry, academia and R&D institutions in research, education and training.

RD&D in advanced materials offers synergies with a number of low-carbon industries (non-exhaustive): fibre-reinforced composites with the nuclear and solar energy; coatings with the solar power, biomass and electricity storage industries; special concretes with building and nuclear; high-temperature superconductors with the electricity transmission and storage sectors, etc. [European Commission, 2011b].

Synergies exist between the offshore sector and the oil and gas (O&G) industry in areas such as the manufacture of installation vessels. This sector can bring in experience and know-how to the offshore wind sector, in particular on substructure installations and on operation and maintenance issues.

Some ocean energy projects share grid-related issues with offshore wind and even with onshore at a lower level. Exchange of technological know-how with the aeronautics industry might result from

the entry of EADS in the wind sector. Other sectors that have possible synergies with wind are the grid components, in particular for offshore installations, and electricity storage sectors. The latter, along

with the auto industry for electric cars, and with the support of smart grids/metering, would create a demand-management scenario able to adapt and assimilate surplus wind electricity.

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2. Solar Photovoltaic Electricity Generation

2.1. Introduction

Amongst all energy resources, solar energy is the most abundant one and compared to the rate at which all energy is used on this planet, the rate at which solar energy is intercepted by the Earth is about 10 000 times higher. There is a whole family of solar technologies which can deliver heat, cooling, electricity, lighting and fuels for a host of applications. Very recently, the importance of renewable energy, including solar photovoltaic electricity, for mitigating Climate Change was highlighted by a special report of the Intergovernmental Panel for Climate Change (IPCC) [IPCC, 2011].

2.2. Technological state of the art and anticipated developments

Photovoltaic solar electricity generation technologies exploit the photovoltaic effect, where electron-hole pairs generated in semiconductors (e.g. Si, GaAs, CuInSe₂, CdTe, etc) are spatially separated by an internal electric field. This leads to a separated negative charge on one side of the cell and positive charge on the other side and the resulting charge separation creates a voltage (Figure 2.1). When the cell is illuminated and the two sides are connected to a load, a current flows from one side of the device via the load to the other side of the cell. The conversion efficiency of a solar cell is defined as the ratio of output power from the solar cell per unit area (W/cm²) to the incident solar radiation.

Various materials can be used to form a photovoltaic (PV) cell and a first distinction is whether the material is based on inorganic or organic; a second distinction in the inorganic cells is silicon or non-silicon material; and the last distinction is wafer-based cells or thin-film cells. Wafer-based silicon is divided into two different types: monocrystalline and multicrystalline (sometimes called “polycrystalline”).

In 2010, 85 % of photovoltaic (PV) systems were based on crystalline silicon technology that is highly matured for a wide range of applications. In the 1st Quarter (Q1) 2011, the average turn-key price of a PV system up to 100 kW in Germany was €2.55/W_p and in the USA \$6.41/W_p (€4.58/W_p) for residential systems and \$5.35/W_p (€3.82/W_p) for non-residential systems were reported [BSW-Solar, 2011; SEIA, 2011]. Large systems in the multi-MW_p range have a different price structure and include a higher fraction of project and administration costs, as well as costs to connect the systems to the grid. For such large-scale utility systems, system prices below €2/W_p were reported in Germany and the US average was \$3.85/W_p (€2.75/W_p). It has to be stressed that the current market prices are strongly influenced by the different national support schemes and only partially reflect the true costs of the systems.

Efficiency of typical commercial flat-plate modules and of typical commercial concentrator modules is up to 15 % and 25 %, respectively. The typical system energy pay-back time depends on the location of the installation. In southern Europe, this is approximately 1 to 2 years and increases at higher latitudes [Fthenakis et al., 2008]. The performance of photovoltaic modules is already guaranteed by the manufacturers for up to 25 years, but the actual lifetime of the modules is well over 30 years [Osterwald and McMahon, 2009]. Finally, the average generation cost of electricity based on the actual investment costs in Q1 2011 is about €0.236/kWh, ranging between €0.158/kWh and €0.35/kWh depending on the location of the system.

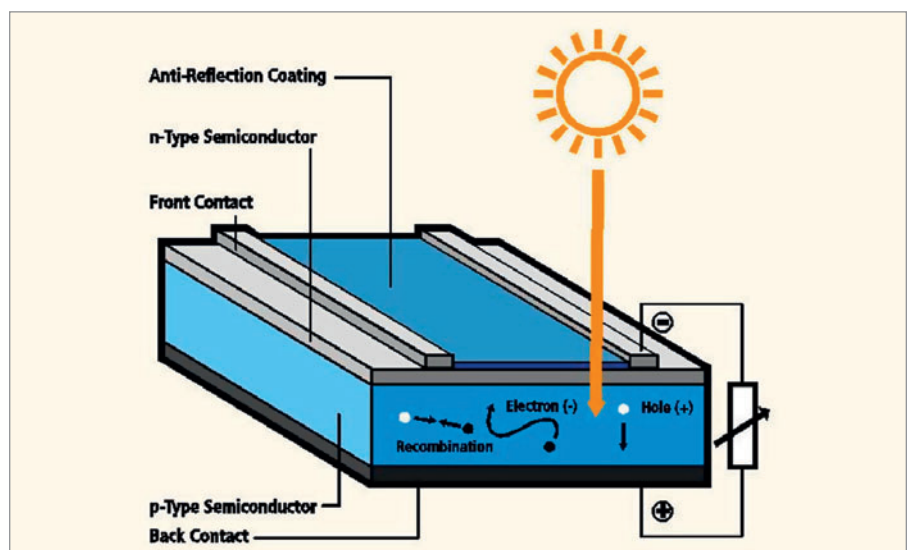


Figure 2.1: Generic schematic cross-section of the operation of an illuminated solar cell. [Source: IPCC, 2011; Chapter 3, Figure 3.5, p3]

Crystalline silicon-based systems are expected to remain the dominant PV technology in the short-to-medium term, but thin films and concentrator PV systems are increasing their market share. In the medium term, PV systems will be introduced as integral parts of new and retrofitted buildings. Finally, in the long term, new and emerging technologies will come to the market. It is expected that crystalline silicon, thin films and other technologies will have equal shares in the installed PV capacity in 2030. The cost of a typical turn-key system is expected to decrease from €2.0-3.0 in 2011 to €2/W_p in 2015, and reach €1/W_p in 2030 and €0.5/W_p in the longer term. Simultaneously, module efficiencies will also increase. Flat-panel module efficiencies will reach 20 % in 2015 and up to 40 % in the long term, while concentrator module efficiencies will reach 30 % and 60 % in 2015 and in the long term respectively. It is expected that if these technology developments are realised, the cost of electricity from PV systems will be comparable to the retail price of electricity in 2015 and of the wholesale price of electricity in 2030.

Both crystalline-Si solar cells and the “traditional” thin-film technologies (a-Si:H and its variations based on proto-crystalline or micro-crystalline Si, as well as polycrystalline compound semiconductors) have developed their roadmaps aiming at further cost reductions. These roadmaps are based on growing industrial experience within these domains providing a solid data base for quantification of the potential cost reductions. The Strategic Research Agenda (SRA) of the European Photovoltaic Platform, which is currently under revision, is one example which describes the research needed for these set of PV technologies in detail, but also points out the opportunities related to beyond-evolutionary technology developments [EU PV, 2007]. These technologies can either be based on low-cost approaches related to extremely low (expensive) material consumption or approaches which allow solar cell devices to exhibit efficiencies above their traditional limits. In fact, the goal to develop crystalline Si and thin-film solar cell technologies with a cost < €0.5/W_p relies heavily on disruptive breakthroughs in the field of Novel Technologies. PV research should therefore be sufficiently open towards developments, presently taking place in material and device science (nanomaterials, self-assembly, nanotechnology, plastic electronics) to detect these opportunities of an early stage.

The 2007 Strategic Research Agenda has deliberately chosen the terms “Emerging Technologies” and “Novel Technologies” to discriminate between

the relative maturity of different approaches [EU PV, 2009]. The category “Emerging” was used for those technologies which have passed the “proof-of-concept” phase or can be considered as longer term options for the two established solar cell technologies, i.e. crystalline Si and thin-film solar cells. The term “Novel” was used for developments and ideas which can lead to potentially disruptive technologies, but where there is not yet clarity on practically achievable conversion efficiencies or cost structure.

Within the emerging PV technologies, a distinction was made between three sub-categories: a) advanced inorganic thin-film technologies, b) organic solar cells and c) thermo-photovoltaic (TPV) cells and systems.

Most of the novel approaches can be categorised as high-efficiency approaches. One can make an essential distinction between approaches which are modifying and tailoring the properties of the active layer to match it better to the solar spectrum versus approaches which modify the incoming solar spectrum and are applied at the periphery of the active device (without fundamentally modifying the active layer properties).

In both cases, nanotechnology and nanomaterials are expected to provide the necessary toolbox to bring about these effects. Nanotechnology allows introducing features with reduced dimensionality (quantum wells – quantum wires – quantum dots) in the active layer. One can distinguish three basic ideas behind the use of structures with reduced dimensionality within the active layer of a photovoltaic device. The first approach aims at decoupling the basic relation between output current and output voltage of the device. By introducing quantum wells or quantum dots consisting of a low-bandgap semiconductor within a host semiconductor with wider bandgap, the current will be increased in principal while retaining (part of) the higher output voltage of the host semiconductor. A second approach aims at using the quantum confinement effect to obtain a material with a higher bandgap. The third approach aims at the collection of excited carriers before they thermalise to the bottom of the concerned energy band. The reduced dimensionality of the Quantum Dot (QD) material tends to reduce the allowable phonon modes by which this thermalisation process takes place and increases the probability of harvesting the full energy of the excited carrier. Several groups in Europe have built up a strong position in the growth, characterisation and

application of these nanostructures in various structures (III-V, Si, Ge) and also, on the conceptual level, ground-breaking R&D is being performed (e.g. the metallic, intermediate-band solar cell).

Tailoring the incoming solar spectrum to the active semiconductor layer relies on up- and down-conversion layers and plasmonic effects. Again nanotechnology might play an important role in the achievement of the required spectral modification. Surface plasmons have been proposed as a means to increase the photoconversion efficiency in solar cells by shifting energy in the incoming spectrum towards the wavelength region where the collection efficiency is maximum or by increasing the absorbance by enhancing the local field intensity. This application of such effects in photovoltaics is definitely still in a very early stage, but the fact that these effects can be tailored to shift the limits of existing solar cell technologies by merely introducing modifications outside the active layer represents an appreciable asset of these approaches which would reduce their time-to-market considerably.

It is evident that both modifications to the active layer and application of the peripheral structures could be combined eventually to obtain the highest beneficial effects.

Research in photovoltaic devices over the last few years has seen major advances in efficiency, reliability and reproducibility, but it is clear that there is the potential for further progress, both in terms of existing device structures and in relation to new device topologies. Key to those advances is an understanding of material properties and fabrication processes. Research is required for specific aspects of device design and fabrication, together with consideration of the new production equipment necessary to transfer these results into the fabrication processes. In parallel, advances in the system architecture and operation will allow the increases in cell efficiency to be reflected in the energy output of the system. Details of the needed research actions are described in the Implementation Plan for the Strategic Research Agenda of the European Photovoltaic Technology Platform [EU PV, 2009].

With respect to European funding, 30 R&D projects on PV have been funded under the Calls 2007-2011, with a total EU contribution of almost EUR 130 million. In addition, a total of six “high-risk-high impact” projects on PV have been supported under the Future and Emerging Technologies Calls

2008 and 2010, worth a total EU contribution of EUR 16.3 million. Whereas the 2007 Calls addressed a wide range of different PV technologies, from thin-films to third generation PV technologies such as intermediate band solar cell (IBSC), as well as cost reductions and improved manufacturing, the 2008 Calls funded demonstration projects addressing PV for grid optimisation and research on new applications for concentrated PV in the Mediterranean Countries. In addition, a joint call with Nanosciences, Nanotechnologies, Materials and new Production Technologies (NMP) resulted in five research projects which address innovative technological developments in PV through incorporation of nanomaterials into the solar cell structure. Thin-film PV was supported in 2009 with 5 research projects addressing efficiency and material issues, and 2 demonstration projects dealing with manufacturing issues. In 2010, two research projects on crystalline silicon PV and three on the technological development of thin-films and concentrated PV (CPV), a co-ordinated Call with India, have been supported. Under the 2011 work programme the focus was on the scaling up of the production processes of solar cells (joint call with NMP Theme) and on demonstration of productivity and cost optimisation for the manufacturing of concentrated PV systems. In addition, projects addressed the development of ultra-high efficient CPV cells (coordinated call with Japan) and standardised building components. The 2012 Calls foresee research on reliable, highly-performing and cost effective PV systems, as well as demonstration activities targeting the smart multi-functional PV modules.

2.3. Market and industry status and potential

Since 1990, PV production has increased more than 500 fold from 46 MW to about 23.5 GW in 2010 [Jäger-Waldau, 2011]. This corresponds to a Compound Annual Growth Rate (CAGR) of little more than 36.5 % over the last twenty years. Statistically documented cumulative installations worldwide accounted for 39 GW in 2010. The interesting fact is, however, that cumulative production amounts to 55 GW over the same time period. Even if we do not account for the roughly 6 GW difference between the reported production and installations in 2010, there is a considerable 9 to 10 GW capacity of solar modules which are statistically not accounted for. Parts of it might be in consumer applications, which do not contribute significantly to power generation, but the overwhelming part is probably used in stand-alone

applications for communication purposes, cathodic protection, water pumping, street, traffic and garden lights, etc.

The total installed capacity of PV systems in the EU in 2010 was 29.8 GW_p, representing approximately 3.7 % of the total EU electrical generation capacity [Jäger-Waldau, 2011; PV Barometer, 2011]. The electricity generated by PV systems that year was approximately 20 TWh. The annual installation of PV systems in 2010 in the EU reached 13.6 GW_p, the second largest amount of newly-built electricity generation capacity after gas-fired power stations. This was due to an exceptional high installation rate in Germany with about 7.4 GW and approximately 2.6 GW_p installed in Italy. Both countries have a stable, long-term financial support in the form of feed-in tariffs. Europe currently is the largest market for PV systems with more than 75 % of the annual world wide installations in 2010. In terms of solar cell production, Europe has slipped behind China and Taiwan to third place, capturing about 13 % of the world market but it is still a world leader in PV technology development.

Based on information provided by the industry, Greenpeace and the European Photovoltaic Industry Association (EPIA) have assumed in their study "Solar Generation VI – 2011" on average, 30 full-time equivalent (FTE) jobs are created for each MW of solar power modules produced and installed [EPIA/Greenpeace, 2011]. This is a significant reduction from the figures (about 45 FTE) a few years ago, which reflects the increased industrialisation of the PV industry. Based on this data, the employment figures in the PV sector for 2010 are estimated well above 500 000 worldwide and above 300 000 in the European Union.

The PV sector has expanded annually in Europe with high growth rates, of the order of more than 40 % on average since 2000. In 2009, the European Photovoltaic Industry Association has published its Vision for 2020 to reach up to 12 % of all European electricity [EPIA, 2009]. However, to realise this vision and reach an installed PV system capacity of up to 390 GW_p, the industry

has not only to continue to grow with the same pace for another ten years but a paradigm shift and major regulatory changes and upgrades of the existing electricity grid infrastructure are necessary.

The market conditions for photovoltaics differ substantially from country to country. This is due to different energy policies and public support programmes for renewable energies and especially photovoltaics, as well as the varying grades of liberalisation of domestic electricity markets. The legal framework for the overall increase of renewable energy sources was set with the Directive 2009/28/EC, and in their National Renewable Energy Action Plans (NREAPs), 26 Member States have set specific photovoltaic solar energy targets, adding up to 84.5 GW in 2020 (see figure 2.2). However, 51.7 GW will come from Germany alone. In the NREAPs, the sun-rich Mediterranean countries only pledged 24.6 GW (8.4 GW Spain, 8 GW Italy, 4.8 GW France, 2.2 GW Greece, 1.0 GW Portugal, and Cyprus and Malta together 220 MW). However, the latest development in Italy, where a limit of support for 23 GW of PV installations by 2017 was given in the 4th *Conto Energia* [Gazzetta Ufficiale, 2011], indicates that the targets set in the NREAPs should be seen as the guaranteed minimum and not the overall goal.

Scenarios for the worldwide deployment of PV technology vary significantly between the 2010 International Energy Agency (IEA) PV Technology Roadmap scenario and the Greenpeace/European Renewable Energy Council Scenarios [IEA, 2008; Greenpeace/EREC, 2010]. The IEA scenarios range between 210 GW (298 TWh) by 2020 and 870 GW (1 247 TWh) by 2030 and the Greenpeace scenarios

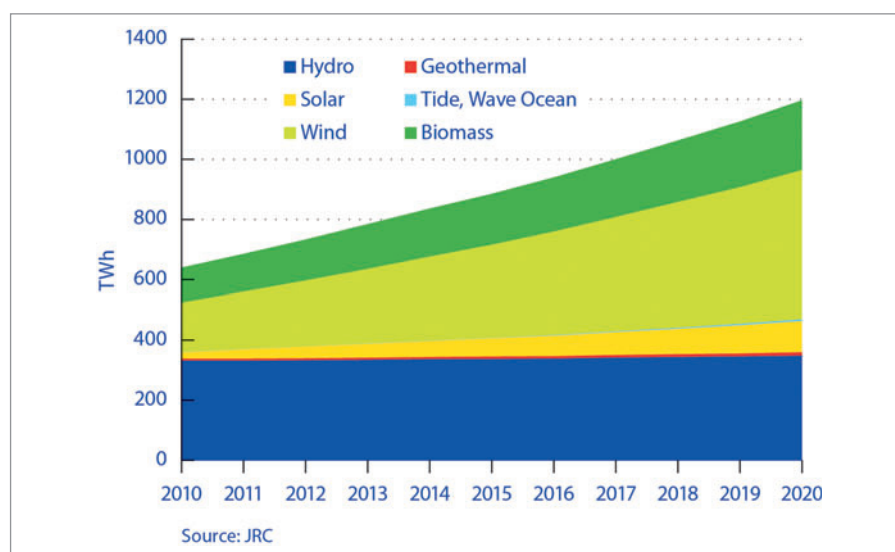


Figure 2.2: Planned European electricity production according to the National Renewable Energy Action Plans [Source:JRC]

which vary between 80 GW (117 TWh) by 2020 and 184 GW (281 TWh) by 2030 for the reference scenario, and 439 GW (594 TWh) by 2020 and 1 330 GW (1 953 TWh) by 2030 for the advanced scenario.

2.4. Barriers to large-scale deployment

The main barriers to large-scale deployment of PV systems are of administrative and regulatory nature and are mainly connected with the access to the grid. In addition, the fact that initial investment costs are still higher than in other electricity generation technologies leads to still higher cost of electricity from PV systems. On the other hand, however, there are no uncertain and volatile fuel cost prices with the corresponding price risks associated to electricity generation from PV systems and the investment costs are continuously decreasing. Techno-economic barriers to the expansion of the sector include the development of advanced manufacturing systems, further optimisation along the different production value chains and building integration of thin films. Other barriers include the lack of skilled professionals, the usage of precious raw materials, e.g. silver, the need to develop methods for recycling, the introduction of new materials, regulatory and administrative barriers, such as access to grid and long waiting times for connection, and finally, lack of public awareness including construction experts.

It is noted that the issue of silicon availability has been resolved. The shortage of silicon in the past has been a consequence of the lack of development of new silicon purification facilities, as well as due to high rates of market growth

With photovoltaic module costs as low as €500/kW and module lifetime up to 30 and even 40 years now in reach, competitiveness is already accomplished in several market segments. Roadmaps and objectives should be revisited because PV now offers a generation of technology which is ready to deliver.

The implementation of the ambitious deployment targets (i.e. EU target of 84 GW of PV installed by 2020), requires that the integration into the grid of a relevant share of power from PV (but also from wind) is facilitated. Issues, such as capacity reserves, unbalancing and frequency disconnection, have to be addressed by affordable technological solutions which are to be fully developed, demonstrated and implemented.

2.5. RD&D priorities and current initiatives

The broad variety of photovoltaic routes continues to progress in performance, reliability and cost: from mainstream wafer-based silicon to thin film, CPV and organic PV. Incremental progress for components and systems are also being made. EU action should focus on the integration (including better forecasting of the production) and on frontier research (for instance, but not only, hot carrier solar cells and cells based on advanced light absorbers) which have the potential for technology leaps and breakthroughs. Further work on the mainstream wafer-based Si solar cells should be carefully considered.

Research is vital for increasing the performance of PV systems and accelerating the development of the technology. The research priorities are documented very well in the 2nd edition of the Strategic Research Agenda of the European PV Technology Platform [EU PV, 2011]. Furthermore, the development of a healthy and growing market is essential for the development of PV technologies as this will stimulate competition within the industry, which in turn will trigger further innovation. Research push tools need however to be combined with market pull mechanisms for the expansion of production capacity and the consequent development of economies of scale will lead to cost reductions. To this end, the maintenance of feed-in tariffs with build in reduction mechanisms reflecting the technology progress and market growth is crucial for the sector for the next decade. Only a reliable framework providing a stable investment environment will allow the industry to grow and unlock the potential of this technology. Furthermore, a framework that will allow the European PV industry to compete with the rapidly increasing manufacturing capacity in Asia will help the expansion of the sector, which will benefit further the deployment of PV systems in Europe.

In 2008, the Commission proposed to launch six European Industrial Initiatives (EII): Wind, Solar (both concentrated solar and photovoltaic), Carbon capture and storage, Electricity grids, Bio-energy and Nuclear fission. The launch of the first four EIIs (including solar) took place at the Madrid SET-Plan conference in June 2010.

The Solar Europe Industry Initiative (SEII) describes the strategic RD&D components of “SET for 2020”, which are essential to enable rapid, large-scale deployment of PV at minimum cost and maximum benefit for society [EPIA and EU PV, 2010]. Besides the efforts of the PV sector, the success

of other Industry Initiatives under the SET-Plan, as well as the development of other technologies (electricity storage, electrical vehicles, demand side management, etc.) are essential for the success of the SEII.

SEII will achieve three strategic objectives:

- SEII will bring PV to cost competitiveness in all market segments (residential, commercial, and industrial) by 2020 (cost reduction);
- SEII will establish the conditions allowing high penetration of distributed PV electricity within the European electricity system (integration);
- SEII will facilitate the implementation of large scale demonstration and deployment projects with a high added value for the European PV sector and society as a whole.

In addition to this, the SEII creates the necessary basis for development beyond 2020 and the 2020 targets, supporting the European industry to also play a leading role on the longer term.

The PV industry is not in competition with other Renewable Energy Sources (RES)-based electricity generation industries. The ultimate goal of the community that supports PV systems is to make the technology competitive with all sources of electricity in the short term and then allow all technologies to compete for their fair share in electricity generation. Moreover, the PV sector has the same concerns about electricity generation and transmission as the other RES-electricity technologies, such as access to grid, financial support and approval procedures. Further synergies should be pursued with the building and construction sector for raising awareness and facilitating the integration of PV systems in new and retrofitted buildings. Shared technology developments could be envisaged with the solar heating and cooling, and the concentrated solar power sectors, with regards to materials and energy storage devices. Last but not least it should be mentioned, that material science, nanotechnology and organic/inorganic chemistry research efforts are needed to prepare for future concepts and system solutions in order to avoid roadblocks in the future.

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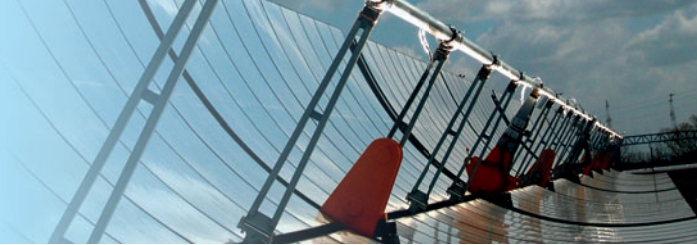
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3. Concentrated Solar Power Generation



3.1. Introduction

Amongst all energy resources, solar energy is the most abundant one and compared to the rate at which all energy is used on this planet the rate at which solar energy is intercepted by the Earth is about 10 000 times higher. There is a whole family of solar technologies which can deliver heat, cooling, electricity, lighting, and fuels for a host of applications. Very recent, the importance of renewable energy, including solar, for mitigating Climate Change was highlighted by a special report of the Intergovernmental Panel for Climate Change (IPCC) [IPCC, 2011].

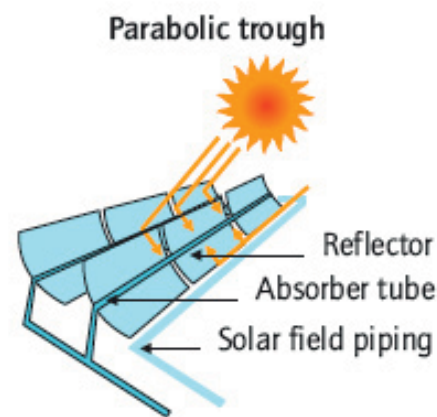
3.2. Technological state of the art and anticipated developments

Concentrated solar thermal power technology (CSP) produces electricity by concentrating the sun to heat a liquid, solid or gas that is then used in a downstream process for electricity generation. A CSP plant consists, schematically, of a solar concentrator system made of a receiver and collector to produce heat and a power block (in most cases a Rankine cycle). The majority of the world's electricity today – whether generated by coal, gas, nuclear, oil or biomass – comes from the creation of a hot fluid. CSP simply provides an alternative heat source. One of the appealing elements of this technology is that it builds on much of the current know-how on power generation in the world today. In addition, there is further potential to improve as improvements are made in solar concentrator technology, but also, as advances continue to be made in steam and gas turbine cycles.

Between 1985 and 1991, 354 MW of solar trough technology was deployed in southern California. These plants are still in commercial operation today and have demonstrated the potential for long-term viability of CSP.

For large-scale CSP plants, the most common form of concentration is by reflection, in contrast to refraction with lenses. Concentration is either to a line (linear focus) as in trough or linear Fresnel systems or to a point (point focus) as in central receiver or dish systems. The major features of each type of CSP system are described below.

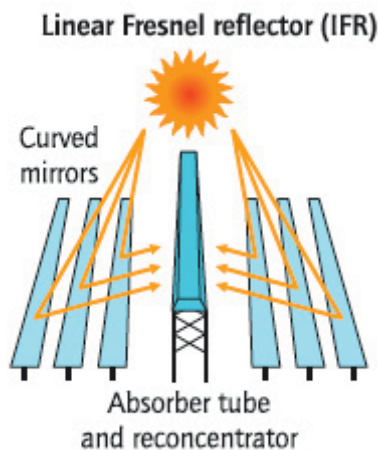
Trough concentrators:⁴ Long rows of parabolic reflectors concentrate the sun 70 to 100 times onto a heat-collection element (HCE) placed along the reflector's focal line. The sun is tracked around one axis, typically oriented north-south. The HCE consists of an inner steel pipe, coated with a solar-selective surface and an outer glass tube, with vacuum in-between. A heat-transfer fluid – in general oil – is circulated through the steel pipe and heated to around 390 °C. The hot fluid from numerous rows of troughs is passed through a heat exchanger to generate steam for a conventional steam turbine generator. Land requirements are on the order of 5 acres per megawatt electricity.



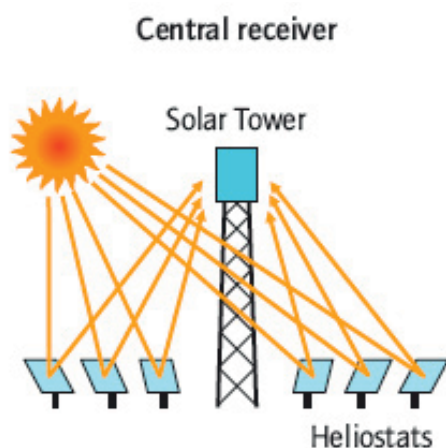
Alternative heat-transfer fluids such as steam and molten salt are being studied to enable higher temperatures and overall efficiencies. The use of molten-salt in both the solar field and thermal energy storage system eliminates the need for the expensive heat exchangers. It also allows the solar field to be operated at higher temperatures than current heat transfer fluids allow. This combination can lead to a substantial reduction in the cost of the thermal energy storage (TES) system. However, molten-salts freeze at relatively high temperatures, 120-220 °C and this means that special care must be taken to ensure that the salt does not freeze in the solar field piping during the night.

Linear Fresnel reflectors:⁴ The attraction of linear Fresnel is that installed costs on a m² basis can be lower than troughs, and the receiver is fixed. However, the annual optical performance is lower than a trough reflector.

⁴ Source of figures: IEA CSP Technology Roadmap 2010

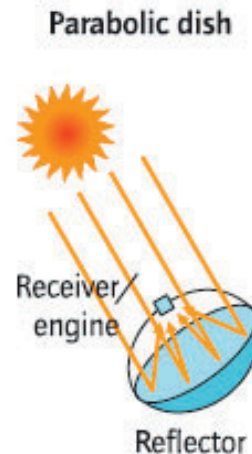


Central receivers (Solar towers):⁴ The thermodynamic cycles used for electricity generation are more efficient at higher temperatures. Point-focus collectors such as central receivers are able to generate much higher temperatures than troughs and linear Fresnel reflectors. This technology uses an array of mirrors (heliostats), with each mirror tracking the sun and reflecting the light onto a fixed receiver on top of a tower, where temperatures of more than 1 000°C can be reached. Central receivers can generate temperatures of advanced steam turbines and can be used to power gas turbine (Brayton) cycles. Trough concentrators and solar towers also require relatively flat land, i.e. less than 1 % slope for one solar field is desirable.



Dish systems:⁴ The dish is an ideal optical reflector and therefore suitable for applications requiring high temperatures. Dish reflectors are paraboloid-shaped and concentrate the sun onto a receiver mounted at the focal point, with the receiver moving with the dish. Dishes have been used to power Stirling engines at 900 °C, as well as generate steam. Operational experience with dish/Stirling engine systems exist and commercial rollout is planned. Up to now, the

capacity of each Stirling engine is of the order of 10 to 15 kW_e. The largest solar dishes have a 400 m² aperture and are used in research facilities. The Australian National University is presently building a solar dish with a 485 m² aperture.



Thermal storage: An important attribute of CSP is the ability to integrate thermal storage. To date, this has been primarily for operational purposes, providing 30 minutes to 1 hour of full-load storage. This eases the impact of thermal transients such as clouds on the plant, and of electrical transients to the grid. Plants are now being designed for 6 to 7.5 hours of full-load storage, which is enough to allow operation well into the evening when peak demand can occur and tariffs are high.

In thermal storage, the heat from the solar field is stored prior to reaching the turbine. Storage media include molten salt (presently comprising separate hot and cold tanks), steam accumulators (for short-term storage only), solid ceramic particles and high-temperature concrete. The heat can then be drawn from the storage to generate steam for a turbine as and when needed.

Availability of water is an issue which has to be addressed for CSP development as the parabolic trough systems and central tower systems require cooling water. Wet cooling requires about 2.8 m³/MWh, which is comparable to other thermal power stations [Stoddard et al., 2006]. Air cooling and wet/dry hybrid cooling systems offer highly viable alternatives to wet cooling and can eliminate up to 90 % of the water usage [US DoE, 2009]. The penalty in electricity costs for steam generating CSP plants range between 2 % and 10 % depending on the actual geographical plant location, electricity pricing and effective water costs. The loss of a steam plant with state-of-the-art dry cooled condenser can be as high as 25 % on very hot summer days in the US

Southwest. The penalty for linear Fresnel designs has not yet been analysed, but it is expected to be somewhat higher than for troughs because of the lower operating temperature. On the other hand, power towers should have a lower cost penalty because of their higher operating temperature.

With respect to European funding, 12 projects on CSP have been supported so far with a total EU contribution of around EUR 78 million. In 2007, a demonstration project dealing with the improvement of the environmental profile of CSP installations and a research project on the use of CSP for water desalination was funded. Research projects on components for CSP have been funded in the 2008 and 2010 Calls. In addition, a research project on dry-cooling methods for CSP plants was supported under the 2010 call. Under the same call, two projects have been selected to demonstrate at large-scale, the combined production of electricity and fresh water from CSP in Mediterranean countries. The 2011 Calls focussed on thermal energy storage for CSP plants (3 research projects) and also on advanced heat transfer fluids. The 2012 Calls will target solar dish systems and the hybridisation of CSP with other energy sources.

3.3. Market and industry status and potential

Between 1985 and 1991, the Solar Energy Generating Systems (SEGS) I through IX (parabolic trough), with a total capacity of 354 MW,⁵ were built in the Mohave Desert, USA. After more than 15 years, the first new major capacities of Concentrated Solar Thermal Electricity Plants came online with Nevada One (64 MW, USA) and the PS 10 plant (11 MW, Spain) in the first half of 2007.

The most mature, large-scale technology is the parabolic trough/heat transfer medium system. Central receiving systems (solar tower) are the second main family of CSP technology. Parabolic Dish engines or turbines (e.g. using a Stirling or a small gas turbine) are modular systems of relatively small size and are primarily designed for decentralised power supply. The lifetime of CSP technologies is about 20 to 30 years [Stoddard et al., 2006]. The solar only capacity factor without thermal storage of a CSP plant is about 1 800 to 3 000 hours per year. The level of dispatching

from CSP technologies can be augmented with thermal storage or with hybridised or combined cycle schemes with natural gas. With storage, yearly operation could theoretically be increased to 8 760 hours, but this is not economically sensible. Systems with thermal storage generally achieve capacity factors between 4 000 to 5 200 hours [Stoddard et al., 2006]. An experimental facility with 17 MW capacity and molten salt storage which should allow almost 6 500 operation hours per year is currently being built in Spain.⁶ Several Integrated Solar Combined Cycle projects using solar and natural gas were completed recently (Algeria, Italy and Morocco) or are under development [Kautto and Jäger-Waldau, 2009].

At the end of January 2011, CSP plants with a cumulative capacity of about 730 MW were in commercial operation in Spain, about 58 % of the worldwide capacity of 1.26 GW.

Also in Spain, an additional 898 MW were under construction and another 842 MW had already registered for the feed-in tariff bringing the total capacity to about 2.5 GW by 2013. This capacity is equal to 60 plants which are eligible for the feed-in tariff. In total projects with a total capacity of 15 GW have applied for interconnection. This is in line with the European Solar Industry Initiative, which aims at a cumulative installed CSP capacity of 30 GW in Europe out of which 19 GW would be in Spain [ESTELA, 2009a].

In the US, more than 4 500 MW of CSP are currently under power purchase agreement contracts. The different contracts specify when the projects have to start delivering electricity between 2010 and 2014 [Mancini, 2009; Spillati, 2009]. More than 100 projects are currently in the planning phase mainly in Spain, North Africa and the USA.

Capital investment for solar-only reference systems of 50 MW_e without storage are currently of the order of €4 800/kW_e varying from €2 100 to €6 000/kW_e. With storage, prices can go up significantly. Depending on the Direct Normal Insolation (DNI), the cost of electricity production for parabolic trough systems is currently of the order of €0.18–0.20/kWh (South Europe – DNI: 2 000 kWh/m²/a) [Marquez Salazaar, 2008]. For DNI in the range of 2 300 or 2 700, as encountered in the Sahara region or in the US, the current cost could be decreased by 20 to 30 %. For a given DNI, cost reduction of the order of 25 to 35 % for parabolic trough plants is achievable due to technological innovations and process scaling up to 200 MW_e [Stoddard et al., 2006].

⁵ The capacity figures given are MW_{el} (electric) not MW_{th} (thermal)

⁶ www.torresolenergy.com/en/proyectos-en-construccion.html

The economical potential of CSP electricity in Europe (EU-27) is estimated to be around 1 500 TWh/year, mainly in Mediterranean countries ($DNI > 2000 \text{ kWh/m}^2/\text{year}$) [DLR, 2005]. Based on today's technology, the installed capacities forecasted in the EU-27 under the European Solar Industry Initiative are 830 MW by 2010, 30 GW by 2020 and 60 GW by 2030 [ESTELA 2009a; 2009b]. This represents respectively, up to 2030, 0.08 %, 2.4 % and 4.3 % of projected EU gross electricity consumption. These penetration targets do not account for imports of CSP electricity. The DESERTEC scenario, which assumes that a grid infrastructure will be built with Northern Africa Countries, CSP electricity imports of 60 TWh in 2020 and 230 TWh in 2030 could be realised [DESERTEC, 2009]. The penetration of CSP electricity for 2030 under these scenarios would be 10 % of the EU gross electricity consumption.

In December 2009, the World Bank's Clean Technology Fund (CTF) Trust Fund Committee endorsed a Critical Technology Development (CTD) resource envelope for projects and programmes in five countries in the Middle East and North Africa to implement CSP [WB, 2009]. The budget envelope proposes CTF co-financing of USD 750 million (EUR 577 million), which should mobilise an additional USD 4.85 billion (EUR 3.73 billion) from other sources and help to install more than 1.1 GW of CSP by 2020.

As a follow up to this initiative, the World Bank commissioned and published a report early 2011 about the Local Manufacturing Potential in the Middle East and North Africa (MENA) region [WB, 2011]. The report concludes: *MENA could become home to a new industry with great potential in a region with considerable solar energy resources. If the CSP market increases rapidly in the next few years, the region could benefit from significant job and wealth creation, as well as from enough power supply to satisfy the growing demand, while the world's renewable energy sector would benefit from increased competition and lower costs in CSP equipment manufacturing.*

Scenarios for the worldwide deployment of CSP technology vary significantly between the 2010 IEA CSP Roadmap and the Greenpeace/European Renewable Energy Council Scenarios [IEA, 2010; Greenpeace/EREC, 2010]. The IEA scenarios range between 148 GW installed capacity or 340 TWh in 2020, 337 GW and 970 TWh in 2030 and 1 089 GW and 4 050 TWh in 2050. The European share in 2050 would be about 2.5 %. On the other hand, the Greenpeace scenarios vary between 12 GW (38 TWh) by 2020, 27 GW (121 TWh) by 2030 and 50 GW (254 TWh)

by 2050 for the reference scenario and 225 GW (689 TWh) by 2020, 605 GW (2 734 TWh) by 2030 and 1 643 GW (9 012 TWh) by 2050 for the advanced scenario.

Within just a few years, the CSP industry has grown from negligible activity to over 4 GW_e either commissioned or under construction. More than ten different companies are now active in building or preparing for commercial-scale plants, compared to perhaps only two or three who were in a position to develop and build a commercial-scale plant a few years ago. These companies range from large organisations with international construction and project management expertise who have acquired rights to specific technologies, to start-ups based on their own technology developed in-house. In addition, major renewable energy independent power producers such as Acciona, and utilities such as Iberdrola and Florida Power & Light (FLP) are making plays through various mechanisms for a role in the market.

The supply chain is not limited by raw materials, because the majority of required materials are glass, steel/aluminium and concrete. At present, evacuated tubes for trough plants can be produced at a sufficient rate to service several hundred MW/yr. However, expanded capacity can be introduced fairly readily through new factories with an 18-month lead time.

3.4. Barriers to large-scale deployment

More than 2 500 MW of planned CSP projects in USA have recently reconverted to PV, for reasons of cost [White, 2011]. It should be recognised that dispatchability and storage, as mentioned and analyzed as part of the future promise of CSP, together with mass production, are not sufficient for competitive electricity production with the current "mainstream" approach (oil/parabolic trough). Therefore, much more research is required on advanced CSP concepts (molten salts/solar trough, direct steam/Fresnel, molten salts/solar tower, hybrid approaches) which have the potential to drastically reduce the cost. Convenient storage systems (up to 8 hours) are a cross-cutting issue for all CSP concepts [Menna, 2011].

3.5. RD&D priorities and current initiatives

The implementation of long-term frameworks with support schemes is critical to accelerate the deployment of CSP technologies. Extending the Spanish model to other EU Member States in the sun-belt and fostering its promotion worldwide is important to build a global market. Joint developments with North Africa would allow the EU to benefit from higher solar resource levels. It is important to open the European market for the import of solar electricity from North Africa. A critical element of this action is the establishment of a pan-Mediterranean grid infrastructure. On the technology front, increased R&D efforts and strategic alignment of national and EU programmes are necessary to realise all the potential embedded in technology innovation. Demonstrating next generation CSP technologies is critical to address medium- to long-term competitiveness, but also to attract investors. Due to the private financing dilemma, innovative funding schemes will have to be developed.

In 2008, the Commission proposed to launch six European Industrial Initiatives (EII): Wind, Solar (both concentrated solar and photovoltaic), Carbon capture and storage, Electricity grids, Bio-energy

and Nuclear fission. The launch of the first four EIIs – including solar - took place at the Madrid SET-Plan conference in June 2010.

The Implementation plan of the Solar Europe Industry Initiative (SEII) describes the strategic RD&D components to boost innovation and reach competitive levels in the energy market [ESTELA 2010]. As a first step, during the first phase of the Implementing Plan, 2010-2012, the European industry considers that top priority should be given to Innovation Objectives:

- Reduction of generation, operation and maintenance costs, and
- Improvement of operational flexibility and energy dispatchability.

Synergies with other sectors

Hydrogen production is a potential industrial field for synergies with CSP technologies. Although these concepts are at an R&D phase, current developments on the heliostat or other heat transfer components will certainly benefit this field. In the short term, shared developments can be envisaged with concentrated photovoltaics as their concentrators respond to the same kind of usage. Other areas of developments besides electricity production are district cooling and water desalination.

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4. Hydropower

4.1. Introduction

Hydropower is the most widely used form of renewable energy with 3 190 TWh generated worldwide in 2010. This corresponds to 16 % of the global gross electricity generation and 88 % of electricity from renewable resources. Moreover, the global hydropower potential is considered to be around 7 500 TWh/y. In more than 60 countries, hydropower covers at least 50 % of the electricity supply [IEA, 2010]. In the EU, hydropower accounts for 11.6 % of gross electricity generation. The top 5 EU countries in terms of hydropower share in the total electricity mix are: Austria 59.3 %, Latvia 49.5 %, Sweden 43.5 %, Romania 29.3 % and Slovenia 24.3 % [European Commission, 2009]. In neighbouring Norway, hydropower covers roughly 95 % of electricity supply and there remains significant unexploited potential. Nevertheless, the European hydropower potential is already relatively well exploited and expected future growth is rather limited [European Commission, 2009]. On the global level, on the other hand, significant growth is expected with annual hydropower generation reaching some 5 000-5 500 TWh in 2050. Strong growth is anticipated during the next decade in China, India, Turkey, Canada and Latin America [IEA, 2010].

Hydropower plants with a storage reservoir generate electricity when needed. They provide reserve capacity and can respond to load changes within seconds. Furthermore, pumped storage schemes currently provide the most commercially viable means of large-scale electricity storage. In this sense, hydropower enables the integration of variable renewable energy sources, such as wind and photovoltaics (PV) in the electricity mix. Hydropower could also be the optimal complement to nuclear power, especially in a power mix with a relatively high nuclear share. Hydropower flexibility could then compensate for the rigid baseload character of nuclear power and adapt generation to daily and seasonal demand fluctuations.

Dedicated hydropower plants provide the substantial amount of power needed for energy intensive industries such as aluminium production plants. Also many solar silicon plants around the globe are supplied with hydropower. This helps to reduce notably the carbon footprint of crystalline silicon PV panels.

The advantages of hydropower can be summarised as: renewable, flexible, mature and relatively cheap. The disadvantages are the limited resources and the potentially high environmental impact and in some cases potential risk due to dam failure.

4.2. Technological state of the art and anticipated developments

There are two hydropower plant configurations: dams and run-of-the-river (ROR) schemes. The first is based around a reservoir, the second is without or with a very small one, referred to as pondage. Hydropower plants are most commonly classified according to their size as: large (>10 MW), medium (1-10 MW), small (100 kW – 1 MW), micro (5 – 100 kW) and pico (<5 kW). Pico plants could even use small turbines of 200-300 W. In the EU there are more than 21 000 small hydropower plants, but in terms of installed capacity, their market share is just 13 %. On the global level, this share is 12 %.

The world's largest hydroelectric power stations are the Three Gorges Dam in China with a generating capacity of 22.5 GW, the Itaipu power plant on the Brazil-Paraguay border with a generating capacity of 14 GW and the Guri Dam in Venezuela with a generating capacity of 10.2 GW. Hydropower stations in the EU are smaller than 2 GW, except for the 2.19 GW Iron Gate I power station on the Romanian-Serbian border.

Pumped hydro energy storage (PHES) plants consist of two or more natural or artificial reservoirs at different heights. Reversible Francis turbines are used for water pumping and power generation. Pumping takes place typically during demand off-peak periods and generation during peak periods. Most PHES plants are operated with daily cycles but some large plants are operated with weekly or even seasonal cycles [Deane et al., 2010]. Round-trip efficiencies are typically in the range of 70 to 85 %, with losses being mainly conversion losses and due to evaporation. Pure PHES plants, also known as closed-loop or off-stream, store energy by pumping water from a lower reservoir, a river or the sea to an upper reservoir with no natural inflow. On the other hand, pump-back plants are located in natural inflow areas and are a combination of a PHES plant and a conventional hydroelectric plant. An advantage with pump-back facilities is that the storage capacity is generally much greater.

Figure 4.1 shows a schematic of a dam-based hydropower plant. Small dams serve for short-term storage, while large dams can provide seasonal storage. The generated power depends on the discharge and the head. A large pipe, the penstock, delivers water to the turbine. Reservoir-based hydropower generates power on demand. Nevertheless, the power plant availability depends on rainfall and may have significant seasonal and

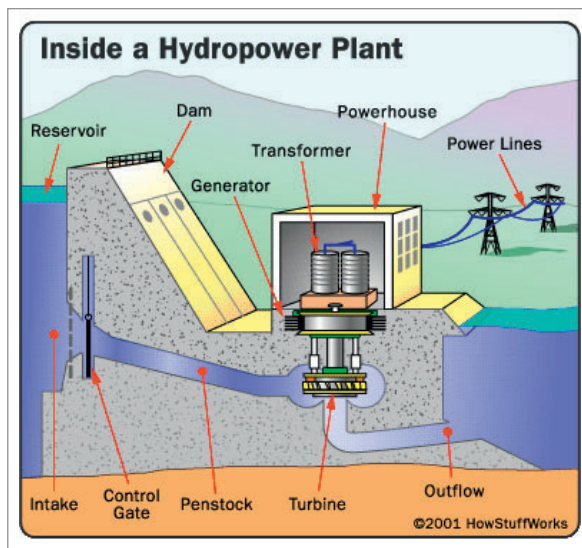


Figure 4.1: A hydropower plant based on a dam
[Source: www.howstuffworks.com]

annual fluctuations. Long-term energy yield may be affected by climate change.

ROR hydropower plants use a small or no reservoir. The water is carried downstream through a penstock to the turbine and returns to the river. A plant without pondage is subjected to water flow variations so that the output of the power plant is highly dependent on the natural run-off. On the other hand, a plant with pondage can still regulate the water flow and adapt power generation to demand requirements. As ROR plants do not require a large impoundment of water, they do not alter significantly the normal course of the river and hence their environmental impact is relatively low.

Figure 4.2 illustrates the application range of the different types of hydropower turbines according to their height and discharge. The range from 50 kW to 30 MW is considered. Small discharge, high-head installations are typically mountain-based dams and are equipped with Pelton turbines. Large discharge, low-head installations are typically large ROR

plants equipped with Kaplan turbines. Intermediate flow rates and head heights are usually equipped with Francis turbines. Kaplan and Francis turbines are reaction turbines. The water pressure drops as it moves through the turbine. On the other hand, the Pelton turbine is an impulse turbine. Prior to hitting the turbine blades, the water goes through a nozzle, generating thereby a water jet, which moves the turbine through its impulse.

Hydropower plants are characterised by relatively high capital costs. Nevertheless, in cases where dams have been originally built for other purposes, such as for flood control and for water storage for irrigation and urban use, a hydropower plant may be added with relatively low capital costs. The rehabilitation and refurbishment of old plants implies also an investment with relatively low initial costs, which translates into favourable levelised costs of electricity. Hydropower plants have a long asset life, with many facilities operating more than 50 years. Labour cost is low as facilities are automated so that few personnel is required on site. Other O&M costs include the replacement of ageing components.

Table 4.1 summarises the investment costs and the levelised cost of electricity for large, small and very small hydropower plants. Capital costs are highly site and project specific. This implies a wide range of values. For instance, sites with low head require a greater capital. Plant size and existing infrastructure, such as a previous facility or grid connection, are very decisive factors.

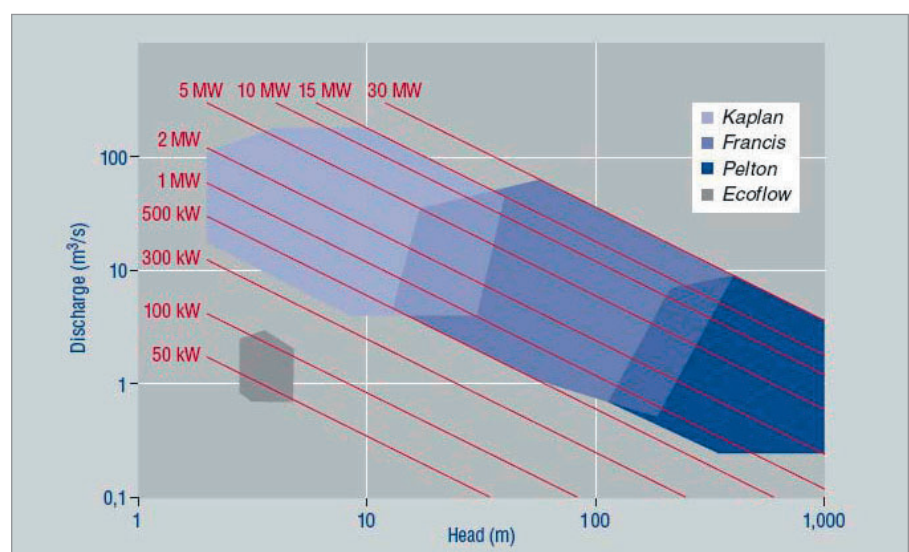


Figure 4.2: Types of small hydropower turbines by head height, discharge and capacity
[Source: Voith Hydro, 2009]

⁷ <http://science.howstuffworks.com/environmental/energy/hydropower-plant1.htm>

	LHP	MHP	SHP
Investment cost [€/kW]	1 200 – 4 600	1 400 – 5 500	1 800 – 7 300
Typical value	3 000	3 300	3 700
LCE [€/kWh]	0.029 – 0.08	0.033 – 0.088	0.04 – 0.0135
Typical value [€/kWh]	0.055	0.06	0.065

The considered lifetime is 50 years, the discount rate is 5 %, and the annual O&M costs are 2 % of the investment cost.

Table 4.1: Investment costs and levelised cost of electricity (LCE) of large, medium and small hydropower plants [IEA, 2010].

The impact of large hydroelectric facilities on the environment is often significant. Small installations, on the other hand, have minimal reservoir and civil construction work, so that their environmental impact is relatively low. The carbon footprint of hydropower is typically in the range of 2 to 10 gCO₂eq/kWh, linked to the construction input in terms of concrete and steel. The upper range corresponds to the more common power plants with a storage reservoir, while the lower range corresponds to ROR installations.

4.3. Market and industry status and potential

The global installed hydropower capacity at the end of 2008 was 723 GW [IEA, 2010]. In a rough estimation, 90 GW have been added over the last three years. Currently, hydropower accounts for 16 % of the global gross electricity generation. This share is expected to increase to around 19 % in 2020 and up to 21 % in 2030 [IEA, 2010].

Growth in the EU in hydropower generation will be much slower compared to the global average. Much of the activity in this sector in Europe will focus on the refurbishment of an overall ageing hydropower park, while a modest exploitation of unused potential, mainly in Austria, Romania, the Iberian Peninsula and France can be expected. Table 4.2 gives the estimated values of hydropower generation in GWh and in terms of the share in the gross electricity generation for the EU Member States for 2010 and indicates the expected evolution for 2020 and 2030 [European Commission, 2009]. Hydropower generation in the EU-27 was 323 TWh in 2010, accounting for 9.8 % of gross electricity generation and around 60 % of electricity generation from renewables. The economic potential is estimated to be around 470 TWh/y. Annual generation is expected to increase modestly up to 341 TWh/y in 2020 and

up to 358 TWh/y in 2030. Nevertheless, in terms of the share in the gross electricity generation, and due to increasing electricity demand, a share decrease to 9.2 % in 2020 and further down to 8.8 % in 2030 is expected. This estimation is based on the fact that the most favourable sites are already being exploited across the EU-27, while due to environmental restrictions, it's unlikely that Europe could see much more expansion.

PHES is currently the only commercially proven, large-scale energy storage technology with over 300 plants installed worldwide with a total installed capacity of over 95 GW. The EU has an installed PHES capacity of around 38 GW. Much of this capacity was built in the 1970s and 1980s, with 7.5 GW and 14.2 GW installed respectively, while only 4 GW have been added between 1990 and 2010. Nevertheless, interest in PHES is again high in the EU, and at least 7 GW of new capacity is expected to be added before 2020. While previously, PHES was used to enable an electricity mix with a high baseload share, there is now a renewed interest driven by an increasing wind and solar power share. As a matter of fact, it has been noted that developers of PHES plants in Europe tend to have diverse generating portfolios usually with significant amounts of wind capacity. Current trends show that developers tend to repower or enhance existing facilities or build pump-back plants rather than building new pure pumped storage facilities. This is based on the favourable economy behind using existing infrastructure and is also partly driven by a lack of economically attractive new sites for pure PHES plants [Deane et al., 2010].

	GWh			% in electricity generation		
	2010	2020	2030	2010	2020	2030
EU-27	323 347	341 246	357 538	9.8	9.2	8.8
Austria	37 651	41 769	45 033	59.3	57.2	54.8
Belgium	366	408	447	0.4	0.4	0.4
Bulgaria	4 065	4 169	4 357	10.2	8.6	7.8
Cyprus	0	0	0	0	0	0
Czech Republic	2 263	2 361	2 433	2.8	2.5	2.2
Denmark	21	29	29	0.1	0.1	0.1
Estonia	17	22	22	0.2	0.2	0.1
Finland	13 206	13 396	13 715	16.7	14.7	14.6
France	56 979	57 354	60 485	10.1	9.2	8.9
Germany	21 054	22 349	23 856	3.3	3.6	3.7
Greece	3 999	4 358	4 805	6.5	5.9	5.6
Hungary	147	1 043	2 345	0.4	2.3	4.6
Ireland	691	707	705	2.6	2.2	1.8
Italy	38 369	38 710	38 992	12.8	10.7	9.5
Latvia	2 881	2 931	3 380	49.5	33.0	33.4
Lithuania	419	449	466	6.5	3.3	2.5
Luxemburg	90	92	94	2.6	1.8	1.4
Malta	0	0	0	0	0	0
Netherlands	99	99	99	0.1	0.1	0.1
Poland	2 263	2 568	2 856	1.4	1.4	1.3
Portugal	10 371	11 092	11 491	22.4	21.2	19.2
Romania	18 003	23 869	25 477	29.3	31.1	30.0
Slovak Republic	4 685	5 115	5 189	14.7	12.4	10.4
Slovenia	3 927	4 332	4 367	24.3	22.1	19.4
Spain	29 499	30 967	33 530	10.0	8.7	8.2
Sweden	67 600	68 100	68 267	43.5	40.5	39.2
UK	4 682	4 958	5 099	1.2	1.2	1.1

Table 4.2: Current and expected future hydropower generation in the EU-27 [European Commission, 2009].

4.4. Barriers to large-scale deployment

Potential hydropower sites imply locations rich with hydro resources with favourable topography and suitable geotechnical conditions. Close access to electricity transmission networks is a big advantage. Of course, within the exploitation of hydro resources, there is a natural saturation of the most cost effective locations. New hydro sites in Europe tend to be small installations or large ones that require extensive transmission lines.

Based on life-cycle assessments, the carbon footprint of hydropower plants is relatively small. Methane emissions due to decaying organic materials in reservoirs have been reported. However, this issue does not relate so much to Europe, as to other continents [Arcadis, 2011]. Furthermore, it can be often avoided by proper reservoir design. So in terms of greenhouse gases, hydropower is a low-impact electricity generation technology. Nevertheless, hydropower plants can be related to other serious environmental impact issues. The

more a hydropower plant intervenes in the natural water flow, the greater this impact. Therefore, plants with huge reservoirs are often critical. Land areas are submerged upstream, while water availability is affected downstream. This can have a large negative impact on valuable ecosystems. Furthermore, the dam can modify water temperature and dissolved oxygen content, affecting aquatic flora and fauna. Large reservoirs could also require the displacement of population upstream. Furthermore, as a large volume of water is held back, a dam failure can be catastrophic to downstream settlements and infrastructures. New hydropower projects, especially large reservoir-based facilities, can face serious public opposition.

Hydropower in the EU is not seen as a political priority, while, on the other hand, environmental issues related to water bodies have become a significant concern [European Commission, 2011]. The construction of a hydroelectric plant requires a long lead-time for site and resource studies, as well as environmental impact and risk assessments. Depending on the country, the administrative procedure can take between 1 to 12 years. Environmental standards can act as a limiting factor in terms of project approval or quantity of exploitable resource.

4.5. RD&D priorities and current initiatives

Current R&D efforts in hydropower include innovative technologies to minimise its environmental impact. Power plant designs that are easier on aquatic life are an active area of research. Low head and ROR technologies are being developed and improved. On the material side, research is focusing on cheaper alternatives to steel in some components and applications, such as fibre-glass and special plastics. Developing more resistant materials to extend the life time of some components is also essential. Within this scope, steel alloys that are more resistant to turbine cavitations are being developed. Efforts are being addressed to improve control systems and power electronics and to optimize generation as part of integrated water-management systems. For both sectors, research includes the reduction of O&M costs through maintenance-free and remote operation technologies.

In the field of PHES, site development with the aim to increase resource is an important research field. For instance, a 30 MW seawater PHES plant with a head of 136 m has been built in Okinawa, Japan. This plant started operation in 1999 and is still the only one of its kind worldwide. Corrosion prevention had been a key development issue. Seawater PHES has great potential in terms of site availability. Other innovative PHES schemes imply the use of underground reservoirs, for instance old mine pits.

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5. Geothermal Energy

5.1. Introduction

Geothermal energy can provide cost-effective energy for industry and domestic applications, displacing oil, gas and electricity – thus reducing our external energy dependency and increasing security of supply. Geothermal electricity, being flexible, provides baseload electricity thus complementing other variable renewables. Geothermal heat has many direct uses which entail broad market opportunities and indirect use, through the use of electricity or gas compressors in ground-source heat pumps (GSHP), which is the fastest-growing of the geothermal energy technologies.

European geothermal potential includes 3.5 GW (28 TWh) of hydrothermal electricity [EER, 2009] and maybe 70 GW (560 TWh) from innovative enhanced geothermal systems (EGS) currently on pilot phase. Heat potential is unknown but huge given the many possible uses. Globally geothermal could supply 3 % of electricity and 5 % of heating and cooling demand by 2050 [Goldstein et al., 2011].

5.2. Technological state of the art and anticipated developments

Geothermal energy is heat stored beneath the surface of the Earth and it takes the form of either: rock or water with low underground temperatures exploitable by ground-source heat pumps (GSHP); hot fluid (water, brine or in the best cases, steam, the traditional exploitation collectively called hydrothermal); and heat stored in deeper hot rocks (dry, wet and/or fractured, sometimes under very-

high-pressure) whose initial permeability does not allow economic exploitation for which it requires additional stimulation – this is termed enhanced geothermal systems (EGS) [Genter at ENER 2011]. The Soultz-sous-Fôret (France) geothermal pilot site, possibly the most important research EGS facility in the world, showed that low natural permeability occurred at depth but must be enhanced by stimulation. Geothermal subsectors can be divided into direct heat use, indirect heat use, i.e. GSHP, and electricity generation. Installations can sometimes provide co-generation of electricity and then heat for district heating networks.

Deep (1–3 km), naturally-occurring, geothermal fluids are extracted from the Earth to convert a part of their energy into electricity or usable heat, and after use they are either re-injected or rejected. EGS, by contrast, are poorly-connected and require the stimulation of the rock/reservoir (by hydraulic, chemical or hydraulic/chemical processes) in order to enable adequate permeability, then fluids are injected to recover the energy in the deeper (3–6 km) rock [Genter at ENER 2011].

Technologies used for electricity production depend on the temperature and pressure of the geothermal fluid. **Direct steam** turbines use the (rare) high temperature steam resources directly to generate electricity and result in the lowest power plant cost [Bloomquist, 2009]. However, their open loop configuration raises environmental concerns, e.g. fluid emissions and well management [EER, 2009]. For the high-temperature mix of brine and steam, a **flash steam** plant is the most economical choice. The steam is first separated from the liquid

and then expanded in a turbine, and the hot brine is then diverted to heat applications in a technique known as cascading. **Double-flash steam** systems pass the hot brine through successive separators each at a subsequently lower pressure. The flashed steam is injected in a dual-entry turbine with each steam flow channelled to a different part of the turbine. Advantages include increased overall cycle efficiency and better utilisation of

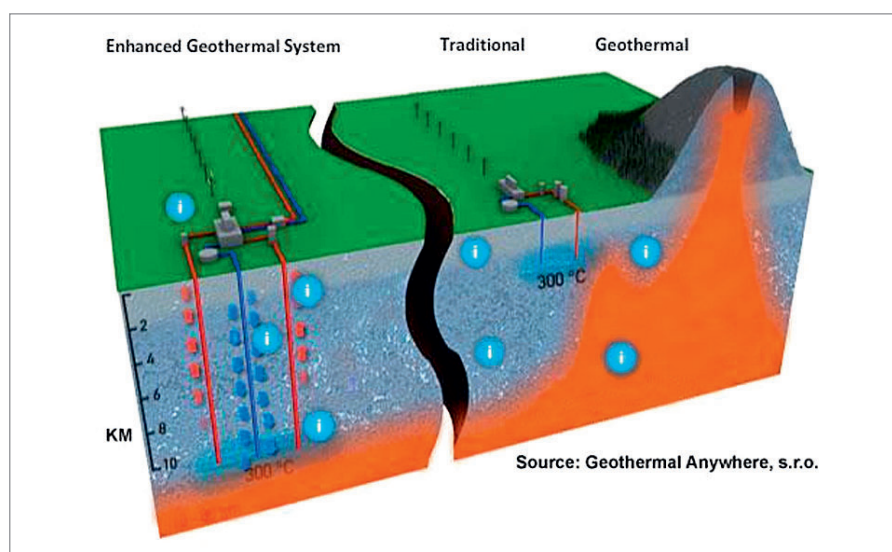


Figure 5.1: EGS vs. traditional geothermal (hydrothermal). Note the difference in the depth of the resource (on the left, in km).

System	Efficiency	Description	Capacity factor (%)
GSHP - average	COP 3.5	1 kWe in for 3.5 kWth out	19-30
GSHP - best	COP 6	1 kWe in for 6 kWth out	25
Hydrothermal	7-20 %	heat-to-power conversion	90
EGS	7-12 %	heat-to-power conversion	90
Space heating			37
Bathing & swimming			52
Industrial process heat			70

Table 5.1: Summary of efficiencies and capacity factors of different technologies. Sources: Miara (2008), ENGINE (2008), Lund et al. (2011) and JRC estimates

the geothermal resource - but at an overall cost increase. **Binary cycle** technology separates in two loops the geothermal brine from a secondary or working fluid that is vaporised, then expanded through the turbine, condensed through an air- or water-cooled condenser, and pumped back to the heat exchanger to be re-vaporised. In a medium temperature (120-180 °C) reservoir, a binary plant is more efficient than a flash-steam one, and has better environmental performance [Bloomquist, 2009], although they are more expensive for resources above 120 °C. Below this temperature, there is no comparison possible because a binary cycle is the only option. A binary plant can adopt the Organic Rankine Cycle (ORC) or the Kalina technologies, as used in other industries, are available from 60 kW to several megawatts, and can exploit multiple energy sources, e.g. geothermal and heat from concentrated solar power or biomass.

Geothermal heat is directly used nowadays for heating and cooling buildings; in district heating networks; bathing, wellness and swimming pools; agriculture in greenhouses or uncovered ground heating to grow crops including vegetables and flowers but also tree seedlings (US) and bananas (Iceland), and to dry crops including seaweed, onion, wheat and other grains, fruit, alfalfa, coconut meat and timber; aquaculture of tilapia, salmon, trout, tropical fish, lobsters, shrimp, prawns and alligators; water purification/desalination; industrial process heat for concrete curing, bottling of water and carbonated drinks, milk pasteurisation, leather, chemical extraction, CO₂ extraction, pulp and paper processing, iodine and salt extraction, borate and boric acid production; and snow melting and space cooling [Lund et al., 2011].

Geothermal or ground-source heat pumps (GHP/GSHP) transform geothermal heat into useful space

or water heating with the support of electricity from the grid. GSHP can be open- or closed-loop, and can be used also for cooling and in single family houses, industrial, education and office buildings. Open-loop systems draw underground water for use as the heat source/sink and return the used water or send it to a drainage field. Closed-loop systems, also called earth-coupled, use water or a water and antifreeze solution, circulated in a ground loop of pipes, to extract heat from the Earth. Direct evaporation of, for example CO₂, is in usage as well. Ground loops can be built vertically or horizontally, the former is more expensive and is used where space is limited. The depth of the loop pipe will vary with soil type, loop configuration and system capacity, from 2 metres for a horizontal loop, to 4 to 50 metres for ground-water wells and 250 metres or more for a vertical loop also called borehole heat exchanger [Fernández, 2009]. GSHP is a mature industry although its high capital cost makes it a necessity to receive financial support. The most efficient use of GSHP occurs when the required thermal rise is small. To achieve this, the temperature of the geothermal heat source has to be relatively high (say 8-10 °C in winter) and the temperature of useful heat output relatively low, for example, wall/underfloor heating that needs only 30-35 °C.

The GSHP efficiency is measured by its coefficient of performance (COP, the ratio of output heat to input electricity), it is normally around 4 but it can reach 6 [Miara, 2008]. A lower COP may be acceptable if a larger heat demand is covered, as in cold climates. By comparison, heat-to-power conversion efficiencies vary between 7-20 % for hydrothermal fields and 7-12 % for EGS [ENGINE, 2008], with a clear potential for improvement. In all cases system efficiency analysis must deduct the parasitic consumption of electricity items, mostly pumps.

The state of the art of reservoir assessment and management includes the crucial phase of reservoir assessment, i.e. reserve estimation and valuation. It includes both volumetric reserve estimation and valuation based on numerical reservoir simulation [ENGINE, 2008]. A number of techniques have been adopted to recover power from problematic brines, including the use of a crystallizer reactor clarifier and pH modification technologies. The use of either technique can add considerably to plant O&M cost. If pH modification is used for scale control, corrosion could also become more severe. The metallurgy of system components thus also becomes crucial and can add significant cost to the plant if more exotic materials such as titanium are used. Recent developments in adding enhanced evaporative cooling to air condensers in binary plant can improve summer efficiency of air-cooled binary plants by as much as 40 %. Compared to ORC, Kalina cycle systems that use a mix of ammonia and water as working fluid reach higher efficiency.

The use of variable speed compressors and pumps in heat pumps instead of fixed-speed components can yield up to 27 % efficiency improvement. New advances in double and even triple-pass absorption equipment allow for a cooling COP significantly above 1 to be obtained, and even at geothermal resource temperatures as low as 80 – 100 °C, absorption cooling may be the answer to meeting the needs of both greenhouse operators and providers of district energy service [Bloomquist, 2009]. The COP for heat pumps is slowly increasing, ~2 % per year [EGEC, 2008]. The use of CO₂ as working fluid in HP is extensive in Japan but less common in Europe. The COP reaches above 5 and CO₂ does not have the environmental problems of freons or propane.

The trend in electricity generation is that flash systems, with their potential for higher efficiencies above 200 °C, remain the standard for high-temperature resources. Below 180 °C, binary systems are imposing over flash systems and they also increasingly mix with flash systems in high-efficiency cascade configurations. EGS technologies are increasingly being used to raise production at conventional sites [EER, 2009]. Two other significant and expected trends are hybrid plants with biomass/biogas, and coproduction of geothermal energy and the metals present in brines to improve overall economics.

Drilling costs constitute 50-70 % of the capital costs of deep geothermal, including both conventional geo-thermal and EGS. Drilling costs include moving the rig and equipment to the site, depend on the price

of oil (see box), on the local geology (the harder the rock the longer it takes to drill), the success rate (in hitting a suitable resource), and the depth at which a suitable resource temperature is found.

A 50 MW conventional geothermal plant with an average production of 5 MW per well requires €1 285-2 285/kW in well costs assuming a 67 % success rate [BNEF, 2011b]. The daily drilling rate of EUR 30 000–100 000 is shared approximately 50 % between drilling rig and staff, and services including mud logging, cementation, etc. [Uhde at ENER 2011]. Total plant investment costs vary in the ranges €1 600-3 200/kW for flash technology, €2 600-4 500/kW for binary cycles [Maack at ENER 2011] above 8 500 for EGS [Law at ENER, 2011] and up to €26 000/kW for the current demonstration projects [EER, 2009]. Cost of electricity is competitive with fossil fuels in high-enthalpy regions (e.g. Italy) at around €50/MWh, but can reach €300/MWh at low-enthalpy sites using binary plant. Cost of heat depends on whether it is the main product or a by-product of the geothermal exploitation with the highest costs for EGS exploitation in a range €40–100/kWh_{th} [Kölbel at ENER, 2011].

The installed cost of heat pumps vary between €1 000/kW and €2 500/kW for typical domestic facilities of 6 - 11 kW, and between €1 700 and €1 950/kW for industrial or commercial installations in the 55 – 300 kW range [NERA, 2009]. Capital costs depend greatly on the ground exchanger layout, whether horizontal or boreholes.

Drilling geothermal vs. oil and gas.

The drilling rigs used for geothermal plants are the same rigs used for oil and gas wells, however, there are some significant differences including:

- geothermal wells are usually completed at a larger diameter than oil and gas wells, increasing the costs;
- salty water is more corrosive than oil and gas requiring different casing materials and cementing methods;
- the effects of thermal expansion require different approaches to well completion;
- high temperatures effect bit life;
- the rock in EGS reservoirs are significantly harder than those found in oil and gas, effecting bit life and rates of penetration.

Source: [CSIRO, 2011]

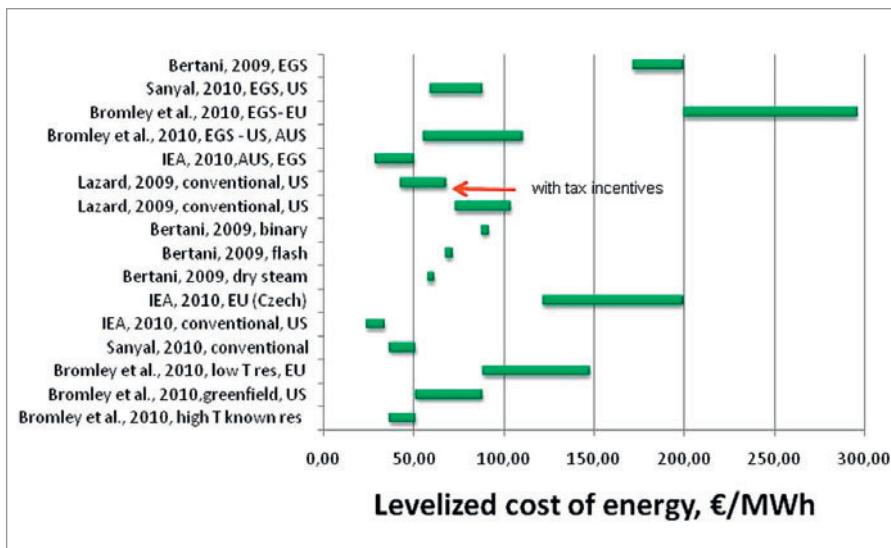


Figure 5.2: Published figures on the cost of energy from geothermal [Sources: Bertani, 2009; Sanyal, 2010; Bromley, 2010; IEA, 2010; Lazard, 2009; compiled by Bombarda at ENER, 2011]

The system availability for a geothermal energy plant can reach 95 %. A capacity factor of 90 % are normal in a new electricity plant, whereas the current world average is 74.5 % and national figures vary from 60 to 91 % [Chamorro et al., 2011]. Heat pumps have a lower factor at around 23 %, whereas other heat uses reach load factors of 18 to 72 % [Lund et al., 2011].

5.3. Market and industry status and potential

Geothermal electricity has three very different markets: two hydrothermal and EGS. The first is the high-temperature hydrothermal market which is low in the EU at 910 MW, compared to other areas of the world: US with 3 100 MW or the Philippines with 1 970 MW [BP, 2011]. The reason for this small European market is the small identified hydrothermal resource within economically-exploitable depths – note the high cost of drilling explained above. In the EU-27, other than unexploited reserves within Italy, the Canary Islands (ES), Azores and Madeira (PT), and Guadalupe (FR) present a certain potential. The second market, low-temperature hydrothermal exploited through binary-cycle plant, presents resources that are more widespread in Europe including Austria, Germany and France. The units are smaller and the cost is higher though, and efficiency lower. Slowly, this market is developing helped by high feed-in-tariffs. The third market is

EGS: EGS technologies, still at an early stage of exploitation, have currently 5 MW installed in Europe and a huge potential, which suggests that this will be a future market, not a present one. Some EGS projects are planned in the UK, Germany, the Czech Republic and Hungary – the last two are seeking NER300⁸ support.

The geothermal heat market is divided among heat pumps and direct heat use, and the former

market is growing faster supported by subsidies to counterbalance the high cost of, for example, piping. The direct heat market, being surprisingly varied, has much room for growth which is not realised, and this suggests the existence of strong barriers.

The addition of geothermal electricity capacity in the EU in 2010 was a meagre 20 MW (in Italy) to reach 863 MW gross cumulative capacity [BP, 2011]. Of this, 765 MW was the net capacity [EurObserv'ER, 2011a]. Elsewhere in Europe, Iceland has 575 MW and Turkey 82 MW installed [BP, 2011]. In total, the world installed capacity reached 10.9 GW in 2010 in a mix dominated by flash technology (single-flash 42 %; double-flash 20 %), and followed by dry steam (26 %), and binary plant/combined cycle (12 %) [Chamorro et al., 2011]. By 2011, geothermal power plants exist in 24 countries, with a 2 % annual growth of installed capacity [BP, 2011]

The European GSHP market installed 1 745 GW_{th} during 2009, which is a 6.6 % reduction in annual installed capacity compared to 2008, and a further 3 % in 2010 putting the 2010 cumulative capacity at an estimated 12.6 GW_{th} [EurObserv'ER, 2011a, b]. At the end of 2009, capacity for direct heat use was 2.86 GW_{th}, compared to global GSHP of 33 GW_{th}, with other direct heat uses reaching an estimated 15 GW_{th}. At least 78 countries used direct geothermal energy and by the end of 2009, the global capacity of geothermal heating (including HP) was estimated at 48.5 GW_{th} [Lund et al., 2011]

⁸ NER300 is a EU funding programme to support demonstration projects for carbon capture and storage (CCS) and innovative renewable energy technology. Full information at: http://ec.europa.eu/clima/funding/ner300/index_en.htm

Gross geothermal electricity production in the EU reached 5.55 TWh in 2009 of which 96 % is in Italy. Global geothermal electricity production reached 67 TWh in 2010 [Chamorro et. Al, 2011]. Useful heat production in the EU in 2009 reached 20.1 TWh from GSHP and 10.6 TWh from direct heat uses, totalling 30.7 TWh [EurObserv'ER, 2011a],⁹ compared to worldwide geothermal heat use of 118 TWh, of which just below 48 % was produced by heat pumps (a COP of 3.5 was assumed), 26 % was used for bathing and swimming and 15 % for heating; the rest was used in greenhouses, industrial purposes, aquaculture, etc. [Lund et al., 2011]. Of the estimated EUR 202 billion (USD 268 billion) invested in renewables worldwide in 2010 [REN21, 2011], less than 1 % (€1.6/m) were directed to geothermal power [BNEF, 2011b].

The European Geothermal Energy Council (EGEC) is highly positive towards a potential installed capacity of 1.5-6.0 GW in 2020, 7.0-21.0 GW by 2030 and 10-100 GW by 2050 [Bertani at ENER, 2011]. Global installed power capacity is expected to stagnate during 2011 but, if projections are realised, 16 GW of installed capacity will be in place by 2020 [BNEF, 2011a]. According to Goldstein et al. [2011] for the IPCC, a global electricity capacity of 51 GW is likely in 2030 producing 380 TWh, and 150 GW producing 1 180 TWh by 2050. The same source suggests the expansion of heat uses to 144 GW (producing 378 TWh/yr) by 2020, 408 GW (1 070 TWh/yr) by 2030, and 800 GW (2 100 TWh/yr) by 2050.

5.4. Barriers to large-scale deployment

The key barriers are the high cost of drilling and a high risk that heat and electricity production does not reach the projected objectives. Success ratios for exploration wells may be between 20 - 60 %, and even production wells fail to reach their target in around 30-40 % of the cases [BNEF, 2011a, 2011b and personal communication]. The industry competes for drilling subcontractors with the O&G industry, which can have an undesirable impact: for example, when the price of oil and gas is high, the cost of drilling for geothermal projects increases.

Two other important barriers to geothermal deployment continue to be a lack of awareness in decision makers of the appropriate legislation, such as on resource ownership, and a complex licensing system. Financial incentives and in particular RES-E support schemes across the different Member States

(MS) are inconsistent. Currently 13 MS offer geothermal electricity feed-in-tariffs, ranging from €25-300/MWh [EER, 2009], which in some cases are inadequate and unattractive. A complex permit and development legal framework and administrative procedures for geothermal exploitation means long lead times for obtaining the necessary permits and licences and uncertainties for investors. Lack of acceptance, due to negative impacts of geothermal exploitation, e.g. visual and odour-related impacts, hinders large-scale deployment. Fragmentation of existing knowledge reduces progress in the sector and technological and environmental knowledge gaps increase the financial risk. Enabling technologies, such as binary cycle and improved exploration and drilling techniques, can improve the economics of geothermal energy and need to be developed accordingly. Finally, there is a shortage of a qualified work force for the sector.

5.5. RD&D priorities and current initiatives

The geothermal energy R&D scenario is complex because most of the technologies are shared with other sectors, and therefore few R&D areas impact exclusively on geothermal energy. These include mainly deep-resource extraction and dealing with corrosive brine and materials for very-high-temperature, high-pressure sources. Research on resource characterisation includes basic science on geothermal gradients and heat flow, geological structure, including lithology and hydrogeology, tectonics and induced seismicity potentials. Research on reservoir design and development includes fracture mapping and in-situ stress determination and prediction of optimal stimulation zones. Stimulation R&D should focus on innovative stimulation techniques able to improve the connection between wells and the reservoir; for hydraulic stimulation on increasing permeability, analysing the shear process with seismic/non-seismic motion, and modelling; and for chemical stimulation on geochemical modelling, laboratory and field test, and new, environmentally-friendly chemicals. Reservoir operation and maintenance includes research in reservoir performance monitoring through the analysis of temporal variation of reservoir properties, innovative monitoring tools, new tracers, the interaction between saline fluids and rock, innovative reinjection scenarios (inter-well circulation, cooling), long-term cooling and induced micro-seismicity, mechanical evolution of the reservoir, coupled reservoir models from a minute

⁹ EurObserv'ER [2011b] updated the renewable energy generated during 2010 to 2.1 Mtoe (24 TWh) but this figure is not used further in this report for consistency reasons: the corresponding 2010 figures for direct heat uses were not available.

to a decade, and reservoir aging. In particular for the exploitation of reservoirs with saline fluids, R&D should look at the scaling and corrosion of surface parts (heat exchangers, filters, pipes) to conceive tools and products that are adapted/protected and the corresponding modelling; and extending the reliability of the production pumps to duplicate their lifetime from 6 to 12 months. [ENGINE, 2008; Genter and Kölbel at ENER 2011].

Flash technology R&D focuses on increased efficiency, improved resistance to corrosion from brine and other contaminants in the geothermal resource, and emission abatement. Binary cycle research explores the use of ammonia and other more environmentally-friendly replacements to hydrocarbons and freons (R11/R22) [Bloomquist, 2009]. ORC R&D focuses on new heat transfer fluids to improve efficiency and on improved manufacturing capabilities to advance modularity benefits. Kalina cycle R&D focuses on reliability and reducing costs to make this technology competitive with current ORC alternatives. EGS research aims at finding improved and newly developed methodologies able to map reservoir conditions suitable for EGS exploitation, in particular on the local scale; providing data integration (static and dynamic) and uncertainty analysis; and finding tools able to improve imaging between existing wells and performing real-time measurements [ENGINE, 2008]. The Icelandic Deep

Drilling Project (IDDP) attempts to test the potential exploitation of sites that contain water at supercritical conditions at 4-5 km deep. Heat exchanger research focuses on heat transfer enhancement and its protection, at a reasonable cost, against corrosive brine. Related energy-storage research includes hot, cold, hot and cold combined and, in particular high-temperature heat storage. R&D also focuses on hybrid systems that combine geothermal with solar energy and biomass, for heating & cooling, and their integration in the low-energy house concept.

In the geothermal heat pump sector, R&D challenges include refrigerants, quality assurance and technology that cuts costs [EHPA, 2011]. The R&D focus is therefore on: the development of components easy to connect and disconnect from the surface; advanced control systems; natural and more efficient working fluids; single-split and multi-split heat pump solutions for moderate climate zones (Japan); the use of a second heat source (hybrid heat sources), increased efficiency of auxiliaries (pump, fan) and change in the control of the systems (Sweden) [IEA HPP, 2008].

Both increased application and innovative concepts for geothermal energy focus on cooling, agricultural uses, industry, de-icing and snow melting on roads and airport runways. Demonstration projects include heat pumps integrated in buildings, e.g. in the foundations.

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6. Marine Energy



6.1. Introduction

In the transition to a low-carbon economy new and emerging energy technologies can play a pivotal role. The sea can become an important energy source, since Europe has the oldest maritime industry, vast marine energy resources and is a pioneer in marine energy technologies. For each MWh generated by marine energy, 300 kg CO₂ can be avoided. Specifically, the annual carbon dioxide abatement in 2020 in Europe can reach for wave energy, 1.0-3.3 MtCO₂/yr and from tidal stream energy 1.0-3.7 MtCO₂/yr [EU-OEA, 2010]. SETIS forecasts that the installed capacity of wave energy will reach 0.9 GW in 2020 and 1.7 GW in 2030. Taking assumptions on the maximum potential for wave energy, forecasts predict capacity in the EU-27 of up to 10 GW by 2020 and 16 GW by 2030. This would generate 0.8 % and 1.1 % of the EU-27 electricity consumption projected for 2020 and 2030 respectively [EC SETIS b].

Marine energy can be harvested from many forms – tides, surface waves, ocean circulation, salinity and thermal gradients. Those found in tidal or marine currents, driven by gravitational effects and wind-driven waves, are derived ultimately from solar energy [Bahaj, 2011]. The best wave conditions for generation are found in high latitudes with deep water power densities of 60-70 kW/m. About 2 % of the world's 800 000 km of coastline exceeds a power density of 30 kW/m, with a technical potential of about 500 GWe based on a conversion efficiency of 40 %. The total European wave energy resources are estimated to be 1 000 TWh. In the area of the north-eastern Atlantic (including the North Sea), the available wave power resource is about 290 GW and for the Mediterranean 30 GW. The potential for marine current turbines in Europe is estimated to exceed 12 000 MW of installed capacity. Locations with especially intense currents are found around the UK and Ireland, between the Channel Islands and France, in the Straits of Messina between Italy and Sicily, and in various channels between the Greek islands in the Aegean [European Commission, 2006]. Globally, wave energy can produce 2 000-4 000 TWh/yr and tidal energy can reach 800 TWh/yr.

Marine technologies may be able to provide capacity factors of 30-45 %. Energy from waves is predictable, thus making the technology suitable for hybrid systems with balancing power from pumped storage or gas [BNEF, 2011].

6.2. Technological state of the art and anticipated developments

Most marine energy technologies are still in the demonstration phase. Nonetheless, marine technology has been working reliably in several sites with a combined capacity of about 50 MW.

There is a great variety of wave energy technologies, depending on the way the energy is absorbed from the waves, the water depth and location. Hundreds of projects have reached the prototype phase. Technically speaking, various hydraulic or pneumatic power conversion systems are used, and in some cases, the mechanical motion induced by the wave energy is converted directly to electrical power (direct-drive). These devices can be bottom-mounted or floating and vary in size, orientation and distance from shore [Falcao, 2010]. The annual average power per unit length of a wave crest in kW/m is an indicative unit of a site potential.

Wave energy systems can be categorized on their operational principles [IEA-ETSAP, 2010; Falcao, 2010; Bedard et al., 2010; EC SETIS a, b and c].

- a) Oscillating Water Columns (OWC) are conversion device with a hollow structure. They harness the motion of the ocean waves as they push an air pocket up or pull it down. Such a device is a partially submerged chamber with air trapped above a column of water. The movement of the column due to the wave entering and exiting is acting as a piston of air, compressing and decompressing. Thus a reversing stream of high-velocity air is generated. This air is channelled through a turbine/generator to produce electricity. An OWC is also a type of wave terminator. Some representative devices are greenWave (Scotland) [BNEF, 2011], Wavegens Limpet (Scotland) [BNEF, 2011], Pico Plant with more than 600 operating hours in 2010 (Azores), Mutriku (Basque Country), OE Buoy and Oceanlix Australia [IEA-ETSAP, 2010].
- b) Oscillating Body systems are offshore devices (sometimes classified as third generation devices) that are either floating or (more rarely) fully submerged. They exploit the more powerful wave regimes available in deep water (typically more than 40 m water depth). Offshore wave energy converters are in general more complex compared with first generation systems [Falcao, 2010]. Some representative systems are: Pelamis in Portugal, AWS of Columbia Power Technologies, Oyster [IEA-ETSAP, 2010] and Wave Star in Denmark.

- c) Overtopping terminators reflect or absorb all of the wave energy - hence they “terminate” the waves. Operation relies on the physical capture of water from waves. One type of terminator is an overtopping device that uses a floating reservoir structure, typically with reflecting arms to focus the wave energy. As waves arrive, they overtop the ramp and are restrained in the reservoir. The potential energy due to the height of collected water above the sea surface turns conventional low head hydro turbines. These turbines are coupled to generators to produce electricity. Some representative devices are the Wave Dragon and the Seawave Slot-Cone Generator.

Tidal energy can be grouped into two types: tidal stream and tidal range. Tidal stream energy results from large bodies of water moving around the ocean due to the gravitational pull of the sun and the moon. As water passes around peninsulas and through restrictions, such as channels between islands and the shore, it accelerates, providing a potential source of energy. The amount of energy that can be extracted depends on the speed of the flowing tidal stream (the ‘mean spring peak velocity’ is a good indicator of this). Systems to convert tidal stream energy take various forms, the most common extraction devices can be thought of as underwater wind turbines. Tidal range systems use energy from the rise and fall of the tide in estuaries and bays: the larger the difference between high and low tide, the more attractive the site. Tidal range technologies are well developed. Capacity factors expected for tidal barrages vary from 1 800 to 3 000 full-load hours.

The last two marine energy technologies are the Ocean Thermal Energy Conversion Technologies and the Salinity Gradient or Osmotic Conversion Technologies. Due to solar heating the amount of energy available in the temperature gradient between hot and cold seawater can be substantially

larger than the energy required for pumping the cold seawater up from the lower layers of the ocean. The warm water from the surface is used to boil a working fluid (or, in open cycle systems, the seawater itself under low pressure), which is then run through a turbine and condensed using cold seawater pumped up from the depths [Vosloo et al, 2008; IEA, 2009]. Salinity gradient power can be extracted either via a process known as “pressure-retarded osmosis”, where the pressure induced by the movement of water across a membrane is used to run turbines or by using freshwater upwelling through a turbine immersed in seawater. The potential energy is large, corresponding to 2.6 MW/(m³/sec), when freshwater is mixed with seawater. The exploitable potential worldwide is estimated to be 2 000 TWh/y. A further technology involving electrochemical reactions is also under development [IEA, 2009]. Temperature and salinity gradient energies are very unlikely to contribute any significant part of energy supply in Europe by 2020.

In conclusion, tidal barrages have reached a mature phase but their applications are limited. On the other hand, wave energies and tidal stream technologies are developed and near to full-scale deployment. OTEC technologies are in an advanced stage of R&D, whereas the Salinity Gradient or Osmotic Conversion Technologies are still at an early stage [Huckerby and Brito Melo, 2010]. Some operational configurations of the dominant marine energy technologies are shown in Table 6.1.

The current costs of both wave and tidal stream energy are considerably higher than conventional and other renewable energy generation. This is not surprising, given the early stage of technologies and the implications of the assumptions noted, particularly that projects are constrained to 10 MW total installed capacity and thus have limited economies of scale. For example, the levelized cost



Figure 6.1: Typical marine energy technologies (from left to right): floating OWC, overtopping Wave dragon and Open Hydro (tidal)
[Sources (left to right): Ocean Energy Ltd., Wave Dragon Ltd., Open Hydro Ltd.]

		WAVE			TIDAL STREAM			TIDAL RANGE BARRAGE		
A	ETSAP (€/kW)	2010	2020	2030	2010	2020	2030	2010	2020	2030
		5650	4070	3350	4930	3570	2930	3750	3000	N/A
	Carbon Trust (€/kWh)	min	max		min	max			-	
11.4		23		11.4	23,4			-		
B	86 (projected to decrease to 47)									
C	286	207	172	243	179	143	186	172	N/A	
D	272			194						
E	0	<<1	~1-2	0	<<1	~1-2	<<1	<<1	N/A	
F	0			0						
G	25-50 g/kWh (wave energy converter of 665 tonnes of steel and production 2.3 GWh/y)			N/A						

A. Capital costs of farms

B. O&M cost €/kW/yr (IEA)

C. Total electricity production cost (€/MWh) (ETSAP)

D. Average levelized cost of energy per MWh (Bloomberg)

E. Market share, % of global electricity output

F. Emissions (direct- operation)

G. Emissions indirect – as manufacturing, fabrication, installation, maintenance and commissioning

Table 6.1: Operational figures of Marine Energy Technologies [CT, 2011; IEA-ETSAP, 2010; IEA, 2010a]

of energy per MWh for offshore and onshore wind is €121 and 57/MWh respectively. Nevertheless, the investment cost according to IEA is projected for 2050 to drop to €1 500-1 750/kW [IEA, 2010b].

6.3. Market and industry status and potentials

Most marine energy technologies are in an early stage of development, under demonstration or have a limited number of applications [IEA-ETSAP, 2010]. Marine wave and tidal stream technologies are in a stage of development similar to that of the wind industry in the 1980s, and commercial systems could become available between 2015 and 2025.

Globally in 2011, more than 25 Marine Energy Technology demonstration projects are being performed with all of them being in the pre-commercial stage. Nevertheless, in 2014, 15 projects will be in the commercial phase. The roadmap for marine energy puts a target of 3.6 GW installed capacity in 2020, which will reach the 188 GW in 2050 [EU-OEA, 2010]. The main markets in 2020 will be France, Ireland, Portugal, Spain, and the United

Kingdom, in other words, the Member States of the Atlantic Arc. The average annual growth rate of ocean energy technologies between 2005 and 2020 has been estimated to be 101.72 MW installed [EREC, 2011]. National targets in marine energy for 2020 are 2 GW in UK, 0.8 GW in France, 0.5 GW in Ireland and Denmark, 0.3 GW in Portugal and 0.1 GW in Spain.

The UK, which is the pioneer in marine energy, has eight devices working at a full-scale demonstration stage (five tidal and three waves). In the global wave and tidal activity, the UK is leading, followed by US, Canada, Norway, Japan and Denmark.

Tidal technology promoters are by far the furthest ahead for wave energy, with Marine Current Turbines being the leading operator in the UK and US with more than 200 MW tidal horizontal axis systems. Open Hydro follows with an installed capacity of 250 kW in the UK. Hammerfest Strom operates in Norway with 300 kW tidal turbine developed in 2009 and Atlantis Resources in the UK with a 1 MW AK 100 turbine. Lunar Energy demonstrated in 2009, a 1 MWe Rotech Tidal Turbine, whilst Tidal Generation Limited in the same year in Italy, installed a 500 kW tidal stream system at Messina.

In wave energy technologies, the leading promoter is Aquamarine with a 315 kW Oyster in the Orkney Islands installed in 2009 and 800 kW in 2011. Pelamis Wave Power presented the 750 kW Pelamis module in 2008 and a 2nd generation device in 2010. Carnegie Wave Energy appears to be a leading technology promoter in Ireland and Wave Dragon and Eneolica in Portugal. In Norway, Langlee Wave power will present a 28 MW and 24 MW wave demo in 2012. EVE has installed 16 wave turbines of 18.5 kW in Spain in 2010. In USA, Canada and Australia, large technology developers are Ocean Power Technologies (operating also in the UK), Oceanlinx and Carnegie Wave Energy (operating also in Ireland).

In 2014, the first ocean farms will appear and could reach 1 GW by 2020 and nearly 10 GW by 2030. Support for marine energy from policymakers and larger manufacturing capabilities in combination with cost reductions, will lead marine energy to become cost competitive with offshore wind and thus a part of the energy mix from 2020 onwards. The global installed capacity could reach in 2030, assuming a high growth of marine energy potentials, 1700 MW [EER, 2010]. European utilities led by EDF, ESBI, Iberdrola, Scottish Power, SSE, Vattenfall and RWE are moving out of the development learning curve. According to IEA projections, the electricity production from marine energy can reach 552 TWh [IEA, 2010c]. Whilst the EU-OEA presents a European marine energy potential of 645 TWh/ year in 2050.

6.4. Barriers to large-scale deployment

The potential of marine energy is very large while the barriers to large-scale deployment are modest and mainly are due to the high technology costs. The success of demonstrating prototypes motivates the support of government and private investment in both technology and project deployment. Nonetheless, only large industries are involved in marine energy, since the fully fledged development and operating costs are still beyond the capacities of small and medium enterprises. Maintenance and plant construction costs are still not clear but they can also be very high, especially in the start-up phase. Due to the lack of experience, operations in offshore infrastructures are carried out by the oil industry and thus are costly.

A market pull is necessary to facilitate the transition from demonstration to commercial deployment. This pull can have three elements – incentives for investors (investment tax credits), incentives for end-users (investment and production tax credits) and feed-in tariffs that would make high-cost, pre-commercial installations attractive to investors and the end-users. A market pull occurs and causes deployment rates to accelerate rapidly.

Regarding the economical barrier, another aspect is the cost-competitiveness due to the initial state of development. Appropriate grid infrastructure and connections will be important for further development. Grid connections to onshore grids can also be problematic, as in some cases the grid is too weak to absorb the electricity production from wave energy power stations. Except for coastal countries, such as Portugal and the SW region of the UK

that have high voltage transmission lines available close to shore, coastal communities lack sufficient power transmission capacity to provide grid access for any significant amount of electricity that can be generated from marine energy.

In addition, licensing and authorisation costs and procedures are very high and complex. It can take several years to obtain the permit from administrations not

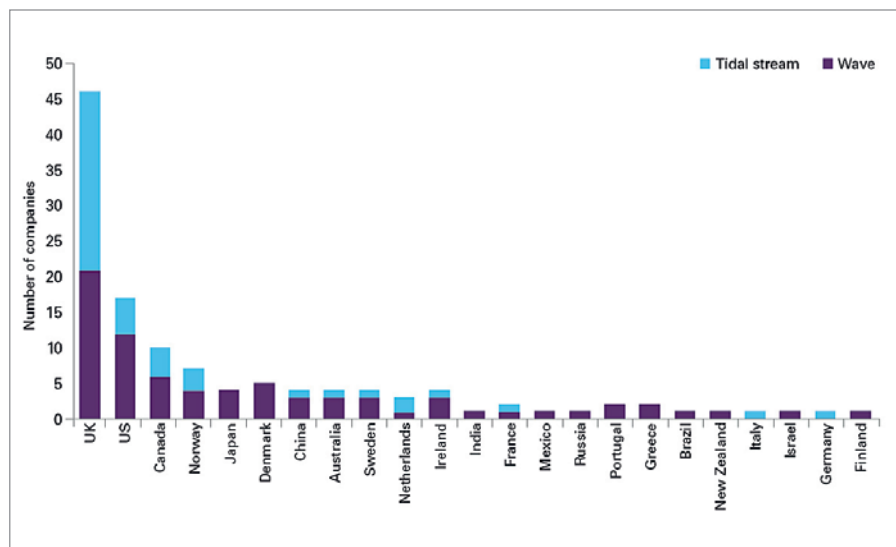


Figure 6.2: Indicative global wave and tidal activity [Source: Carbon Trust, 2011]

prepared to tackle marine energy, with costs up to one million euro. A lack of dedicated or experienced administrative structures causes long permit procedures.

Moreover, with the advent of the deployment of marine energy technologies, coastal management is a critical issue to regulate potential conflicts for the use of coastal space with other maritime activities [EC-SETIS c, 2009].

Technical barriers are due to insufficient experience and demonstration. There is a lack of information and understanding regarding performance, lifetime, operation and maintenance of technologies and power plants. For the marine technologies to succeed, much attention needs to be paid to technical risks in design, construction, installation and operation. Importing knowledge and experience from other industry sectors, such as offshore oil and gas, including risk assessment procedures and engineering standards is of great importance. Rigorous and extensive testing, including single components, sub-assemblies and complete functional prototypes are still necessary to establish the new technologies.

Large deployment can be successful with the convergence of technologies, thus reducing the number of isolated actors and allowing technology development to accelerate. Industrial R&D should be moving in parallel with continuing academic R&D. Large farms should demonstrate their performance and reliability and become technical evidence to industries, academia, associations, governments and the public.

6.5. RD&D priorities and current initiatives

The situation in Europe was dramatically changed by the decision made in 1991 by the European Commission of including wave energy in their R&D programme on renewable energies. The first projects started in 1992. Since then, about thirty projects on wave energy were co-funded by the European Commission involving a large number of teams active in Europe. In 2001 the IEA Ocean Energy Systems Implementing Agreement (OES-IA) was launched to provide a framework for international collaboration in energy technology R&D, demonstration and information exchange in the fields of ocean wave and tidal current energy. Until now the IEA-OES numbers 19 contracting parties.

The WERATLAS, a European Wave Energy Atlas, also co-funded by the European Union, uses high quality results from numerical wind-wave modelling, validated by wave measurements where available and contains detailed wave climate and wave-energy statistics at 85 points off the Atlantic and Mediterranean coasts of Europe. The WERATLAS remains the basic tool for wave energy planning in Europe [Falcao, 2010]. Technologies to exploit OTEC and salinity gradients have not yet been addressed. On the other hand, there is a lot research into wave and tidal energy targeting lowering of costs and improving performance of specific components in existing marine energy devices.

Organisations and universities with the most advanced, ongoing marine energy projects are: University of Lancaster (UK), University of Southampton (UK), University of Strathclyde (UK), Queens University of Belfast (Northern Ireland), Ulster University (Northern Ireland), Instituto Superior Técnico (Portugal), Wave Energy Centre (WavEC, Portugal), University of Limerick (Ireland), Electricity Research Centre, University College Dublin (Ireland), Maynooth University (Ireland), Agency for Innovation and Science and Technology (Belgium), Lindo Offshore Renewable Centre (Belgium), Aalborg University (Denmark), Norwegian University of Science (Norway), Runde Environmental Centre (Norway), Scientific and Technological Park of Molise (Italy) and Uppsala University (Sweden). Meanwhile, a series of European Wave Energy Conferences have been held with the support of the European Commission (the more recent ones including also Tidal Energy): Edinburgh, UK (1993), Lisbon, Portugal (1995), Patras, Greece (1998), Aalborg, Denmark (2000), Cork, Ireland (2003), Glasgow, UK (2005), Porto, Portugal (2007), Uppsala, Sweden (2009), Bilbao, Spain (2010) (ICOE), Brussels, Belgium (2011) and Southampton (2011).

In 2006, the European Ocean Energy Association [EU-OEA] was established with more than 70 members, with core objective to strengthen the development of marine energy in Europe.

The recent FP7 Call on deep offshore, multi-purpose, renewable energy conversion platforms for wind/ocean energy conversion should provide material for further developing these future concepts. The FP7 budget is EUR 20–30 million [European Commission, Implementation Plan 2010-2012]. Moreover the Energy Strategy 2020 [European Commission, 2010] states that the European Commission will promote energy research infrastructures including marine renewable energy, which is considered to have a great potential.

In the European countries which are more active in the marine energy development, political initiatives have pushed forward the marine energy market. More specifically, the UK has announced successful bids for wave and tidal energy leases in UK waters for a proposed total installed power of 1.6 GW for 2020; including the preparation of an offshore renewable energy strategic action plan 2009-2020 for Northern Ireland waters, with a target of 300 MW of tidal stream by 2020. The Irish government allocated a financial package for marine energy administered by a new Ocean Energy Development Unit (OEDU) based within the Sustainable Energy Authority of Ireland (SEAI), covering support for device developers, enhancement of test facilities and development of grid-connected test facilities. Moreover, the policy support package for wave and tidal energy includes a commitment of a feed-in tariff of €0.22/kWh for electricity produced from wave and tidal devices, guaranteed up to 2030. In Belgium, the Flemish government guarantees a price of €90/MWh for a Tradable Green Certificate for wave or tidal energy, guaranteed for a period of 10 years (2009). In Portugal, the government and the

management body, REN (National Energy Networks) decided on the development of the Wave Energy Pilot Zone and the creation of the dedicated REN subsidiary, ENONDAS. Spain has announced the targets of 100 MW of installed power by 2020 while the first 10 MW are expected in 2016. The interest of the Italian government is to promote wave and tidal energy, through a Green Certificates System as a support scheme, equivalent to a higher feed-in tariff of €0.34/kWh. While Germany is preparing the “National Master Plan Maritime Technologies” to support the development of the maritime technology industry in the coming years, anticipating that marine energy will play a prominent role in the plan.

Innovation focuses on bringing forward components and equipment that offer advantages when used at scale. The next steps for device developers will be in scaling-up their technology into farms or arrays. Equipment or methods that help with this scaling process, such as specialist installation and maintenance vessels and electrical connection equipment, will soon be in demand.

6.6. References

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7. Cogeneration or Combined Heat and Power

7.1. Introduction

There is an increasing interest in Cogeneration or Combined Heat and Power (CHP) - the terms are used interchangeably - to reduce the global warming effects of the use of fuels for heating, as this technology provides a way to use heat to heat buildings, that otherwise would be rejected to the environment as part of the conversion of fuel to power and electricity.

The reason for the interest is that the heat can be considered zero carbon or low carbon heat without an adverse effect on the electricity sector in many EU countries.

Thus CHP is a name given to power plants where their reject heat performs a useful purpose on its path to the environment and the inevitable degradation of energy to the temperature of the environment in line with laws of thermodynamics.

All power plants, transport vehicles and utility-scale electrical power stations, transform less than half the energy content of their input fuel into electricity. The rest of the fuel's energy they 'reject' or 'waste' as heat to the environment, typically to river- or sea-cooling water bodies or through cooling towers and exhaust stacks.

The amount of fuel usefully converted to electricity is defined by the percentage of electricity or power produced per unit of energy in the input fuel. This efficiency depends on the thermodynamic cycle used for the conversion. One of the most efficient thermodynamic cycles¹⁰ for conversion is the combined cycle gas turbine (CCGT) power station which combines the use of a gas turbine with a steam turbine. Such plants convert about 60 %¹¹ of the fuel energy to electrical power. In contrast the steam turbine cycle for nuclear fuel, biomass or coal has efficiencies in the range of 34-40 %. Cycles using steam turbines are most effective when they reject the waste heat at as low a temperature as possible to the environment typically at around 30 °C, a temperature too low for practical large-scale heating purposes, but useful for horticulture or fish farming and local under-floor heating.

Other power cycles based on engines, also reject heat normally at higher temperatures of over 80 °C making the use of the reject heat easy for buildings commonly otherwise heated by boilers at such temperatures.

Examples of the power or electrical efficiency for a small car engine is about 33 % and ranges up to the largest and most efficient diesel engines in ships at around 60 %.

By contrast to the power-only power plants mentioned above, the reject heat in a CHP plant satisfies a heat demand, such as heating a factory process or heating buildings, where this would otherwise require energy from typically another fuel, burnt in a heat-only boiler.

A simple example of the use of this reject heat is in a motor car heater which heats the occupants in winter with no impact on fuel use, i.e. the engine efficiency, and in whose absence would require a separate fuel burning heater, which would indeed diminish the fuel consumption of the car.

A further type of power generation is a fuel cell which operates on an electro-chemical basis. These also reject heat as part of the process.

When heat from a CHP station is used to heat a number of separate buildings spread over an area using District Heating (DH) pipes, this is known as CHPDH

CHP technology covers a very broad range of both technologies and sizes, from 1 kW electrical output unit to 400 MW. Technologies can include steam turbines, gas turbines, engines, combined cycles, micro-turbines, fuel cells and others.

Total losses (excluding end-user system losses) from the European energy system in 2008 were 7 754 TWh (37 %) of primary energy input and are largely from the electricity generating sector [COGEN, 2011]. Analysis shows that CHP can provide large primary energy savings in comparison to the conventional production of electricity and heat in separate plants, albeit at an extra capital cost typically of 10 % up to

¹⁰ A Thermodynamic cycle involves a gas being subject to a compression, heating and cooling process during which mechanical work can be extracted.

¹¹ Based on the Net Calorific Value (NCV) of fuel convention, which subtracts energy contained in the water vapour in the exhaust gas from the input fuel energy. The alternative HCV convention, which includes total fuel energy, would give an efficiency in this case of 54 %. With the introduction of condensing heat recovery in the exhaust gas streams of CHP plants and boilers, this can confusingly give overall efficiencies of over 100 % in the NCV case, the former (NCV) is used throughout this document.

25 % of the electricity-only station. The extra capital cost is usually repaid in a commercially realistic time frame particularly for industry and where CO₂ heat, is usually provided in the form of hot exhaust gases, steam or hot water, and sometimes thermal oil.

Fossil, nuclear, waste and renewable fuels can be used to power CHP plants.

CHP is about power, so where the power directly drives mechanical equipment such as a heat pump, a water pump or fan, this is also a more efficient form of CHP, as it does not incur the associated losses of converting power to electricity and then back to power again.

Use of the reject heat can also replace the burning of fuel or use of other heat sources in absorption cooling cycles. Some cities, as a result, have district cooling using the process and other methods to deliver cooling.

7.2. Technological state of the art and anticipated development

Operating Principles

CHP can be applied in a range of power generating technologies. In each case the power generating technology is available as an electricity-only generator. For the largest units heating cities, these are designed so that they can just produce electricity at times when no heat is required, rejecting heat to the environment at 30 °C or alternatively, producing electricity and low-carbon heat at temperature 80-95 °C suitable for city heating when both heat and electricity are required.

Typical CHP technologies include: steam turbines, gas turbines, combined cycle gas turbines CCGTs (a combination of the first two plant types) and gas engines (similar to a car engine). Other more niche technologies include: organic Rankine cycle (ORC) turbines (similar to steam turbines but using an

organic fluid rather than steam) which are suitable for small (1-3 MW) biomass combustion plants, diesel engines, micro turbines (i.e. gas turbines below about 50 kWe) and Stirling engines. Work proceeds on commercialising fuel cell CHP.

In power cycles, a working fluid such as steam, air, hydrogen or an organic compound vapour, is subjected to a thermodynamic cycle, i.e. a gas is compressed, heated and then expanded when work is done and power generated followed by heat rejection to cool the working fluid.

In CHP, the steam cycle may be modified so that the heat is rejected at a sufficiently high temperature to be used for a separate heating purpose and some of the plant details may be changed.

In gas engines or gas turbines, waste heat is readily available at high temperature and use of this heat has no effect on power output or efficiency. In both cases, extra heat exchangers are fitted to recover the various waste-heat streams and to transmit them to the heating medium.

The steam cycle plant shown below can be operated as if it were a normal electricity-only power station, in which case all the steam from the turbine is cooled in a condenser and turned from steam to water giving up its latent heat at around 30 °C temperature. This is referred to as fully condensing mode maximising the power from the steam. When using it as CHP, there is an option to extract some of the steam at a higher temperature and pressure and feed it to a

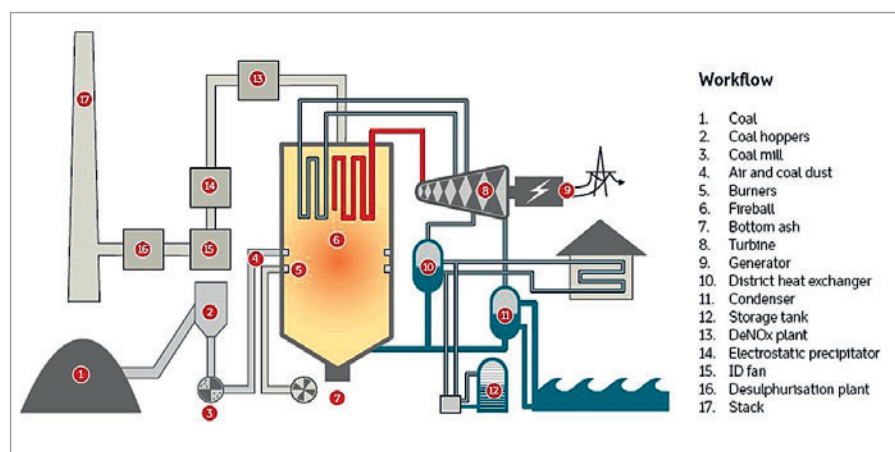


Figure 7.1: Large steam-cycle based CHP power station feeding a District Heating (CHPDH): In the condensing or electricity-only mode all steam goes to the condenser (11) and the plant has maximum electricity production and the lowest temperature of heat output. In CHP mode, steam is extracted from the turbine via heat exchangers (10) at high temperature and the electricity output falls slightly. [Source: DONG Energy A/S]¹²

¹² http://www.dongenergy.com/SiteCollectionDocuments/business_activities/generation/Esbjergv%C3%A6rket_UK%5B1%5D.pdf

district heating condenser containing city heating water. When this happens the electrical output of the power station will drop as a small amount of the energy in the steam is lost by condensing it at a higher temperature, but the fuel consumption remains constant.

The fuel used to enable the waste heat to be at a useful temperature is measured by the turbines Z factor. Typically a loss of 1 unit of electricity output will result in between 5 and 10 (depending on the power plant) units of heat becoming available at a useable temperature. The higher the temperature at which the heat is required, generally the lower the Z factor will be. This is identical to the way an electric heat pump reduces its heat delivery per unit of power used, with the difference between its source heat temperature and its delivery heat temperature

Comparison of performance with electric heat pumps and CHP

The ratio of power loss to heat gained compares very favourably with an electric heat pump, which typically will use 1 unit of electricity to provide 3 units of heat, i.e. has a coefficient of performance (COP) of 3. Thus, CHP may be considered as a virtual steam-cycle heat pump [Lowe, 2011], i.e. a loss of electricity to make heat available. According to theoretical studies, if the lowest possible DH temperature is chosen and multi-stage steam extraction is used, then a Z factor of 18 can be achieved¹³ which is equivalent to a COP of 18. For information on the analysis of factors affecting the analysis of CHP and electric heat pumps and where the effects of heat and electricity networks are evaluated, see [Orchard, 2010].

State of the art

CHP is not a specific technology but a technique to use a waste energy product for a useful purpose which significantly improves the optimal provision of the different grades of energy needed by consumers from high-quality, high-grade electricity or power to low-grade heat. As a result, CHP can be applied in various situations and using various technologies. Several broad classes of application can be distinguished, each with their own features of temperature and load profile, making them more suitable to different types of CHP systems coupled with the location of consumer choice and the availability of supplies of energy through different energy networks for electricity, gas and heat.

¹³ W.R.H. Orchard, Orchard Partners London Ltd and Robert Hyde, R H Energy Associates, 2011, Personal communication.

Typical classifications fall into different categories that tend to be a function of the size and extent of the heat network the CHP serves.

Buildings can be served either with a dedicated CHP for each building or groups of buildings can be connected together to form a larger heat network.

The carbon and energy savings are greatest where the buildings are connected to a heat network and the heat is supplied from large-scale CHP. This is due to two factors, first of all the benefit of the diversity effects for both electricity networks and heat networks when serving large numbers of consumers, as their demands for electricity and heat, do not occur at the same time. Also with heat networks, the heat can be readily stored to meet daily changes in demand.

Individual houses and buildings (often termed micro-CHP)

This is where a small CHP unit of about 1 kW of electrical output serves the house to provide some of the house's heat and power needs. The electrical output is determined by the average electrical demand for the house which tends to be around 1 kW. Such very small units tend to be referred to as micro-CHP.

The CHP performs a similar function to conventional heat-only boilers or electric and other heating methods to provide domestic hot water all year round and space heat in the winter. In many cases supplemented by a heat-only boiler during peak demands which often forms an integral part of the unit. The electricity generated feeds into some of the houses electrical circuits and surplus electricity may be exported. There are a number of such units commercially available, e.g. Honda make a modified gas engine unit and several European manufacturers are making or are about to make a unit based on a Stirling engine (similar to a car engine, except the combustion occurs outside the cylinders). Fuel cell devices are reportedly close to commercialisation.

Such engine based units currently have relatively low electrical efficiency (from around 10 % for Stirling engines up to 25 % for ICE engines), although fuel cells currently being trialled have demonstrated field efficiencies of 60 %. Overall efficiency is similar to a gas boiler, so that electricity is generated at the carbon cost of gas. Their operation will typically be biased towards winter operation when heating demand is highest, as is the value of the electricity produced. Micro-CHP is a cost-

effective mass market, carbon mitigation solution for the replacement of gas boilers in individual homes and can be introduced incrementally with low investment risk. It is particularly well suited to lower density housing areas and due to its location within the LV network and provides valuable peak following generation to support the introduction of domestic heat pumps.

Larger individual buildings

(hospitals, leisure centres, hotels, prisons)

These kind of building are ideal for gas engine CHP, typically in the range 50 kW to 2 MW, since they are characterised by a steady, year-round demand for domestic hot water (occasioned by the constant presence of people who require washing and bathing water) for around 17 hours per day summer and winter. This kind of CHP for heating is not generally applied to office type buildings which are only occupied about 12 hours per day, 5 days per week and have a low demand for hot water, and are heated only during the winter.

City centre office complexes

Certain cities, such as, for example, Paris, Barcelona and Helsinki, have dense office accommodation with a very high year-round cooling load. In these situations, it has been economic to equip them with centralised cooling systems where chilled water is distributed from a central point to multiple buildings. In many such cases, it has been found economic to fit CHP systems allied to an absorption chiller. Typically, these use several large gas engines, since this kind of plant is able to deliver heat at high temperatures suitable for efficient absorption chiller operation, but large power station waste heat is also used for small waste incineration stations.

Large industrial complexes

(chemical works, oil refineries, industrial drying facilities and food processing plants)

These often have an energy centre, where steam and electricity are generated. Steam and/or high temperature hot water are distributed around the site. Such sites use the steam or heat within their industrial process with possibly some additional use for space heat. The heat demand follows the industrial process and tends to be fairly predictable and continuous on a year-round basis. These plants would typically use a steam turbine or gas turbine and for large sites, combined cycle plant. Some locations such as mineral or grain drying sites may use the exhaust gas from an engine or turbine fed directly into the drying kiln, with no requirement for heat distribution.

District heating DH applications

In this kind of application, heat generally below 120 °C but as low as 70 °C is piped to houses, industry and commerce for space and some forms of process heating by means of generally buried and insulated hot water pipes. Some legacy systems still use steam as the transport medium, however this is increasingly rare as it is a less efficient method of heat transport with associated problems with efficient condensate return.

Piped hot water heating can be very large covering parts of a whole city or as little as a group of 10 houses. The heat can be transported over long distances: the current longest case in Europe is probably the Prague system where the length of the main pipeline is 40-60 km from the power station to the heat load with a 200 MW heat capacity. Another example is the Linköping Mjölby pipeline with a 25 MW capacity and 28 km pipeline.

The major benefit of such systems is their ability to accept any fuel or heat source to serve the heat network. This effect is becoming increasingly important as increased use of biomaterials for heat and electricity supply is being encouraged, as well as consideration of such technologies as carbon capture and storage suited to large-scale conversion of fuel to heat and power but not to small-scale operation.

The operation of these systems, like all heating, is clearly seasonal with more heat being needed in winter. Peak loads for heating can be problematic for both heat pumps and CHP. The solution is to use heat from a high-carbon source and stored fuel to meet the peak outputs which only occur for a short period.

A rule of thumb is that if the peak heat output of the CHP plant or other low-carbon heat supply system equals about half the peak heating load on the district heating system, then the CHP plant or other low-CO₂ heat source such as a heat pump will provide about 90 % of the heat to the heat network taken annually. Separate heat-only boilers give the CHP plant a good load factor by meeting the short-term extreme peaks. Many Scandinavian and German schemes have large heat stores, e.g. water tanks, which can store 1-2 days of heat and again to improve CHP load factor by minimising boiler usage and optimising the variation of electricity demand by producing heat when electricity demand is low.

These district heating schemes, particularly with heat storage are seen as fundamental to the

increased use of renewable energy in Scandinavia because surplus wind energy can be fed into and stored in these systems. Often the CHP plant is of the condensing / extraction type, so that whilst in winter it operates to use its district heating condensers, producing heat at say 75 °C as well as rejecting some heat at 30 °C during the summer, the plant switches to full condensing mode rejecting all its heat at 28 °C. Again in Scandinavia, it is planned that this ability to change the amounts of electricity and heat production will work well in terms of balancing large wind penetrations.

In general, these large city-wide schemes will be based on coal or biomass (often co-firing with coal) fired steam turbines or gas fired CCGT of hundreds of MW. From 5 to 10 MW, a shift to gas turbine or steam turbine tends to occur and CCGT is generally for the large plants. In the small sizes, dedicated waste combustion or biomass combustion plants of 5-30 MW with steam turbine are common and these could feed several thousands of dwellings. There are several hundreds of biomass plants of around 2-3 MW fed by biomass based on ORC plants. (There will be exceptions to all these rules of thumb).

The key difference between the district heating applications and the other types of CHP discussed is the very large cost of the district heating network, which can be much more than the cost of the CHP power station. However, analysis by the JRC shows that this extra cost is more than adequately compensated for by the savings in heating fuel [JRC, 2011a] and the associated carbon benefits.

Conversion of electricity only power stations to CHP

There are many electricity-only power stations in Europe and it is possible to convert these to CHP operation and to then connect them to a heat load if

one is suitably located. The actual conversion costs will depend very much on the type of plant and its age. The majority of plants are likely to be converted for around 20 % of the equivalent cost of a new plant. Flensburg [Prinz, 1994] and Prague [Pražská teplárenská a.s., 2009] are typical examples where this has been done.

The key however to using the heat from such plants is the investment in heat infrastructures to accept the heat from such plants.

7.3. Market and industry status and potential

Fuels and technologies

CHP as noted earlier covers a wide variety and size of plant types. Whilst a particular CHP plant can be found for a particular fuel, not every technology is suitable for every fuel. Thus coal can only be economically burnt in large steam turbine plants – generally at least above 30 MW. Gas can be burnt in virtually any plant type from a 1 kW Stirling engine to a 400 MW CCGT.

Biomass and waste is usually burnt in a steam turbine plant which tends to be of the smaller size – around 30 MW. However, biomass can be co-fired in a large coal fired plant, whilst for smaller size ORCs (Organic Rankin cycles) of around 3 MW are suitable. Recently gas engine plants have been demonstrated operating on small biomass gasifiers with an output of around 1 MW.

As a fuel, natural gas dominates the European CHP market (about 40 % by annual fuel consumption), followed by solid fossil fuels at 35 %. Renewable fuels, mainly biomass, but also combustible waste, are becoming increasingly important.

	Typical fully installed cost (€/kW)	Overall efficiency, ¹⁴ NCV basis (%)	Annual O&M costs €/kW
CCGT 30 – 300 MW	759 -1 242	90	35
Steam cycle coal FBC 400 MW	2 070 – 2 760	90	70
Gas Turbine	621 – 1 035	90	28
Biomass CHP steam cycle	2 070 – 4 140	90	70
Gas engine 0.75 -1.6 MW	607 – 1 345	90	250

Table 7.1: Typical costs and performances [IEA/ETSAP, 2010]

¹⁴ Significantly higher efficiencies can be achieved with condensing of exhaust gases, confusingly approaching 110 % if the NCV convention is used.

The increasing recognition of the importance of the heat sector in the energy policy due to its size and the costs for different options of decarbonising this sector, has given new impetus to the role heat networks can play in this process, coupled with other low-carbon heat sources, such as geothermal, solar thermal and biomass CHP.

Whilst the option of nuclear electricity generation is controversial, based on decisions to invest in nuclear electricity generation, its low electrical efficiency results in significant amounts of waste heat and provided that its safety and other issues can be addressed then low-temperature heat networks provide an opportunity for the utilisation of this low-carbon heat source. Calder Hall in the UK is an example of one of the earliest nuclear CHP installations. Ignalina in Lithuania is another example.

Current market penetration and potential

According to EUROSTAT, the existing share of CHP by electricity generated in the European generation mix was 10.9 % in 2007. The potential CHP output in a scenario in which CO₂ emissions allowance prices stay constant at €15/t - the “15-15-15” scenario - up to 2020 has been considered by JRC [JRC, 2011b]. Under this scenario, the economic potential represents an increase in CHP electricity output from 320 TWh per year in the current situation to 655 TWh in 2020, i.e. an increase of 335 TWh. The economic potential represents a 5.7 % annual growth rate up to 2020, thereby increasing CHP penetration from 10.9 % in 2007 (according to Eurostat) to 21.2 % in 2020. The growth in technical potential is roughly twice the growth in economic potential. Another European Commission study gave an estimate of the potential impact of the economic potentials – again under the “15-15-15” scenario – on Primary Energy Savings (PES, as defined in the Directive) and avoided CO₂ emissions, which estimated the present primary energy savings due to CHP to be up to 5 Mtoe/y and up to 10 Mt/y CO₂.

A more recent report estimates that if all European countries were brought up to a 50 % level of building heating, provided by CHPDH [JRC, 2011c], then there would be an approximate doubling of installed CHP electrical capacity from 100 GW to over 200 GW.

Penetration by size

In general, the existing 10.9 % of Europe’s electricity generated annually by CHP plant is produced predominantly by large-power plants feeding substantial district heating schemes or large industrial plants but where many of the industrial

turbines are under 5 MWe. These are typically of the extraction/condensing steam cycle type although there are a number of large gas turbines and some CCGTs.

It should be noted that in theory, very large numbers of very small CHPs could be installed in domestic buildings and very quickly – and this would give a very large installed capacity in a relatively short space of time. For example, in the UK, the total installed power station capacity, all of which is non-CHP, is around 60 GW. With 20 million dwellings in the UK, a 1 kW micro-CHP unit in each house would give 20 GW of CHP equal to one-third of the present capacity - a significant increase in CHP capacity. This is by no means an unfeasible option – Japan has installed hundreds of thousands of 1 kWe CHP based on a small Honda spark-ignited engine. In the Netherlands, there are 4 600 decentralised (small) CHP and 22 large central plants. This route would of course compete with the option of CHPDH in large cities. The Lichtblick [Lichtblick/VW, 2010] company is promoting a virtual power station based on 100 000 x 20 kW Volkswagen car engine based cogeneration units, which will be centrally controlled and operated as a virtual 2 GW power station.

European manufacturers

Key European players include Siemens and Alstom who manufacture across the range except for the very small sizes. There are nascent indigenous small (1 kWe) engine and Stirling engine suppliers. There are several industrial gas engine manufactures, such as Jenbacher, MTU, MAN, Wartsila and numerous companies who package them into CHP units.

Turboden are a leading Italian supplier of small ORC CHP plants 2-5 MWe.

However, there are many world-class, non-European manufacturers, such as Caterpillar from the USA for engines and smaller turbines, Mitsubishi from Japan and General Electric from the USA operating in the large power station field.

7.4. Barriers to large-scale deployment

The most fundamental barrier to CHP is that most large-scale investment in power generation is carried out by the well-established large energy utilities with a well-established simple business model. Their natural business model is to sell as much fuel / primary energy or fuel-derived electricity as possible in as simple and as low risk an investment environment as possible.

CHP will require a more complicated business model and higher investment, since it sells low-energy content heat and thus much less primary energy.

Established utility players are also much more able to control the risks they are exposed to, for example, the price at which they can purchase fuel and sell power due to their large portfolio of end users and their ability to manage sophisticated trading positions. This tends to leave smaller independent generators, often CHP, at a disadvantage. This ability to control risks means that the incumbents can obtain long-term funding at much better rates than newcomers.

Since CHP operators tend to be new players with small portfolios and less ability to control risks, the CHP generators will tend to be much more exposed to risk which puts up the cost of capital.

Furthermore, the simplest and most rational model for profit driven utilities is to focus on a small number of very large and very efficient, in electrical terms, power stations. Developing a portfolio of smaller, local, and in some cases house-level plants, is clearly more cumbersome and administratively awkward, whatever the rewards may be in terms of better efficiency. Note this means that large industrial CHP units do not tend to suffer from these kinds of problems, being of sufficient size and sophistication to interact profitably and on equal terms with the large utilities.

However, it is possible that micro-CHP may offer an alternative investment model which engages with individual householders and minimises investment risk. It is also able to deliver incremental generation capacity without the need for the substantial up-front capital investment required for CHPDH and central plant.

Generally speaking, statistics, commercial arrangement and policy tend to be structured around the concept of Delivered Energy. Delivered energy however does not signal either the amount of fuel or primary energy used to produce the delivered energy. CHP is fundamentally disadvantaged due to this factor, as its major benefit is the low primary energy for the heat it supplies as delivered energy compared to heat from other sources. The benefits from such CHP systems are thus not signalled within commercial, policy and statistical systems using delivered energy as the basis for signals to consumers and for energy savings.

As an example, two to three units of fuel primary energy are required to deliver one unit of electrical energy. One and a quarter units of fuel primary

energy are required to deliver heat from a boiler. Heat from large-scale CHP in contrast has one-third of a unit of primary energy per unit of delivered energy.

If the EU is moving more towards CO₂ reductions and measures to decarbonise fossil fuel usage, then the current actual CO₂ emissions on different heat routes is a useful indicator in relation to the different options. An indication of the relative impact is shown in Table 7.2. The table signals CO₂ emitted when a biofuel, such as wood is burnt. The table allows review of carbon capture and storage signalling the potential to maximise CO₂ displacement using biomass when potentially co-firing it with coal to give overall negative CO₂ emissions: note the relative average CO₂ losses for different energy supply networks. Marginal distribution losses for heat will tend to zero. For electricity they will follow a square law.

Other barriers which can be cited are:

- Volatile fuel prices
- Competition with large written-down plant that is old plant where the capital has long been paid off
- Unstable heat demand due to industrial restructuring and energy efficiency measures
- High electrical network connection and access charges and lack of transparency in connection conditions and charges (this tends to be more significant to small CHP units)
- Lack of access to capital for refurbishing ageing plants
- Regulatory uncertainty from complex permit procedures, as regards access to support mechanisms (this tends to be significant for small CHP units)
- Policy uncertainty, in particular as regards the future of support schemes and the functioning of the EU emissions trading scheme
- Lack of expertise and awareness (this tends to be significant to small CHP units)
- Lack of district heat infrastructure
- Lack of a district heating tradition and culture, which leads to lack of awareness at a policy level.

For each MS, clusters of barriers have been identified (see Figure 7.2) [JRC, 2010].

It should be noted that CHP district heating is particularly problematic in a liberalised market environment where, whilst the primary energy and CO₂ savings may be significant, the risks of construction of the heat grid and where the purpose of the heat network is to capture current customers using gas or electric heating. Unless significant incentives or legislation is introduced, it is difficult

Heat supply options gross (higher) calorific value (CV) basis and efficiency (eff)	kg/CO ₂ /kWh per unit of Energy	Energy Average loss %	CO ₂ Average loss kg	kg/CO ₂ /kWh Energy delivered
Hydrogen fuel from electricity(coal) 80 % (eff)	1.046			
Biogas burnt in 86 % (eff) domestic boiler.				1.008
Electricity from coal 36 %	0.837	10	0.084	0.920
Biogas as a fuel 40 % (eff) conversion from biomass (Lund University Maria Berglund Pal Borjesson)	0.850	2	0.017	0.867
Biomass wood boiler 78 % (eff).	0.436	5	0.022	0.458
Electricity from gas 48 % (eff)	0.397	10	0.040	0.437
Biomass (dry wood) as a fuel	0.340			0.340
Air source heat pump COP 2.9 (Electricity from coal)				0.317
Coal as fuel	0.301			0.301
Old gas boiler 75 % (eff)				0.255
New condensing natural gas boiler 86 % (eff)				0.222
Heat micro CHP 1 kW _{el} 6 % (el) (eff), 86 % (eff) overall				0.212
Natural gas as a fuel	0.191	2	0.004	0.195
Heat pump ground source winter heat source, COP 3.8 electricity from gas.				0.115
Piped heat from gas fired condensing 500 kW _{el} CHP 34.7 % (el) (eff), 86 % (eff) overall	0.103	10	0.010	0.113
Piped heating from very large biomass CHP co-fired with coal.	0.075	20	0.015	0.089
Piped urban district heating from coal fired CHP equivalent COP 12.7	0.066	20	0.013	0.079
Piped urban district heating from gas fired CCGT CHP equivalent COP 12	0.033	20	0.007	0.040
Electricity from wind ¹⁶	0.020	10	0.002	0.022
Electricity from nuclear ¹⁶	0.010	10	0.001	0.011
Piped district heat from nuclear fired CHP equivalent COP 10	0.001	20	0.000	0.001

Table 7.2: CO₂ footprints for heat and electrical energy supplies¹⁵

to see how current incumbents will actively wish to persuade their current customers to switch from their current systems to connect to district heating.

7.5. RD&D priorities and current initiatives

The RD&D priorities of large-scale CHP are in general identical to those for advanced fossil fuel power generation technologies, addressed in Chapter

9. In general, if the regulatory and economic environment is such that CHP of whatever size can succeed, then the existing manufacturers are well able to technically develop their products due to the well established markets offering a steady income stream. Manufacturers are constantly developing their products as they strive to beat their competitors on price and performance. This is essentially the development of better techniques and materials to enable power plants overall to become more efficient, and to be produced and operated at lower cost.

¹⁵ Private Communication, W.R.H. Orchard, Orchard Partners London Ltd, "CO₂ footprints for heat and electrical energy supplies". (<http://www.orchardpartners.co.uk>).

¹⁶ <http://webarchive.nationalarchives.gov.uk/+/http://www.berr.gov.uk/files/file39197.pdf>; p49.

However, preliminary discussions with manufacturers indicate that there may be a lack of awareness of the potential large increase in Z factors, which are theoretically available with multi-stage extraction and low-DH temperatures and that therefore there is an unawareness if more research in this area is needed.

For micro-CHP engines and fuel cells, this market retains the *status quo* in countries that sell gas to domestic consumers. The development of micro-CHP is thus well supported by large gas supply utilities. Much recent development work has focused on small-scale CHP systems based on very small spark ignited engines, Stirling engines and fuel cells of around

1 – 5 kW. This is because of the large market potential in the residential and commercial sectors supplied with gas. Again a focus on better and cheaper production methods, allied with better materials is needed. In particular, the overall efficiency and the electrical efficiency need to be improved.

Regarding the smaller technologies, 1 MW and lower, effort should also be focussed on methods of optimising the performance within the wider energy system of these very large numbers of small generators using the Virtual Power Plant concepts.

	Fuel Prices	Heating or cooling demand	Complexity of the law	Lack of promotion	Access to the electrical grid	Risk/Economic Justification	Access to/availability of fuels	Lack of financial resources	Uncertainties due to the ETS	Rest of infrastructure not prepared	Lack of expertise	Lack of awareness (by potential end-users)	Maturity of the technologies	Other	Total Blocks
Austria															5
Belgium															7
Bulgaria															7
Cyprus															5
Czech Republic															6
Denmark															1
Estonia															4
Finland															4
France															0
Germany															4
Greece															6
Hungary															1
Ireland															7
Italy															7
Latvia															2
Lithuania															0
Luxembourg															6
Malta															5
Netherlands															4
Poland															6
Portugal															9
Romania															6
Slovakia															13
Slovenia															3
Spain															6
Sweden															1
United Kingdom															6

Figure 7.2: Clusters of barriers identified by the Member States

Probably the sector with the largest potential is where CHP is applied to district heating. Here effort should be focussed on new and cheaper piping materials, means of installing the pipes cheaply such as directional drilling and better piping routes. Means of directly connecting district heating to the large power stations should also be investigated – this is practiced in Denmark and obviates the need for the normal interposing heat exchanger. This lowers costs and reduces losses but there are various challenges.

A major potential source of growth in CHP is the use of small absorption cycle air conditioning units, since these can be employed to absorb district heat in the summer to provide cooling, particularly in the hotter southern regions of Europe.

An industry view is that the industry needs to innovate and adapt to meet the changing energy market needs and the rate of change needs to be accelerated if we are to reduce emissions from fossil fuels through the wider use of the Cogeneration principal.

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8. Carbon Capture and Storage in Power Generation

8.1. Introduction

Fossil fuels are likely to remain the main source for electricity generation in Europe, at least in the short-to-medium term, despite the significant ongoing efforts to promote renewable energy technologies and energy efficiency. Therefore, Carbon Capture and Storage (CCS) may be generally considered as a promising technological option for reducing CO₂ emissions to the atmosphere from the power generation sector, as well as from other heavy industries. CCS is a process consisting of the separation of CO₂ from industrial and energy-related sources, transport to a storage location (such as a depleted hydrocarbon field or a saline aquifer) and long-term isolation from the atmosphere [IPCC, 2005]. With due assessment of sustainability and resource efficiency aspects, CCS could play a very significant role in the transition from a fossil fuel dependent economy to a low-emission future.

8.2. Technological state of the art and anticipated developments

CCS technologies could be applied in the energy sector wherever CO₂ is produced in large quantities. This includes, but is not limited to, power generation. CCS promises near-zero emission electricity from fossil fuels. CCS is generally understood as consisting of three major steps: CO₂ capture from the energy conversion process; CO₂ transport; and CO₂ storage. For each step there are currently several technology options, with different levels of performance and maturity, so numerous constellations for CCS can be envisaged. The portfolio of technologies currently being developed applies to both newly built power plants and retrofits of existing plants. Although each step can be realised with proven technologies, these technologies need to be adapted for use in the full CCS value chain. Internationally, more than 20 pre-commercial implementation projects are aiming to demonstrate various combinations of CCS technologies, with more projects in the construction and development phase. The major components of CCS technology are presented as follows:

8.2.1 Capture

Currently there are three main methods for capturing CO₂ in power plants:

Post-combustion capture involves removing the CO₂ from flue gases after combustion of the fuel. Currently, the favoured technique for post-

combustion capture is *chemical solvent scrubbing*. The flue gases are washed with a solvent that separates CO₂ from nitrogen. In a desorber, the solvent is reheated and the CO₂ is released. CO₂ is then cooled and compressed, ready to be piped away. The technique can be applied to both pulverised coal (sub- and super-critical) and natural gas power plants, and can be retrofitted to existing plants without significant modifications to existing infrastructure. The most widely used solvent for CO₂ scrubbing is monoethanolamine (MEA). Apart from the solvent degradation by impurities such as SO_x, NO₂ and O₂, the main challenge with MEA is the large amount of energy required for its regeneration. Alternative solvents which require lower energy for regeneration and at the same time present better absorption-desorption and corrosive properties are being developed, with currently amino salts and chilled ammonia the most promising. Solid sorbents at high temperature, such as calcium-lithium based oxides, and sodium and potassium oxides are also being investigated, as well as membrane systems.

Pre-combustion capture involves removal of CO₂ prior to combustion of hydrogen in a gas turbine, in an integrated gasification combined cycle (IGCC) plant. Solid, liquid or gaseous fuel is first converted to a mixture of hydrogen and carbon monoxide using one of a number of proprietary gasification technologies. In a so called 'shift reactor', the carbon monoxide is oxidised to CO₂, which is subsequently separated from the hydrogen. The hydrogen is diluted with nitrogen and burned in a gas turbine. The partial pressure of the CO₂ in the gas to be treated is much higher than for post-combustion capture [Davison and Thambiuthu, 2004] and *physical solvents* for the separation are preferred. Scrubbing of CO₂ with physical solvents is a well established process in the chemical industry, e.g. ammonia production and synthesis gas treatment. Cold methanol (Rectisol process), dimethylether of polyethylene glycol (Selexol process) and propylene carbonate (Fluor process) are the most commonly used solvents. Other possibilities for CO₂ separation include: adsorption on solid materials, such as zeolites or activated carbon; pressure-swing adsorption, in which the adsorbent is regenerated by reducing the pressure; and temperature-swing adsorption, in which the adsorbent is regenerated by increase of temperature. Separation can also be achieved with selective membranes. However at the present time membranes cannot achieve a high degree of separation and improvement is needed for their cost-effective use on a large-scale. Another challenge is the modification of gas burner and turbine technologies to achieve higher efficiencies in the electricity production from hydrogen combustion.

In **oxy-fuel combustion**, the air is separated in an air separation unit, often cryogenic, prior to combustion, into nitrogen and oxygen. The fuel is then burned in pure oxygen. In practice for temperature control, oxygen is diluted by recycling some of the CO₂ from the flue gas. The main advantage of oxy-fuel combustion is the high concentration of CO₂ in the resulting flue gas (> 80 %), so that only relatively simple purification of CO₂ is needed before storage.



Figure 8.1: Schematic impression of the 250 MW_e capture unit (post-combustion) at the ROAD project in Rotterdam, the Netherlands [Source: ROAD / Global CCS Institute]

This process, which is currently being tested in the EU at pilot scale, promises high efficiency levels and offers major business opportunities, including the possibility of retrofitting existing plants. The main disadvantage is the large quantity of oxygen required, which is expensive both in terms of capital costs and energy consumption.

Among all capture methods, CO₂ scrubbing techniques are the most mature. MEA-based scrubbing has been utilised for more than 60

years for natural gas purification and food-grade CO₂ production. In particular, Rectisol and Selexol processes have been commercially in use since the 1990s for CO₂ capture in the refining, chemical and fertilizer industries and are today extensively used in gasification plants to purify synthesis gas for downstream chemical applications. Current units, using these techniques, are able to remove thousands of tonnes of CO₂ per day [Arnold et al., 1982; Lurgi, 2011].¹⁷ However, they have not yet been demonstrated at the large scale necessary for 90 %

		Pulverised Hard Coal – Post-combustion capture	Integrated Gasification Combined Cycle IGCC (Hard Coal) – Pre-combustion capture	Pulverised Hard Coal – Oxy-fuel	Combined Cycle Gas Turbine CCGT with CCS – Post-Combustion
Timing assumption		Early commercial, range, 1 st -of-a-kind to n th -of-a-kind	2020, n th -of-a-kind	Early commercial, 1 st -of-a-kind	Early commercial, 1 st -of-a-kind
Efficiency	Percent	~38	~35.7-40	35.4-35.5	~48
Capital cost	€ ₂₀₀₉ /kW _{el}	2 530-2 860	2 915-3 300	3 428-4 060	1 828
Fixed annual operating cost	Percent of capital cost	1-2	~2	~1	1
Variable operating cost	€ ₂₀₀₉ /MWh	3.0-3.7	1.5-2.1	1.4-1.7	~4
Direct CO ₂ emissions	kg _{CO2} /MWh	92	87-98	98-99	59
Indirect CO ₂ emissions ¹⁸	kg _{CO2} /MWh	125	125	n.a	85

Table 8.1: Typical efficiency and cost parameters

¹⁷ http://www.linde-engineering.com/en/process_plants/hydrogen_and_synthesis_gas_plants/gas_processing_plants/rectisol_wash/index.html

¹⁸ From European Commission (2008)

CO₂ capture from a typical 500MW coal-fired power plant where 10 000 – 15 000 tonnes of CO₂ would be removed per day. Other capture technologies such as anti-sublimation, enzymes and algae for post-combustion and chemical looping and high pressure oxy-reactor are still at an early stage of development, with commercial deployment generally considered to be unlikely before 2025. Typical efficiency and cost parameters, estimated by ZEP [ZEP, 2011a] are provided in the following table.

8.2.2 Transport

Carbon dioxide is already transported for commercial purposes by road tanker, by ship and by pipeline. Due to the fact that potential CO₂ storage sites are not evenly distributed across Europe and the fact that some Member States, considering their significant levels of CO₂ emissions, have only limited potential storage within their national boundaries, construction of a European CO₂ transport infrastructure spanning across State borders and in the maritime environment may become necessary [European Commission, 2010a].

The technologies involved in pipeline transportation vary little from those used extensively for transporting gas or oil. Indeed, in some cases, it may be possible to re-use existing but redundant pipeline infrastructures. Large networks of CO₂ pipelines, mainly associated to CO₂ flooding of oil reservoirs for Enhanced Oil Recovery (EOR), have been in use since the early 1980s and are operated commercially with proven safety and reliability records. Most of them lie in the US, where more than 4 000 km of pipelines already exist, with the Permian Basin containing between half and two-thirds of the active CO₂ floods in the world [Kinder Morgan, 2011; UTPB-CEED, 2009]. Recently networks have started to operate in Europe, with the biggest infrastructures in the North Sea, e.g. 160 km pipeline for the Snøhvit LNG project, and in the Netherlands, about 80 km of pipeline from Rotterdam to Amsterdam to transport CO₂ to greenhouses. By

2030, the CO₂ transport network for CCS could span 8 800 km [European Commission, 2010a]. The cost of a large-scale network would be around €5/tonne of CO₂ transported, excluding local collection and distribution pipelines. In a demonstration project with a capacity of 2.5 million tonnes per year and a 180 km point-to-point pipeline between source and sink, total transport costs per tonne of CO₂ could range from €5.4 for onshore transport to €9.3 for offshore transport, and a multiple of that number if distances are longer, e.g. €51.7 for 1 500 km offshore transport [ZEP, 2011b].

Transportation by ship has a number of attractive features including flexibility, potential for transport over longer distances (e.g. for the purpose of EOR in other continents), different economics which allow for servicing smaller sources and sinks, and potentially faster realisation since there are fewer permitting obstacles [ZEP, 2008]. In a small-scale demonstration project with a capacity of 2.5 Mt/yr, total shipping costs per tonne of CO₂ could range from €8.3 for 180 km distance to €14.5 for 1 500 km. Liquefaction costs need to be added, which are estimated at €5.3/tonne [ZEP, 2011b].

8.2.3 Storage

Various technical options for the long-term storage of CO₂ are being researched. Geological storage is by far the cheapest and most promising option and industrial geological CO₂ storage projects have already been initiated in Europe and worldwide. Different types of geological formations are being used and investigated, especially oil and gas



Figure 8.2: CO₂ capture and injection at Sleipner (Norway)
[Source: Klm Laland/ Statoil]

reservoirs, deep saline aquifer formations and unmineable coal beds. There is an estimated global storage potential of 10 000 Gt CO₂, with 117 Gt in Europe [Vangkilde-Pedersen et al, 2009], nearly all of which is in depleted oil and gas reservoirs and saline aquifers. Compressed CO₂ is already injected into porous rock formations by the oil and gas industry, e.g. for EOR, and is proven on the commercial scale. Storage sites will require environmental impact assessment (EIA) with wide public participation.

Due to its possible environmental implications, the possibility of CO₂ storage deep in the oceans is no longer considered an option [CSLF, 2010].

Mineral carbonation is an alternative for storing CO₂ in materials. However, due to the large amounts of energy and mined minerals needed, it is not likely to be cost effective [CSLF, 2010].

CO₂ storage in oil and gas reservoirs is less expensive than in saline aquifers, even more so when re-usable legacy wells – from earlier oil and gas exploration and production activity – are present. Onshore is less expensive than offshore. Typical storage costs per tonne of CO₂ range from €1.0-7.0 for onshore storage in depleted oil and gas reservoirs with legacy wells, rising up to €6.0-20.0 for offshore storage in saline aquifers [ZEP, 2011c].

8.3. Market and industry status and potential

Seven commercial projects with CO₂ capture, transport and storage are currently running. The Canadian Weyburn-Midale project, part of an EOR plan, demonstrates CO₂ storage using CO₂ from a gasification plant producing synfuel. In Norway, CO₂ removed from natural gas up-grading has been injected since 1996 and 2008, into the offshore Sleipner and Snøhvit fields respectively, and in Algeria in the In Salah field, since 2004. Two large projects are currently on-going in Australia (Otway basin) and in the Netherlands (K12B) and several are in preparation. Altogether, about 3 million tonne of CO₂ are stored annually [CSLF, 2010; European Commission, 2010b]. In 2007, about 95 CO₂-EOR projects worldwide, mainly in the USA, injected about 40Mt of CO₂ into oil reservoirs [Moritis, 2008].

The world's first coal-fired oxyfuel CCS plant with power generation is Vattenfall's Schwarze Pumpe 30 MW pilot plant, which was inaugurated in September 2008 in Spremburg, Germany, and started operation in early 2009 [Vattenfall, 2011]. Part of the

captured CO₂ is being transported by road tanker to a research facility at Ketzin where it is injected into a saline aquifer. Around June 2010, it was announced that Schwarze Pumpe had already been in operation for over 6 500 hours and that an alternative CO₂ processing line was being built, in order to eliminate the desulfurisation unit and make the clean-up of the CO₂ easier and better, while simultaneously increasing both capture rate and eliminating almost all emissions. Vattenfall announced in November 2009 that it was achieving nearly 100 % CO₂ capture at Schwarze Pumpe. Another 30 MW pilot, built by CUIDEN at Cubillos de Sil in Leon, North West Spain, will be commissioned very soon. According to Global CCS Institute nearly 40 projects for demonstration of CO₂ capture from power plants, based on a variety of storage techniques, are currently planned in Europe [Global CCS Institute, 2011].

Despite the longer-term need for further R&D to reduce costs and the efficiency penalty, the CCS power plant technology is widely considered ready for large scale demonstration. The European Commission has committed to support up to 12 projects to be operational by 2015. Funding will come from individual governments, the EU and industry.

Due to their comparatively higher emission levels when unabated, it is expected that the first CCS plants will be coal-fired. Under a €2.4/GJ fuel price scenario, the addition of CO₂ capture and the processing of the CO₂ for transport, increase the levelised cost of electricity (LCOE) from around €48/MWh to €73-87/MWh, depending on the technology. Future technological evolution and switching to more optimised CCS power plant designs may reduce the LCOE to €70/MWh or even less [ZEP, 2011a]. When also adding transport and storage costs, as well as residual emissions allowance costs, the total LCOE would then amount to around €80/MWh [ZEP, 2011d].

The PRIMES Baseline 2009 and Reference Scenarios [Capros et al., 2010] project less than 6 GW of CCS power generation capacity in the EU-27 by 2020, with the Baseline 2009 projecting a further capacity increase to 35 GW by 2030, while the Reference Scenario foresees more or less a stabilisation. Industry actors envisage around 20 GW by 2020 and 80 GW by 2030 [ZEP, 2008]. The Power Choices scenario by Eurelectric [EURELECTRIC, 2010] foresees 63 GW by 2030 and 191 GW by 2050. Globally, the BLUE Map scenario envisages 850 projects by 2030, of which 42 % in the power sector [IEA, 2009]. By 2050, 1 140 GW of CCS power plants could be installed world-wide.

Currently, two main industrial sectors are involved in developing CCS technology: electricity utilities and oil and gas companies, along with the corresponding fuel, equipment and service suppliers. This suggests a potential division within the CCS value chain, whereby the utilities could operate the capture step, and oil and gas companies could be involved in transport and storage. There is also likely to be a future role for pipeline operators: new networks of CO₂ pipelines are now being considered in different parts of the world and their development and management could become a major international business opportunity.

Power plants equipped with CCS would compete with conventional power plants for a share in power generation capacity if, as anticipated, they become commercially viable within a carbon pricing framework such as the EU Emission Trading Scheme (EU ETS). Alternatively they could be further enabled by regulation. The actual level of penetration will depend on the time of commercialisation and deployment, on the regulatory framework, the environmental constraints and the extent of the CO₂ transport network.

From an emissions mitigation point of view, it is important to consider the geographical profile of fossil fuel reserves and, hence, likely locations for fossil fuel use and deployment of CCS. Since a number of developing countries have significant fossil fuel reserves, it will be important to consider the possibility of developing the technology in industrialised countries with later diffusion to emerging economies. In order to stimulate such cooperation, work is presently on-going to adapt international financial instruments, such as the Clean Development Mechanism under the Kyoto framework [Bakker et al., 2009]. The European Commission in the context of the EU-China Climate Change Partnership is already active in this field, financing the EU-China Near Zero Emissions Coal Plant project [European Commission, 2009a, 2011a], whilst collaboration with other emerging economies, such as South Africa [European Commission, 2009b], OPEC countries [European Commission, 2009c], India [European Commission, 2011b] and Brazil [European Commission, 2011c] are under discussion.

In future scenarios in which renewables are projected to play an ever greater role in electricity production, fossil-fired power plants, inherently flexible, could be used to balance changing demand and provide back-up capacity for intermittent renewable generation. It is also important to note that a portfolio of

renewable options are under development and these other technologies should not be ignored when considering the potential for carbon capture. For example, there are specific opportunities to use carbon capture with biomass combustion for power generation, particularly when biomass is co-fired with pulverised coal. Carbon capture on a biomass-fired plant would allow for negative CO₂ emissions, as the CO₂ is first taken from the air in the biomass production process, and subsequently captured and permanently stored after combustion.

Industry – including such sectors as iron and steel, cement, aluminium, fertiliser, hydrogen and ethanol production and refineries – account for about 19 % of total world GHG emissions [IPCC, 2007]. CO₂ can be captured at such industrial facilities, but industry response has been less active than in power generation. In some cases, CO₂ is already captured in significant quantities in ammonia production, in coal-to-chemicals, coal/gas-to-liquids operations, and well heads at gas fields. Companies operating in these fields could therefore also benefit from CCS deployment. Hydrogen has been identified as one of the possible additional products that could give an added value to CCS equipped plants operating in a poly-generation scheme based on gasification technology, potentially producing other synthetic fuels, including natural gas.

8.4. Barriers to large-scale deployment

Financial, regulatory, infrastructure, environmental and social issues could all present barriers to CCS demonstration and deployment.

As mentioned before, CCS will initially increase the LCOE by €25/MWh or more compared to a reference plant. Under current EU ETS pricing, publicly funded incentives are needed to make the investment as commercially attractive as a non-CCS reference plant. Dependence on such publicly funded incentives entails additional policy risk on top of the uncertainty in EU ETS pricing – especially given the ongoing public debate around CCS (see below). Risk is also increased by the long-term liabilities arising from underground CO₂ storage. Besides R&D aimed at lowering costs, financing issues are therefore likely to be addressed by stable and facilitative policy frameworks for capture incentives and storage liabilities.

Key regulatory issues are the permit/licensing procedures for storage sites and long-term liability. The CCS Directive (2009/31/EC) provides

an EU framework for minimum requirements on permits for storage sites and management of environmental and health issues related to long-term geological storage of CO₂. Only Romania and Spain reported full transposition of the Directive by the June 25 deadline. Ten additional Member States have partly transposed the Directive. In July, the German parliament granted its approval for testing of CCS technology, despite public objections that the potential dangers of the technology had not been adequately addressed. In late September however, the German parliament failed to pass a proposed CCS law. The delays in transposing the CCS directive, as well as delays with planning and other approvals could hamper development of projects. The European Commission is launching infringement procedures against a number of EU Member States for failing to fully transpose the Directive [Platts, 2011]. Large-scale deployment of CCS would also be underpinned by a European CO₂ transport infrastructure, especially for smaller projects or capture plants located far away from storage sites. This may again depend on policy intervention to stimulate the development of large-scale transport networks.

Securing public confidence of the CO₂ emission reduction potential of CCS are key social and political challenges. Such confidence will first of all require a due assessment of environmental impact (including safety) and the associated considerations of sustainability and resource efficiency. The challenges regarding public confidence are confirmed by a Eurobarometer survey on CCS [TNS, 2011]. While nearly half of the respondents agree that CCS could help to combat climate change, the survey observes that 61 % of people would be worried if an underground storage site for CO₂ were to be located within 5 km of their home. An illustrative example of the importance of public acceptance is the Barendrecht project in the Netherlands. The project, initiated by Shell, aimed to store CO₂ originating from its Pernis oil refinery (in the Rotterdam port area), in two depleted gas fields largely located under the town of Barendrecht. After years of protests from residents, the plan was finally abandoned by the Dutch Minister of Economic Affairs, who on 4 November 2010 informed the Dutch House of Representatives that the proposed CO₂ sequestration project in Barendrecht would be stopped due to a 'complete lack of local support', as well as a delay of more than three years in obtaining permits [Nature, 2010]. Since public perception will have a significant role to play in CCS deployment, education on climate change and communication of the main technical economic and social aspects of

CCS could be the key to the ultimate success of CCS in reducing CO₂ emissions. Finally, lessons learnt from real large-scale demonstration plants may provide the basis for future deployment.

13.5. RD&D priorities and current initiatives

The SET-Plan is the main European vehicle for technological development in the energy field. The SET-Plan has led to the formation of European Industrial Initiatives (EIs), which foster research and innovation, by bringing together industry, the research community, the Member States and the Commission. The *European Industrial Initiative on CCS (CCS EII)*, which was launched on 3 June 2010, has two strategic objectives: to enable the cost competitive deployment of CCS after 2020 and to further develop the technologies to allow application in all carbon intensive industrial sectors. Specific tasks of the EII include: identification of priority actions; synchronisation of agendas through coordination of timeline and actions; identification and management of synergies between ongoing activities and possible interdependencies on risks between activities; and monitoring and reporting of progress to stakeholders in reaching EII objectives. Although industry driven, the CCS EII will build on the comparative strengths of each of the partners [ZEP, 2010]:

- Industry: to manage technology and market risk; to deliver on technology and cost objectives etc.;
- Member States: to ensure regulatory compliance by way of providing a clear regulatory framework at national level; to provide financial support as needed taking into account the favourable State Aid rules for CCS; to take into account the agreed CCS EII R&D priorities in their national RD&D programmes, etc.;
- European Commission: to provide guidance as necessary in relation to regulatory framework; to provide clarity over applicable EU law and policy and how these may affect business decisions; to coordinate CCS demonstration at EU level through the Project Network and provide support through the EEP and the NER, etc.;
- Research organisations and EERA: to undertake necessary research activities complementing those of industry and therefore deliver required breakthrough research at the least cost and on time;
- NGOs: to promote understanding and raise awareness of the advantages of CCS in civil society and to advise on actions as appropriate.

The role of industry and several other stakeholders in the deployment of CCS in Europe is consolidated through the *European Technology Platform for Zero Emission Fossil Fuel Power Plants (ZEP ETP)*, which was founded in 2005 and is a coalition of the European utilities, petroleum companies, equipment suppliers, scientists, academics and environmental NGOs with three main aspirations:

- Enable CCS as a key technology for combating climate change;
- Make CCS technology commercially viable by 2020 via an EU-backed demonstration programme;
- Accelerate R&D into next-generation CCS technology and its wide deployment post-2020.

On the global level, the European Union has a strong presence at the *Carbon Sequestration Leadership Forum (CSLF)*, which is comprised of 25 members, including 24 countries and the European Commission. CSLF member countries represent over 3.5 billion people or approximately 60 % of the world's population. The CSLF Charter, established in 2003, establishes a broad outline for cooperation with the purpose of facilitating development of cost-effective techniques for capture and safe long-term storage of CO₂, while making these technologies available internationally. The CSLF seeks to:

- Identify key obstacles to achieving improved technological capacity;
- Identify potential areas of multilateral collaborations on carbon separation, capture, transport and storage technologies;
- Foster collaborative RD&D projects reflecting Members' priorities;
- Identify potential issues relating to the treatment of intellectual property;
- Establish guidelines for the collaborations and reporting of their results;
- Assess regularly the progress of collaborative R&D projects and make recommendations on the direction of such projects;
- Establish and regularly assess an inventory of the potential areas of needed research;
- Organize collaboration with all sectors of the international research community, including industry, academia, government and NGOs; the CSLF is also intended to complement ongoing international cooperation in this area;
- Develop strategies to address issues of public perception; and
- Conduct such other activities to advance achievement of the CSLF's purpose as the Members may determine.

The *Global CCS Institute*, announced by the Australian Government in September 2008 and formally launched in April 2009, aims to connect parties around the world to address issues and learn from each other to accelerate the deployment of CCS projects through:

- Sharing knowledge: collecting information to create a central repository for CCS knowledge; analysing and disseminating information to fill knowledge gaps and build capacity;
- Fact-based advocacy: using facts to inform and influence domestic and international low carbon policies; supporting the commercialisation of CCS by advancing the understanding of appropriate funding and financing solutions and risk regimes; increasing the awareness of the benefits of CCS and the role it plays within a portfolio of low carbon technologies; and
- Assisting projects: bridging knowledge gaps between demonstration efforts; developing project specific solutions particularly amongst early movers.

A prerequisite for the large-scale deployment of CCS is the demonstration of the technical and economical feasibility of existing technologies in a fully integrated chain. For this purpose, the 2007 Spring European Council decided to support deployment of up to 12 large-scale CCS demonstration plants in Europe by 2015. EUR 1 billion of funding has been made available for 6 projects via the European Energy Programme for Recovery (EPR). The following table provides EPR project details and progress as of 20 April 2011 [European Commission, 2010c, 2011d].

Further funding is being made available from the proceeds of the sale of 300 million emissions allowances from the New Entrants Reserve (NER 300) of the EU ETS. The first Call was published in 2010 and 13 CCS projects applied. The following table provides a breakdown of projects by Member State and technology [Bellona, 2011; European Commission, 2011e].

To ensure that lessons learned from the first demonstration projects are maximised, the European Commission is sponsoring and coordinating the CCS Project Network, the world's first network of demonstration projects, all of which are aiming to be operational by 2015. The goal is to create a prominent community of projects united in the goal of achieving commercially viable CCS by 2020. The CCS Project Network fosters knowledge sharing amongst the demonstration projects and leverage this new body of knowledge to raise public understanding of the potential of CCS. This accelerates learning and

Location	Technology	Plant size (MW) – CCS only	CO ₂ captured (million tonnes per year)	Progress
Belchatow, Poland	Post-combustion	250	1.8	The final decision on selection of the storage site will be made in 2011. FEED work for the carbon capture plant started in November 2009 and was completed in the course of 2011.
Jaenschwalde, Germany	Oxyfuel	250	1.7	The tendering process for the nine main components has started and qualified bids were received. The negotiations for the contract for the air separation unit, the biggest component of the EEPR project, were conducted in February 2011. On the transport and storage side, the main operating plan for Birkholz was authorised in January 2011.
Rotterdam, The Netherlands	Post-combustion	250	1.1	The capture plant was put out to tender; six preliminary studies and two FEED studies were conducted for this process. In parallel, a technical plan for transport and storage was selected, routing studies on the pipeline were completed and a geological field study was conducted. The 'starting note' for the environmental impact assessment for this project was submitted in 2010, with permit applications following in March 2011.
Porto Tolle, Italy	Post-combustion	250	1.0	FEED studies for the capture part have been submitted by suppliers and are being evaluated – results are expected in Autumn 2011. One saline aquifer located offshore in the northern Adriatic Sea has been selected and detailed reservoir studies are being carried out to build up a fuller picture of it.
Compostilla, Spain	Oxyfuel	320	1.0	The main technical achievements were related to construction of the 30 MW oxyfuel technology development plant that will come into operation later this year. The major milestones reached in CO ₂ storage were the structural analysis and strategic studies for site assessment and characterisation of reservoirs.
Don Valley [Murray, 2011]	Pre-combustion	900	5.0	Work on the capture side was stopped because the parent company of the project coordinator went into administration. Activities resumed in May 2011.

Table 8.2: European Energy Programme for Recovery (EEPR) project details and progress

	Post-combustion	Pre-combustion	Oxyfuel	Industry	Total
France				1	1
Germany			1		1
Italy				1	1
Netherlands				1	1
Poland	1				1
Portugal					
Romania	1				1
United Kingdom	5	2			7
TOTAL	7	2	1	3	13

Table 8.3: Breakdown of CCS projects applying for funding per Member State and technology in the 2010 Call

ensures that CCS can be assisted to safely fulfil its potential, both in the EU and in cooperation with global partners.

Meanwhile more efficient and cost competitive CCS technologies have to be developed through ongoing R&D. Improvement of power plant efficiency, development of new materials (for advanced ultra-supercritical boilers and steam and gas turbines), development of innovative and more cost-effective capture processes, and assessing the safety of CO₂ storage are the priority topics. Reducing the costs of CO₂ capture through better technologies is considered feasible and essential, and alternatives such as ionic liquid solvents, enzymatic separation and physical separation are emerging. The greatest concern in long term geological storage is its security. The environmental impact and safety of CO₂ storage require better understanding. More refined and cost-effective monitoring and modelling techniques, for checking CO₂ migration, diffusion, fluid-rock interactions, and cap rock integrity need

to be developed for verifying storage security. In parallel, a better assessment of storage potential and site characterisation, especially of saline aquifers, is needed. CO₂ transport has been demonstrated on a commercial scale, however CO₂ pipelines operate at much higher pressures than, for example, natural gas pipelines, and CO₂ technology has not developed to the same extent as oil and gas pipelines. Concepts for transportation in challenging environments (e.g. highly populated areas) are needed, and issues, for instance, related to CO₂ composition, pipe rupture and longitudinal cracking are still of concern and need to be addressed. Further information on R&D priorities can be found in the Technology Roadmap of the SET-Plan [European Commission, 2009d], which provides a high-level overview of the main activities needed in order to enable the cost competitive deployment of CCS technologies in power plants by 2020-2025. The implementation plan of the European Industrial Initiative on CCS lists the short-term priority actions for 2010-2012 [ZEP, 2010].

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9. Advanced Fossil Fuel Power Generation

9.1. Introduction

Despite efforts to introduce power generation from renewable energy sources and increase its share in the European energy mix, fossil fuels are and will continue to hold the largest share of Europe's total electricity generation capacity, in both the short and medium term (53 % in 2010; 43.5 % in 2020; 39.8 % in 2030) [EC DG ENER, 2009]. Of the 53 % fossil-fuel based electricity generation in Europe (see Figure 9.1); 23 % is based on natural gas, 16 % on hard coal, 11 % on lignite and 3 % on fuel oil [Eurostat, 2008]. The European picture is slightly "greener" than the global picture, where fossil fuel power generation provides more than 60 % of the world's electricity output, of which 42 % is coal based [IEA ETSAP, 2010b; IEA ETSAP, 2010c]. More than 70 % of China's installed electricity capacity is based on coal fired power plants [IEA ETSAP, 2010b]. In the US, 40 % of power generation is natural gas-fired [IEA ETSAP, 2010c]. Consequently fossil fuelled power generation is the biggest contributor to CO₂ emissions, with 35 % of 2009 anthropogenic CO₂ emissions in EU-27 coming from power generation [EEA, 2011].

Despite the financial crisis in 2008, which caused a drop in the production from energy intensive industries and negative rates of change in the energy and electricity demand in 2009, electricity consumption is expected to continue increasing in the coming years. Baseline projections for the EU indicate that electricity consumption will grow on average by 2 % per year to 2030, with a potentially slightly slower pace each year because of energy efficiency improvement measures and higher fossil fuel prices, in particular natural gas, which will carry through into electricity prices [EC DG ENER, 2009].

There is therefore a lot of scope to improve technologies on fossil fuelled power generation and more specifically on improving conversion efficiency, since any gains would translate into substantial CO₂ and fuel savings. For example, each percentage point efficiency increase is equivalent to about 2.5 % reduction of CO₂

emitted. Power plant efficiency is therefore a major factor that could be used to reduce global CO₂ emissions.

9.2. Technological state of the art and anticipated developments

The technologies used to generate electricity from fossil fuels can be categorised based on the type of fuel used (coal, lignite, oil or natural gas), the technology of conversion of the chemical energy of the fuel to thermal energy (conventional thermal/fluidised bed/internal combustion or gasification), the type of turbine used (gas turbine or steam turbine) and the generated steam conditions (see Figure 9.2). The heat is used to generate high pressure steam that passes through a turbine to generate electricity. In the gas turbine the produced hot exhaust gases pass through the turbine to generate electricity. More advanced systems include a combination of both. In a combined cycle, the fuel is first combusted in a combustion turbine, using the heated exhaust gases to generate electricity. After these exhaust gases are recovered, they heat water in a boiler, creating steam to drive a second turbine. Apart from combustion, fossil fuels can also be gasified producing syn-gas (CO and hydrogen). Syn-gas can be directly used as a fuel for power generation. Alternatively, the hydrogen can be separated and used as a fuel in an open or combined cycle process.

The key operational figures of all the state of the art power generation technologies from fossil fuels are presented in Table 9.1. The main fossil fuel-based

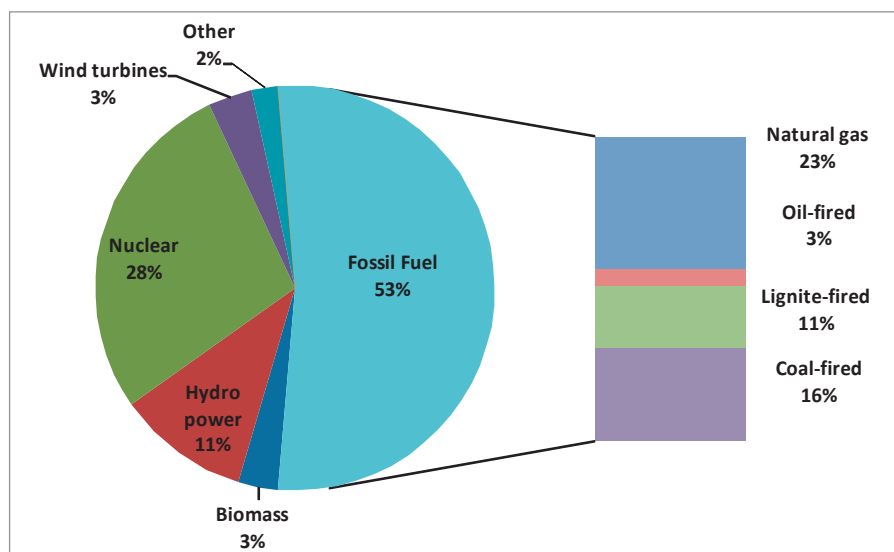


Figure 9.1: Electricity generation by fuel used in power stations, EU-27, 2008 [Source: Eurostat, 2008]

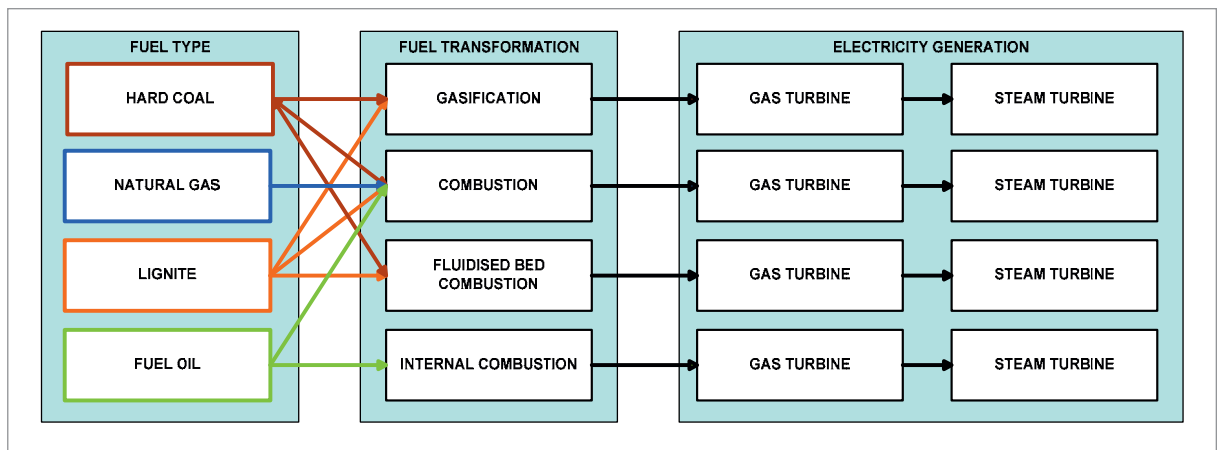


Figure 9.2: State of the art of fossil fuel power generation technology.

electricity generation technology in the world and in the EU is pulverised coal (PC) combustion. The majority of pulverised coal plants are more than 15 years old and operate with sub-critical steam. Upgrading low-efficiency fossil plants should be a high priority in the future. Supercritical (SC) plants with steam conditions typically of 540 °C and 25 MPa have been in commercial operation for a number of years. However, if the best available technologies were to be used, as for example, “advanced supercritical” plants with steam conditions up to 600 °C and 30 Mpa [CAT, 2006; IPPC, 2006], it should be possible to reach higher net efficiencies than with the SC operation. Reaching these steam conditions demands successive reheating cycles and stronger and more corrosion resistant steels that are inevitably more expensive than standard boiler steels. Nevertheless, the achieved overall efficiency improvement easily counterbalances additional cost and on-site energy consumption. There is a limit to the benefit of increasing steam pressure at a given temperature in that a reduced volume of steam leads to higher rates of leakage as the steam passes through the turbine. Amongst numerous other factors, site specific requirements such as geographical location, i.e. inland or coastal, availability of cooling water, as well as ambient temperature are also key factors determining the actual

efficiency achieved. The next step for the utilisation of coal is ultra-supercritical (USC) power plants. Steam conditions of 600 °C and 30 MPa can be achieved today, resulting in higher efficiencies for bituminous coal fired power plants [Beer, 2007]. Several years of experience with good availability have already been achieved [Bugge et al, 2006], for example with Unit 3 of the Nordjyllandsvæket USC combined heat and power plant near Aalborg in Denmark (see Figure 9.3), where 47 % electrical efficiency is achieved with an output of 410 MW and steam conditions of 582 °C and 29 MPa. High electrical generation efficiency of 43 % has also been achieved with the more difficult-to-handle lignite (brown coal) at the 1 012 MW_e Niederaussem K plant in Germany [RWE, 2004]. Future USC plants are planned to use 700 °C and 35 MPa or higher, which should give net efficiencies of the order of 50-55 %.



Figure 9.3: Nordjyllandsvæket USC combined heat and power plant [Source: Vattenfall]

High power generating efficiencies can also be reached with natural gas which has been used increasingly over the last 20 years, initially to address concerns over acid emissions (SO_x and NO_x) and to provide better demand management. It also has been a lower cost option, at least in terms of plant investment, although combined cycle mode with gas and steam turbine are needed to achieve high efficiencies. Advanced air cooled gas turbines have been reported to achieve Combined-cycle thermal efficiencies of over 60 %, with more than 40 % efficiency in single cycle operation [Siemens, 2010]. Recent high natural gas prices and large fluctuations in price have increased the financial risk of operation.

For combustion, fuel flexibility seems to be best achieved using fluidised bed systems which have been extensively exploited for biomass in the Nordic countries. A large-scale coal-fired circulating fluidised bed (CFB) was commissioned in 2009 in Poland. The Lagisza CFB plant has a capacity of 460 MWe and operates with supercritical steam giving in excess of 43 % efficiency, with very low NO_x emissions and easy in-bed capture of sulphur. Integrated gasification combined cycle (IGCC) has been successfully demonstrated at two large-scale power plant demonstration facilities in Europe (Buggenum-NL and Puertollano-SP), achieving plant availability up to 80 %. The technology is ready

for commercial deployment. IGCC has a smaller cost differential between CO₂ capture and non-CO₂ capture than PC combustion. The cost of IGCC without capture is still higher than PC [Beer, 2007]. High temperature entrained flow gasification avoids tar-related problems and increases the gasification rate, allowing better matching with modern high capacity gas turbines that achieve high efficiencies. Further into the future, IGCC with hybrid fuel cells, gas turbines and steam turbines could conceivably reach 60 % efficiency with zero emissions. The costs of new power plants have increased substantially over the last 3 to 4 years, mainly as a consequence of worldwide demand for raw materials (steel and other building materials) and the shortage of manufacturing capacity due to rapid industrial expansion. The impacts of the recession that started at the end of 2008 cannot yet be judged so the data given below should be treated with care. All costs should be considered to include engineering, procurement and construction (EPC).

Oil-fired power plants are not that common any more (8 % of the European electricity production is coming from oil-fired power stations) and for the most part, electricity producers no longer invest in oil-fired capacity. The available oil reserves are mainly used for transport and the petrochemical industry. Peak units running on jet fuel do exist, but more and more, are being replaced by more efficient and environment-

	Net Efficiency	Capital Cost	Operating Cost Excluding Fuel Cost	Direct CO ₂ Emissions
Sub - Technology	%	€2008/kW	€2008/kWh	kg/kWh
Pulverized Coal Combustion	46 - 47	1 380-1 680	0.041 - 0.050	0.73 - 0.88
Circulating Fluidized Bed Combustion	41 - 43	2 040-2 490	0.040 - 0.048	0.68 - 0.70
Coal Conventional Thermal	34 - 37	2 810-3 430	0.023 - 0.028	0.95 - 1.16
Lignite Conventional Thermal	32 - 34	2 550-3 110	0.037 - 0.045	0.99 - 1.21
Integrated Coal Gasification Combined Cycle	45 - 46	2 320-2 830	0.093 - 0.113	0.70 - 0.75
Combined Cycle Gas Turbines	60 - 61	690 - 840	0.046 - 0.056	0.34 - 0.40
Gas fired Conventional Thermal	50 - 51	430 - 530	0.049 - 0.059	0.46 - 0.56
Gas Fired Gas Turbine	40 - 42	560 - 690	0.131 - 0.161	0.48 - 0.58
Oil Conventional Thermal	32 - 33	390 - 470	0.039 - 0.052	0.74 - 0.90
Oil Fired Gas Turbines	35 - 36	405 - 475	0.027 - 0.046	0.65 - 0.75
Internal Combustion Engine	41 - 43	630 - 820	0.022 - 0.024	0.71 - 0.86

Table 9.1: Key operational figures of state-of-the-art fossil fuel-fired power generation technologies in Europe [IEA ETSAP, 2010a; IEA ETSAP, 2010b; IEA ETSAP, 2010d; IEA, 2007; Wu, 2006; FW, 2009; European Commission, 2008a; Sargent & Lundy, 2009; Vuorinen, 2007]

friendly gas turbines. The main reason why oil would be used for electricity generation (even taking into account price fluctuations of oil/gas/coal which will to some extent be offset by CO₂ taxes) would be for security of supply reasons: oil is a locally storable fuel, which is not the case for gas.

9.3. Market and industry status and potentials

In all the scenarios to 2050, as presented by the IEA ETP, world economy is expected to grow at an average annual rate of 3.3 %. Higher economic growth means higher living standards. Consequently the demands for goods and services and undoubtedly energy will grow. Even the most optimistic scenario yields an annual world energy consumption growth rate of 0.7 % [IEA, 2008]. The EURELECTRIC Power Choices scenario shows a reduction in final energy consumption through a shift towards electric applications. The scenario indicates very strong reduction of gas and oil end use – from 52 % of final energy demand to only 34 %. This is mirrored by a consequent increase in the proportion of electricity in end-use applications – up from 20 % to 45.5 %. Although electricity will claim a greater share of total energy consumption, the total EU net power generation will not reach a much greater level than Baseline, rising from some 3 100 TWh in 2005 to around 4 800 TWh in 2050, as the energy-efficiency drive will phase out less efficient vectors [EURELECTRIC, 2010]. All energy forecasts show that fossil fuels will remain the main fuel for electricity generation in the medium and long term, owing to the existence of extensive coal reserves and their good distribution across politically stable regions, retaining a share in power generation of the order of at least 40-50 % in 2030 [IEA, 2004]. The use of coal will likely increase in the future under any foreseeable scenario because it is cheap and abundant and CO₂ capture and storage (CCS) is the critical enabling technology that would reduce CO₂ emissions significantly while also allowing coal to meet the world's pressing energy needs [MIT, 2007]. Electricity from solid fuels will decrease until 2025, when the implementation of CCS facilitates a revival. However, the level of solid fuel-fired generation in 2050, at 770 TWh, still remains significantly lower than the 2005 figure of 900 TWh and its share actually falls from about 29 % to 16 % over the period. Gas-fired power reaches its peak in 2025, followed by a slight decline as gas and carbon prices rise and CCS also becomes necessary for gas-fired plants, stabilising at 660 TWh in 2050, 14 % of total EU electricity compared to 21 % in 2005. Oil-fired

plants have only a marginal role, with production progressively reducing over time to reach just 1 % of total power generation in 2050 [EURELECTRIC, 2010].

A scenario where the price of CO₂ is high, should lead to a substantial reduction in coal use in 2050 relative to “business as usual”, but still with an increased use in coal relative to 2000. In such a carbon-constrained world, CCS, addressed in Chapter 8, is the critical future technology option for reducing CO₂ emissions [MIT, 2007]. Consequently, application of advanced supercritical and ultra-supercritical fossil power technologies to function alone or in combination with CCS is essential to minimise CO₂ emissions.

With continually growing electricity demand and limitations on the potential for exploitation of alternative, renewable sources of energy, fossil fuel power using coal in particular as a widely available, low cost and familiar resource, appears highly likely to dominate globally well into the 21st century and also in a number of EU Member States [MIT, 2007]. Improved efficiency of conversion of the fuel to electricity, particularly of low-efficiency sub-critical power plants, with maximum utilisation of residual heat is now driving industry to cut emissions. Sub-critical power plants (35 % efficiency) emit 943 kgCO₂/MWh of electricity, while the best available supercritical power plants with an efficiency of 46 % emit 720 kgCO₂/MWh of electricity [Adams, 2009], so major retrofitting of old sub-critical power plants with supercritical steam cycles or retiring old plants and replacing with new ones could save 23.6 % CO₂ emissions for the same power produced. The main factors affecting efficiency have been described in detail by Beer [Beer, 2007]. Various additional measures can be taken to improve efficiency, for example, intensive coal up-grading (mainly drying) could reduce CO₂ emissions by 0.3-0.5 Gt each year globally (from 8 Gt annual CO₂ emissions from coal use), retrofitting of existing plants by adding reheating stages, increasing the number of feed heaters, increasing the final feed water temperature and generally improving housekeeping by reducing leakages and heat losses, collectively providing 4-5 percentage points efficiency increase [Adams, 2009]. Co-firing with biomass also reduces fossil CO₂ emissions, the higher the base-plant efficiency, the higher the CO₂ saving, although technical challenges associated with fuel feeding, fouling and corrosion, limit the amount of biomass that can be added without compromising operating reliability [IEA, 2006]. Improved efficiency and biomass co-firing will save costs imposed by the future Emissions Trading Scheme (ETS) from 2013 and save costs in the open

energy market developing in the EU. The next step, involving CCS on a demonstration scale beyond 2015, will demand the highest power generation efficiency in order to compensate for the inevitable energy cost associated with CO₂ capture processes.

9.4. Barriers to large-scale deployment

The power generation sector in the EU is a mature sector and up until quite recently, has been thriving in a relatively undisturbed commercial environment. Privatisation in many countries over the last 10-15 years resulted in reduced investment in new plants, although work on improving the supercritical steam technology advanced without significant interruption. The industry also saw the need for and acted accordingly to ensure development of technology to support ultra-supercritical steam conditions and associated higher generation efficiency. The main driving forces for technology development have been, and continue to be, reduced emissions and both investment and operating costs. Costs and emissions are intimately linked.

The absence of a stable economic climate is the main reason for the observed halt in investment in high efficient coal plants, and primarily, in coal in general. Beyond the technology challenges, the lack of a consistent policy signal in most MS creates uncertainty about the future EPS, IED or ETS rules, the security of supply of coal and lignite in the EU, future revenues from electricity, as well as the need for baseload plants. This hinders investment towards building new coal plants. There is therefore a need for greater stability of investment cost than has been experienced in the last 3-5 years and a stable CO₂ price when the ETS is in full operation. Higher cost of investment combined with the cost of CO₂ emissions have to be weighed against increased income from electricity and heat from each unit of fuel.

This translates into the development of a regulatory market framework and of appropriate policies that will promote financial stability of the energy market, which will in turn provide stability to the power generation sector. The financing and regulation of the infrastructure for CO₂ transport and storage will need to be addressed on both the European level and the Member State level to enable the power generation sector to plan its capacity and fuel supplies for the future.

Coal-fired power offers advantages over gas-fired power in a high or volatile natural gas price scenario,

or in light of supply security issues. Emissions of airborne pollutants may be lower as well. A disadvantage is the high investment cost (compared to gas-fired power), which is counterbalanced however by the lower fuel cost. CCGT technology is a strong player in power generation technology. With a fast growing share in electricity generation over the past decades, CCGT plants offer shorter construction time, lower investment costs, half as much CO₂ per kWh and high service flexibility than coal power plants, but higher fuel costs. Non-GHG emissions such as SO₂, NO_x and particulate matter are also relatively low. Fossil fuel-fired power not only competes within its own boundaries, but also with nuclear and renewable power. While some renewable technologies are growing fast and will have an increasing impact on the electricity market, the competition with nuclear power will largely depend on licensing and regulatory aspects, environmental issues, social acceptance and long-term CO₂ policies.

The price of CO₂ may also be a barrier for new coal-fired capacity. Therefore, long-term emission reduction policies and high CO₂ prices are needed for CCS to become commercially available. The cost of CO₂ emissions within the European Emissions Trading Scheme (ETS) is likely to have a substantial impact on the cost of electricity production. The current price in the European Emissions Trading System (some €10-11/tCO₂) is not high enough to discourage the construction of new coal-fired capacity. This cost impact can be reduced by maximising the efficiency of power production. New coal-fired power plants have higher efficiency and lower emission of CO₂/kWh than existing plants. Hence, supercritical and eventually ultra-supercritical steam conditions of the highest grade need to be used. Refitting and upgrading power plants are possible and there are possibilities to make small efficiency improvements. Fossil CO₂ emissions can be reduced by co-firing with biomass. The barriers to direct co-firing biomass is very low as only fuel feed systems need to be changed significantly. Co-firing of waste, of which there are potentially millions of tonnes available, pose both a legal barrier and a technical challenge. Under the European Waste Framework Directive (WFD) [European Commission, 2008b], waste combustion may only take place in a plant that conforms to the European Waste Incineration Directive (WID) [European Commission, 2000]. While a number of fossil power plants have experimented with waste as a fuel, most of them had to abandon the work at the end of 2005 as the WID came into full force. There were also some problems of increased boiler

corrosion. However, the amount of Solid Recovered Fuel (SRF) produced from municipal solid waste amounts to millions of tonnes each year and at least some of the SRF could be used in power plants without adverse effects. The main problem is classification of the SRF as a “product” rather than waste.

The main technology challenge by far on the immediate horizon is the introduction of CCS. In the near future, the plants that have to comply with emissions trading systems may consider implementing CO₂ capture and storage technologies (CCS). This may lead to a significant increase of the investment cost and an efficiency reduction. Full introduction of ultra-supercritical plants seems to be a matter of cost associated with the expected high risk of using a new technology. Reliability will need to be proved for ultra-supercritical steam cycle plants. Whether or not poly-generation becomes a commercial reality in the power generation sector in Europe is as yet unknown.

Fuel flexibility is becoming increasingly important as fuel resources are depleted and costs can fluctuate significantly over the life of a power plant. Substantial efforts have been made to use alternative fuels in pulverised coal power plants. In recent years this has been driven mainly by the need to increase power generation from renewables and so biomass has been widely used in amounts typically up to 5 % energy input. Markets for trade in biomass for co-firing are not yet mature and as a consequence feedstock costs can vary widely in a relatively short space of time. The impact of biomass co-firing on power generation efficiency is very small within the low range of inputs of biomass currently used. There is an additional cost for preparation of the biomass (milling) for injection into pulverised coal plants (direct co-firing). Indirect, co-firing via a pre-gasification step followed by injection of a product gas (rich in CO and H₂) into the coal boiler is not yet commercial, although large-scale demonstrations, e.g. the Amercentraale in NL, have been made.

Finally, public acceptance is of paramount importance for the deployment of large fossil fuel power generation project. An illustrative example of how public opinion affects the development in the power generation industry is in the UK, where the UK Government has been using the term ‘capture ready’ when granting licences for fossil-fuelled power plants. Capture readiness has been used as a regulatory requirement in the UK since 2006 [Markusson and Haszeldine, 2010].

9.5. RD&D priorities and current initiatives

The implementation of the SET-Plan, adopted by the European Union in 2008 includes the European Industrial Initiative (EII) on CCS that was launched in 2010. The objective is to demonstrate the commercial viability of CCS technologies in an economic environment driven by the emissions trading scheme, with in particular, to enable the cost competitive deployment of CCS technologies in coal-fired power plants by 2020-2025 and to further develop the technologies to allow for their subsequent wide-spread use in all carbon intensive industrial sectors. The 2009 Roadmap for CCS explicitly states that work needs to focus also on the improvement of conventional power plant efficiency [European Commission, 2010]. This will enable European fossil fuel power plants to have near-to-zero CO₂ emissions by 2020.

In 1998, a group of major suppliers to the power industry and some of the major utilities in Europe started a 17-year demonstration project, financially supported by the European Commission’s THERMIE programme, called the “Advanced (700 C) PF Power Plant”. The higher USC steam conditions necessitate use of stainless steels and nickel-base alloys in the highest temperature regions of the boiler to resist corrosion degradation and mechanical deformation. With the elevated steam conditions, advantage will have to be taken of advanced turbine blade technology and state-of-the-art condenser configurations to achieve very low turbine exhaust pressures, thereby maximising the pressure drop across the turbine to provide maximum power generation. In addition, it has the potential to provide large quantities of low-pressure process steam extracted from the turbine for district heating, industrial use or an on-site CO₂ capture plant. The main aim of the THERMIE 700 °C steam coal power plant project is to make the jump from using steels to nickel-based super alloys for the highest temperatures in the steam cycle which should enable efficiencies in the range of 50-55 % to be achieved. When a 700 °C steam coal power plant will become a reality is not known. Beyond fuel flexibility, there is increasing interest in poly-generation from coal, so that not only electricity and heat are the products, but also chemical feedstock and alternative fuels for transport will be important. The IEA Clean Coal Centre has recently published a report on the potential for poly-generation [Carpenter, 2008].

For both retrofitting of existing pulverised coal (PC) plants and new PC combustion plants, oxy-fuel combustion is a promising option that will minimise the cost of the CO₂ capture step, since the flue gas contains around 90 % CO₂. There are many non-quantified operational effects associated with

oxy-fuel combustion that will need to be addressed before it could be used commercially. A 30 MW pilot-scale project was started in 2008 in Germany¹⁹ and a 30 MW pilot plant designed by Foster Wheeler for CIUDEN²⁰ commenced operation in North West Spain in the second half of 2011.

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¹⁹ <http://www.vattenfall.com/en/ccs/index.htm>

²⁰ http://www.fwc.com/publications/pdf/EEPR_072611.pdf

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10. Nuclear Fission Power Generation



10.1. Introduction

Nuclear power has been shown to be an outstanding baseload solution for low carbon electricity [Nicholson et al., 2011]. The future also holds new opportunities for nuclear to contribute to a low-carbon economy. Generation III (Gen III) reactors, while continuing to produce no greenhouse gas emissions, will also include enhanced safety systems. Generation IV (Gen IV) reactors will further reduce environmental burdens while gaining higher resource utilization and waste reductions. Future reactors will take on new roles in the generation of carbon-free process heat for industries which are currently heavily dependent on fossil-fuel heat sources. Nuclear reactors will be used to produce hydrogen fuels and biofuels for the transportation sector. Small and medium-sized reactors can replace older fossil fuel plants and fill niches in small transmission grids where large nuclear plants are unsuited. New flexible reactors could facilitate renewable energy in reaching high penetration levels in the energy mix by balancing the variability from wind and solar on the electricity grid. In summary, nuclear energy can evolve with the needs of the low-carbon economy by, maintaining a reliable supply of electricity and replacing carbon-based technologies in process heat and transportation fuel markets and by helping to expand the renewable energy resource.

10.2. Technological state of the art and anticipated developments

Commercial nuclear plants operating today are mainly light water reactors. Utilities use the nuclear reactor as a boiler to produce steam which is converted into electricity through a turbine. The source of heat in the boiler is generated by a controlled nuclear reaction, i.e. fission. The fuel used in the reactors is mainly composed of particular isotopes of uranium and plutonium. The reactor pressure vessel contains, in the particular case of a slow (thermal) neutron reactor, the neutron moderator, the coolant and the reactor fuel where the nuclear reaction takes place. Depending on the type of reactor (thermal or fast), the fuel requirements and configuration of the components (e.g. boiling or pressurised), the design requirements can be quite different. Generation I reactors were developed in 1950-60s. The current nuclear power plants in operation worldwide are Gen II reactors, which typically use low-enriched uranium fuel and are mostly cooled and moderated with water.

The current state of the art in commercial nuclear power plants is the Generation III (Gen III) reactor, which is an evolution of the presently operating Gen II reactors with enhanced safety features and reliability. The first two Gen III reactors in Europe are under construction in Finland and France, and were planned to be connected to the grid in 2013 [Parliament, 2006] and 2014 [Bloomberg, 2010], respectively. The Finnish reactor (1.6 GWe) shown in Figure 10.1, is a first-of-a-kind (FOAK) unit which has experienced some construction delays and detailed design changes resulting in a cost escalation from EUR 3.7 billion to EUR 6.4 billion; however the second reactor in France (also 1.6 GWe) is showing signs of improved economies with a current cost estimate of EUR 5 billion [Businessweek, 2010]. Additional experience gained from building these reactors overseas will lead to further cost reductions, as estimated by international studies [NEO, 2008; MIT, 2009; NEA, 2005; DTI, 2007], in the range of €2 000±500/GW_e (overnight costs). The economics of these very large plants (~1 700 MWe) is largely a function of the capital costs, which make up 60-70 % of the total electricity costs. The capital costs are further compounded by regulatory and economic conditions which influence construction times and financing expenses [ibid].

A new generation of nuclear reactors are being developed in response to the need for greater sustainable and intergenerational environmental responsibility. These reactors will require less extraction of natural resources from the Earth and produce less long-lived radioactive waste requiring deep geological disposal. New fast neutron breeder reactors are expected to produce up to 100 times more energy from the same quantity of uranium than current designs while significantly reducing waste toxicity [SNETP, 2009; NEA, 2009; GIF, 2002]. Fast reactor concepts have been demonstrated in research programmes and national prototypes in the past, but further R&D is needed to make them commercially viable in order to meet the Gen IV goals for safety, reliability and proliferation resistance. The costs for fast reactors may initially be 10-30 % greater than Gen III reactors [Shropshire et al., 2009] but the goals are to have a life-cycle cost advantage over other energy sources and a level of financial risk that is comparable to other energy projects.

Small and Medium-sized Reactors (SMRs) have recently come under the spotlight due to, primarily, their greater affordability. Several new concepts with modular designs, long refuelling cycles and integrated power systems are being developed



Figure 10.1: EPR construction at Olkiluoto site in May 2011 [Source: Teollisuuden Voima Oyj] [Source: Teollisuuden Voima Oyj (TVO)].

[DCNS, 2011; NuScale, 2011; TerraPower, 2011]. Reactor types range from conventional light water reactor designs to systems using sodium and lead bismuth coolants. They all have in common an increased level of safety (sometimes inherently safe) and the portability needed for construction and operation in remote locations. Low capital cost will allow SMRs to expand into utility markets previously unable to afford nuclear power.

To date, nuclear power is primarily used to produce electricity, but in the future it can expand into new heat applications [NEO, 2008; NEA, 2009]. Currently light water reactors (LWRs) are used in

some low temperature applications (< 200 °C) such as district heating and desalination of seawater. High-Temperature Reactors (HTR) that can reach 550 °C can be used to replace fossil-fuelled boilers in process heat industries such as paper and pulp processing, and can be used for biomass torrefaction to prepare carbon neutral fuel stocks for co-firing in coal plants and for processing into biofuels. Gen IV Very-High Temperature

Reactors (VHTR) with gas coolant temperatures up to 1 000 °C will expand the opportunities further in process heat applications such as: petroleum refinery applications (400 °C), recovery of oil from tar sands (600-700 °C), synthetic fuel from CO₂ and hydrogen (600-1 000 °C), hydrogen production (600-1 000 °C) and coal gasification (900-1 200 °C). These highly efficient reactors (achieving > 50 % efficiency) will conserve energy and reduce the process industry carbon footprint [WNA, 2011].

Table 10.1 provides a comparison of performance data for the Generation III and III+ LWR, SMR and a SFR over time periods ranging from 2010 to 2050.

	Units of Measure	Gen III LWR (2010)	SMR (2030)	SFR (2050)	Gen III+ LWR (2050)
Electrical power output	MWe1	1 000	380	1 000	1 000
Load (capacity) factor	%	90	90	82	90
Thermal efficiency	%	36	36	38	38
CAPEX (Capital overnight)	€/kWe ²¹ (\$/kWe)	3 595 (5 000)	3 595 (5 000)	3 020 (4 200)	1 650 (2 300)
Fixed Operations & Maintenance (FOM)	% of capital	2.2	2.2	1.7	1.5
Variable Operations & Maintenance (VOM)	€/MWh (\$/MWh)	1.8 (2.5)	1.6 (2.2)	1.4 (2.0)	0.6 (0.8)
Greenhouse gas emissions	tCO ₂ (eq.)/GWh	5.91	4.95	3.76	3.76

Table 10.1: Plant data for LWR GenIII/III+, SMR and SFR [ETSAP, 2010; Shropshire et al., 2009; NEEDS, 2007].

²¹ Average exchange rate EUR/USD in 2009 was 0.719

10.3. Market and industry status and potential

Nuclear fission energy is today a competitive and mature low-carbon technology, operating at a very high level of safety. The installed nuclear electricity capacity in the EU is 132 GWe (July 2011), which provides one third of the EU's generated electricity [WNA, 2011; IAEA, 2011]. This is about 35 % of the global nuclear capacity. The reactors in Europe have been in operation for 29 years on average. Most of the current designs are LWR of the second generation providing base-load electricity often with availability factors of over 90 %. Even though the total number of reactors in Europe has decreased during the last two decades, electricity supply from nuclear has remained constant due to power upgrades and improved availability factors. Current plans in most EU member countries are to extend their lifetime on a case-by-case basis beyond 40 years, and even beyond 60 years in some cases, in combination with power upgrades.

Until the recent accident in Fukushima, there was a surge in interest in nuclear energy which was mainly driven by concerns over climate change, energy security, independence of supply and energy costs. Fukushima has clearly resulted in some setbacks for nuclear energy that are resulting in some early shut downs of Gen II reactors. The plants safety margins available in case of some beyond-design basis accidents are under evaluation by the Member States. No substantial reductions in the use of nuclear energy from current levels are expected at the pan-European level. Some countries are placing a moratoria on new-builds or shutting down their reactors, e.g. Italy and Germany, however the plans of some countries to build new reactors go on unimpeded, e.g. Finland and UK.

The European Energy Outlook (2009) included modelling with the economic competitiveness of energy technologies as driver [EC DG ENER, 2009]. Two scenarios were analysed, a baseline scenario (Business As Usual) and a reference scenario in which low-carbon technologies were promoted. Both cases estimated similar nuclear production outputs in 2030 as in 2009 on the European level, but with different developments in Member States. The percentage share of nuclear power production from the total would decrease to about 25 % in 2030 as compared to 30 % at 2010 levels. The number of nuclear new builds was higher in the baseline relative to the reference scenario in the period 2020-2030 with 71.3 and 60.9 GW, respectively.

Presently there are four reactors under construction in Europe including the two European Pressurised Reactors (EPRs) in Finland and France, and two small reactors of Gen II type (VVER 440) in Slovakia. Several European countries (Finland, France, Netherlands, Romania, Bulgaria, Lithuania, and United Kingdom) have plans to build new reactors. However, in response to Fukushima, Germany shut down seven nuclear reactors and made plans to shut down the remaining 17 reactors no later than 2022. Switzerland decided against the life extension of old nuclear reactors and decided to forgo new build. Italian plans for a nuclear programme were also terminated.

Europe plays a leading role in the development of nuclear energy with Areva as the vendor of the EPR, provider of large components and services. Worldwide several other vendors are active. Westinghouse has four AP1000 units under construction, which is a pressurized water reactor (PWR) of 1 200 MWe that has a focus on simplification and passive safety. General Electric has four Advanced Boiling Water Reactors (ABWR) in operation, four under construction and four more planned for Japan and two in the US [WNA, 2011]. Additionally, two South Korean APR1400 reactors and two Russian VVER AES 2006-1200 reactors are under construction.

Programmes to build fast reactor and high-temperature reactor demonstrators are being implemented in Russia, Japan, India and China. Although these are not Gen IV designs, transfer of knowledge and experience from operation will contribute significantly to future Gen IV development. In Europe, a concerted effort is proposed in the form of a European Industrial Initiative in sustainable nuclear fission as part of the Community's SET-Plan. A commercial deployment for a sodium fast reactor (SFR) is expected from 2040 and for an alternative design (either a lead-cooled or gas-cooled), a decade later.

High temperature reactors dedicated to cogeneration of process heat for the production of synthetic fuels or industrial energy products could be available to meet market needs by 2025 (initially in China), which would trigger to the construction of "first-of-a-kind" demonstrators in the next few years. The key aspect is the demonstration of the coupling with a conventional industrial plant. Supercritical water reactors and molten salt reactors, as well as accelerator driven sub-critical systems dedicated to transmutation of nuclear waste, continue to be assessed in terms of feasibility and performance.

10.4. Barriers to large-scale deployment

After Fukushima, extreme external events (e.g. tornados, hurricanes, floods) and cascading failures from co-located nuclear plants will be incorporated in the scope of current operating reactors and future reactor design reviews. The objective of the stress tests planned to be conducted in the EU is to identify and eliminate potential, identified weaknesses.

Public acceptance remains an important issue, and after Fukushima the public opinion is more negative in most Member States. The stress tests began formally on 1st June 2011. These tests are quite comprehensive and will cover a large range of conditions, including the capacity to withstand natural disasters and to cope with any prolonged station blackout or loss of cooling capabilities. Another type of test will look at security prevention and resistance to terrorist attacks. The tests will be conducted first by experts at the power plants, then next by national regulators, and finally by an independent seven-member ‘peer review’ team consisting of experts from other EU countries. The first results will be made available to the public at the end of 2011. As a long-term view of these events, a better informed population should emerge that has a better understanding of the risks from nuclear energy and the safety measures taken to prevent failure.

The high capital cost of nuclear energy in combination with uncertain long-term conditions constitutes a financial risk for utilities and investors. The lack of widespread support in the EU Member States may undermine the strength of the nuclear industry in the EU with regard to the development of new technologies. Harmonised regulations, codes and standards at the EU level would strengthen the competitiveness of Europe’s nuclear sector and facilitate deployment of Gen III technology in the near term.

The industry, infrastructures and services that support nuclear power has shrunk significantly during the last decades. Even though this situation is not unique for Europe it may pose a bottleneck for the deployment of reactors in the relatively near future. One example is large forgings needed for pressure vessels. World capacity is limited and even at the present new build construction rate, there is a waiting list for delivery of these components.

International cooperation currently exists at the level of research, and this is being facilitated by the Generation-IV International Forum (GIF). EU industry is facing stiff competition, especially in Asia where

strong corporate support for R&D is putting industry in a better position to gain leadership in the near future. The European Industrial Initiative is aimed at meeting this challenge by combining efforts and resources in order to compete on a global level.

For most of the Gen IV concepts one major issue involves development of new materials that can withstand higher temperatures, higher burn-ups and neutron doses, and corrosive coolants.

Another significant potential barrier for nuclear fission is the shortage of qualified engineers and scientists as a result of the lack of interest in nuclear careers during the 1990s and the reduced availability of specialist courses at universities. Preservation of nuclear knowledge remains a major issue, especially since most of the current generation of nuclear experts are nearing retirement.

Despite all the above challenges, where some of them are common to all new technology deployments, nuclear energy development maintains many assets, in particular, its low sensitivity to the cost of the fuel in the final price of the electricity generated. This is a key aspect for long term investments. Also, the continuous improvement of the plants’ safety which is highlighted by the current stress test exercise in Europe, will contribute to its wider acceptance by the stakeholders.

10.5. RD&D priorities and current initiatives

A new research and innovation system is needed that can assure additional funding, especially for the development of Gen IV technologies. In this context the Sustainable Nuclear Energy Technology Platform [SNETP, 2009] plays a key role. The timescales involved, and the fact that key political and strategic decisions are yet to be made regarding this technology, mean that a significant part of this new investment must be privately funded.

The launch of the European Sustainable Nuclear Industrial Initiative (ESNII) under the community’s Strategic Energy Technology Plan (SET-Plan) brings together key industrial and R&D organisations. ESNII has identified the sodium fast reactor (SFR) as its primary system with the basic design selected by 2012 and construction of a 250-600 MW_e prototype is planned to be operational around 2023. In parallel, gas- or lead-cooled fast reactors (GFR/LFR) will be investigated. These reactors will be 50-100 MW_{th} demonstrator reactors that should also be

in operation by 2025. The SFR prototype and LFR/GFR demonstrator will be supplemented by a fuel fabrication workshop and by new and refurbished experimental facilities for qualification of safety systems, components, materials and codes.

Preparations for an industrial initiative proposal on nuclear cogeneration are ongoing with the aim of demonstrating the cogeneration of process heat and the coupling with industrial processes. This would be built and funded through a European or international consortium, which should also include the process heat end-user industries.

The implementation of geological disposal of high-level waste is also being pursued as part of national waste management programmes, though some countries are not as advanced as others. The new Implementing Geological Disposal Technology Platform, launched in November 2009, is coordinating the remaining research in Europe leading up to the start of operation of the first geological repositories

for high-level and long-lived waste around 2020, and will facilitate technology transfer with other national programmes.

The European Nuclear Energy Forum (ENEF) provides a unique platform for a broad open discussion on the role that nuclear power plays today and in the low-carbon economy of the future. ENEF analyses the opportunities (competitiveness, financing, grid, etc.), risks (safety, waste), need for education and training associated with the use of nuclear power and proposes effective ways to foster communication with and participation of the public.

The European Energy Research Alliance (EERA) is also expected to provide opportunities for synergies and collaborative work in the area of nuclear materials. In general, cross-cutting research would benefit from more clearly defined channels of interaction, responsibilities and increased flexibility regarding funding and programming.

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11. Nuclear Fusion Power Generation

11.1. Introduction

Although nuclear fusion is unlikely to be ready for commercial power generation in the coming decades, it remains nevertheless an attractive energy solution and arguably, the only truly sustainable option for large-scale baseload supply in the long-term. If the research and development in fusion energy deliver the advances predicted, then it will continue on a steady course to achieve this aim in the second half of this century.

Fusion energy's many benefits include an essentially unlimited supply of cheap fuel, passive intrinsic safety and no production of CO₂ or atmospheric pollutants. Compared to nuclear fission, it produces relatively short-lived radioactive products, with the half-lives of most radioisotopes contained in the waste being less than ten years, which means that within 100 years, the radioactivity of the materials will have diminished to insignificant levels.

Fusion energy production has already been demonstrated by the European flagship experiment, the Joint European Torus (JET).²² The next step on the path to fusion energy is the international project International Thermonuclear Experimental Reactor (ITER),²³ which is under construction at Cadarache (France), see Figure 11.1. It aims to carry out its first experiments before the end of the decade and in the following years it should demonstrate the scientific and technical feasibility of fusion energy. Europe is financing about 45 % of the total construction cost, with one-fifth of this from France as the host state and four-fifths from the EU. The remainder is split between the other six participants (China, India, Japan, South Korea, Russia and USA). The EU Council has capped the EU contribution to ITER construction at EUR 6.6 billion²⁴ for the period

2007-2020, including about EUR 600 million for associated costs. Most of the hardware is being supplied as in-kind contributions from the seven ITER Parties. Cash contributions from the Parties cover the ITER Organisation's running costs and some centralised hardware procurements. The successful operation of ITER is expected to lead to the go-ahead for the following step, a Demonstration Power Plant (DEMO), which would aim to demonstrate the commercial viability of fusion by delivering fusion power to the grid by 2050.

11.2. Technological state of the art and anticipated developments

Nuclear fusion occurs when the nuclei of atoms collide with one another and bind together. This releases large amounts of energy, which can be converted to heat and used to generate electricity as with other thermal power plants. The most efficient fusion reaction to use on earth is that between the hydrogen isotopes, deuterium (D) and tritium (T), which produces the highest energy at the 'lowest' (although still extremely high) temperature of the reacting fuels.

For the fusion reaction to occur, the nuclei need to be brought very close together. If the atoms of a gas are heated, the motion of the electrons and the



Figure 11.1: The ITER site in Cadarache (September 2011, preparatory work is well underway) [Source: ITER/Altivue]

²² <http://www.jet.efda.org>

²³ <http://www.iter.org>

²⁴ The modalities for the provision of this funding during the next Multi-Annual Financial Framework are still being developed. In the shorter term, the mechanisms by which an additional EUR 1.3 billion can be provided in 2012 and 2013 (above the originally planned amount for this period, but within the EUR 6.6 billion cap) is being discussed by the EU Council and Parliament.

nuclei will increase until the (negatively charged) electrons have separated from the (positively charged) nuclei. This state, where nuclei and electrons are no longer bound together, is called plasma. Heating the plasma further to temperatures in the range of 100-200 million °C, results in collisions between the nuclei being sufficiently energetic to overcome the repulsive force between them and to fuse. Experiments such as JET and ITER

use the favoured “magnetic confinement” approach to fusion, in which strong magnetic fields confine the plasma - no solid material is able to confine a plasma at such high temperatures. The aim is that the plasma should maintain its high temperature over long periods from the heat generated by the fusion reactions. Producing and maintaining a plasma with the necessary high temperature and sufficiently high density, is a challenging problem, requiring for example “additional heating” systems which can inject very high power into the plasma. Results from existing experiments give confidence that this can be done successfully in ITER.

The best developed magnetic confinement device is the tokamak, where a magnetic field is used to confine a plasma in the shape of a torus (doughnut), see Figure 11.2.

The Joint European Torus (JET) located in Culham in the UK, was the first tokamak in the world to be operated with the deuterium and tritium fuels. However, even the most successful experiments in JET still need more input energy than is produced by the fusion reactions. The main purpose of JET is to open the way to future nuclear fusion experimental reactors such as ITER, which will enable scientists to study plasmas under conditions similar to those expected in a future power plant. ITER will be the first fusion experiment to produce power gain, aiming for ten times more fusion power than input power into the plasma. Although the fusion power in ITER should reach some 500 MW for hundreds of seconds at a time, the investment required to produce very limited amounts of electricity is not worthwhile. Rather, the scientific and technical knowledge gained in ITER will provide the basis on which the following

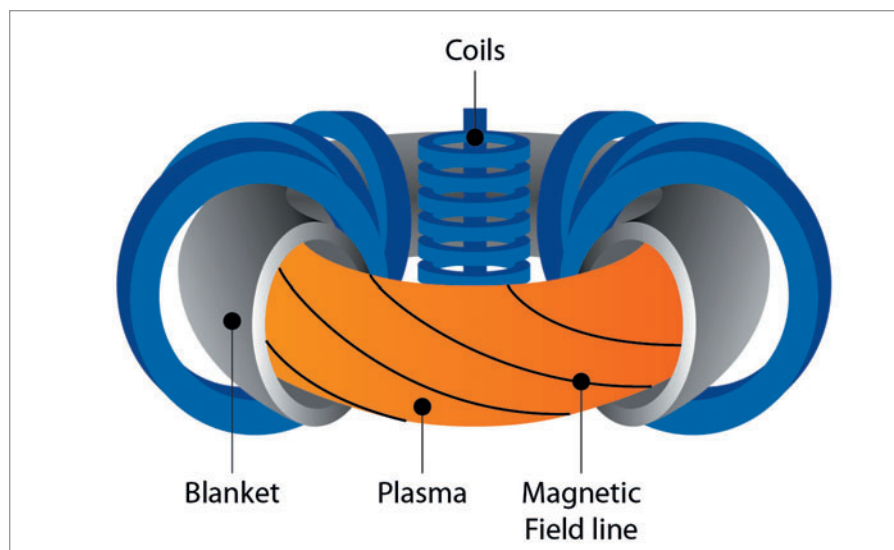


Figure 11.2: Principle of a tokamak [Source: EFDA]

step, the Demonstration Power Plant (DEMO) will be built. DEMO should operate at high fusion power for long periods, so that the demonstration of reliable electricity generation will be possible.

While ITER is being constructed and DEMO is in its conceptual phase, a number of fusion installations, with different characteristics and objectives, will continue to operate around the world to conduct complementary research and development in support of ITER. Fusion research in Europe has evolved through a number of generations of devices. Several of these, although smaller than JET and not able to operate with the real fusion fuels, deuterium and tritium, continue to make important contributions.

Outside Europe, a number of countries are pursuing the tokamak approach. Both the USA and Russia have been major players in fusion research since the early days - the tokamak concept was first developed in the Soviet Union at the end of the 1960s. Japan also has a substantial fusion R&D programme. More recently, China has shown an impressive ability to develop its fusion research capacity and has constructed a tokamak using superconducting coils to generate the magnetic fields. It started its experimental programme in September 2006. A South Korean tokamak is intended to study aspects of magnetic confinement fusion, as part of that country's contribution to the ITER effort. India is a relative newcomer to this field, but like the others, has joined ITER since it will provide the best way to move the research forward quickly with shared costs and risks.

The research into fusion devices other than the tokamak is centred mainly on stellarators, which is

considerably more complex to design and build, but which may have significant operational advantages. A large, advanced stellarator is currently under construction in Germany, and it is anticipated that its results will be used to optimise the DEMO design.

An alternative to magnetic confinement is the so-called “inertial confinement” approach to fusion in which extremely high power, short pulse lasers are used to compress a small pellet of fuel to reach fusion conditions of density and temperature. Major facilities have been constructed in France and the USA, but primarily for military purposes since the micro-explosions of inertial fusion model the processes in nuclear weapons. The lasers used in these experiments fall far short of the necessary efficiency and repetition rate which would be needed for a fusion power plant. This issue, nevertheless, will be a primary focus of an experiment being proposed in the UK, called HiPER.

In addition to the plasma devices, fusion research employs a number of facilities to study the technologies needed for fusion. The most challenging area of fusion technology is to develop materials suitable for the lining of the reactor, so-called “plasma facing” materials, which must maintain structural integrity under strong thermal and nuclear loads. In Japan, the engineering design phase of the International Fusion Materials Irradiation Facility (IFMIF) has begun. This installation, part of the “Broader Approach” Agreement between Europe and Japan, will test and qualify the advanced materials needed for DEMO and future fusion plants.

Costs

Many studies have been carried out to estimate the cost of fusion generated electricity. When trying to predict costs of power plants decades in advance, huge uncertainties are to be expected and consequently the cost range fluctuates drastically. A study by the Socio-Economic Research on Fusion (SERF) estimated a projected cost-of-electricity (COE) of €0.165/kWh [Borrelli et al., 2001], where COE is the sum of the capital costs for the fusion core (39 %) and the rest of the plant (23 %), the costs for the replacement of diverter and blanket during operation (30 %), fuel, operation, maintenance and decommissioning (8 %), assuming an annual load factor of 75 %, an operating lifetime of 30 years and a real interest rate (corrected for inflation) of 5 %, and based on expected investment costs for DEMO of roughly €10 000/kW (1995). A paper from 2002 [Cook et al, 2002] shows how the internal COE from a fusion power station depends on the extent to which the plasma physics and materials technology

of fusion are optimised as a result of further R&D. The paper shows that the projected internal cost of fusion electricity is in the range \$0.07-0.13/kWh (in 1996 dollars). It is concluded broadly that the expected internal costs of fusion electricity are competitive with typical renewables (without storage costs) and about 50 % greater than coal (without emission abatement costs) or fission.

A study by Maissonnier [2007] using a mathematical model with the latest data on costs and varying the free parameters of the design so as to minimise the cost of electricity, concluded that the costs to supply electricity from fusion varies between €0.03-0.09/kWh. This would make fusion power competitive with other sources of energy. An earlier paper by Ward [Ward et al., 2005], stated that a mature fusion technology could supply electricity in the range €0.03-0.07/kWh.

11.3. Market and industry status and potential

Fusion energy differs from all other low-carbon energy technologies, in that it will not make any viable and commercial contribution into the electricity grid until after 2050. Nevertheless, with the continued progress in ITER and the increased in-kind contributions from the partner countries, this suggests an industrial involvement would be expected, especially regarding DEMO, where it is essential that industry contributes strongly to the DEMO design team from an early stage, in addition to industry’s key role in ITER construction and operation. A timeline overview of fusion technology is shown in Figure 11.3.

Installed capacity

It is premature to speculate about the situation in 2050, but the current planning foresees fusion starting to be rolled out on a large-scale around the middle of the century. There do not appear to be any resource issues that would prevent fusion being deployed at least as rapidly as fission was deployed after the mid-20th century, given the will and the funding to do so.

Cooperation

To combat the challenges of fusion energy, the European Fusion Development Agreement (EFDA) was created in 1999 to provide a framework between European fusion research institutions and the European Commission in order to strengthen their coordination and collaboration and to participate in collective activities [Fusion news, 2009]. EFDA

is responsible for the exploitation of JET, the coordination and support of fusion-related R&D activities carried out by the Associations and European Industry, and the coordination of the European contribution to large-scale international collaborations, such as ITER. In 2006, a significant change to the structure of the European Fusion Programme was introduced. The ITER parties agreed to provide contributions to ITER through legal entities referred to as

“Domestic Agencies”. Europe fulfilled its obligation by launching the European Domestic Agency called “Fusion for Energy” (F4E), in 2007 [F4E, 2007]. In 2008, the IAEA and ITER signed a Fusion Cooperation Agreement to cooperate on training, publications, organisation of scientific conferences, plasma physics and modelling and fusion safety and security [IAEA-ITER, 2008]. Recently, in April 2011, the Domestic Agency of China signed the 54th and 55th Procurement Agreements.

Another important step was the “Broader Approach” agreement in 2009 between the EU and Japan [EU, 2007], which includes final design work and prototyping for the International Fusion Materials Irradiation Facility (IFMIF) [Ehrlich and Möslang, 1998], which will subject small samples of materials to the neutron fluxes and fluences that will be experienced in fusion power plants. The goal beyond ITER and IFMIF is to demonstrate the production of electricity in a demonstrator fusion power plant (DEMO), with its first demonstration of electricity production in about 30 years hence, after which it is hoped that fusion will be available for deployment on a large scale [Maisonnier et al., 2006].

11.4. Barriers to large-scale deployment

Fusion power is still at the research phase. Even under an optimistic scenario fusion research will need another 30-35 years or even longer until all technological and physical problems are solved. The first commercial fusion power plant is not expected to enter the energy mix before 2050.

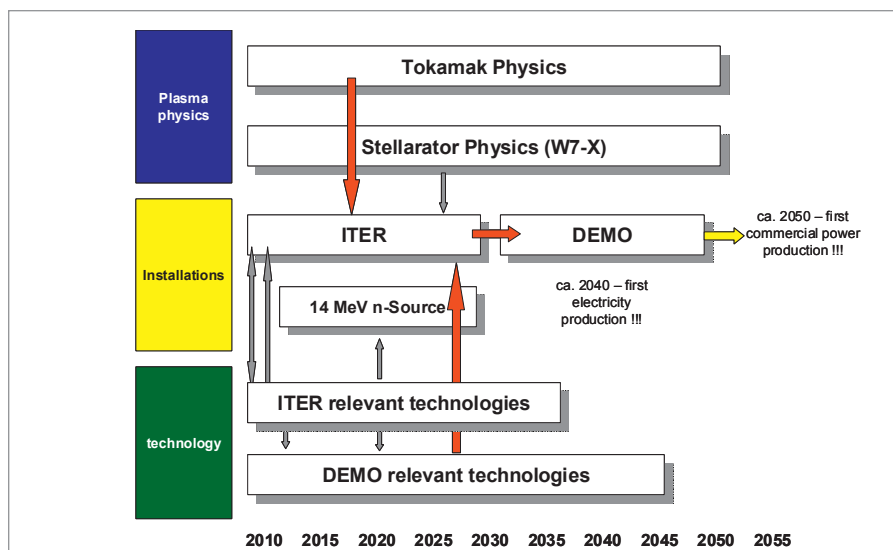


Figure 11.3: Fusion energy research and development timeline [Source: Stand der Fusionstechnik, Prof. Dr. Günther Hasinger, Max-Planck Institute for plasma physics, Garching Germany.]

There are currently no political barriers to nuclear fusion development. Public perception, in particular concerning safety and waste, will be important once a commercial plant is planned for construction. The potential for difficulties will very much depend on the reputation of conventional nuclear (fission) energy production.

Financial barriers will remain, since funding is derived from national and international sources with limited industrial contributions. As for many first-of-a-kind plants, the costs are very high, with some hundreds of millions of euro required to accelerate the research and complete the DEMO design. The Component Test Facility is estimated as a few billion euro and the cost of the planned DEMO of at least EUR 10 billion.

Scientific and technical barriers include plasma physics and materials engineering, which already figure in the Fusion Technology Roadmap. The lack of appropriate harmonised European Codes and Standards may also delay the necessary developments.

From a report by Ecorys [Rademaekers, 2010], the following question was posed “What would be the consequences if the EU withdrew from fusion research and ITER in particular?” A number of relevant points were raised:

- On the political level: the EU would lose considerable credibility at the international level by withdrawing from the ITER project. If the EU withdrew from a project which it has strongly supported in the past, the international partner countries may lose faith in the EU as a reliable partner for international cooperation;

- On the economic level: The EU would miss out on “making the last step” towards the commercialisation of nuclear fusion energy and risk wasting the investments already made;
- On the technological level: The EU would face the risk of a knowledge drain. Some of the partner countries would certainly continue to pursue commercial electricity from fusion energy and would be likely to seek to take the knowledge, including the expert scientists, away from Europe.

Lastly, as fusion is now moving from R to the R&D phase under a multi-national, multi-institutional approach, Intellectual Property Rights (IPR) is also an issue that will need addressing properly.

11.5. RD&D priorities and current initiatives

Ongoing research

Although the concept of fusion has been demonstrated there are still a number of fundamental issues relating to the physics where understanding needs to be improved [Andreani, 2000], including: plasma containment and operating modes; magneto-hydrodynamics and plasma stability; particle and power exhaust; and alpha particle physics.

One of the most important technology areas is the development of materials that can operate for long periods and extended lifetimes in the extreme conditions of thermal load and neutron irradiation in close proximity to plasma. A number of materials have been identified as candidates for future fusion power plants, but detailed experimental data is limited since there is presently no neutron source comparable to a fusion power plant. The availability of suitable materials will be an important factor determining the cost of electricity from a future fusion power station.

Another area where technology development is required concerns the part of the reactor known as the blanket. The blanket surrounds the vacuum chamber which contains the plasma and plays a vital role in fuel cycle required for a reactor to maintain continuous fusion and production of power. The neutrons produced in the fusion reaction are absorbed in the blanket and react with lithium contained within it to produce tritium which re-enters the plasma and sustains the fusion reaction. A working fluid is circulated around the blanket. This working fluid transfers the heat energy produced to

the electricity generating equipment (known as the balance of plant). Identifying and refining the steels required to produce a blanket with reasonably long life is a key challenge. The blanket will eventually degrade and need replacement due to the high neutron load and extreme temperatures it faces. Blanket longevity and ease of replacement is key to the availability, and hence cost of electricity produced, of a fusion reactor.

Another technology area that is key to minimising the down time of a fusion reactor is remote handling. This describes the machinery that is required to access those parts of a fusion reactor where it would be impossible for humans to enter due to the heat, radiation and need for cleanliness. Such entry is periodically required to replace and service components.

Beyond ITER

ITER is the bridge towards a plant that will demonstrate the large-scale production of electrical power and tritium fuel self-sufficiency. The next step after ITER is DEMO. This first demonstration of electricity production is expected in the next 30 years, with fusion then becoming available for deployment on a large scale. Nevertheless, there are still many issues and challenges to be resolved, such as those around reliability.

It is also under serious consideration that electricity production could be demonstrated sooner, within the next 25 years, by a relatively modest ‘Early DEMO’ or ‘EDEM0’ plant. It would not be required to produce electricity at a stipulated cost and would use known materials that are expected to survive under fusion power plant conditions. This approach may gain the interest of industry earlier by demonstrating fusion feasibility.

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12. Smart Grids

12.1. Introduction

Smart grids are seen as key enablers for the future deployment of sustainable energy, particularly in the context of satisfying the European Union's (EU) targets for 2020 and beyond. In particular, the share of variable renewable energy sources (RES), such as wind, solar, wave and run-of-the-river hydropower, is predicted to be in excess of 20 % of the total power generation in 2030 [EC DG ENER, 2009]. Moreover, smart grids allow for increased energy efficiency - a requirement for the future power system. Another important aspect is the enhanced security of supply with less dependency on external energy resources. Within this framework, smart grids provide critical options for the development of the present and future European energy infrastructure [European Commission, 2010a]. Smart meters, which provide utilities with a secure, two-way flow of data, are a key component of a smart grid, but alone do not assure its development.

The electricity network is usually divided into the longer distance and higher voltage transmission network and the medium distance and lower voltage distribution network. Consequently, synergies in the evolution towards a smart distribution grid and to a smarter transmission network are important, especially within the current context of steep changes at the distribution level, simultaneous with the introduction of some new technologies at the transmission level. Therefore, in order to take advantage of these synergies, the coordination of their evolution is a major stepping stone.

12.2. Technological state of the art and anticipated developments

A smart electricity grid is an upgraded electricity network that can intelligently integrate the actions of all users connected to it (producers, consumers and the so-called prosumers (producers-consumers), in order to ensure economically efficient, sustainable power systems with low losses and high levels of quality and security of supply and safety [SmartGrids ETP, 2010a]. A smart grid needs to employ advanced metering and communication technologies in order to accommodate the dynamic behaviour of end users [European Commission, 2011b]. This integration allows features such as demand side management, smart active protection of the network, energy savings and cost reduction.

Smart grids are under development. Most of the projects on smart grids developed in Europe

are at the research and development stage. These projects have been initiated to reshape the networks involved, while illustrating the sustainable, economic and secure benefits resulting from smart grids. Nevertheless, several of the components of the smart grid are undergoing commercial deployment. This is the case, for instance, of distributed generation and smart metering (European Commission DG JRC and DG ENER, 2011).

Furthermore, smart grids support the development and thus the unbundling of the electricity markets, supporting the involvement of all the stakeholders, down to the consumer/prosumer level in the energy issue. Moreover, it creates a platform for the existing and future entrants in the market to develop innovative energy services, while fostering the competitiveness and worldwide technological leadership of the EU technology providers (European Commission, 2011b).

Further deployment of distributed generation

One of the drivers of smart grid deployment is the optimal integration of distributed generation (DG), as well as of distributed energy storage systems (DESS) and demand side management (DSM) systems. These three technologies are usually grouped under the name of distributed energy resources (DER). DG is mostly based on medium or small power plants, whether they are generated from renewables or not. The access to the distribution networks for DER in general and DG in particular is still largely based on the "fit and forget" principle. The units are allowed to connect/operate without an accurate and continuous control of their impact on network operation. Even if a certain amount of DER can be accommodated by today's distribution system, their massive deployment calls for a new operation philosophy, revised design criteria and upgraded architecture concepts. In order for DER units to reach significant penetration levels and to cover a substantial amount of demand, they need to be fully integrated into the system management. Hence, a future prerequisite for their development will be the inclusion of DER in system control and in provision of ancillary services including reserves, similar to large conventional power stations.

Denmark, a forerunner in this field, has more than 50 % of its total electricity capacity based on DG [Lopes Ferreira et al., 2011a]. This situation poses interesting challenges also due to the variability of its output. The Danish 'Cell project' addresses this issue by actively controlling both the production and load, supporting islanding mode (meaning that

local distribution networks have the capability of working independently of the transmission network) and black start mode (the capability to support the restart of the transmission network in case of black out) [Ackermann et al., 2011]. Also in Denmark, several projects are being tested on Bornholm Island by using its “real power system for research, development and demonstration activities of the future smart grids” [Østergaard and Nielsen, 2010]. These projects are paving the way for designing concept cases for smart grid networks.

Distributed energy storage systems (DESS)

The development of cost-effective and coordinated high-power energy storage systems will also play a vital role in facilitating a larger penetration of DER by decoupling energy generation and use. Energy storage has a wide range of applications such as congestion relief, network upgrade deferral and variable renewables grid integration [Lopes Ferreira et al., 2011b]. Further information on energy storage technologies is provided in a Chapter 16 in this Technology Map.

Electrical vehicles (EV)

Electrical vehicles will not only affect energy consumption, as they can also be used as a storage medium in a concept commonly referred to as vehicle-to-grid (V2G). A project that is expected to present results soon is the “*Greening European Transportation Infrastructure for Electric Vehicles*”, which intends to deploy the first battery switch stations in Europe – one in Copenhagen and another in Amsterdam [TEN-T EA, 2010]. The expected massive roll out of electric mobility in Europe, as described in [European Commission, 2011a], will be a major driver for the deployment of smart grids, not least due to the increased potential of intelligently balancing the network. In a smart grid environment, electrical vehicles can be used to flatten the daily consumption load curve, which increases the overall efficiency of the system.

Power electronics

Flexible AC Transmission Systems (FACTS) are advanced power electronics devices that allow increased efficiency at several levels (e.g. transmission capacity, power flow control, loss reduction, voltage support) [REALISEGRID, 2010]. FACTS devices are suitable and deployed at the transmission level and are in the process of being deployed also at the distribution level under the designation of D-FACTS or Custom Power. One of the most promising devices of the D-FACTS family is the D-STATCOM (Distribution Static Compensator) [Chong et al., 2008].

In terms of synergies between technologies, the case of the joint deployment of energy storage and FACTS is well documented. This synergy allows the optimization of the power transfer capacity ratings and higher flexibility in the network [Ribeiro et al., 2000].

Another relevant technology in the area of power electronics is High Voltage Direct Current (HVDC) transmission, which is mostly used at transmission level. HVDC has advantages over high voltage alternating current in terms of long distance and underwater transmission, such as enabling no limitation in line length, increase in transmission capacity, quick and bidirectional power flow and no increase of short-circuit power at the connection points [REALISEGRID, 2010]. HVDC, both point-to-point and the under-development multi-terminal HVDC, are building blocks needed for the development of super grids and offshore wind farms.

Role of information and communication technology (ICT)

ICT is essential for the deployment of smart grids, since it empowers the effective communication between all connected actors and components. It encompasses smart metering, telecommunication and remote control technologies, allowing a more secure and reliable grid operation with increased share of DER. An enhanced data exchange, with dedicated ICT platforms supervising the information flows between the electricity system players, may strengthen the capabilities of real-time trading, fault prevention, asset management, generation control and demand side participation.

SCADA (Supervisory Control and Data Acquisition) systems have been part of the electrical system for decades. The evolution towards smart grids will require a more integrated usage of these systems, with the necessary adaptations and connections at the distribution level. The trend towards massive deployment and control of industrial and residential generation, in combination with demand-side participation, requires new means and ways for operating the power systems. Key challenges are power flow controls, the prevention of disturbances and enhanced operational security.

Other technologies used at transmission level are synchronized phasor measurement units (PMUs) and wide area monitoring systems (WAMS). PMUs are used to measure the synchronised voltage and current in a system. The synchronisation is achieved by using Global Positioning System (GPS) satellite signals. WAMS use a SCADA-based approach

to perform dynamic measurements using PMUs together with added features, such as stability assessment and stabilisation algorithms [Bertsch et al., 2003].

The main protocol currently used for communication in SCADA systems is the International Electrotechnical Commission's 61850, which sets the standards for communication and control for electric power systems [IEC, 2011]. Based on these standards, and taking advantage of remote sensing capabilities, smart protection systems based on power electronics are being developed. These protection systems are a necessity due to the emergence of inverted flows between transmission and distribution that, in situations of significant deployment of DER, can sometimes occur. This development is expected to foster the deployment of future smart grids.

Deployment of smart metering

Smart metering allows, on the one hand, the consumers or producers-consumers (prosumers) to have a greater awareness of their consumption, which in turn results in a consumption decrease. Several projects confirm this finding in the locations where it has been installed [European Commission, 2011b]. Smart metering allows system operators to perform "quasi real-time" measurements of the consumption levels, empowering the optimisation of the system.

Installation of smart meters coupled with DSM enables the rationalisation of energy consumptions, supporting a more responsive and flexible load. DSM will take an important role on load shifting and peak shaving in the future smart grid; however it demands bidirectional communication and a partial control of some of the customer resources, usually heavy loads. This control can be limited by contractual arrangement to a few times per year. The deployment of DSM will be an important step for the economically sustainable power balancing of the future smart grids, particularly in extreme situations.

Smart grid architectures

Smart grids include innovative architectures such as active distribution networks, microgrids and virtual power plants. These have different characteristics, which may sometimes overlap.

An active distribution network presents, with due differences, a structure similar to the one

of a transmission network. It includes DG, ICT technologies, appropriate protection schemes and power electronics, such as D-FACTS.

A microgrid includes, besides the technologies referred to earlier on active distribution networks, distributed energy storage and demand side management. These networks present black start capability and/or intentional islanding mode features [SmartGrids ETP, 2007].

Virtual Power Plants (VPP) can be divided into two subtypes. The technical virtual power plant (TVPP) uses resources either physically connected by the local distribution network or located in the same geographical area. The commercial virtual power plant (CVPP) integrates resources that can be more dispersed and may even be linked to each other only at the transmission level, being thus housed in separate distribution networks. It can also aggregate several TVPPs. The main objective of a CVPP is power market access, providing visibility to distributed energy resources and maximisation of the revenues for the involved players [Fenix, 2009].

Standards

In order to cope with the challenges of an increasing deployment of innovative technologies and to foster the interconnectivity between these technologies, the European Commission has mandated the European standardisation organisations, i.e. CEN, CENELEC and ETSI, to adopt a set of standards for smart grids. Resulting from the mandate M/490, these standards will be a key step for the deployment of smart grids in Europe [CEN/CENELEC/ETSI, 2011]. Moreover, they will allow the clarification of issues such as business models, privacy and the architectures of both the electrical networks and of the information and communication technologies.

12.3. Market and industry status and potential

To upgrade and modernise the European network, conservative estimates forecast an investment need of EUR 56 billion by 2020,²⁵ EUR 390 billion by 2030 and EUR 480 billion by 2035, respectively [EURELECTRIC, 2011b; IEA, 2010].²⁶ However, up until now, the preliminary overview of the level of investment in RD&D projects accounts for just over EUR 5.5 billion, around 10 % of the previously

²⁵ <http://www.pikeresearch.com/newsroom/lithium-ion-batteries-to-become-a-1-billion-segment-of-the-stationary-energy-storage-industry>

²⁶ <http://www.smartgrids.eu/>

mentioned value [EC DG JRC and DG ENER, 2011]. Figure 12.1 shows the distribution of this investment across the Member States. More than half of the EUR 5.5 billion (3.0 billion) has been invested in the deployment of smart metering, involving the installation of 40 million devices, which would appear to be the first significant step towards the roll out of smart grids in Europe.

Within the funding programmes of the EU, a special focus has been given to the SET-Plan European Electricity Grid Initiative (EEGI) with an estimated overall budget of EUR 2 billion for the period 2010-2018 [EEGI, 2010].

From the above paragraphs, it is apparent that the industry has been maturing and expanding over recent years. It has been possible to see the increasing interest of multinational companies in these technologies and their apparent availability to participate in the commercial deployment. Moreover, the first commercial deployment steps are already visible in Europe, usually in portions of the network with particular characteristics, such as remote islands electrical systems. Malta,²⁷ Greece (Aegean Sea islands) [Chatzimpiros, 2011] and France (ultramarine possessions) [Rioual, 2011] are among the forerunners in this approach. Moreover, the inclusion of these technologies in larger systems, taking advantage of synergies with the transmission network has increased as witnessed in the UK [Lippert, 2011] and Denmark [Ackermann et al., 2011]. Finally, in recent years, advanced metering systems and demand side management, such as

the ones in the Netherlands²⁸ and Portugal,²⁹ have started to be deployed. These two technologies are amongst the ones expected to flourish in the short term.

Another important component for smart grids is distributed generation (DG). DG output is not constant as it may vary with natural resource changes or with the thermal output desired for combined heat and power (CHP) systems. The integration of these variations is one of the main technical drivers for the further deployment of smart grids. Amongst the DG technologies, wind generation³⁰ and CHP technologies are mature technologies, having a high (although not uniform) deployment in the EU-27. Moreover, photovoltaic deployment worldwide has been exponential in recent years, seeing an increase of 132 between the years 2009 and 2010 [REN21, 2011].

As far as the storage market is concerned, there is a wide range of applications and technologies.

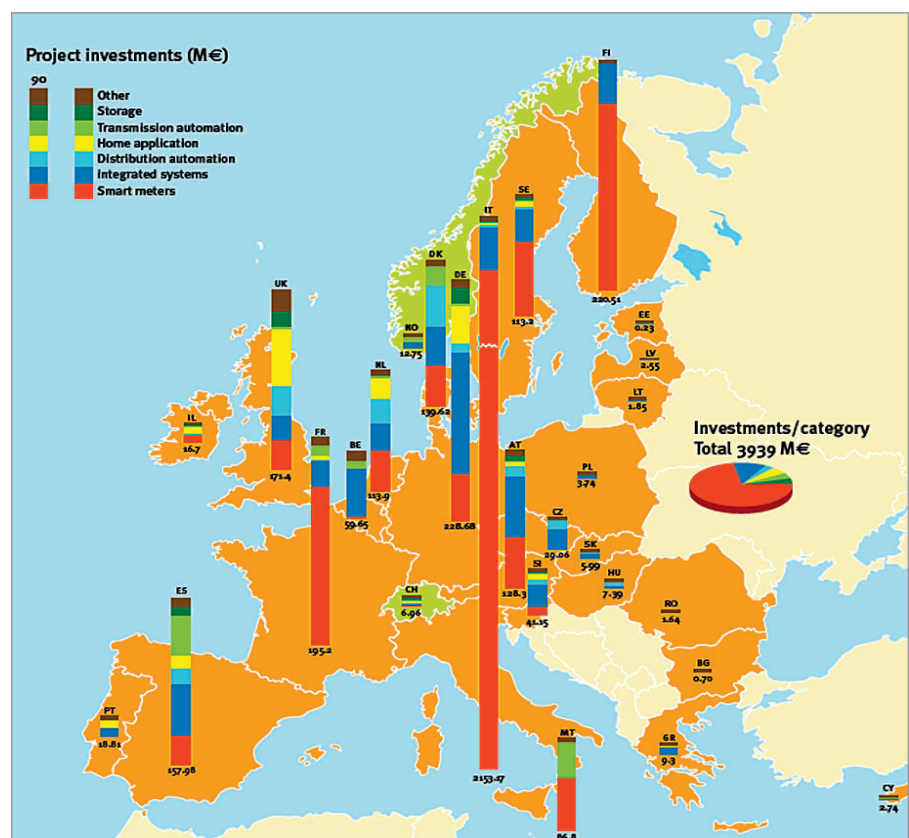


Figure 12.1: Project investments in Europe [Source: EC DG JRC and DG ENER, 2011]

²⁷ <https://mitc.gov.mt/page.aspx?pageid=263&lid=1>

²⁸ www.amsterdamsmartcity.com

²⁹ <http://www.inovcity.pt/en/Pages/homepage.aspx>

³⁰ It has to be noted however, that with the increasing size of wind turbines and wind farms, these are becoming more and more connected at the transmission level. The ones connected at DG level are medium- and small-sized power plants.

Consequently, several numbers for the dimension of this market exist in the literature, which vary depending on the application and/or technology analysed. For instance, the utility market for stationary batteries is predicted to be EUR 5.74 billion by 2018.²⁵ With DG arriving at unprecedented deployment levels throughout Europe, it is expected that storage systems will be used to balance DG output variations and provide ancillary services directly at the distribution level.

In the particular case of smart metering, the last 10 years have seen different projects carried out in Europe. From Telegestore in Italy to Inovgrid in Portugal, the smart metering systems have become more ambitious and flexible. The Telegestore project concerns the installation of more than 32 million meters [Battocchi, 2011] supporting customer care improvement, fraud reduction and diagnostic acquisition. The intention of Inovgrid is to go further, deploying a fully active distribution network and allowing an increased penetration of RES.³¹ These steps go in the direction of the EU-27 goal of reaching the minimum target of 80 % of consumers equipped with smart meters by 2022 as set in point 2 of Annex I of the Directive 2009/72 [European Parliament and Council, 2009].

In terms of power electronics, among the several FACTS and HVDC technologies, it is possible to identify devices that present a high potential of commercial deployment, such as D-STATCOM. Multi-terminal HVDC is a technology under development and will be a major advancement for the roll out of offshore wind farms.

12.4. Barriers to large-scale deployment

Whilst smart grid deployment is at its first stage in Europe, stakeholders and market players perceive multiple uncertainties and barriers.

Technically, the need for standards constitutes one of the main barriers. Prior to embarking on a massive production of smart meters, ICT technology and smart devices, the smart grid industry needs standards that guarantee interoperability and open market competition, and even more, that ensure uniform levels of protection against threats as well as fast responses to cyber and physical attacks.²⁶ In particular, improved data exchange security, privacy and data protection issues need

to be rapidly addressed [SmartGrids ETP, 2010b; T&D Europe, 2011]. As mentioned before, European standardisation organisations have published recommendations for the development of a set of standards for enhanced interoperability and the implementation of a high level of smart grid services and functionalities [CEN/CENELEC/ETSI, 2011].

The regulatory framework is also perceived as a significant barrier to the large-scale deployment of smart grids: it is generally agreed that a stable and predictable regulatory context would allow, amongst others, the development of a sound financing environment for smart grid initiatives [EURELECTRIC, 2011a]. This would also pave the way for new business models involving wider participation of consumers and prosumers in the market. Uncertainty and the need to build confidence in future business models may therefore be another consequence of a regulatory framework that presents space for a future inclusion of smart grid features. Presently, the regulation concerning network management and operation is being developed involving the European Agency for the Cooperation of Energy Regulators (ACER), for the sake of interoperability (ACER, 2011), coping with issues such as network guidelines for congestion management and market balancing. Moreover, a debate concerning the control of the different assets involved is on the rise amongst several market stakeholders. Furthermore, regulation can also mitigate the impact of high level initial costs, which hinder the short term deployment of smart grids, due to, among others, the traditional conservative approach from utilities. To solve this issue, a more secure investment environment for utilities involving quantifiable benefits, including revenues coming from grids enhancement, would be helpful.

Social barriers, besides technological and regulatory barriers, aggravate the general situation. If, on the one hand, there is a need for information about smart grids and their features that can trigger consumer awareness and engagement which, in turn, can enable faster and more effective deployment of smart grids. As an exemplary initiative, a smart grid contest was launched in 2011 to “accelerate and encourage open innovation and build up the international Smart Grid community”.³² On the other hand, concerns about consumer protection, both in terms of privacy and of security, need to be taken into consideration. On the infrastructure side, the growing acceptance difficulties for new overhead lines create concern among European grid operators. Furthermore, the expected roll out of

³¹ <http://www.inovcity.pt/en/Pages/inovgrid.aspx>

³² <http://www.smartgridcontest.com/start.php>

extensive smart grid programmes in Europe calls for a continuous development of skills and knowledge, through a wide and effective communication to the public and the workforce. As one of the several Knowledge and Innovation Communities, KIC InnoEnergy has been given the specific purpose to aggregate efforts in ensuring circulation of people and knowledge of the Energy Community. The Colocation Center Sweden, in particular, is focusing expressly on the European smart grid community.³³

Finally, efforts in overcoming the barriers perceived would be in vain without coordination among all the actors involved (policy-makers, researchers, industry and finance players, consumers).

12.5. RD&D priorities and current initiatives

In 2004, the EC set up the SmartGrids Technology Platform for “Electricity Networks of the Future” in order to bring together the smart grid community and to propose a vision “responding to the needs of customers and the delivery of European policy”. Its Strategic Research Agenda set out the following points of focus: distribution infrastructure and operation, transmission and distribution assets management, interoperability between transmission and distribution, and cross-cutting issues [SmartGrids ETP, 2007]. The main stakeholders have also presented their visions and roadmaps for the development of future electricity networks [EURELECTRIC, 2011a; IEA, 2011; SmartGrids ETP, 2007], as well as their R&D priorities [EERA, 2010; ENTSO-E, 2010b], contributing therefore to a better understanding and a better focus on RD&D priorities. An updated Strategic Research Agenda is currently under construction.

European RD&D efforts in the realm of smart grids are mainly addressed via the FP7 framework programme.

As described in the FP7 Energy Work Programme [European Commission, 2010b], for the years 2009-2013, R&D priorities focus on open standards (project OPENMETER),³⁴ networking of R&D projects (forthcoming) and coordination and integration of European R&D activities for smart grids, through the ERA Net Smart Grid network,³⁵ which specifically addresses cross-cutting issues, such as the social impact, cross-border issues, and the legal and regulatory frameworks, with the goal of establishing a durable European Research Area.

Furthermore, to support the joint implementation of research programmes, the European Energy Research Alliance (EERA) is a partnership founded in 2009 among European Research organisations for “sharing world-class national facilities in Europe and realising pan-European research programmes”. A specific Joint Programme is dedicated to smart grids [EERA, 2010].

At a more advanced development stage, nearer to demonstration, emphasis within smart grid projects is given to interactive distribution networks (e.g. ADDRESS project)³⁶ and the tools for the coordination and the reliability assessment of a pan-European electricity transmission network (PEGASE,³⁷ REALISEGRID³⁸ or TWENTIES³⁹ projects) are prioritised. Communication systems to improve automation and coordination between suppliers and consumers (e.g. OPENNODE projects)⁴⁰ or high performance computing technologies for smart distribution network operations are also supported through joint Energy - ICT calls. E-mobility projects tackling the issue of an adequate infrastructure for an accelerated roll-out of electrical vehicles (e.g. Green eMotion projects)⁴¹ are also expected to have an impact on the development of smart grids. Since 2009, selected electricity infrastructure projects with European added-value have benefited from the European Energy Programme for Recovery (EEPR) so as to contribute to the construction of the pan-European network, as a precondition for an effective internal electricity market.

A specific instrument of the SET-Plan, the European Electricity Grid Initiative (EEGI), deals with accelerating innovation and technological deployment in European electricity grids [EEGI, 2010]. The EEGI Implementation Plan 2010 builds on priorities identified by stakeholders, as, for example, the European Network of Transmission

³³ http://www.innoenergy-initiative.com/co-location_plan.html

³⁴ Open Meter for the development of an open access standard for smart multi-metering services, European Project OPENMETER, <http://www.openmeter.com>

³⁵ <http://www.eranet-smartgrids.eu>

³⁶ <http://www.addressfp7.org>, for active distribution networks with large-scale penetration of renewable and distributed energy sources

³⁷ <http://fp7-pegase.eu>

³⁸ <http://realisegrid.rse-web.it>

³⁹ http://cordis.europa.eu/fetch?CALLER=FP7_NEWS&ACTION=D&DOC=9&CAT=NEWS&QUERY=01294602ec37:aebc:03822462&RCN=32201

⁴⁰ <http://www.opennode.eu>. For open architectures for smart grids

⁴¹ European Project Green eMotion, 2011-2015. <http://www.greenemotion-project.eu>

System Operators for Electricity (ENTSO-E)'s ten-year Network Development Plan and the European Distribution System Operators for Smart Grids (EDSO₄SG)'s vision [ENTSO-E, 2010a].⁴² Emphasis is given to the need for coordinated efforts in RD&D and mostly to concentrate on the development of a pan-European electricity grid with a sound architecture, demonstrated technologies, improved network management and control and new market rules for an increased integration of renewable and distributed energy sources. Demonstration projects are also deemed necessary at the distribution level for an increased integration of smart customers, development of smart metering infrastructure, integration of renewable and distributed energy production and the improvement of the management and control of networks. Coordinated projects between transmission system operators and distribution system operators are also prioritised. Most FP7 projects also support the EEGI.

EACI, the European Executive Agency for Competitiveness and Innovation, through its Competitiveness and Innovation Programme: Intelligent Energy Europe, addresses non-technical barriers to energy efficiency and renewable integration.⁴³ In 2011, actions aiming at simplifying procedures for grid development to deliver more renewable energy and to integrate more energy efficiency have been supported. For example, the European Smart Metering Alliance for increased energy efficiency from greater use of smart metering installations across Europe has been funded under this scheme.⁴⁴

As far as human capital development is considered, the Knowledge and Innovation Communities aim at "turning ideas into solutions and into products"

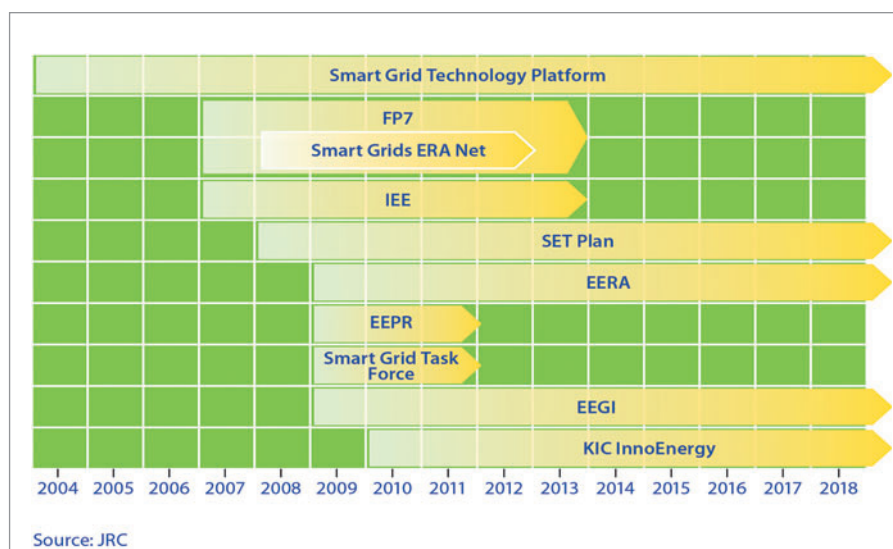


Figure 12.2: Overview of electricity grid initiatives at the EU level [Source: JRC]

through joint ventures between the European Institute of Technology and European partners, by financing business-oriented education programmes. The Swedish Centre, coordinating the Smart Electric Grid and Electric Storage activities in 2010, focused on power systems from producer to consumer, ICT for smart grids, controllable and intelligent components and electrical energy storage and materials.³³

Consistent efforts in ensuring timely and effective dissemination of information are carried out by the SET-Plan Information System.⁴⁵ SETIS is also contributing to coordination between EU and national efforts and initiated the mapping of SET-Plan relevant national R&D activities. Smart Grid Pilot Projects have also been collected by EC-JRC into a Catalogue [ENTSO-E, 2010b; EC DG JRC and DG ENER, 2011].

A summary of the initiatives referred to and their timeline are shown in Figure 12.2.

⁴² <http://www.edsoforsmartgrids.eu/>

⁴³ http://ec.europa.eu/energy/intelligent/index_en.htm

⁴⁴ <http://www.esma-home.eu/>

⁴⁵ <http://setis.ec.europa.eu/>

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13. Bioenergy - Power and Heat Generation



13.1. Introduction

Bioenergy is expected to have an important role within the EU's key ambitions to develop a low-carbon economy. Different bioenergy pathways are at various stages of maturity from RD&D to commercial stage and new technologies are expected to enter the market soon. According to the forecast of the National Renewable Energy Action Plans, prepared by the Member States under the requirements of the RES Directive 2009/28/EC, biomass is expected to maintain a major role in the renewable energy consumption (57 %) at the European level in 2020, compared to 62 % in 2005. Bioenergy production is expected to increase from 61.7 Mtoe in 2005 to 140 Mtoe in 2020.

RES electricity production will reach 1 217 TWh, representing about 34 % of electricity production in 2020. The contribution of bioenergy to electricity generation in 2020 is predicted to be 232 TWh, equal to 19 % of RES electricity, compared to 14 % in 2005.

RES heating and cooling will contribute about 112 Mtoe in 2020, representing about 21 % of the heating and cooling consumption, compared to almost 10 % in 2005. Biomass will remain the dominant fuel for heating and cooling, contributing about 90 Mtoe in 2020, compared to 52.6 Mtoe in 2005, and providing a share of more than 17 % of heating and cooling and 81 % of RES heating in EU-27.

13.2. Technological state of the art and anticipated developments

There are several conversion technologies at different stages of development based on thermo-chemical (combustion, pyrolysis and gasification) and biochemical/biological (digestion and fermentation) processes. A wide range of biomass materials can be used to produce energy: wood, wood residues, forest residues, agricultural residues (straw, animal manure, fruit stones, prunings, etc.), residues from food and paper industries, the biodegradable fraction of municipal solid wastes (MSW), sewage sludge and dedicated energy crops, such as Short Rotation Forestry/Short Rotation Coppice (SRF/SRC), e.g. willow, poplar, eucalyptus and energy grasses, e.g. miscanthus, reed canary grass and switchgrass. However, biomass shows a large variability of physical and chemical properties, making handling, transport, storage and feeding systems more complex and more expensive than for fossil fuels. Additional pre-treatment might be

required to meet the quality requirements of many conversion technologies. There is rapidly increasing use of pellets and briquettes. A wide variety of products are also possible, including energy as well as biofuels and platform chemicals. Biorefineries are a rapidly emerging concept in which all residues are valorised and the economics of bioenergy or biofuel production can in principle be made viable thanks to high value non-energy products. A number of the technologies described below are included in the "Value Chains" of the European Bioenergy Industrial Initiative (EIBI) which aims to provide a "push" towards commercialisation.

Economically, most biomass technologies have difficulties to compete with fossil fuels for a number of reasons, mainly related to the level of maturity of technology and the cost of biomass feedstock. However, substantial operational experience is being gained and production costs are being reduced. Some bioenergy options, such as large-scale combustion of residues, are already providing energy at a competitive price, as well as small-scale pellet boilers in residential applications.

Biomass combustion

The technologies in use are largely based on mature direct combustion boiler and steam turbine systems. The products are heat, electricity or Combined Heat and Power (CHP) at small- and large-scale for residential and industrial applications. Key sectors for biomass combustion and co-combustion are the pulp and paper, timber processing and waste incineration industries and power generation. However, the scale of biomass CHP plants is often limited by local heat demand and by its seasonal variation, which can significantly affect economic performances. Technology development has led to efficient, industrial-scale heat production and District Heating (DH) systems, with efficiencies of 70-90 %. Biomass-based DH provides a significant share of the heating requirements in some Member States, e.g. Sweden, Denmark and Austria. Although a proven technology, the economics for biomass-based DH depend on a number of complex techno-economic parameters, not least the existence of a DH infrastructure and a reliable source of biomass supply. Moreover; in future, there is a trend to hybridisation of technologies, i.e. to combine bioenergy equipment with solar systems and heat pumps. District cooling systems, in combination with heat and electricity production, i.e. tri-generation, could provide an efficient way of providing cooling and improve the load factor and the economic viability of biomass CHP, particularly in warm regions.

Traditional household heating systems using wood logs have low efficiency (10-30 %) and emit high levels of particulate matter. Modern wood chips and pellet boilers have efficiencies as high as 90 %. The market for biomass pellets in the EU is expanding, with a capacity of 15 Mt/yr in 2008. Pellets are used in automated small- (< 25-30 kW), medium- and large-scale (< 500 kW) residential and commercial boilers for heat, power and CHP production. Biomass combustion using fixed grate, travelling grate and fluidised bed boilers is suitable for a large range of capacities, from very small (a few kW) to large-scale power plants of ~100 MW_e. Electric efficiency varies depending on the plant capacity between 15-30 % for 1-30 MWe installations. Corrosion, particularly when burning high chlorine-containing waste feedstock, is usually the reason for the low efficiencies achieved compared to fossil fuel systems.

The capital costs of a biomass heat plant range from €300 to €700/kW_{th}. CHP plants have typical capacities of 1-50 MW_e with overall efficiencies of 80-90 % and investment costs of €1 000-2 500/kW_e for 5-25 MWe, while electricity-only plants have 10-50 MW_e capacity with 25-35 % electrical efficiencies and investment costs of €1 000-1 500/kW_e [Thornley et al., 2009]. Fluidised bed combustion (FBC) permits higher electrical efficiencies of 30-40 % at relatively low specific investment cost in the range €2 500-3 500/kW_e [Faaij, 2006; Bauen et al., 2004; Siemons, 2004; Van Tilburg, 2008; Thornley et al. 2009]. Higher efficiencies are obtained with plant capacities above 100 MWe and in biomass co-firing in coal power plants [Faaij, 2006; Brown et al., 2006; Bridgwater, 2002, Fagnäs et al., 2006; Koop et al., 2010].

Incineration of MSW is a mature technology with very effective emissions control. Boiler corrosion problems limit the steam temperature and reduce electrical efficiency to typically less than 25 % with MSW. New CHP plants using MSW are expected to reach 26-30 % electrical efficiency and 85-90 % overall efficiency in CHP mode [IEA, 2007; Koop et al., 2010].

The Stirling Engine (10-100 kWe) and the Organic Rankine Cycle (ORC) (50-1 500 kWe) are promising technologies for future small-scale and micro-scale CHP distributed cogeneration. Stirling Engine technology is currently at the pilot-to-demonstration stage, aiming to surpass historically achieved efficiencies of greater than 30 % in the last century. The Organic Rankine Cycle (ORC) engine can offer technical and economic advantages for small plant capacities and low operating costs. However, electric efficiency is limited to about 16-20 % (due to low operating pressure), and specific investment costs are high (between €6 000-9 000/kW_e). The biomass ORC process has been demonstrated and is now commercially available [Liu et al., 2009; Wood and Rowley, 2011; Koop et al., 2010].

Biomass plants, using complex treatment, handling and feeding systems for “difficult” forms of feedstock require higher capital and operating costs. Such plants are cost effective only when the biomass is available at low costs, and/or when carbon tax or incentives are in place. The use of higher performance cycles (higher steam temperature and pressure, and reheat and regenerative steam turbines) could significantly increase energy conversion efficiency provided that fouling and corrosion can be avoided.

Biomass co-firing

Biomass co-firing with coal in existing boilers is the most cost-effective and efficient option of heat and electricity production from biomass. This is an attractive option for GHG emissions mitigation by substituting biomass for coal. Direct co-firing with up to about 10 % biomass (energy base) has been successfully demonstrated in pulverised fuel

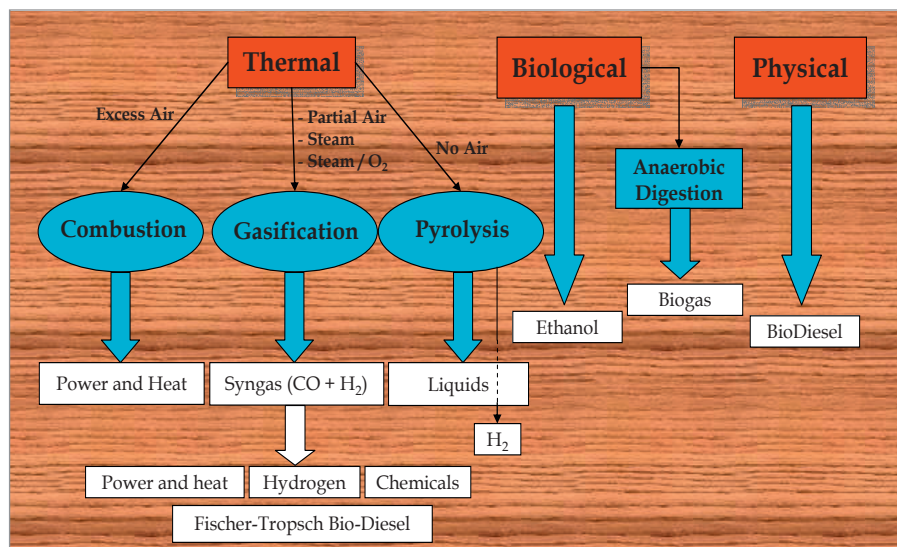


Figure 13.1: Options for selection of bioenergy processes [Source: JRC]

and fluidised bed boilers and with a wide range of biomass feedstocks (wood and herbaceous biomass, crop residues, and energy crops), although feeding, fouling and ash disposal pose challenges that reduce reliability and lifetime of coal plants. Biomass co-firing with coal in large-scale coal plants has significantly higher electrical conversion efficiency (35-45 %) than dedicated biomass plants (typically 25-35 %) [BOKU-IFA, 2006]. The capital cost for retrofitting an existing coal power plant for biomass co-firing is much lower than building a dedicated biomass plant, estimated at €100–250/kW_e of added biomass [Faaij, 2006; Bauen et al., 2004; Hansson et al., 2009; Thornley et al. 2009].⁴⁶

Anaerobic digestion

Anaerobic digestion (AD) is the conversion of organic material to biogas by bacteria, in the absence of air. This process is particularly suitable for a range of wet biomass feedstocks such as agricultural, municipal and industrial organic residues and wastes, sewage sludge, animal fats and slaughtering residues. There are thousands of AD plants in the EU treating wastes/residues and some use energy crops as feedstock. The product, biogas is a mixture of methane (50-70 %) and carbon dioxide with small quantities of other gasses, such as hydrogen sulphide. Cleaning of biogas is required before use as a fuel for heating or CHP. The conversion of various wastes and manure to biogas can bring significant environmental and health benefits while providing a valuable fertiliser [Eriksson and Olsson, 2007]. If properly treated, the solid residue, the digestate, can be used as a bio-fertiliser in agriculture.

Anaerobic digestion is a commercial technology. However, the economics rely on the availability of cheap feedstock, waste with a gate fee and feed-in tariffs. Biogas can be used for local heating, district heating or CHP in small capacity plants in boilers, internal combustion engines and gas turbines. Biogas can also be upgraded to natural gas quality for injection into the natural gas network as biomethane (Synthetic Natural Gas (SNG)) or for direct use as gaseous biofuel in gas engine powered vehicles. A number of upgrading technologies operate commercially, e.g. absorption and pressure swing adsorption, and new systems using membranes and cryogenics are at the demonstration stage. The capacity of biogas plants with CHP ranges from typically < 250 kW_e to > 2.5 MW_e, with conversion efficiencies to electricity

between 32 and 45 %. The capital cost of a biogas plant with a gas engine or turbine is estimated to be in the range of €2 500–5 000/kW_e [Van Tilburg, 2008; BOKU-IFA, 2006].⁴⁶ Research is being carried out (on technology optimisation, pre-treatment, etc.) to improve technical performance in an attempt to reduce reliance on economic support (e.g. feed-in tariffs).

Landfill gas utilisation

Landfill sites are a specific source of methane rich gas. Methane emissions from MSW in modern landfills would be between 50-100 kg/t [IEA, 2007]. Landfill gas contains about 40-60 % methane, the remainder being carbon dioxide and nitrogen, and trace gases, such as oxygen, water, hydrogen sulphide and other organic contaminants. Landfill sites can produce gas over a 20-25 year lifetime. Collecting this gas can contribute significantly to the reduction of methane emissions [Eriksson and Olsson, 2007] and, after cleaning, provides a fuel for heat and/or electricity production. For example, landfill gas accounted for about 3 Mtoe out of 8.3 Mtoe of biogas produced in the EU in 2009, especially in the UK, followed by France and Italy and Germany.⁴⁷ However, due to the requirements to minimise landfilling of organic waste and increase levels of re-use, recycling and energy recovery (Landfill directive 1999/31/EC), landfill gas is expected to decrease over time in the EU. The plant capacity of landfill gas collection varies from a few tens of kW to 4-6 MW, depending on the size of the landfill site. The capital cost of a plant coupled with a gas engine or turbine is estimated to be in the €1 200–2 500/kW_e range, at conversion efficiency to electricity of 25-35 % [Van Tilburg, 2008; Willumsen, 2000].⁴⁶

Biomass gasification

Gasification is the thermo-chemical conversion of biomass into a combustible gas by partial oxidation at high temperatures. Gasification is a highly versatile process and virtually any biomass feedstock can be converted to fuel gas (syngas). Biomass gasification is still in the demonstration phase and faces technical and economic challenges. There are several gasification concepts available, based on the gasification medium (air, oxygen or steam), operating pressure (atmospheric or pressurised) and type (fixed bed, fluidised bed or entrained flow). Air gasification typically produces a syngas with a relatively high concentration of N₂ and a low heating value (4-6 MJ/Nm³). Oxygen and steam gasifiers produce a syngas with a relatively high concentration of H₂ and CO and high heating value (10-12 MJ/m³ for oxygen gasification and 15-20 MJ/m³ for steam gasification). Fuel gas (syngas) is an intermediate

⁴⁶ <http://www.eubia.org/>

⁴⁷ <http://www.observe-er.org/>

product that can be used for heat and/or electricity production, or for synthesis of transport biofuels, e.g. hydrogen, methanol, DME and synthetic diesel via the Fischer-Tropsch process, SNG and chemicals production in biorefineries. Syngas can be used in internal combustion gas engines (10 kW to 10 MW) with electrical efficiency (22-35 %) or gas turbines with electrical efficiencies (up to 40 %), or in gas and steam turbine combined cycles (up to 42 %).

Typical gasification plant capacities range from small, a few hundred kW_e for heat production, 100 kW_e – 1 MW_e for CHP with a gas engine, to high capacity of 30-100 MW_e for Biomass Integrated Gasification/ Combined Cycle (BIG/CC). Fixed-bed gasification is suitable for small-scale reactors (from tens of kW_{th} to 1 MW_{th}), while fluidised bed gasification is suitable for larger scale. Atmospheric downdraft gasifiers function well up to about 1.5 MW_{th}, while atmospheric updraft gasifiers are suitable for units up to 2.5 MW_e. Bubbling fluidised bed gasifiers are suitable for up to about 25 MW_{th} and circulating fluidised beds are suitable from a few MW_{th} up to 100 MW_{th}. BIG/CC ensures high electrical conversion efficiency of 40-50 % for 30-100 MW plant capacity. In cogeneration, overall conversion efficiency can reach 80-90 % [Faaij, 2006; Bridgwater, 2002; Fagnäs et al., 2006]. Small gasifier and gas engine units of 100 – 500 kW_e are available on the market. The capital cost of a gasification plant connected to gas engines or gas turbines (250 kW_e – 5 MW) is estimated to be in the €2 100–2 900/kW_e range for conversion efficiencies to electricity of 30-40 %, falling to €1 750-2 000/kW_e for 25 MWe combined cycle [Thornley et al. 2009]. The capital cost of a biomass gasification plant with combined cycle (30-100 MW_e) is estimated at €3 500–5 000/kW_e, for conversion efficiencies to electricity of 40-50 % [Faaij, 2006; Bauen et al., 2004; Rodrigues et al., 2003].

The (BIG/CC) concept is a promising, high-efficiency technology, although more complex and costly, for syngas generation and conversion to energy in a combined gas/steam turbine cycle. A complex gas purification system is needed for hot gas particulate and tar removal. Effective removal of N, S, Cl and other trace elements (Na, K) from the raw syngas is required. Biomass gasification can also provide fuel to fuel cell systems [McKendry, 2002]. The syngas can be converted to hydrogen-rich gas which can be used in a Solid Oxide Fuel Cell (SOFC). Biomass gasification and Solid Oxide Fuel Cell (SOFC) or Integrated Gasification Fuel Cell (IGFC) conversion systems could afford high efficiency electricity production (50-55 %) [Egsgaard et al.,

2009]. However, significantly more RD&D is needed to develop, demonstrate and commercialise IGFC systems. The biomass-hydrogen route could be a promising future technology for fuel cells.

Pyrolysis

Pyrolysis is the conversion of biomass to liquid, solid and gaseous components in the absence of air at temperatures around 450-600 °C. Fast pyrolysis (at 450-500 °C) and short residence times (< 5 s), for bio-oil production (heating value of about 17 MJ/kg) is of particular interest. The conversion efficiency of biomass to bio-oil is up to 80 %. However, there are many technical challenges to the use of bio-oil in boilers, IC engines and turbines for heat and/or electricity generation. Hence, pyrolysis and bio-oil upgrading technology is not commercially available, although considerable experience has been gained and several pilot plants and demonstration projects are in operation. Research is needed on the conversion process, on the quality and subsequent use of the bio-oil, to overcome various problems related to the control of bio-oil composition, thermal stability and process reliability [Bridgwater, 2002; Fagnäs, 2006; McKendry, 2002; Laird et al., 2009]. The main challenges concern the development of new techniques and catalysts for bio-oil up-grading. Investment costs for CHP (5 MWe) from pyrolysis with IC engine or gas turbine are given as €2 100-2 400/kW_e [Thornley et al. 2009]. Pyrolysis can also be used as a pre-treatment step for biomass gasification.

Biorefineries

An option for the improvement of the competitiveness of bioenergy is to co-produce high value products and bioenergy in biorefineries. Biorefineries can produce a variety of products such as: bio-based products (food, feed, chemicals, materials) and bioenergy (biofuels, biogas, heat and/or power). Biorefineries are largely at the conceptual stage, with potentially interesting new products and routes still being identified. The deployment of the new biorefinery concepts will rely on the technical maturity of a range of processes to produce bio-based materials, bio-chemicals and energy [Van Ree and Annevelink, 2007; Cherubini et al., 2009].

Hydrogen from biomass

Hydrogen can be used to power vehicles, via fuel cells or dedicated internal combustion engines. Hydrogen is expected to play an important role in building a low-carbon economy in the long-term. There are several different routes for the conversion of biomass to hydrogen [Hamelinck and Faaij, 2002; Claassen and de Vrije, 2009; Foglia et al., 2011]. However,

they are not yet economically viable. Processes for hydrogen production is under laboratory scale development, including:

- fermentation of biomass to hydrogen (dark fermentation) or anaerobic digestion followed by methane reforming;
- gasification followed by upgrading and reforming of syngas;
- pyrolysis and reforming of bio-oil;
- direct hydrogen production in a phototrophic environment (photo fermentation) through organisms.

13.3. Market and industry status and potential

Biomass plays an important role in energy generation in the EU-27, with 6.1 % of the EU gross energy demand covered by biomass resources in 2009. The contribution of biomass was more than two-thirds (68.6 %) of all renewable primary energy consumption in 2009. Primary energy production from biomass reached 100.6 Mtoe in 2009: 72.5 Mtoe from solid biomass, 8.4 Mtoe from biogas, 7.7 Mtoe from MSW and 12.1 Mtoe biofuels. Solid biomass use for energy increased from 44.8 Mtoe in 1995 to 59.3 Mtoe in 2005, 66.4 Mtoe in 2007 and 72.5 Mtoe in 2009². Of the total biomass consumption, 53.0 % was used in 2009 for heat production, 33.8 % for electricity and cogeneration and 13.2 % for liquid fuels (Eurostat).

In the EU-27, the installed bioenergy power capacity in 2009 was 23.1 GWh, of which 14.2 GW was from wood/wood wastes, 5.8 GW MSW, 5.8 GW biogas plants and 0.9 GW liquid biofuel plants. The installed bioenergy power capacity in EU-27 is expected to reach more than 43 GW in 2020, according to the NREAPs, 30 GW from solid biomass plants, 11 GW from biogas plants and 2 GW from liquid biofuel plants. The installed capacity of biomass power plants is expected to further increase in the EU-27 to 52 GWe by 2030.

Biomass is expected to contribute to more than 57 % of the renewable energy share in 2020 according to the NREAPs. According to the NREAPs forecast, about 180 Mtoe biomass will be used to provide about 140 Mtoe as bioenergy in 2020, including biofuels. About 236 Mtoe of sustainably produced biomass could be available in the EU in 2020 and 295 Mtoe by 2030, [EEA, 2006], while, according to AEBIOM, the contribution of biomass could reach 220 Mtoe in 2020 [Kopetz, 2009].

Gross electricity production in EU-27 in 2009 reached 61 809 GWh from wood / wood waste, 25 166 GWh from biogas, 15 191 GWh from MSW and 4 681 GWh from liquid biofuels (Eurostat). According to the NREAPs, the RES contribution to electricity in the EU-27 will be 1 216.8 TWh, representing about 34.5 % of electricity production in 2020. The contribution to electricity made by bioenergy will be 231 971 GWh in 2020, representing 19 % of RES electricity.

The market for renewable heating (biomass, solar thermal and geothermal) has a substantial potential for growth since the heating and cooling sector represent between 45-50 % of the final energy consumption. Biomass consumption for heat generation increased from 40 Mtoe in 1997 to 51.2 Mtoe in 2002, 61.5 Mtoe in 2007 and 70 Mtoe in 2009. The biomass heat represented 12.5 % of 512 Mtoe of total heat generation in the EU in 2009. In EU-27, only 1.5 % of the heat demand is covered by district heat coming from biomass and biomass share in the district heating was about 16 % in 2009 (Eurostat). Denmark, Sweden and Finland have all a well-developed district heating sector, accounting for almost 50 % of the heating market. The use of biomass for district heating has been expanding and biomass and waste contribute about 62 % of district heating fuel in Sweden, 30 % in Denmark and 18 % in Finland [Scarlat et al., 2011].

Renewable heating and cooling will make a total contribution of almost 112 Mtoe in 2020 in the EU, according to the NREAPs. Biomass will still have the major contribution of 81 % (~ 90 Mtoe) for heating and cooling in 2020, of which, solid biomass will provide 81.0 Mtoe, biogas 4.5 Mtoe and bioliquids 5.0 Mtoe. The contribution of biomass used in households is expected to have a moderate increase from 27.0 Mtoe in 2005 to 35.0 Mtoe in 2020, to represent almost 38 % of the biomass used for heating compared with 26 % share of biomass used in households. The contribution of biomass from district heating plants is expected to increase more than three-fold. District heating using biomass will increase from 5.8 Mtoe in 2005 to 17.8 Mtoe in 2020.

13.4. Barriers to large-scale deployment

The main barriers to widespread use of biomass for bioenergy are cost competitiveness with fossil fuels, low conversion efficiency for some, particularly combustion technologies, and feedstock availability at low cost. Deployment of bioenergy requires demonstration projects at a relevant scale, which will be costly but crucial for improving and verifying

technical performance and to achieve cost reduction. This is one of the key aims of the European Bioenergy Industrial Initiative (EIBI).

Sustainable biomass production and reliable supply of large quantities of feedstocks is a critical factor for large scale deployment of bioenergy technologies. Energy crops (e.g. SRC/SRF and energy grasses) with high yields could increase biomass supply provided that land-use issues can be adequately addressed. Various concerns were recently expressed on several sustainability aspects. Water availability is also an important issue to consider and might have a large impact on future biomass availability. Biomass certification is expected to play a positive role addressing these issues [Scarlat and Dallemand, 2011].

Competition between alternative use of biomass resources for food, feed, fibre and fuel is a major issue for bioenergy deployment. New technologies for the production of biofuels from lignocellulosic feedstock could also lead to competition between transport fuel and heat and power applications. Increasing demand from biomass consumers will likely lead to increased prices of biomass. A comprehensive assessment of biomass resources is needed which takes into account various environmental constraints and competitive uses.

Infrastructure and logistical planning will be needed to ensure efficient utilisation of high volumes of biomass for bioenergy. There is already a significant challenge to balance the sensitive interplay between biomass price, biomass availability for long-term supply contracts and the bioenergy plant size that will allow economic operation.

Since bioenergy technologies require significant investments, the lack of long-term policies has so far been the main factor discouraging long-term investments, and has prevented deployment at large scale. However, various Member States' schemes are now emerging following implementation of the EU renewables directive in 2009. There is nevertheless the challenge of balancing biomass utilisation and avoiding market distortion between bioenergy and other markets for wood processing, pulp and paper and bio-based materials.

13.5. RD&D priorities and current initiatives

RD&D priorities

The availability of sustainable biomass feedstocks

is a critical factor for the successful long-term development of bioenergy technologies on a large scale. More research effort should be devoted to feedstock production, including development of new feedstocks (higher yield, increased oil or sugar content, drought resistant, etc.), to increase productivity and to develop reliable supply chains. More intensive forest management, improved agricultural practices and better use of various wastes and residues would contribute to increased biomass utilisation.

Improvements in feedstock pre-treatments and supply logistics can contribute to overcome the problems related to the variability of physical and chemical properties of biomass feedstock. RD&D efforts should target the whole integrated biomass chains including efficient, sustainable cultivation, harvesting, pre-treatment, logistics, conversion and by-product use. The development of pre-treatment methods can improve biomass characteristics, increase energy density, reduce storage, transport and handling costs, and increase the conversion efficiency.

Further research is needed to improve bioenergy technologies, system integration, cost effectiveness and flexibility to use different feedstocks. Technological development is expected to improve process reliability and permit the introduction of high efficiency options such as Organic Rankine Cycles (ORC), fuel cells, advanced steam cycles and biomass gasification combined cycle systems. RD&D priorities include the development of new thermo-chemical and bio-chemical conversion processes with feedstock flexibility for different kinds of lignocellulosic biomass. Given the limited amount of biomass, the most efficient use of biomass resources should be pursued. The development of biorefinery concepts should make full use of a variety of biomass feedstocks to obtain diverse higher added value end-products.

There is a crucial need to demonstrate and scale-up bioenergy technologies to relevant industrial scales. For innovative biofuels value chains, not yet commercially available, RD&D should aim to demonstrate reliability and performance of new technologies at appropriate scale. The research should also include small/medium-scale combustion technologies, as well as micro-CHP installations.

Strict sustainability requirements could restrict biomass availability for bioenergy. Adequate sustainability requirements are critical to ensure the long-term availability of biomass and to

increase customer/public acceptance of biofuels/bioenergy production. Practical implementation of sustainability requirements must be based on relevant, transparent and science-based data and tools. It is essential to develop science-based and transparent criteria, indicators and worldwide accepted methodologies (e.g. Life Cycle Analysis) to be applied to the full biomass value chain (from feedstock production and conversion processes all the way through to end uses).

Current initiatives

The Bioenergy Technology Roadmap of the SET-Plan [European Commission, 2009b] was set up to address the techno-economic barriers to the development and commercial deployment of advanced bioenergy technologies. The Bioenergy Roadmap is based on three pillars. The first is to bring to commercial maturity the most promising technologies and value-chains for sustainable production of advanced biofuels and highly efficient heat and power from biomass at large scale. This includes optimisation of the most promising value chains, to scale up and optimise process integration, to improve feedstock flexibility, energy and carbon efficiency, and to ensure capex efficiency, reliability and maintenance of bioenergy plants. The second pillar is to ensure sustainable biomass feedstock availability, involving realistic assessment of short, medium and long term potential, development of advanced feedstock production, management and harvesting, and of the scaling up of promising feedstock options. The third pillar is to develop a longer term R&D programme to support bioenergy industry development beyond 2020. The total estimated budget for the implementation of the roadmap was estimated at EUR 9 billion over the next 10 years [European Commission, 2009b].

Based on the SET-Plan proposal [European Commission, 2007], the European Industrial Bioenergy Initiative [EIBI 2010] was established with the aim to accelerate the commercial deployment of advanced technologies to boost the contribution of sustainable bioenergy to EU 2020 Climate and Energy targets [EBTP, 2009]. The EIBI was launched in 2010 and the two specific objectives are to achieve bioenergy production costs that compete with fossil energy and to strengthen EU technology leadership for renewable transport fuels serving the fastest growing area of transport fuels in the world. EIBI focuses on innovative bioenergy value chains that could be deployed commercially, in partnership with industry. The EIBI has seven technology-based value chains:

Conversion paths based on thermo-chemical processes:

- Synthetic liquid fuels and/or hydrocarbons and blending components through gasification
- Bio-methane and other gaseous fuels through gasification
- High efficiency heat and power generation through thermo-chemical conversion
- Intermediate bioenergy carriers through techniques such as pyrolysis and torrefaction.

Conversion paths based on biological and chemical processes:

- Ethanol and higher alcohols from lignocellulosic feedstock through chemical and biological processes
- Hydrocarbons (e.g. diesel and jet fuel) through biological and/or chemical synthesis from biomass containing carbohydrates
- Bioenergy produced by micro-organisms (algae, bacteria) from CO₂ and sunlight.

Complementary measures and activities within EIBI include biomass feedstock for bioenergy and promoting longer term R&D on emerging and innovative bioenergy value chains.

The EIBI Implementation Plan for 2010-2012 describes the core activities aimed at building and operating demonstration and/or flagship projects for innovative value chains with large market potential [EIBI, 2010]. The implementation approach is to organise selection procedures for demonstration and flagship plants starting in 2011/2012. The public funding for the demonstration project will be provided as grants to be completed with public loans up to 50 % of the project cost. Public funding of flagship plants (up to 50 % of project costs) would be provided mostly as loans (e.g. by the EIB) and/or public guarantees for private loans, i.e. most part of the funding will be provided by private actors. The target is for at least one demonstration and one flagship project for each of the seven generic value chains, this would represent funding requirements of up to about EUR 2.6 billion, representing about 30 % of the total cost of EIBI over the 10 years.

13.6. References

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14. Biofuels for the Transport Sector

14.1. Introduction

Biofuels are an option to contribute to the security and diversification of energy supply, reduction of oil dependence, rural development and greenhouse gas (GHG) emissions reduction. Biofuels production provides new options for using agricultural and energy crops, agro-forestry residues and waste streams, although environmental, social and economic concerns need to be taken into account. The diversity of feedstock and the large number of production pathways render calculation of GHG performances of biofuels in comparison to fossil fuels quite complex. This is due to the fact that so far the various biofuel value chains for diesel and petrol are each only compared to a single, idealised point, while no comparison of GHG emissions of biofuels is made, for example, for diesel and petrol produced from oil and tar sands. The future of biofuels development depends to a large extent on policy support and technology deployment of new promising options using lignocellulosic biomass, aquatic biomass, etc. and to establishing a fair, level playing field with fossil fuels concerning GHG emissions calculations.

14.2. Technological state of the art and anticipated developments

Bioethanol and biodiesel are the most common liquid biofuels used in transport worldwide. Other biofuels are also in use, such as ETBE (ethyl-tertiary-butyl-ether), pure vegetable oil, hydrogenated vegetable oil (HVO) and biomethane, although

with a more limited market penetration. The production of **first generation biofuels** from crops containing starch, sugars and vegetable oils is characterised by commercial markets and mature technologies. First generation bioethanol production is a well established, mature technology, based on fermentation of starch and sugar-based crops, followed by distillation. Bioethanol is produced from a wide variety of feedstock, but is mainly produced from sugar cane (Brazil), wheat and sugar beet (EU) and maize (US). The ethanol productivity per land area in the EU is of the order of 1.0–1.5 toe ethanol/ha for cereals as feedstock and 3–4 toe ethanol/ha for sugar beet, while ethanol productivity from US maize and Brazilian sugar cane is about 1.5 and 3.5 toe /ha respectively.

Biodiesel (fatty acid methyl ester) production from vegetable oil and fats is based on a relatively simple and established technology. Biodiesel is produced via transesterification, a chemical process converting oil or fat into methyl ester with methanol and a potassium hydroxide catalyst. The feedstock can be vegetable oil, such as that derived from oilseed crops (e.g. rapeseed, sunflower, soya bean, oil palm, etc.), used oil (e.g. frying oil, etc.) or animal and fish fat. Methyl esters can either be blended with conventional diesel or used as pure biodiesel. Rapeseed is the main raw material for biodiesel production in the EU, soya bean in US and Brazil and palm oil in Malaysia and Indonesia. The biodiesel productivity per land area from different oil-seed crops in the EU amounts to 0.8 to 1.2 toe biodiesel/ha, while oil palm yields about 3.8–4.0 toe biodiesel/ha.



Figure 14.1: Inbicon Biomass Refinery at Kalundborg in Denmark [Source: Inbicon A/S]

Biofuel blending limits in the EU are set according to conventional fuel standards, designed to ensure compatibility with conventional power trains and refuelling infrastructure. Bioethanol is regulated by standard EN 228/2004 allowing up to 5 % v/v (volumetric value) blending in gasoline fuel. Bioethanol can be used in conventional petrol engines at low blends (up to 10-15 %), in Flexible Fuel Vehicles (FFV) (up to 85 %), in modified diesel engines (up to 95 %) or after being converted to ethyl-tertiary-butyl-ether (ETBE), as a petrol component (typically up to 15 %). FFVs, as commercialised in Brazil and Europe (mainly Sweden), can operate with gasoline/ethanol blended in the range 0-85 % ethanol.

Biodiesel is regulated by standard EN590/2004 allowing up to 5 % v/v blending of fatty-acid methyl ester (FAME) in diesel fuel. According to the manufacturers, the latest generation of diesel engines equipped with sophisticated after-treatment technologies (DPF, SCR,...) cannot tolerate more than 7 % of biodiesel blended with diesel fuel, while in older technology engines, there are no problems with higher biodiesel contents and minor modifications may be necessary when using pure biodiesel. In general, pure vegetable oils cannot be used in modern diesel engines. They can be used in simple adapted engines, but this has a limited potential since no car manufacturer will warranty their engines with pure vegetable oil.

Upgraded biogas to natural gas quality biomethane produced through anaerobic digestion can also be used as gaseous biofuel in modified gas engines. A number of upgrading technologies operate commercially (e.g. absorption and pressure swing adsorption) and new systems using membranes and cryogenics are at the demonstration stage. Upgrading increases the methane content from typically 50-60 % in biogas to 97 % in natural gas pipeline-quality biomethane. Biomethane can also be produced synthetically from biomass gasification followed by synthesis over an appropriate catalyst (as discussed in the next session). Presently, biomethane is used mainly for heat and electricity production, although the share used as fuel gas for transportation is increasing rapidly, especially in captive fleets. The future use of biomethane use in transport will depend on policy support and whether natural gas, as a transport fuel, can further penetrate the EU market.

Recent developments in hydrogenated vegetable oil (HVO) fuels have yielded very good results showing that high quality diesel type fuel can be produced. Since 2007, HVO is already produced commercially in a refinery in Porvoo, Finland (170 000 t/year). Other refineries are planned in Singapore (800 000

t/year) and Rotterdam (800 000 t/year). This fuel is chemically almost identical to conventional diesel and requires no engine modifications.

The aviation sector is moving quickly to introduce biofuels for use in commercial flights. Aviation biofuels must comply with strict standards that do not require aircraft engine modifications. Aviation biofuels produced from HVO and synthetic kerosene, from biomass-to-liquid (BTL) type processes, are compatible with conventional fossil jet fuel (JET-A1). The International Air Transport Association IATA has set a goal to use 10 % of its fuel from renewable sources by 2017 [IATA, 2008]. The European Advanced Biofuels Flightpath Initiative plans to use 2 million tonnes of biofuels in the EU civil aviation sector by the year 2020. The portfolio of fuels should include Fisher-Tropsch diesel, HVO, upgraded pyrolysis oil and algal biofuels. Recent technology breakthroughs concentrate on converting sugars to kerosene.

The main cost component for conventional, first generation biofuels is feedstock, which accounts for 45 to 70 % of total production costs, whereas the main cost factor for advanced biofuels is capital followed by feedstock costs [IEA, 2011]. In the longer term, the volatility of feedstock prices will be more of a disadvantage to first generation biofuels than advanced biofuels. Although production costs of biofuels should fall as scale and efficiency increase. Oil prices will have an impact on feedstock and production costs. The production costs of ethanol and biodiesel currently remain higher than that of petrol and diesel, with the exception of sugarcane bioethanol in Brazil where the cost is lower. However, low cost production of sugarcane ethanol in Brazil is unlikely to be replicated in other countries due to lower crop yields and demand exceeding low-cost supply. EU producer prices in 2009 for ethanol and biodiesel were 88 €/MWh and 136 €/MWh, respectively [OECD, 2011]. These prices are forecast to increase in 2011 to 109 €/MWh for ethanol and 172 €/MWh for biodiesel [OECD-FAO, 2011]. Investment costs for a wheat bioethanol plant in the EU are about 800 - 1 200 €/kW ethanol [Punter et al., 2004; Gangl, 2004]. Investment capital costs for a biodiesel plant are about 200 - 500 €/kW biodiesel [BTN 2002; Eder and Schulz, 2006; IFEU, 2003; Kaltschmitt and Reinhardt, 1997].

Advanced ***lignocellulosic biofuels*** are expected to deliver more environmental benefits and higher feedstock flexibility than first generation biofuels, but future costs are uncertain. Lignocellulosic biofuels can be produced from agricultural and forest residues, wood wastes, the organic part of Municipal Solid Wastes (MSW) and energy crops

such as energy grasses, short rotation forestry and aquatic biomass. These feedstocks have low or no additional land requirements or impacts on food and fibre production. Relatively high energy yields (GJ/ha) can be obtained from energy crops compared to the traditional food crops. Advanced biofuel productivity is of the order of 2 to 4 toe biofuels/ha while conservative estimations for algal biofuels report productivity in the range of 6 to 8 toe biofuels/ha. New varieties of energy crops might have increased yields, lower water demand and lower agrochemical requirements.

Production of biofuel from cellulosic feedstocks is more complex than production from sugar- and starch-based feedstocks. Bio-chemical processes involve the conversion of cellulose or hemicellulose by a variety of enzymes and other micro-organisms that break the cellulosic material into sugars (saccharification stage) followed by traditional fermentation and distillation. Thermo-chemical processes are based on a high temperature thermal treatment (e.g. pyrolysis or gasification) to produce an intermediate bio-oil or synthesis gas, which after upgrading and further processing can be converted into liquid or gaseous synthetic fuels, e.g. Fischer-Tropsch diesel, dimethyl ether, biomethane, ethanol or methanol.

Both bio-chemical and thermo-chemical processes remain unproven on a commercial scale, although several advanced demonstration projects are planned or are underway in the US and the EU. There are currently no clear technical or economic advantages between the bio-chemical and thermo-chemical pathways. Both conversion routes offer biofuel conversion efficiency of around 35 % and similar potential yields in energy terms per tonne of feedstock. Lignocellulosic ethanol production through enzyme hydrolysis is expected to produce up to 300 litres of ethanol/tonne of feedstock and the BTL route could yield up to 200 litres of biodiesel/tonne of feedstock [IEA, 2008; IEA, 2010].

Algae can be cultivated on non-productive land (i.e. degraded, non-arable) that is unsuitable for agriculture or in brackish, saline and waste water from waste water treatment plants as well as in the sea. Algae can be produced in open ponds, raceway ponds, closed photobioreactors and closed fermenter systems. The potential oil yields (litre/hectare) for algae are significantly higher than yields of oil seed crops. Theoretically, algae could produce around 45 000 litres of biodiesel/ha, compared to 1 500 litres of biodiesel/ha from rapeseed, 4 500 litres of biodiesel/ha from oil palm and 2 500 litres of bioethanol/ha from maize. High productivity in open ponds is

reported in the range of 15-30 g/day/m² of pond area [Darzins et al., 2010]. Algae biorefinery could produce biodiesel, bioethanol, biomethane, bio-kerosene as well as valuable co-products including oils, proteins and carbohydrates.

Biofuel production from algae is presently at the demonstration stage. There are technical challenges and there is a need for innovation and technical improvement in all steps of algal biofuels production process. Efforts are needed to further develop optimum strains of algae, with fast growth, harvesting techniques and efficient oil extraction. Algae harvesting methods include sedimentation, flocculation, centrifugal dewatering, membrane filtration and screening. Oil extraction options from algae include solvent extraction with organic solvents, supercritical fluids, mechanical, biological extraction, etc.

Hydrogen produced from biomass can be used to power vehicles, via fuel cells or internal combustion engines. Hydrogen is expected to play an important role in building a low-carbon economy in the long-term (2050). Various options are available for bio-hydrogen production: electrolytic routes, thermochemical (pyrolysis and gasification) and biochemical/biological (fermentation) processes. Several different routes are in the research and development stage and can play a role in the long term [Hamelinck, 2002; Claassen, de Vrije 2009; Foglia et al. 2011]. The future of hydrogen use in vehicles depends on the advancement in the hydrogen production technologies and fuel cells technologies and cost reduction. Hydrogen onboard storage and distribution are major challenges. Various storage options are available and need to be developed: low temperature (cryogenic), high pressure or chemical as hydrides.

Integrated, **bio-refinery** concepts are considered better options for the production of a variety of products, including liquid biofuels, such as food, feed, chemicals and bio-materials, bioenergy (heat and/or power) and biogas. Different concepts, pathways and a portfolio of products are being investigated to identify the most interesting options. Market deployment is expected by 2020. The deployment of the new bio-refinery concepts will rely on the technical maturity of a range of processes to produce a range of products [Van Ree and Annevelink, 2007; Cherubini et al., 2009]. Energy bio-refineries are largely at the conceptual stage, with potentially interesting new products and routes still being identified, whereas there are some chemical bio-refineries already producing bio-based chemicals commercially.

Production costs of advanced biofuels will start to emerge as large-scale demonstrations get underway. Currently, only a small amount of data is available. Whilst HVO seems to have achieved commercial status in Finland, many advanced biofuels production processes still need improvement in the technology to enter the market. An estimate of the global production price for ethanol from woody energy crops is 107 €/MWh and production prices for straw ethanol range between €70-101/MWh (oil price 41 €/bbl) [IEA, 2010].

Capital investment costs reported for lignocellulosic ethanol are in the range of 1 800 to 2 100 €/kW ethanol [Hamelinck et al., 2005; Riva, 2009]. Capital investment costs reported in the short term for biodiesel production through biomass gasification (Fischer-Tropsch process) are in the range of 3 000 - 4 000 €/kW biodiesel [Hamelinck, 2004; Dena 2006]. Since most lignocellulosic biofuels are in a pre-commercial phase, further improvement in technology and cost reduction are expected due to the learning-curve effect.

14.3. Market and industry status and potential

Traditional, first generation biofuel production has increased continuously worldwide in recent years. In 2009, global biofuel production reached about 91 billion litres/year, of which 19 billion litres was biodiesel and 72 billion litres bioethanol (80 % of biodiesel being produced in the EU). In the US, biodiesel production reached 650 million gallons (2.5 billion litres) in 2008 [Emerging Markets, 2008; IEA, 2011]. The land used for biofuels was estimated in 2008 at around 20 million hectares worldwide or around 1 % of the global agricultural land, of which about 8 million hectares were used for sugarcane plantations in Brazil [Gallagher, 2008; Searchinger et al., 2008].

New biofuel mandates, such as the Renewable Fuels Standard (RFS) in the US or the Renewable Energy Directive 2009/28/EC in the EU and others in Latin America and Asia, provide perspectives for an increased production for biofuels across the world. Mandates for blending biofuels into vehicle fuels have been set worldwide. Most mandates require blending 10–15 % ethanol with gasoline or blending 2–5 % biodiesel with diesel fuel [REN21, 2010]. In the EU, the Renewable Energy Directive set mandatory targets of 10 % share of renewable energy in transport for 2020 in each EU Member State, and 6 % reduction in greenhouse gas (GHG) emissions from road transport fuels (EC, 2009). In

the US, the Energy Independence and Security Act (EISA) of 2007 set overall renewable fuels targets of 36 billion gallons (136 billion litres)⁴⁸ by 2022, with 15 billion gallons (57 billion litres) of ethanol and 21 billion gallons (79 billion litres) of advanced biofuels by 2022 [Environmental Protection Agency, 2010]. In addition to the bioethanol programme, the Brazilian biodiesel national programme was established to ensure blending 2 % of biodiesel in 2008 and up to 5 % until 2013 [Pousa et al., 2007]. In China, proposed targets for 2020 are to produce 12 million tonnes of biofuels to replace 15 % transportation energy needs. India's National Biodiesel Programme started in 2006 and includes a target of 20 % of diesel fuel by 2012, mainly based on a *Jatropha* plantation programme [Emerging Markets, 2008].

The share of biofuel in liquid fuels consumed for road transportation in the EU accounted for only 0.2 % in 2000, but increased to 1 % in 2005, 1.8 % in 2006 and 2.7 % in 2007 and is projected to reach 10 % by 2020. Biofuel consumption further increased to 8.0 Mtoe (2.6 % of energy use in transport) in 2007, 10.2 Mtoe (3.4 %) in 2008 and 12.1 Mtoe (4.4 %) in 2009.⁴⁹

According to the National Renewable Energy Plans (NREAPs), prepared by the EU Member States (MS), the renewable energy share in the energy use in transport is expected to reach 11.6 % in the EU by 2020 (equivalent to 30 Mtoe), while the biofuel contribution should be 9.5 %. The greatest contribution in 2020 is expected to come from biodiesel with 21.6 Mtoe, followed by bioethanol/bio-ETBE with 7.3 Mtoe and other biofuels (such as biogas, vegetable oils, etc.) with 0.7 Mtoe. According to the NREAPs forecast, the contribution made by biofuels produced from wastes, residues, non-food cellulosic material and lignocellulosic material is expected to reach 2.7 Mtoe, representing about 9 % of the estimated biofuel consumption in the EU in 2020. NREAPs data shows that in 2020 about 11 Mtoe biofuels could be imported by all the MS in order to reach the 10 % binding target. This should represent about 37 % of the biofuel use in the EU in 2020.

According to the Biofuels Research Advisory Council, up to one quarter of the EU's transport fuel needs could be met by biofuels in 2030 [Biofrac, 2006]. It is forecast that the ethanol and biodiesel producer prices in 2020 will be 105 €/MWh and 179 €/MWh respectively [OECD-FAO, 2011].

⁴⁸ 1 US gallon = 3.777 litres

⁴⁹ <http://www.observ-er.org/>

14.4. Barriers to large-scale deployment

The main barrier to widespread use of biofuels in transport is cost competitiveness with fossil fuels. Improved conversion efficiency and reduced investment and operating costs should help to bridge the gap with fossil fuels and these improvements need to be taken into account in funding programmes for advanced biofuel demonstration projects. Biofuels production is strongly supported by policy worldwide.

There are technology challenges for both the bio-chemical and thermo-chemical routes for advanced, lignocellulosic biofuels. Technology improvements are needed for pyrolysis and gasification and integration of technologies that will afford energy savings and better use of all process residues. For the bio-chemical pathway, there is scope to improve the feedstock pre-treatment stage, by improving the efficiency of enzymes and reducing costs, and to improve overall process integration and overall investment reduce cost.

Biofuel production provides new opportunities for agriculture, although new agricultural practices need to be learned and the balance between the advantages of new enterprises and environmental and social impacts need to be carefully balanced. Studies on the impacts of biofuels on the environment, biodiversity and water resources, land use changes and GHG emission reductions will continue to be made. Increased world population, and consequent increased demand for food, feed, fibre and fuels inevitably calls for more land use and increased crop yields. Land use change impacts are still not well understood. However, better land management techniques could easily increase productivity in several large crop producing countries and better use of residues and wastes from agriculture and forestry could be utilised for advanced biofuels. Competition for lignocellulosic biomass from producers of biofuels and other sectors, most notably heat and power and from pulp and paper, will eventually have an impact on the price of biomass.

Typically, lignocellulosic biofuel plants need to be of large scale in order to operate on a cost-effective basis. Biomass availability at low cost is an important issue. Biomass supply costs increase due to the need of large amounts of biomass required and increasing transport distances. The good experience of the forest products companies (such as pulp and paper) of handling large quantities of biomass can be useful for new, large biofuel plants.

The diversity of feedstock and the large number of biofuel pathways leads to some uncertainty over the GHG performances of biofuels, especially if land use change is involved [Dallemand, 2008, Fehrenbach and Reinhardt, 2006, Fritsche, 2008]. Notwithstanding this, the Renewable Energy Directive presents a unified methodology for GHG calculation and default values for several biofuel pathways. Indirect effects are still very difficult to measure, although several assessment methodologies have been proposed which estimate the GHG emissions from Indirect Land Use Changes (ILUC) [Al Riffai et al., 2010; JRC, 2010a; JRC, 2010b]. Although there are still uncertainties in the definition of exact GHG emissions from ILUC, it is now recognised in most of the scientific community [JRC, 2011a; IFPRI, 2011] and in the EU Commission's report on "Indirect land use change related to biofuels and bioliquids" (EU Commission, 2010) that the effects are significant and need therefore to be properly addressed. Other environmental impacts, besides GHG emissions, must be considered when land use change is involved, including the impact on water use and water resources. Some studies also evidenced that the extensive use of bioenergy crops will increase the rate in loss of biodiversity [Van Oorschot et al, 2010; JRC 2011b].

Sustainability aspects are critical for the future development of biofuels production. Biofuel certification is expected to reduce the concerns related to the sustainability of biofuels. There are several certification schemes developed for a wide range of products and new initiatives for biofuels/bioenergy [BTG, 2008; Van Dam et al., 2008, Scarlet and Dallemand, 2011]. The European Commission has already recognised seven certification schemes that complying to the sustainability requirements of the Renewable Energy Directive [European Commission, 2011].

14.5. RD&D priorities and current initiatives

RD&D priorities

Effort is needed to advance new technologies to develop high efficiency, cost effective thermo-chemical and bio-chemical conversion routes to biofuels production (advanced enzymatic hydrolysis and fermentation, gasification, pyrolysis and synthesis, torrefaction, algae production, harvesting and oil extraction). Further research is needed to improve conversion processes, system integration, cost effectiveness and flexibility to use different feedstocks. The development of bio-refinery concepts, producing a variety of high-value end-products, can significantly

improve the competitiveness of bioenergy and biofuels production.

There is a crucial need to demonstrate the reliability and performance and scale-up bioenergy technologies to relevant industrial scales. The development of several demonstration or flagship plants for advanced biofuels is crucial for process development and validation of technical and economical performances. Several demonstration plants for advanced biofuels are already in operation or under construction (thermochemical or biochemical lignocellulosic ethanol, BTL and biomethane) in Canada, Denmark, Finland, Germany, Italy, Spain and the United States⁵⁰. A number of the technologies are included in the value chains of the European Bioenergy Industrial Initiative (EIBI) of the SET-Plan, which aims to bring to commercial maturity the most promising large-scale bio-energy technologies.

There is a need to enlarge the feedstock base, to develop new feedstocks (e.g. Short Rotation Forestry/Short Rotation Crops, energy grasses, aquatic biomass, etc.), with high-yield, increased oil or sugar content, and to adapt farming practices in order to increase biomass availability. Detailed biomass resource mapping, taking into account the sustainability requirements of the EU Renewables Directive, is needed to establish what is already available and where extra resources might be exploited. More effort is needed to develop reliable supply chains and improved biomass logistics, at different scale.

Meeting sustainability requirements is a key issue for the large-scale deployment of biofuel production. Practical implementation of sustainability requirements must be based on relevant, transparent and science-based data and tools. It is essential to develop science-based and transparent criteria, indicators and worldwide accepted methodologies (e.g. LCA) to be applied to the full biomass value chain (from feedstock production and conversion processes to end uses). The adequate measures for monitoring several impacts and a robust mechanism to enforce compliance, as well as the identification, mapping and monitoring of no-go areas are of prime importance.

Improved methods must be developed to evaluate direct and indirect land use changes due to biofuel production whenever applicable. The impact of indirect land-use change on GHG emissions must

be assessed on the basis of verified and accepted methodologies. The impact of biofuel production on the availability of food products and changes in commodity prices and land use associated with the use of biomass for energy must also be evaluated.

For a fair playing field, it will be important that LCA should be developed for all types of fossil resources producing transport fuels, including tar sands, while taking care of geographical differences in the quality of the fossil resources and the actual well-to-wheel calculation, i.e. not just a theoretical one considering a single quality for petrol and diesel.

Finally, one should consider whether sustainability criteria and GHG limits should not be introduced for imported and EU fossil resources and or fossil fuel products.

Current initiatives

The Strategic Research Agenda (SRA) of the European Biofuels Technology Platform⁵¹ aims to provide the main direction and RD&D efforts required to achieve the biofuels research advisory council (BIOFRAC) goal of 25 % share of biofuels in the road transport energy consumption in 2030 [Biofrac, 2006]. In 2009, the Bioenergy Technology Roadmap of the SET-Plan [European Commission, 2009b] was set up to address the techno-economic barriers to the development and commercial deployment of advanced bioenergy technologies. The Bioenergy Roadmap is based on three pillars, which have been described in more detail in Section 3.5, Chapter 13. The Roadmap set the basis for the European Industrial Bioenergy Initiative [EIBI 2010], also described in Chapter 13, and defines seven Value Chains with a large emphasis on advanced biofuels:

Conversion paths based on thermo-chemical processes:

- Synthetic liquid fuels and/or hydrocarbons and blending components through gasification
- Bio-methane and other gaseous fuels through gasification
- High efficiency heat and power generation through thermo-chemical conversion
- Intermediate bioenergy carriers through techniques such as pyrolysis and torrefaction

Conversion paths based on biological and chemical processes:

- Ethanol and higher alcohols from lignocellulosic feedstock through chemical and biological processes

⁵⁰ IEA Bioenergy 39, <http://biofuels.abc-energy.at/demoplants/>

⁵¹ http://www.biofuelstp.eu/srasdd/SRA_2010_update_web.pdf

- Hydrocarbons (e.g. diesel and jet fuel) through biological and/or chemical synthesis from biomass containing carbohydrates
- Bioenergy produced by micro-organisms (algae, bacteria) from CO₂ and sunlight

Complementary measures and activities within EIBI include biomass feedstock for bioenergy and promoting longer term R&D on emerging and innovative bioenergy value chains.

The European Advanced Biofuels Flightpath Initiative was set up in 2011 to speed up the commercialisation of aviation biofuels in Europe. This action aims to achieve 2 million tonnes of sustainable biofuels to be used in the EU civil aviation sector by the year 2020. The “Biofuels Flightpath” is a voluntary commitment to support and promote the production, storage and distribution of sustainably-produced biofuels for use in aviation. It also targets establishing appropriate financial mechanisms to support the construction of industrial “first-of-a-kind” advanced biofuel production plants. The actions foreseen in the Flight

path include, amongst others the following actions:

- short term (0-3 years): make available more than 1000 tonnes of Fisher-Tropsch biofuel; production of aviation class biofuels in the hydrotreated vegetable oil (HVO); start construction of the first series of second generation plants to become operational by 2015-2016;
- mid term (4-7 years): make available more than 2000 tonnes of algal oils; supply of 1.0 million tonnes of hydrotreated oils and 0.2 tonnes of synthetic aviation biofuels; start construction of the second series of second generation plants including algal biofuels and pyrolytic oils from residues to become operational by 2020;
- long-term (up to 2020): supply of an additional 0.8 million tonnes of aviation biofuels based on synthetic biofuels, pyrolytic oils and algal biofuels; further supply of biofuels for aviation, biofuels to be used in most EU airports; 2 million tonnes of biofuels are blended with kerosene.

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15. Fuel Cells and Hydrogen



15.1. Introduction

Hydrogen has been used as a chemical for centuries and now emerges as a universal energy carrier with important environmental and energy security advantages. As energy carrier, it requires energy to be produced from a variety of sources. It can be used as fuel in combustion motors or in fuel cell systems, combining with oxygen to produce electricity and water. Greenhouse gas (GHG) emissions are avoided completely when producing hydrogen from non-fossil energy sources or using CO₂ sequestration. In addition to its direct use as a feedstock in power generation and transport, because of its full interchangeability with electricity, hydrogen can be used as an energy buffer to balance the production and demand cycles of intermittent power sources, enabling integration of large volumes of renewable energy in the energy system.

Fuel cells convert the chemical energy stored in fuels into electricity and heat. They can be fed by fuels that are readily available as well as by waste-streams from industrial processes, thus reducing reliance on oil and on an electricity grid that is ageing and increasingly pushed beyond capacity. As there is no combustion, fuel cells do not produce any emissions at their point of use, and as there are no moving parts, they are quiet and reliable. Due to their high efficiency, fuel cells are considered the most efficient means of converting any fuel to useful power. They can be used: in stationary applications, such as generating electricity for the utility grid or micro-grids or heating buildings; in transport to power vehicles, buses, materials handling equipment and; in portable applications such as laptops, toys, cell phones. Fuel cell features include reliable start-up and can be scaled into small and large power packages. They are manufactured with repetitive processes for which automation has a large potential for cost reduction.

Fuel cells and hydrogen are medium- and long-term energy technology options whose contribution to meet the 2020 EU targets on GHG emissions, renewable energy and energy efficiency are limited. However, they

are expected to play an important role in achieving the EU vision of reducing GHG emissions by 80-95 % compared to 1990 levels by 2050 [European Commission, 2011]. Large-scale deployment of hydrogen technologies increases the use of domestic energy resources, and hence contributes to enhancing EU security of energy supply.

15.2. Technological state of the art and anticipated developments

In recent years remarkable improvements have been achieved in fuel cells and hydrogen technologies and several applications have reached commercial market status. The near future will see fuel cells and hydrogen systems meeting an increasing range of consumer and industrial needs that equal or surpass the performance of incumbent technologies, thereby contributing to economic prosperity, environmental sustainability and diminishing reliance on fossil fuels. The technology uptake is expected to generate considerable employment in the near future.

15.2.1 Transport and refuelling infrastructure

Hydrogen fuel cells are currently used in demonstration programmes of light-duty vehicles and bus fleets, where in recent years considerable improvements have been seen in performance and durability. Due to the higher requirements for light-duty vehicles in terms of performance and commercial deployment challenges, this section focuses on passenger cars only.

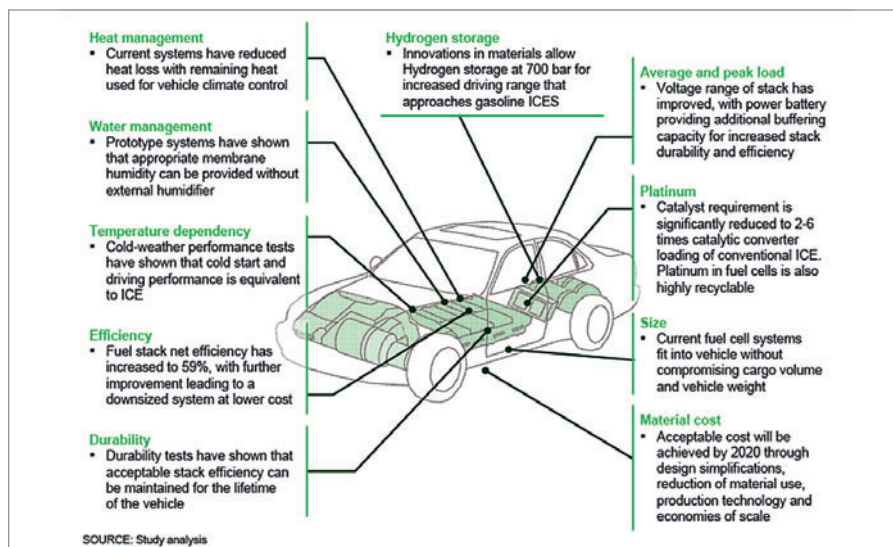


Figure 15.1: Overview of recent improvements in light-duty FCEVs [Source: McKinsey, 2010]

	2010 status	2015 targets	2020 targets
Power density of stack	1.8 kW/litre	2 kW/litre	2.4 kW/litre
FCEV durability	2 000-2 500 h	5 000 h	> 5 000 h
System efficiency		60 %	60 %
Fuel consumption	1 kgH ₂ /100 km	0.9 kgH ₂ /100 km	0.85 kgH ₂ /100 km

Table 15.1: Performance characteristics of light-duty FCEV [NREL, 2011; IPHE, 2010; JHFC, 2010; MAIP, 2011; Korea, 2011; Fuel Economy] [Sources: http://www.fueleconomy.gov/feg/fcv_sbs.shtml; NREL; IPHE; JHFC; MAIP, KETEP]

Light-duty fuel cell electric vehicle (FCEV)

For passenger vehicles, the major improvements that have been realised over the last years are the implementation of 70 MPa gas pressure storage technology which has increased the driving range without sacrificing comfort and volume, and the cold start ability of polymer electrolyte membrane fuel cells (PEMFC) to temperatures below – 25 °C by application of shut-down purging strategies and optimised heat management in the stack. Improved understanding of fuel cell degradation mechanisms and the implementation of mitigating measures have considerably increased durability. Fuel cells using hydrogen can now achieve nearly 60 % efficiency in vehicle systems, more than twice the efficiency of petrol internal combustion engines, and substantially higher than even hybrid electric power system. Recent improvements in light-duty FCEVs are summarised in Figure 15.1.⁵²

The enhanced performance and durability of FCEVs have been validated in a number of demonstration programmes in the EU, US, Japan and South Korea. On-road fuel economy⁵³ has ranged between 56 and 88 km/kgH₂ in the US demo, with actual driving ranges on a single tank between 313 and 406 km. On-road fuel economy figures from the Japanese demo are between 81 and 110 km/kgH₂. Fuel economy measured according to standard driving cycles for the latest FCEV models is between 85 and 96 km/kgH₂. Some manufacturers claim values up to 110 km/kgH₂.

⁵² FCEV share the electric drive and power electronics with other types of electric vehicles. These aspects are not included here.

⁵³ The fuel economy (km/kg of hydrogen) is inversely proportional to fuel consumption. The latter is expressed in g/km or in MJ/km. 1 MJ/km equals 8 g/km (Low heating value (LHV) of hydrogen = 121 MJ/kg), which corresponds to approximately 3 litres of gasoline per km.

Source	Year	FC stack/system		FCEV	
		# units	FC cost range (average)	# vehicles	Price (kEUR)
McKinsey	2010	1 000	€221-781 (500)/kW - stack		160
	2015	100 000	€42-252 (110)/kW - stack	> 100	
	2020	1 M	€16-98 (43)/kW - stack	< 1 M	31
	2030			20 M	26
MAIP	2010 status		> €1 000/kW -system	> 100	500
	2015 target		€100/kW -system	> 5 000	< 50
	2020 target		€50/kW -system	0.5 M	< 30
DoE 2010	2010	small	\$228/kW - system		
	2010 projected	0.5 M	\$49/kW - system		
	2015 target	0.5 M	\$30/kW - system \$15/kW - stack		
JHFC 2010	2020 target				20 % more than ICE

Table 15.2: Cost status and projections for fuel cell stacks and systems for light-duty FCEV

for their latest models, with driving ranges extending up to 690 km. The 2020 target in the Multi-Annual Implementation Plan (MAIP) of the Fuel Cells and Hydrogen Joint Undertaking (FCH-JU) is 118 km/kgH₂. Other status figures and targets are included in Table 15.1.

In Table 15.2, a comparison between the deployment and cost data for fuel cell systems in the EU and the US are shown. (For comparison: current costs of conventional internal combustion engines are about \$30/kW for light-duty vehicles). The DoE stack cost of \$49/kW projected for large volume production with today's best technology represents an impressive five-fold reduction since 2003 and further substantial cost reductions are expected through economies of scale and incremental technology improvements, as is also evident from the expected 90 % reduction in average stack cost by 2020 in the McKinsey study. With reducing stack costs, balance-of-plant components become responsible for a larger percentage of the overall costs, presently about 50 %.

Hydrogen storage on-board

Next to fuel cell performance and durability, the energy density of hydrogen stored on-board represents the other main challenge for FCEVs. The current status of various hydrogen storage technologies as well as the 2015 DoE targets for on-board storage systems are indicated in Figure 15.2 (gasoline densities are 26 weight percent and 180 g/litre), where it is shown that none of the current technologies are capable of reaching the 2015 system targets. In addition, other requirements such as durability, hydrogen purity, filling rates and costs have to be met. Issues with compressed hydrogen gas tanks are high pressure, conformability and cost. Pre-cooling of hydrogen to limit the maximum temperature during type-IV tank filling may be required to obtain acceptable fill times. For liquid hydrogen tanks, the energy required for hydrogen liquefaction, boil-off and tank cost

are important. Some newly developed chemical hydrides have at the material level, well exceeded the gravimetric system storage target within an acceptable operating temperature range, making them potential candidates for on-board storage. However, significant technical issues remain regarding the regeneration of the spent material and whether regeneration can be accomplished on-board. Although metal hydrides can reversibly store hydrogen at relatively low temperatures and pressures, they suffer from low hydrogen capacity, slow uptake and release kinetics and cost. Due to the reaction enthalpies involved, thermal management during refuelling is a big challenge. Reversibility still needs to be demonstrated for over a thousand cycles. Due to their weight, metal hydrides do have a potential as storage medium in fuel cell forklifts, where they can be used as a ballast load. High surface area sorbent materials do not require special thermal management during refuelling because of their low enthalpies, which enables fast fill and discharge rates. However, their low enthalpy necessitates the use of cryogenic temperatures which adversely impacts volumetric capacity, available gravimetric capacity and system costs.

The cryogenic pressure vessel concept capable of accepting fuel in liquid and in compressed form has allowed progress in on-board storage density (see Figure 15.2): for liquid hydrogen, high operating pressures allow maintaining high energy density without evaporation losses; for compressed hydrogen the more compact storage reduces

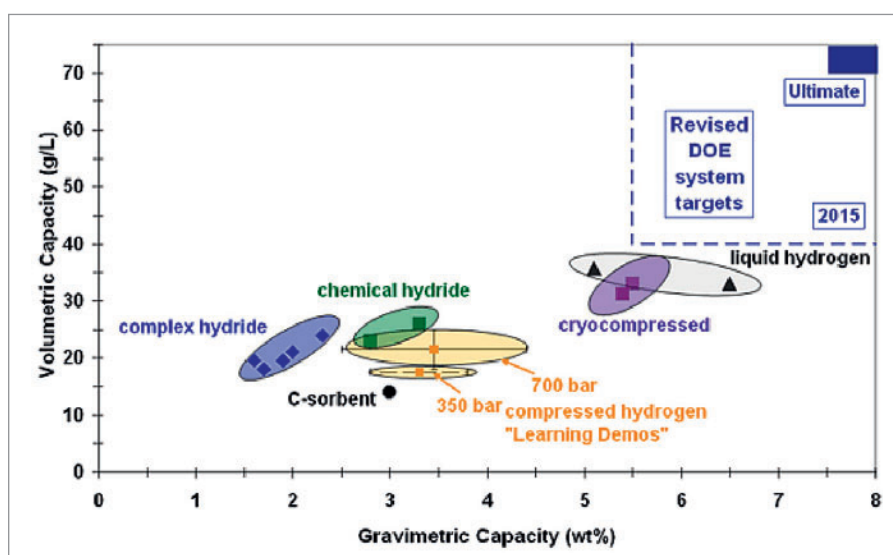


Figure 15.2: Overview of current technologies in comparison to 2015 system targets [Source:US DoE-Office of Energy Efficiency and Renewable Energy]⁵⁴

⁵⁴ http://www1.eere.energy.gov/hydrogenandfuelcells/storage/tech_status.html

the need for expensive carbon fibre. Storage of supercritical cryo-compressed hydrogen is currently under investigation, with a potential of achieving a density above 90 g/litre (30 % density increase above pure liquid and more than 2.5 times that of compressed hydrogen).

Learned-out hydrogen storage costs (500 000 units/year) for 70 MPa Type-IV storage tanks (5.6 kg capacity) is currently estimated at \$14/kWh, far above the DoE 2015 on-board storage target of \$2/kWh. The cost of the carbon fibre layer amounts to more than 75 % of the tank cost. The corresponding storage system costs are \$19/kWh. In the near term, lower production volumes (10 000/year) may cost twice as much. For liquid storage, an ultimate system cost of \$8/kWh is claimed (\$2.5/kWh for the cryogenic tank), whereas for a cryo-compressed tank it is estimated at \$12/kWh (\$5/kWh for the tank). Solid state storage concepts are more expensive and estimated at \$49/kWh for metal hydride, \$26/kWh for chemical hydride and \$19/kWh for adsorbent [DoE, 2011a]. Targets in the EU HyWays project⁵⁵ are €10/kWh for 2020 and €5/kWh in 2030. A cost of €8/kWh translates into a total tank cost of about EUR 1 200 for a typical four-passenger FCEV.

Refuelling infrastructure

In the ramping up to large-scale deployment of FCEVs, stations will be under-utilised and more expensive because of absence of economies of scale. Today's investment cost for a refuelling station, depending on the capacity (50 to 1 000 kgH₂/day), ranges between below EUR 1 million to EUR 3 million, targeted to decrease to EUR 0.6 million to EUR 1.6 million in 2020 [MAIP, 2011]. Due to much more stringent safety requirements, Japan's estimated cost of a 300 Nm³/h (~26.8 kg) station in 2015-2020 is about EUR 3.3 million [NEDO]. According to DoE the following factors will contribute to cost reduction of stations: increase of dispensed volume, station duplication, R&D progress in compression, storage and manufacturing, and harmonisation of the permit procedures.

The McKinsey study estimates that the cost of dispensed hydrogen (untaxed) will decrease from €17/kg (2010) to €6.6/kg in 2020, to reach a level below €5/kg by 2030. Practically the whole decrease between 2010 and 2030 originates from the contribution of the refuelling station. Depending on

the feedstock and the station size, the MAIP targets an overall refuelling cost of hydrogen (excl. taxes) of €5-10/kg in 2020, from a present status of €15-20/kg. DoE has recently reviewed the cost target for dispensed hydrogen for automotive applications and has set it at \$2-4/gge⁵⁶ to become competitive with gasoline in hybrid electric vehicles in 2020 (untaxed) [DoE, 2011b]. Due to the lower US petrol tax, which imposes lower cost targets for new technologies to become competitive, cost targets in the EU are less stringent than in the US.

15.2.2 Hydrogen production

All hydrogen production processes are based on separating hydrogen from hydrogen-containing feedstocks. Today, two primary methods are used: thermal (reforming, gasification) and chemical (electrolysis). Other methods (biological, photo-electrochemical) are in the exploratory research and development phase.

Steam reforming of natural gas has been used for decades for bulk hydrogen production. Steam Methane Reforming (SMR) produces hydrogen-rich gas that is typically of the order of 70-75 % H₂ on a dry basis, along with smaller amounts of CH₄ (2-6 %), CO (7-10 %) and CO₂ (6-14 %), which is subsequently purified. Energy efficiencies are of the order 70-75 %. Scaling down into units for distributed generation that are operationally stable and economically viable has been a challenge, but nowadays small steam methane reformers, partial oxidation reformers and auto-thermal reformers are manufactured and operated [NHA, 2010]. Energy efficiencies for continuous operation can reach 68 %. In non-continuous operation because of non-optimal matching of generation and demand, efficiencies are lower. At the local level, hydrogen can also be produced from wastewater or biowaste, using anaerobic digestion to produce biogas which is subsequently reformed into hydrogen. As biogas contains many corrosive trace gases, a cleaning process is required. Internal reforming of biogas in a high temperature fuel cell is also possible. The MAIP 2020 efficiency target for CCS-ready, large-scale reforming is 72 %, whereas that for distributed generation using biogas is 67 %. The 2010 status figures are 71 % and 64 % respectively.

Electrolysis is a well-established technology. Although on an overall chain basis, large-scale electrolysis using fossil or nuclear generated electricity is not efficient (round-trip 35-40 %), it is nevertheless a key technology to enable high

⁵⁵ HyWays: The European Energy Roadmap: www.hyways.de

⁵⁶ The energy contained in 1 gallon gasoline equivalent (gge) is practically the same as in 1 kg of hydrogen.

penetration of renewable electricity, particularly in the transport sector. Electrolysers are widely used in distributed generation because they can more easily meet a variety of the smaller quantity needs for hydrogen. In recent years, improvements in materials and processes have led to improvements in efficiencies, operation, life and gas purity, and resulting cost reductions. R&D in power electronics has resulted in improved efficiency and reliability for hydrogen production from renewables. Efficiency (excluding auxiliaries) is close to 80-85 %. Larger units are usually less efficient at 75-80 %. System efficiencies are around 65 %. Whereas alkaline systems have track records for lifetime, reliability and lower capital costs, membrane electrolysis offers the advantage of higher production rates and efficiencies. Most units are easily adapted to produce hydrogen at pressures up to 0.7 MPa, thereby eliminating the need for large tanks and for the energy-intensive, low pressure compression stages. Units for high pressure (> 10 MPa) are under development. Efficiency improvement by using solid polymer electrolytes and high temperature (700-900 °C) supercritical water vapour electrolysis has been demonstrated, but units are not yet commercially available [NHA, 2010]. The MAIP 2020 efficiency target for distributed electrolysis is 70 %, up from the 2010 status of 65 %.

At present, significant amounts of hydrogen are produced as a by-product of ethylene and chlor-alkali plants. Smaller amounts of by-product hydrogen are also recovered and used internally at coking facilities. By-product hydrogen may need to be cleaned before being used on site, and liquefied or pressurised, if it is to be transported.

For production of hydrogen from coal, gasification will most likely be used because higher operating efficiencies in gasification plants (55-60 %) allow for significant reductions in pollutants, compared to conventional pulverised coal power plants. The application of CO₂ capture is expected to result in an efficiency drop of 6-8 percentage points and a 20-30 % cost increase. The greatest challenge to large-scale, coal-based hydrogen production lies with demonstrating the capacity and safety of long-term geological CO₂ storage. The MAIP 2020 efficiency target for hydrogen production by CCS-ready IGCC is 72 %. Next to coal, also biomass can be gasified on a large scale, with expected efficiencies of the order of 45-48 %. As biomass is produced in relatively small quantities per surface area, a biomass plant is likely to be much smaller than a coal plant. Small-scale (100-300 t/day biomass) gasification test plants use indirectly heated air at low pressures for gasification, thereby eliminating an expensive air separation unit

for oxygen feed. Gas clean-up technologies, that adequately remove contaminants and tar, still need to be demonstrated.

Nuclear energy can produce high quality hydrogen in large quantities at a relatively low cost without any emissions. In future, advanced high temperature reactors (HTR) with an efficiency of up to 50 % could provide more economical, large-scale hydrogen production with less nuclear waste and energy use overall. There are two main hydrogen production technologies using HTRs: in high temperature electrolysis (up to 1100 °C), heat from the reactor is used to replace some of the electricity required in conventional low temperature electrolysis, leading to a potential saving of more than 35 %. In thermochemical production, water is separated into hydrogen and oxygen at high temperatures (450-1000 °C). Next to nuclear heat, concentrated solar thermal power may be used for large-scale thermochemical hydrogen production, as successfully demonstrated in a 100kW pilot plant in the EU-funded Hydrosol project.⁵⁷ To achieve acceptable efficiencies at lower operating temperatures, solar-assisted catalytic water splitting is investigated. In thermochemical hydrogen production, all reactants and compounds are regenerated and recycled. The biggest challenge with these processes is corrosion of process reactors and system materials.

Research is also under way on low-temperature, low-cost sustainable biohydrogen production processes and photo-electrochemical processes for direct hydrogen production. At present, both pathways suffer from low hydrogen yields.

Hydrogen can in principle be produced by operating fuel cells in reverse mode. Such a regenerative fuel cell uses electricity to split water into oxygen and hydrogen to be re-used by the fuel cell. In a unified regenerative fuel cell both modes are performed within the same stack. The ability to produce both power and generate hydrogen and oxygen for future use allows regenerative fuel cells to function much like a rechargeable battery, hence they are typically intended as a back-up or supplemental power source. The energy vectors water, as well as hydrogen and oxygen used in a closed system, the only exchanges with the environment are electrical power and heat. R&D focuses on effective and cheap catalysts suitable for both operating modes and on cell materials that remain stable during alternating operation under very different chemical conditions.

⁵⁷ www.hydrosol-project.org

Production method	production cost 2030 (€/kg)	distribution cost 2030 (€/kg)	total plant-gate cost (€/kg)
Central reforming	2.0	0.8	2.8
Id. With CCS	2.3	0.7	3.0
IGCC with CCS	2.8	0.8	3.5
Coal gasification with CCS	3.0	0.8	3.8
Central electrolysis	4.4	0.8	5.2
Distributed reforming	5.4	0	5.4
Distributed electrolysis	5.5	0	5.5

Table 15.3: Project plant-gate production costs for the EU FCEV fleet in 2030 [McKinsey, 2010]

[Source: McKinsey: A portfolio of power-trains for Europe, 2010]

High temperature fuel cells offer a very attractive avenue for producing renewable hydrogen. This combined production of hydrogen, heat and power (CHHP), exploits the internal reforming capability of high temperature fuel cells fed by biogas. The performance of the fuel cells is improved by separating and subsequently compressing the hydrogen contained in the waste gas in a highly efficient electrochemical hydrogen compressor to pressures up to 70 MPa. The absence of moving parts increases reliability over mechanical compressors. The hydrogen can be recycled to increase the efficiency of the high temperature fuel cell or stored for subsequent use [NHA, 2010]. The CHHP approach with electrochemical hydrogen compression is promising for establishing an initial infrastructure for fuelling vehicles with minimal investment risk in areas where biogas from landfills and from waste water treatment plants is available.

The cost of hydrogen to the customer is determined by a number of factors: the feedstock cost and conversion technology, the plant size, the required purity level and the method and distance for hydrogen delivery. Investment costs for 200 t/day centralised production by CCS-ready reforming or gasification range from M€0.66/(t/day) in 2010 to M€0.61/(t/day) in 2020 [MAIP, 2011].⁵⁸ For 50 t/day electrolysis, the 2020 target is M€1.5/(t/day). As investment costs are inversely proportional to plant size, they are higher for decentralised than for centralised production. For small-scale reforming of biogas, they range from M€4.2/(t/day) for a 1.5 t/day capacity in 2010 to M€2.5/(t/day) for a 3 t/day

capacity in 2020. For electrolysis, the figures are M€3.1/(t/day) in 2010 and M€1.9/(t/day) in 2020 for the same daily capacities. DoE claims that cost for the electrolyser stack (about 55 % of overall system cost) has reduced by 80 % (5-fold decrease) since 2001, reaching a projected high volume capital cost of below \$400/kW (M\$0.56/(t/day)).

Projected plant-gate production costs (capital + operation) from the McKinsey study for producing the hydrogen needed for the FCEV fleet in the EU in 2030 are shown in Table 15.3. The most cost-effective future production methods use existing technologies of steam reforming and coal gasification with production costs in the 2030-2050 time frame range between €1.8-2.8/kg. The production costs by these technologies increase with time because of increase in feedstock price. Hydrogen production through electrolysis is more expensive, yet gets cheaper with time and reaches €4/kg by 2050.

The plant-gate costs quoted in Table 15.3 do not represent the price of hydrogen delivered at the pump because they do not include the cost of the refuelling station.

For comparison, the DoE 2009 status of high-volume production costs for distributed electrolysis (1 500 kg/day) is \$4.9/kg and for distributed reforming less than \$3/kg. Costs for central wind electrolysis (50 t/day) are \$6/kg. Actual present day costs range between \$8-10/kg for a 1500 kg/day capacity refuelling station based on distributed reforming and between \$10-13/kg based on electrolysis. Current estimated hydrogen costs in Japan are €9.3/kg, with an estimated 2015-2020 cost of €7.5/kg [NEDO, 2011].

⁵⁸ Capital costs in €/kWh₂ are related to those in €/(t/day) through the specific energy density of gaseous hydrogen of 121 MJ/kg. A capital cost of 1 M€/(t/day) is equivalent to 713 €/kWh₂.

15.2.3 Hydrogen storage, transmission and distribution

Centralised hydrogen production necessitates a hydrogen transmission and distribution infrastructure as well as facilities for large- and medium-scale storage. Depleted gas fields, aquifers and caverns may serve as large-scale underground storage, whereas pipeline transmission has built-in buffering storage capacity. Medium-scale storage uses buried liquefied hydrogen tanks and compressed hydrogen tanks above ground. Large-scale hydrogen storage has received increasing attention recently in connection with the need of including an increased amount of intermittent renewable energy sources in the power generation mix. Hydrogen is very appealing for this application because it contains about 60 times the electricity equivalent in the same volume as adiabatic compressed air and in transmission, the capacity of hydrogen is a factor 4 to 5 higher than that of electricity using HVDC (resp. 27 and 6 GWh/h) and of the same order of natural gas (38 GWh/h). Mixing with natural gas up to a certain percentage has been investigated for hydrogen transmission by pipeline using the natural gas pipeline network.

The MAIP capital cost targets for 2020 for distributed above-ground storage of gaseous hydrogen are €400/kg (the DoE 2015 target for station storage is \$300/kg) and for storage in solid state materials €830/kg, down from the 2010 status of €500/kg and €5 000/kg respectively. Capital costs for large-scale compressed storage in underground caverns are targeted at €6 000/t.

Delivery costs are affected by volume and distance. As installation cost of on-site liquefaction equipment is much higher than for gaseous hydrogen, gaseous hydrogen is more cost effective below a certain delivery volume. Similarly, below a given distance, tube trailer delivery of gaseous hydrogen is cheaper because for higher distances the driving cost exceeds that of the hydrogen delivered. When high-pressure hydrogen is needed, tube trailer delivery may even be economical for larger distances, because of the additional costs of installing compression and storage equipment required for bringing liquid hydrogen to the desired pressure. The MAIP 2020 target capital cost for trailer transport is €400/kg for a hydrogen capacity of 1.6 t, compared to a 2010 status of €550/kg for a 600 kg capacity.

In the DoE programme, the projected delivery costs have been reduced by new materials for tube trailers (30 % reduction), advanced liquefaction processes

(15 %) and by replacing steel with fibre-reinforced polymers for pipelines (20 %). The 2015 target for the cost of delivery from a central production plant to the point of use is < \$1/kg, whereas that for storing the hydrogen at the refuelling station is \$0.2/kg.

15.2.4 Stationary fuel cells

Stationary fuel cells are compact power plants that use hydrogen or hydrogen-rich fuels to generate electricity or electricity and heat (CHP) for domestic (1-5 kWe), residential (5-50 kWe) and industrial (> 100 kWe) applications. They are attractive because of high efficiencies, low noise and vibration and potentially low operation and maintenance requirements, hence less down-time than other power generation devices such as diesel generators and gas engines. Their modularity allows tailoring their capacity to the power and heat requirements.

Different fuel cell types are used for stationary applications. In high-temperature fuel cells (Molten Carbonate Fuel Cells (MCFC), Solid Oxide Fuel Cells (SOFC)), natural gas and biofuels are expected to remain the dominant feedstock up to 2030. In selected applications, biogas, sewage gas and (bio) methanol are used. Hydrogen is used as a fuel for PEMFC alkaline fuel cells (AFC) and phosphoric acid fuel cells (PAFC). Low-temperature PEMFC and AFC need high-purity hydrogen, whereas lower purity can be used in PAFC and in high-temperature PEMFC.

Attainable efficiencies vary considerably with technology and the size of the installation. In the high power range, 45 % electrical efficiency is currently achievable, with the potential to reach more than 70 % electrical efficiency in hybrid fuel cell/turbine systems and more than 80 % overall efficiency in CHP systems.

Fuel flexible MCFC is currently the most mature technology for applications above 100 kWe, with SOFC in the demonstration stage. For MCFC fuelled on natural gas, the MAIP 2020 targets an electrical efficiency > 52 % (2010 status: 42 %) and lifetime requirements (durability) of 40 000 hours at stack level. Average durability in laboratory tests recorded by DoE is 8 000 h. The SOFC efficiency target is higher at 60-65 % with 40 000 h stack lifetime. Due to their low component cost and high efficiency, hydrogen-fuelled AFC are raising interest for stationary power generation. However, they are sensitive to CO₂ in fuel and in air and presently still have a low lifetime. For AFC, the MAIP targets an efficiency of 58 % with a 16 000 h stack life.

For lower power ranges for domestic and residential applications, SOFC as well as PEMFC, are being demonstrated. For micro-CHP, PEMFC is considered a bridging technology towards exclusive use of considerably simpler, yet presently more expensive SOFC. For this application, MAIP targets electrical efficiency of 45-50 % and total efficiency of 80-90 % by 2020. For residential CHP, SOFC electrical efficiency is targeted to increase from a 2010 status of around 40 % to 60 % in 2020, with corresponding overall efficiency increasing to over 90 %. For all CHP applications, MAIP targets a durability of 30 000 h by 2020. Some SOFC manufacturers have already demonstrated stack durability exceeding 12 000 h. At present, the low quality of heat available from low-temperature-PEMFC systems may limit their use beyond residential cogeneration. DoE claims that 45 % electrical and 90 % total efficiency by 2020 is achievable for high-temperature PEMFC for CHP applications in the range 1-10 kWe operating on natural gas, with durability targeted at 60 000 h.

In Figure 15.3, the performance of PEMFC and SOFC are compared to that of incumbent technologies for domestic CHP applications (micro-CHP). The solid line represents an 85 % overall (electrical + thermal) efficiency. A major advantage of fuel cells is that because of their higher electrical efficiency, cost-effective operation can be achieved with a lower heat demand.

SOFC are used as auxiliary power units (APU) to cover non-propulsion needs in the 1-10 kWe power range in

heavy-duty road transport vehicles. DoE targets 40 % efficiency by 2020 compared to 25 % currently with an operating lifetime (including a high number of on/off cycles) of 20 000 h versus 3 000 h at present. MAIP targets for 2020 are 30 % and 20 000 h with a 2010 status of 20 % and 12 000 h. Fuel cell APUs installed on aircraft (20-120 kW) perfectly fit with the more-electric aircraft concept and allow reducing emissions during flight as well as during gate and taxiing operations. The water produced reduces the amount of water the plane needs to carry, reducing overall weight and resulting in further fuel savings. Efficiencies of 50 % and lifetimes exceeding 10 000 h with very high mean times between failures are targeted. At higher power ranges, next to base-load electricity generation in CHP mode, high temperature FCs can also be used as large APUs (50-500 kW) on board cruise ships, where the quietness and absence of pollution are key advantages. Moreover, because they produce rather than consume water and require lower amounts of cooling air, ship-borne APUs allow simplification of the utility supply system and decentralised power generation on board. MAIP targets 55 % and 80 000 h lifetime in 2020, up from the present status of 42 % and 20 000 h, respectively.

In higher power ranges, PEMFC and AFC are very well suited for energy recovery from high purity excess hydrogen, as for example from chlorine production. PEM technology is closest to the market but AFC has the advantage in terms of higher efficiency and potentially lower cost per kW. MAIP targets for MW-range PEMFC applications in 2020 are 55 % efficiency and a stack life of 40 000 h, up from present status of 50 % and 8 000 h.

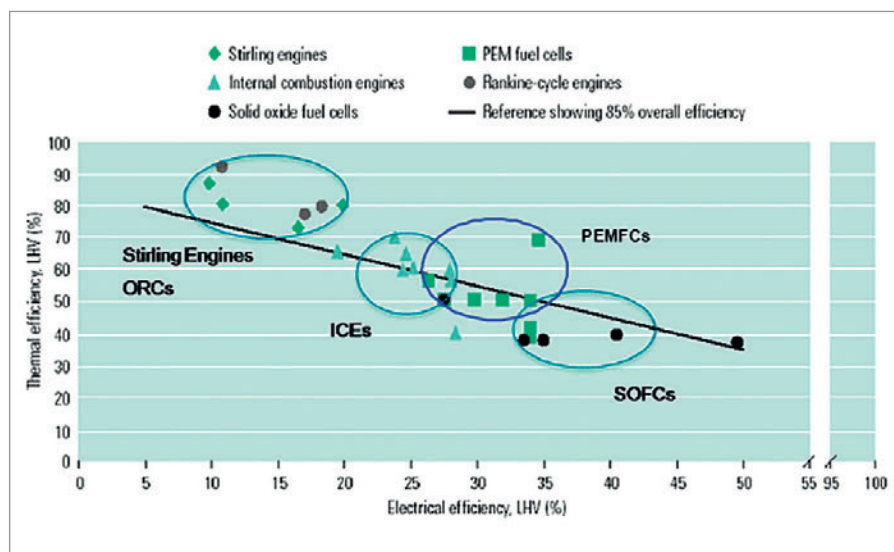


Figure 15.3: Performance of PEMFC and SOFC, as compared to other technologies for domestic CHP applications [Source: Delta Energy & Environment Ltd]⁵⁹

An interesting recent development is adding stationary fuel cells to an IGCC. In such a “triple cycle” IGFC (integrated gasification fuel cell) plant, part of the syngas produced from the coal is fed to high temperature stationary fuel cells. Advantages of the fuel cells are higher efficiency, load following capability without loss of efficiency, increased reliability and easier CO₂

⁵⁹ http://www.delta-ee.com/downloads/PRESENTATION_CogenEspana_03_Nov09_MB.pdf

capture from the syngas stream. The use of waste heat from the fuel cells in the turbine section additionally increases overall efficiency.

An interesting feature of MCFC and SOFC, next to the already mentioned capability of producing hydrogen, is that CO₂ fed to the cathode (as part of the cathode air supply) leaves at the anode in a concentrated form, making subsequent CO₂ capture much easier.⁶⁰

A relatively unknown type of high temperature fuel cell is the direct carbon fuel cell (DCFC) which allows converting the chemical energy stored in a solid fuel (such as coal or biomass) directly and efficiently into electricity without forming any of the by-products associated with conventional combustion. The CO₂ produced is pure and can directly be stored or used as chemical feedstock. DCFCs have a clear advantage over other fuel cells in terms of thermodynamic efficiency which is slightly above 100 % because complete oxidation of carbon to CO₂ is accompanied by a positive near-zero entropy change. Realisation of the high intrinsic efficiency is at present hampered by performance limitations and degradation of the electrodes and electrolytes, resulting in an impressive coal-to-electricity efficiency of higher than 60-65 %, making DCFC very promising for large-scale stationary power generation. In Figure 15.4, the electrical efficiency is shown for various fuel cell types and other power generation technologies used in stationary applications.

As is the case for efficiency and durability, the cost reduction potential for stationary fuel cells depends on the application. For small-power range systems, enhanced integration is a major cost-reducing factor whereas for large-power range, improving fuel flexibility and gas clean-up are important. Both power ranges will also benefit from higher manufacturing volumes. For domestic and residential CHP below

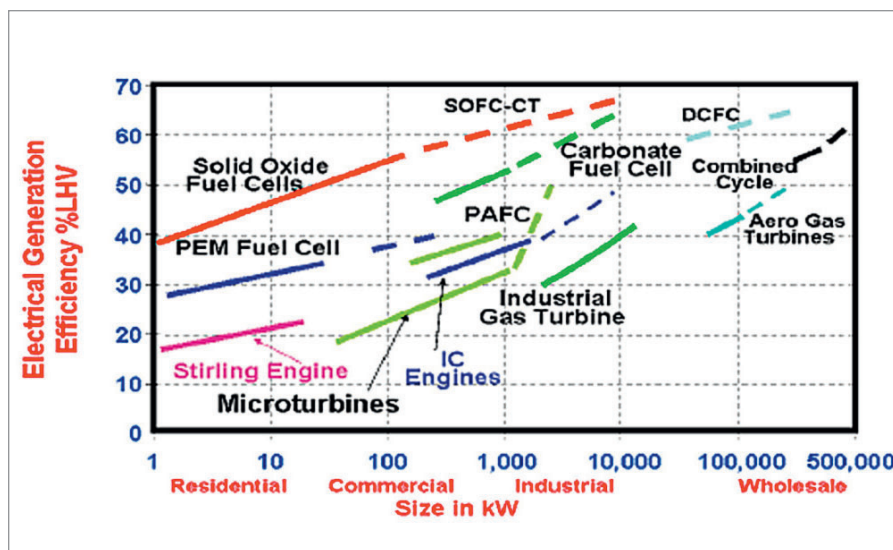


Figure 15.4: Electrical efficiency of various fuel cell types and other power generation technologies [Source: EPRI, 2007]

50 kWe, the MAIP 2020 target is €2 000/kW at system level, a factor of 2.5 down from a present cost of €5 000/kW. According to the DoE 2010 Program Plan, stationary fuel cells in the 1-100 kWe range cost from \$3 000 to \$10 000/kW today with a target of \$900/kW. The respective figure for 1-10 kWe APU is \$1000/kW, whereas MAIP mentions €500/kW, down from a present status of €3 000/kW. For APUs in non-road transport, the MAIP 2020 targets are €500/kW for aviation and €2 000/kW for maritime applications. For stationary fuel cells in the range 300 kW to 5 MW, system-level capital costs in MAIP range from a 2010 status of €8 000/kW for MCFC down to €4 500/kW for PEMFC, and 2020 targets of respectively €2 000/kW and €1 500/kW. MAIP target for AFC is €600/kW.

15.2.5 Early markets

Although fuel cells and hydrogen technologies are still some distance away from full commercialisation, industry has identified early markets that exploit one or more advantages of the technology (high efficiency and reduced energy consumption, low noise, low heat signature, absence of exhaust fumes, reduction of space requirements and weight, longer runtime, etc.) and that can already be implemented using current technology. Such markets include material handling vehicles (> 5 original equipment manufacturers (OEMs)), back-up and UPS stationary power (> 10 OEMs), portable applications (> 40 OEMs), vehicle auxiliary power units (> 5 OEMs), captive fleets (> 5 OEMs), scooters/wheelchairs (> 10 OEMs). The majority of these early market applications compete with pure-battery electric counterparts

⁶⁰ In this sense, MCFC and SOFC fed by CO₂-containing flue gas to the cathode represent a carbon capture technology that does not use power for capture and hence decreases overall power generation efficiency, but actually produces power while allowing easy capture of CO₂.

and make use of PEMFC and DMFC technology. The MAIP lists actual technical status and targets for efficiency and durability for these applications. Due to their much lower weight and hence higher energy density than rechargeable batteries, fuel cells are also very attractive in military applications for powering mobile equipment of soldiers and of unmanned sensors, surveillance systems and unmanned vehicles.

15.3. Market and industry status and potential

Due to the substantial contribution they can deliver towards achieving the EU energy and climate change policy goals and in enabling the transition towards low-carbon energy and transport systems across a very high power range, fuel cells and hydrogen technologies have a very high development potential. Their market penetration is envisaged to develop as follows: micro and portable fuel cells will increase sharply in the very near future, followed by increasing numbers of residential heat and power systems, auxiliary power units, fleets and buses, and then light-duty vehicles powered by PEMFC as of 2015. Between 2007 and 2009, global shipments of fuel cell systems doubled, and tripled in terms of power [DoE, 2011a]. Forklifts and other materials-handling vehicles constituted a breakout market in 2008 and 2009. The global total of fuel cell units installed in 2010 is close to 3 000 and is expected to reach 20 000 units by 2020.

Cumulative global investment in fuel cell and hydrogen technologies totalled roughly USD 630 million between 2008 and 2010, with fuel cells amounting to USD 578 million. The top-10 investors in fuel cells and hydrogen in 2010 contain seven European-based companies, up from three in 2009, indicating a growing interest in these technologies in the EU [DoE, 2011b]. A recent US study on the near- to mid-term market potential of fuel cells estimates that the global fuel cell/hydrogen market could reach maturity over the next 10 to 20 years. Within this timeframe, it is estimated that global revenues would reach

between USD 43 billion and USD 139 billion annually [DoE, 2010], distributed as follows: USD 14–31 billion/year for stationary power, USD 11 billion/year for portable power and USD 18–97 billion/year for transportation. Increasing investments and revenues go hand in hand with a considerable growth in employment, as indicated for the US in Figure 15.5, where ranges from two studies are shown.

15.3.1 Fuel Cells

The adoption of fuel cell powered products is gathering increasing momentum within a wide range of applications and the shift from an R&D-based industry to a fully commercial one has clearly started. Beyond early market applications, a number of stationary fuel cell manufacturers have made announcements of investments in manufacturing, indicating that market penetration is imminent, whereas FCEVs will continue to see growing deployment.

The size of the fuel cell trade in 2010 and market forecasts for the major application areas are listed in Table 15.4 [PikeResearch, 2011; FuelCellToday, 2011].

Notwithstanding the global recession, between 2008 and 2010 the fuel cell industry experienced a compound annual growth rate in shipments of 27 %, with more than 50 % stationary fuel cell systems by the end of 2010. Over 90 % of units shipped in 2010 were low-temperature fuel cells (PEMFC and DMFC). However, low-temperature fuel cells made up only 50 % of the total MW shipped. South Korea aspires to supply 20 % of worldwide shipments of fuel cells by 2025 and to create 560 000 jobs.

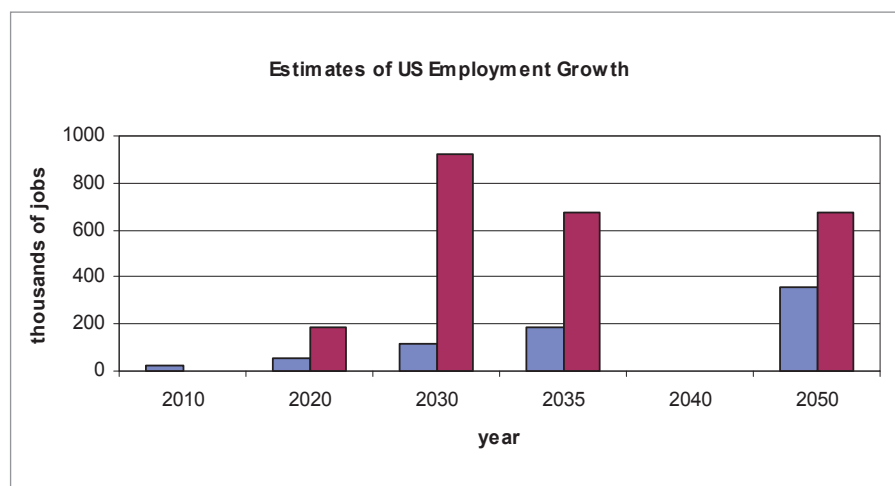


Figure 15.5: Results from two US studies, indicating increased investment and revenue is related to increased employment [DoE, 2010]

		2010 global shipments	market forecast
Stationary – PEMFC	off-grid power generation (telecommunications); micro-CHP for domestic and commercial (hotels, hospitals); prime power; back-up power	<ul style="list-style-type: none"> • 9 200 units (45 %), of which more than 5 000 (domestic) in Japan • 63 MW, of which more than 20 MW in South Korea 	USD 9.5 billion (2017)
Stationary - MCFC, AFC, SOFC	Large-scale power generation + CHP		
Portable PEMFC, DMFC	remote monitoring units; external battery rechargers; consumer electronics (laptops, smartphones), military	<ul style="list-style-type: none"> • 22 % of units • Very low MW 	USD 2.8 billion (2017)
Transport PEMFC	LDV, buses, materials handling, unmanned aerial vehicles	<ul style="list-style-type: none"> • 33 % of units • 27 MW 	390 000 LDV (2020)
Transport SOFC	APU (trucks, recreational vehicles)		
		Total 90 MW; 15 000 units	

Table 15.4: FC trade in 2010 and market forecasts

Transport applications

The highest profile application of fuel cells is in light-duty road transport, where FCEV commercialisation is anticipated in Europe in 2015, led by Germany, and in Asia, led by South Korea and Japan. Production is expected to be in the hundreds of units in 2011 and in the tens of thousands by 2015. Germany aims to have 500 000 fuel cell powered (and 1 million battery-powered) vehicles on the road by 2020 and projects the mass market of FCEV to start in 2015. Denmark announced an ambitious clean-vehicle programme with the objective that all new vehicles sold after 2025 will be either electric or hydrogen powered [IPHE, 2010]. In the first 5 years of commercialisation (2015-2020), a global growth averaging around 47 % is expected from around 60 000 cars in 2015 to just below 400 000 in 2020 [PikeResearch, 2011]. Automakers involved are Mercedes, Ford, GM/Opel, Honda, Renault/Nissan Toyota, Hyundai/Kia and SAIC (China), with Hyundai the most ambitious targeting 2 000 and 10 000 vehicles per year in 2013 and 2015 respectively.

In recent years, because of possible advantages in terms of reducing CO₂ emissions and oil dependence in the shorter-term, battery-electric vehicles (BEV) have drawn attention and public funding at the expense of FCEV. The McKinsey study highlighted the complementarity of BEV and FCEV in terms of range and of duty-cycle and stated that significant penetration of both fuel cell and battery electric vehicles will be needed to build a sustainable transportation system

by 2050. Other important conclusions are that FCEV provide the best low-carbon solution in the medium and large car segments, which account for 50 % of all cars and 75 % of CO₂ emissions. Both FCEVs and BEVs could be cost-competitive with internal combustion engines (ICEs) as early as 2025 (and with tax incentives even as of 2020) and costs for electrical and hydrogen infrastructures would be comparable and affordable.

Next to LDV applications, PEMFC can also be used in medium- and heavy-duty vehicles such as buses, vans and light-rail trains that have to operate primarily in densely populated and increasingly congested urban areas where zero tailpipe emissions and low noise are most important. The MAIP aims at the deployment of 1 000 buses by 2020. For other heavy-duty road transport applications, such as trucks and coaches, diesel engines with advanced emissions control are at present well placed to meet the requirements in terms of long-distance and speed duty cycles. Even with increasing CO₂ emission requirements, because of the high power needed, fuel cells for trucks and long-distance coaches are expected to remain cost prohibitive and other alternative fuel options, such as biofuels, preferred.

For non-road transportation, the current EU interest, triggered by environmental considerations, of shifting freight transport from road to rail and to in-land waterways, strengthens the position of hydrogen fuel cells for use in in-land vessels, as

well as in leisure craft. For airplanes and ocean-going ships, hydrogen fuel cells are not considered for propulsion due to the much longer lifetimes and higher power requirements which would result in prohibitive costs. However, as fuel cell cost scales directly with power rating and hence fuel cells are cheaper for lower-kW applications, they are currently explored as range extenders in BEVs, as well as incorporated in small, lightweight platforms (e.g. golf carts). A number of taxis in London use a 30 kW fuel cell that acts as range extender for the 14 kWh lithium-ion battery pack, bringing the range to 400 km. Another small power range application with a fast growing market is the replacement of lead-acid battery forklifts for indoor-use with hydrogen fuel cell-powered alternatives. Due to their increased performance and decreased maintenance needs, fuel cells can be competitive with batteries on a life-cycle basis. This is contributed to by fast refuelling possibilities (2-3 minutes on average), maintenance of full power capability for extended time periods between refuelling (more than 8 hours), performance independent of ambient temperature and absence of battery storage and battery changing areas. At present the life of the fuel cell stack and the lack of hydrogen availability at reasonable cost are the most important hurdles for this application.

APU for transport

Fuel cells can provide clean, efficient auxiliary power for trucks, recreational vehicles, marine vessels (yachts, leisure crafts, commercial ships), airplanes, locomotives and similar applications where the primary motive-power engines are often kept running solely for auxiliary loads, resulting in significant additional fuel consumption and emissions. As emissions from idling and auxiliary power are the subject of increasing regulations worldwide, fuel cells (SOFC, as well as in future high-temperature-PEMFC) are expected to play an increasing role as APUs in these applications. The EU market size for truck APUs is estimated at 100 000 units. The MAIP targets some hundreds of aircraft APUs by 2020 and a similar number in maritime applications. The use of hydrogen-to-fuel APUs in maritime applications and in aviation offers a large synergy potential for linking with hydrogen-fuelled logistical and public transportation applications in ports and airports.

Stationary power generation and combined heat & power (CHP)

The stationary sector represents the largest demand potential and the most promising option to adopt renewable energy sources and to reduce GHG emissions and dependence on fossil fuel. In stationary applications, fuel cells are used where

their high part-load electrical efficiency, high combined power and heat efficiency and their load-following ability provide a competitive edge.

For small-scale residential applications, the increased efficiency reduces electricity costs, but more importantly slows down the rate of increase of energy demand. Other small-scale, high volume application areas are off-grid power generation for islands and remote locations (mobile telephone transmitter stations, ski resorts, military deployments, etc.) where reliability and avoided cost of downtime are the main considerations. For back-up power systems, hydrogen fuel cells offer fast start-up, long continuous runtime and do not lose energy when not in use, resulting in a far lower replacement rate than batteries. Compared to generators using fossil fuels (diesel, propane, gasoline), they are quieter, produce no emissions and require less maintenance. Typical back-up applications include hospitals, data centres, telecom towers and stations of the public safety communication network.

At present, thousands of small low and high temperature PEMFC and SOFC systems, fuelled by hydrogen or natural gas, are being demonstrated in private homes in Germany, Denmark,⁶¹ Japan and the Republic of South Korea. The German Callux⁶² project aims at deploying up to 800 units of 1 kW and 5 kW in residential CHP applications up to 2015, after which commercialisation is expected to start. A total of 100 units using low- and high-temperature PEMFC and SOFC are being demonstrated under the Danish demo project on Fuel Cell Based Micro-CHP. In 2009, Japanese gas companies started selling PEMFC systems for residential use, fed by natural gas, LPG or kerosene. About 10 000 residential fuel cells with a power level of 0.7-1.0 kW provide Japanese homes with heat and electric power. Today only PEMFCs are being used with SOFC technology, which is expected to pick up in the coming years. The target is to sell 2.5 million units by 2030. The Japanese Ministry of Economy, Trade and Industry recently launched its Hydrogen Town Project, the first demonstration of its kind in the world where hydrogen for fuel cells in residential and commercial buildings is distributed by pipelines in an urban district. Starting from 200 micro-CHP systems in 2010, the South Korean government aims installing more than 100 000 residential fuel cells and an

⁶¹ In 2008, Denmark had the highest global public investment in fuel cell and hydrogen technologies per GDP.

⁶² Practical Tests for Fuel Cells in a Domestic Setting, www.callux.net

export industry by 2020 [PikeResearch, 2011; DoE, 2011b]. The MAIP targets the deployment of 50 000 domestic and residential CHP systems by 2020.

A specific feature of CHP fuel cell systems is that in combination with an absorption chiller, they can use waste heat for refrigeration, which makes them very attractive for covering the cooling needs of supermarkets, convenience stores and data centres. A number of such applications are being demonstrated in the US. Another new application is the provision of reduced oxygen-content air (15 %) from the fuel cell exhaust gas for fire-suppression systems.

For industrial scale-base power generation, efficiency under base-load operation is the prime criterion, whereas the fact that generation of power does not require any water – and even produces it – is getting more and more important. In this sector, high temperature MCFC and SOFC constitute the larger part of the market⁶³, and PEMFC and AFC are only expected where pure hydrogen is available in sufficient quantity at low-cost, e.g. vented by-product hydrogen. In the EU, an estimated $2\text{-}3 \times 10^9$ m³ is vented, corresponding to 400 MWh [Krediet, 2009]. Both in the EU and in the US, a 1 MW PEMFC plant will be put on line in 2011, whereas in Italy, a hydrogen-fuelled 12 MWe combined cycle plant has started electricity production in 2010. The plant uses 1.3 t/h of hydrogen by-product from a nearby petrochemical site and has an overall efficiency of about 42 %. In South Korea, a 2.4 MW MCFC power plant has been installed, with a 5.6 MW plant to be built still in 2011 and a 60 MW plant being proposed. The MAIP targets 100 MW installed capacity using natural gas and 50 MW hydrogen-based in 2020. Additionally, with increasing needs for energy storage to balance the intermittency of renewable energy sources, a substantial growth in PEMFC-based peak power generation is expected because of the superior performance of fuel cells in terms of response time and partial load efficiency.

The importance of CHP and micro-CHP will continue to increase in the future as smart grids integrate a large number of distributed power generation units in “virtual plants”. Ultimately, stationary fuel cells are expected to become the reference technology for on-demand power generation in the residential and industrial sectors.

15.3.2 Hydrogen production

The bulk of the hydrogen business revolves around its use as an industrial chemical, for petroleum refining, in fertiliser production and in metals and food processing. Hydrogen production capacities in Europe in 2009 amounted to 26 t/day cryogenic liquid and 2 340 t/day gaseous hydrogen, a total of 0.86 Mt/yr [DoE, 2009].

Global demand for hydrogen fuel (FCEVs, buses, forklifts, UPS, scooters) is expected to reach over 0.4 Mt/yr by 2020, reflecting a 2010-2020 compound average growth rate of 88 % globally. A steep increase is expected from the projected introduction of commercial FCEVs in 2015. The largest part of hydrogen fuel demand prior to 2015 is at present expected to stem from the forklift sector [Pike Research, 2011].

The technologies and primary energies used for hydrogen production depend on government ambitions and framework conditions at national, regional and local level, regionally-available energy sources, as well as achievements in technological development. The MAIP targets a 100 t/day hydrogen production capacity from renewables by 2020. By 2050, hydrogen should be produced through carbon-free or carbon-lean processes. In the McKinsey study, an economically driven production mix scenario is considered for producing the necessary hydrogen for the FCEV fleet leading to CO₂-free hydrogen production by 2050. Before 2020, centralised and distributed SMR, as well as distributed electrolysis, will be used in addition to by-product hydrogen, all using existing facilities. Beyond 2020, with the uptake of FCEV deployment, additional production facilities come on-line, with CCS applied to the centralised production methods (SMR, IGCC and coal gasification) and the share of renewables in the power generating mix steadily increasing. Large-scale electrolysis and gasification are key technologies beyond 2020.

15.3.3 Hydrogen Infrastructure

The deployment of FCEVs must be accompanied by setting up the required refuelling infrastructure. Worldwide, 22 new hydrogen refuelling stations opened in 2010, increasing the total to 212. Another 127 stations are in the planning stage.⁶⁴ Respective

⁶³ Due to the departure of a German MCFC manufacturer from the business, the German lighthouse project for high-temperature fuel cells of about 300 kW with up to 10 installations (in hospitals, airports, breweries) is presently on hold.

⁶⁴ www.h2stations.org

figures for Europe are 11, 80 and 13. In 2009, leading auto and energy companies and the government in Germany formed the H2Mobility Initiative. Between 2012 and 2015, this will develop a comprehensive nationwide hydrogen fuelling network with up to 1 000 hydrogen stations. Similarly, in Japan, domestic oil and gas companies joined with automakers to announce a collaborative effort to build 50 to 100 filling stations in 4 Japanese cities and along linking highways by 2015. By 2025, 1 000 stations and two million FCEVs are targeted and profitable business for both fuelling stations and FCEVs is expected. South Korea anticipates 13 stations by the end of 2011 [PikeResearch, 2011]. The MAIP targets 2 000 stations by 2020. For fuel cell buses and forklifts, the refuelling equipment is implemented together with their deployment and does not require the roll-out of a dedicated infrastructure.

The McKinsey study evaluates the total cumulative investments till 2050 for build-up of the refuelling infrastructure for a FCEV fleet of around 70 million vehicles at EUR 101 billion. This amounts to around 5 % of the overall cost of FCEVs, i.e. EUR 1 000-2 000 per vehicle. These costs per vehicle are very similar to those in the US, estimated at USD 1 500 per vehicle, for a number of 219 million vehicles with a corresponding infrastructural capital cost of USD 415 billion in 2050 [NAS, 2008].

Use of hydrogen as a storage medium enables time-shifting of wind and solar generated electricity to compensate for daily and seasonal variability and ensure a balance between supply and demand. In addition to helping balance generation and load, storage at regional level can also increase network stability and power quality and improve frequency regulation. Electrification of road transport will contribute to this: BEV in large numbers can provide buffering and reserve capacity in a grid with associated demand management ("smart" grid), whereas FCEVs provide reserve capacity that can be fuelled from long-term high-volume hydrogen storage. The MAIP targets a 580 tonne, total installed storage capacity of hydrogen produced from renewable grid electricity by 2020.

15.3.4 Early markets

Despite their limited commercial contribution to critical mass markets (such as automotive), as well as to reduction of GHG emissions, early markets are recognised to have a strong positive effect on the maturing process of the technologies: they serve as stepping stones towards commercial roll-out in large

volume applications by accelerating the learning among manufacturers, developers, financiers, authorities and the general public. They build a manufacturing and supplier base, create an initial revenue stream and new employment and allow the timely build-up of an enabling regulatory, codes and standards (RCS) framework.

The consumer electronics market is of enormous potential (> 250 000 portable units by 2020 in MAIP), mainly because of the high energy density offered by fuel cells. However, further significant improvements in power density are needed to enable the miniaturisation necessary for fuel cells to be integrated directly into consumer electronics. New niche markets, such as remote monitoring (environment, security) also have significant potential because of lower maintenance costs and longer endurance offered by fuel cells. In these applications, fuel cells are also safer and more environmentally benign compared to batteries for recycling.

15.4. Barriers to large-scale deployment

A major barrier to large-scale deployment of fuel cell and hydrogen technologies is their disruptive nature. In order not to disturb the existing energy system, they have to be phased-in gradually in applications where they surpass existing, as well as less disruptive, new technologies in terms of overall performance and/or lifecycle costs. As an energy carrier, hydrogen has thus to compete with electricity and biofuels for its production from primary energy sources, increasingly renewable ones, whereas fuel cells, particularly for automotive applications, face increasing competition from other zero-emission technologies, such as battery electric and plug-in hybrid electric vehicles. Together, fuel cells and hydrogen technologies have to face the established market position and public acceptance of competing incumbent technologies and systems for which external costs are not included in their overall costing.

Specific technological barriers for fuel cell and hydrogen technologies include performance and durability of fuel cells, efficiency of large-volume carbon-free hydrogen production and storage safety of captured CO₂, energy density of on-board hydrogen storage and systems integration. Economical obstacles include cost of fuel cells and of hydrogen and lack of cash-flow and of a supply base during the first phase of deployment. The main institutional hurdles are difficulties of

policy and regulatory frameworks for disruptive technologies moving from demonstration to large-scale deployment across the “valley of death”. Societal barriers include insufficient coverage of fuel cells and hydrogen technologies in education curricula and the resulting safety perception and low awareness of societal benefits. An important barrier is that current regulations, codes and standards do not adequately reflect real-world use of fuel cells and hydrogen technologies and that they are not harmonised between countries.

As market forces alone cannot overcome these barriers, technology-push, as well as regulatory-pull measures, including tailored and time-phased policies and incentives that target public and private market actors, are needed to bridge the transition to self-sustaining FCH commercial activities. In

view of the long-term horizon and the very high pay-off in terms of contribution to EU policy goals of GHG emissions reduction, supply security, urban pollution reduction and enhanced competitive base, public support is and will remain necessary to help reduce industry development times and offsetting first-mover disadvantages. This is even more the case in the current economical situation. An overview of policies and strategic plans aimed at supporting increased use of fuel cells and hydrogen in IPHE member countries is given in [IPHE, 2011]. For example, in the US, dedicated government funding of USD 42 million under the American Recovery and Reinvestment Act has successfully funded projects to deploy up to 1 000 fuel cells for material handling, back-up power, and CHP, thereby allowing fuel cell manufacturing companies to gain new customers, notwithstanding adverse economic conditions.

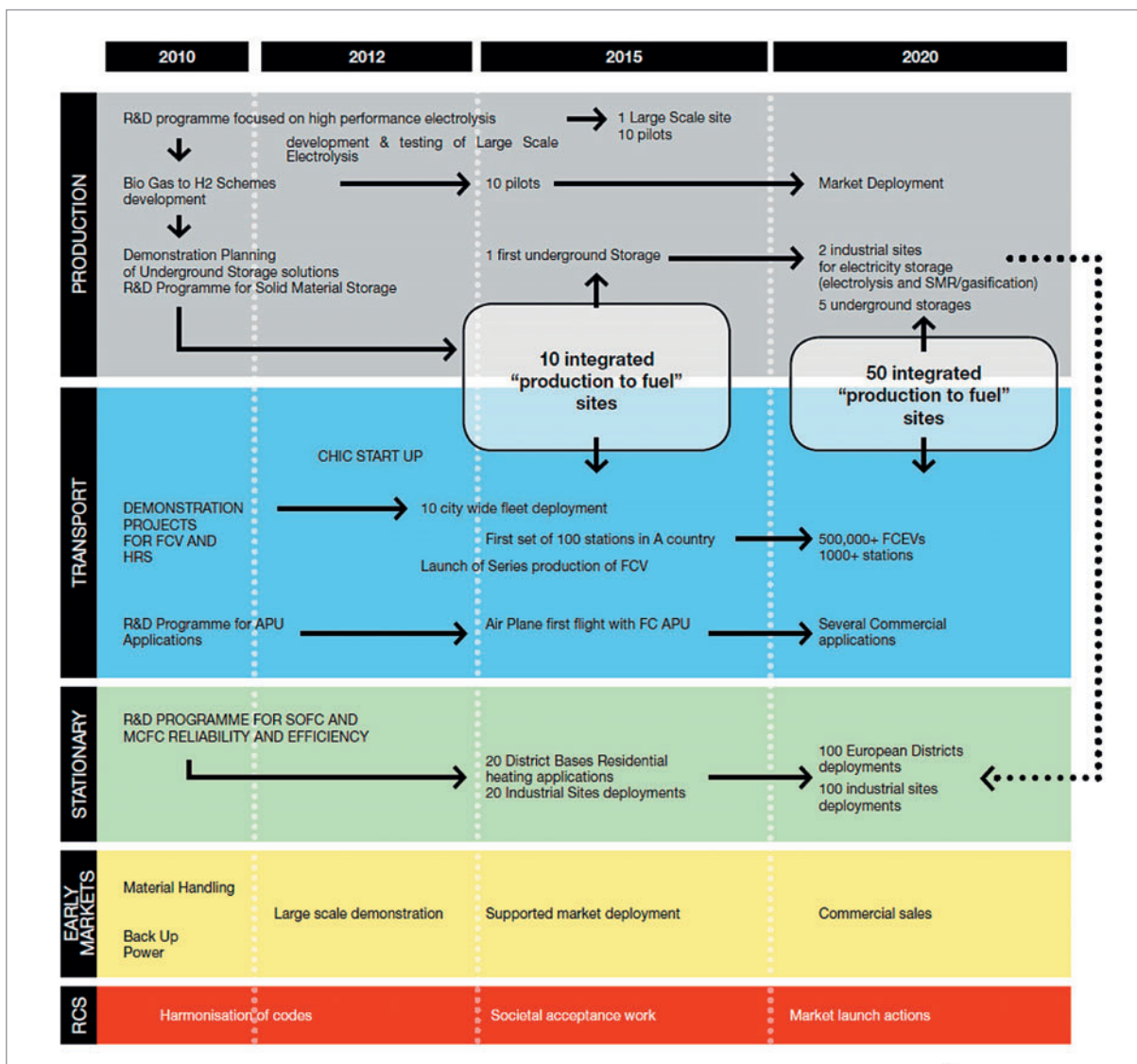


Figure 15.6: Schematic roadmap for RD&D activities in FCH [Source: FCH Technology Roadmap]⁶⁵

15.5. RD&D priorities and current initiatives

Whereas fuel cells and hydrogen technologies are already penetrating the market in a number of applications, sustained R&D, private and public, is still needed for effectively addressing the remaining high-risk technological barriers in a pre-competitive environment. This includes in particular, R&D into cost-reduction, new concepts and alternative engineering approaches in all application areas, especially for the automotive sector. The research priorities on materials and product development, on component and system manufacturing technologies, as well as the required research infrastructure have been identified in the fuel cells and hydrogen chapter of the SET-Plan Materials Roadmap, which also includes the technical state of the art, as well as targets for 2020 and beyond. Other R&D areas, preferably to be carried out through international cooperation, are pre-normative research for the establishment of fit-for-purpose RCS to ensure safety, compatibility and interchangeability of technologies and systems, fair competition in a global market, socio-economic modelling to optimise the entry of fuel cells and hydrogen technologies in the energy system at the right place and time, and hence to guide infrastructure transition planning. With an increasing number of technologies nearing maturity, emphasis in the near future will shift from supporting R&D to support large-scale demonstration, validation and deployment.

RD&D activities on fuel cells and hydrogen technologies at the EU level are coordinated by the public-private partnership FCH-JU. Under the steering of the Programme Office, the Multi-Annual Implementation Plan has been updated and a Technology Roadmap has been drafted for the period 2010-2020, similar to the technology roadmaps of other European Industrial Initiatives (EII) of the SET-Plan. This Roadmap identifies concrete actions in the 2010-2020 period to reach the technology maturity needed for achieving large market penetration beyond 2020, as well as estimates of the associated financial effort. The schematic roadmap is shown in Figure 15.6.

In implementing the actions identified in the Technology Roadmap, synergies will be sought with actions included in the SET-Plan EIIs⁶⁶ and in other relevant partnerships with (partial) EU funding⁶⁷ and with relevant programmes in EU Member States and Regions.⁶⁸ Long-term and breakthrough-oriented research will be streamlined with activities performed under the European Energy Research Alliance (EERA).

An accompanying measure to increase efficiency and effectiveness of public-private RD&D funding on fuel cells and hydrogen is the organisation of progress review days, adopting the US model to EU circumstances.⁶⁹ FCH-JU will organise its first review days in 2011.

⁶⁵ Fuel Cells and Hydrogen Joint Undertaking (FCH-JU) www.fch-ju.eu

⁶⁶ For example with the EII on Sustainable Nuclear Energy hydrogen production, with the EIIs on Wind, on Solar and on Smart Grids for energy storage and grid interaction

⁶⁷ e.g. FP7 energy projects, the European Green Car Initiative launched under the EU Recovery Plan

⁶⁸ The largest among these is the German programme [<http://www.now-gmbh.de>], focused on demonstration and commercialisation of fuel cell and hydrogen technologies, with a budget envelope of EUR 1.4 billion for the period 2007-2015, exceeding that of FCH-JU.

⁶⁹ Financial and other benefits of peer review in reducing programme costs by avoiding continued investments in projects determined to be unproductive or misaligned with programme goals, are described in [DoE, 2008]

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16. Electricity Storage in the Power Sector



16.1. Introduction

Electricity storage is identified as a key technology priority in the development of the European power system, in line with the 2020 and 2050 EU energy targets [European Commission, 2007; 2009; 2010]. Power storage has gained high political interest in the light of the development of renewables and distributed generation, as a way to reduce carbon emissions, to improve grid stability and to control the fluctuations of variable resources.

Power storage systems can benefit generators, transmission and distribution utilities, and end-users. They can balance energy flows, thus facilitating the integration of variable renewables, and can provide system services⁷⁰ and support to electricity infrastructure, such as asset deferral [EAC, 2008]. Among storage technologies commercially available or under development, the following systems are mapped hereafter: pumped hydro storage (PHS), compressed air energy storage (CAES), hydrogen and fuel cells, flywheels, supercapacitors, superconducting magnetic energy storage (SMES) and conventional/advanced/flow batteries.

The services needed by the power system indicate the technical requirements to be met by the storage devices suitable for energy and for power quality applications. Energy applications differ from power applications mainly for the discharge time and the capacity involved.

For energy applications, a storage discharge time over several hours and a nominal capacity in the order of 1-500 MW are expected on the generation side, and of kW on the end-user side. Wind and solar curtailment avoidance, load shifting and forecast hedging are typical energy related applications. The most suitable technologies are pumped hydro, CAES, fuel cells and hydrogen and batteries (lead-acid, nickel-cadmium, sodium-sulphur or vanadium-redox).

Power applications are related to services provided for periods from a few seconds to less than an hour with a typical power rating lower than 1 MW.

They are needed to face network disturbances requiring a response time in order of milliseconds for regulating voltage fluctuations,⁷¹ and in the order of a few seconds for adjusting frequency fluctuations. Adequate technologies are flywheels, ultra-capacitors, SMES and some of the advanced batteries.

Figure 16.1 gives an overview of the power storage technologies, as a function of their commercial maturity stage and the power investment cost.⁷² Applications suitable also for transport electrification, such as lithium-ion, hydrogen and supercapacitors are mapped with services provided to the power system only.

16.2. Technological state of the art and anticipated developments

A wide array of technologies and underlying principles - mechanical, electro-chemical and physical - is today available to store electricity, providing a large spectrum of performance and capacity for different application environments. The current installed capacities worldwide are around 127.9 GW [EPRI, 2010].⁷³

Table 16.1 gives the main technical and economic features of the storage technologies which are mapped in this chapter. The various sources used for this review can provide different figures for the same technology. These sources might use different operational parameters, market indicators, prices and tariffs. Therefore intervals for some technologies can be large to withstand the uncertainty related to developing technologies, but also the specificities of project environments for different valuation methodologies.

Hydropower with storage

Hydropower with storage is a mature technology, being the oldest and the largest of all available energy storage technologies. The facilities are usually distinguished in two main categories: hydropower with reservoir and pumped hydro-storage (PHS). The basic principle of a PHS system is to store energy by

⁷⁰ System services are all services provided by a system operator to users connected to the system. Some users provide system services that are ancillary to their production or consumption of energy [EURELECTRIC, 2004].

⁷¹ Voltage swells, impulses, notches, flickers, harmonics [EPRI, 2004].

⁷² The on-line version of this document allows for an interactive overview of technologies as a function of their energy cost, efficiency and number of cycles.

⁷³ The following capacities are installed worldwide, admitting that the comparison of large- with small-scale capacities is not the purpose, and that the number of installed units should complement the size of capacities: PHS 127 GW, CAES 440 MW, Sodium-sulphur 316 MW, Lead-acid 35 MW, Nickel-cadmium 27 MW, Flywheels 25 MW, Lithium-ion 20 MW, Redox-Flow batteries 3 MW [EPRI, 2010], SMES 100 MW [EERA, 2011].

means of two reservoirs located at different elevations. In times of low demand, electricity from the grid is used to pump water to the higher reservoir, while in times of peak demand the water is released to generate electricity, hence operating a reversible cycle of grid electricity.

In Europe, the installed capacity of pure hydro-pumped storage amounts to approximately 40 GW. It is estimated that by 2030, about 50 % of the currently installed capacity of hydro-pumped storage in Europe will have to be refurbished due to ageing [SETIS, 2008]. Some of these projects have already started and moreover, they have been optimising the turbine and pumps system in order to increase the generation capacity, for example, in the Alpine region, where new and larger converter units have being added to existing storage basins [RRI, 2008]. The capacity of planned or ongoing projects in Europe is estimated to about 7 GW to be built by 2020 mainly in Switzerland, Austria, Portugal, Germany and Spain [Deane et al., 2008]. Additionally, the large pumped hydro-storage potential existing in Norway, estimated to 10-25 GW of new projects, could be further exploited, triggered by the large deployment of wind power in the North Sea [Haaheim, 2010; SETIS, 2009].

Main barriers to the installation of new pumped hydro-plants are the environmental concern and the public acceptability when projects might affect the resource availability and inundate the ecosystem. New PHS plants require usually large electricity transmission infrastructures, which might raise political, social and regulatory issues. The initial investment costs are high, the construction time could be long up to 15 years along with the time lag for obtaining the approval for concession rights and connection to the grid [ETSAP, 2010]. Life cycle emissions related to the construction of a PHS storage facility are in the range of 35 tCO₂eq/MWh_e of storage capacity [Denholm and Kulcinski, 2004].

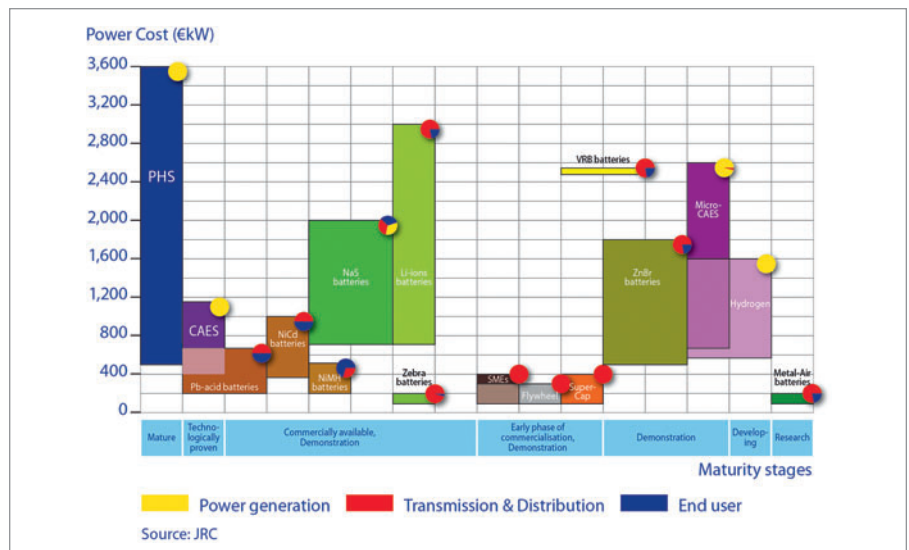


Figure 16.1: Power storage technologies as a function of their cost and development stage [Source: JRC]

The main advantages of PHS systems are high storage capacity, quick start capabilities, low self-discharge, long technical life-time and high number of cycles, which make the technology suitable for regulation provision and for supporting the variable electricity generation. The main applications are load shifting, price arbitrage, tertiary and secondary reserves for up and down regulation, as spinning or standing reserve, peak power supply, forecast hedging, grid congestion avoidance, load following, energy balancing and seasonal fluctuations regulation [EPRI, 2002].

Recent technological advances are mainly related to the double stage regulated pump-turbine, which gives the possibility to utilise a very high head for pumped storage. This provides higher energy and efficiency, and also variable speed drive. This allows wider grid support and better economics, flexibility and reliability [Deane et al., 2010; EPRI, 2004]. Further developments concern the challenges to the technology of using sea water, as at present only one scheme has been built that uses the sea as lower reservoir, i.e. in Okinawa, Japan [Peters and O'Malley, 2008]. Alternatives to conventional geological formations are PHS plants using underground reservoirs [Ekman and Jensen, 2010] or former opencast mines, e.g. from granite mining in Estonia [Kruus, 2010] and from coal mining in Germany [Schulz and Jordan, 2010].

Storage technology	PHS	CAES	Hydrogen	Flywheel	SMES	Supercap	Conventional Batteries		Advanced Batteries			Flow batteries	
							Pb-acid	NiCd	Li-ion	NaS	NaNiCl ZEBRA	VRB	ZnBr
Power rating, MW	100-5000	100-300	0.001-50	0.002-20	0.01-10	0.01-1	0.001-50	0.001-40	0.5-50	0.001-1	0.03-7	0.05-2	
Energy rating	1-24h+	1-24h+	s-24h+	15s-15min	ms-5min	ms-1h	s-3h	min-h	s-hours	Min-h	s-10h	s-10h	
Response time	s-min	5-15 min	min	s	Ms	ms					ms	ms	
Energy density, Wh/kg	0.5-1.5	30-60	800-10000	5-130	0.5-5	0.1-15	30-50	75-250	150-240	125	75	60-80	
Power density, W/kg			500+	400-1600	500-2000	0.1-10	75-300	150-315	90-230	130-160	15-30	50-150	
Operating temp (°C)				-20 - +40		-40 - +85			300-350	300	0-40		
Self-discharge (%/day)	~0	~0	0.5-2	20-100	10-15	2-40	0.1-0.3	0.1-0.3	20	15	0-10	1	
Round-trip efficiency	75-85	42-54	20-50	85-95	95	85-98	60-95	85-100	85-90	90	85	70-75	
Lifetime (years)	50-100	25-40	5-15	20+	20	20+	3-15	5-15	10-15	10-14	5-20	5-10	
Cycles	2x10 ⁴ - 5x10 ⁴	5x10 ³ - 2x10 ⁴	10 ³ +	10 ⁵ -10 ⁷	10 ⁴	10 ⁴ -10 ⁸	100-1000	10 ³ -10 ⁴	2000-4500	2500+	10 ⁴ +	2000+	
Power cost €/kW	500-3600	400-1150	550-1600	100-300	100-400	100-400	200-650	700-3000	700-2000	100-200	2500	500-1800	
Energy cost €/kWh	60-150	10-120	1-15	1000-3500	700-7000	300-4000	50-300	200-1800	200-900	70-150	100-1000	100-700	

Note. The power price reported for hydrogen relates to gas turbine based generator. The power price for fuel cells is in range of 2 000-6 600 €/kW. Sources: Schoenung and Hassenzahl, 2003; Chen et al., 2009; Beaudin et al., 2010; EERA, 2011; BNEF, 2011b; Nakhamkin, 2008.

Table 16.1: Technical and economic features of power storage technologies

Compressed air energy storage (CAES)

In CAES systems, the energy is stored mechanically, usually in underground caverns, by compressing the air from the atmosphere. A typical CAES system is a combination of natural gas combustion and high pressure of the compressed air to drive the turbines. When electricity is required, the compressed air is drawn from the cavern, then heated in gas burners and expanded in a gas turbine [Lund and Salgi, 2009; Hadjipaschalis et al., 2009].

The compression of air creates heat, whilst air expansion causes cooling. The way the heat and cooling are processed generates three categories of thermodynamic processes:

- 1) Diabatic CAES, where the compressed air is stored and the heat from the compression is lost. When energy is needed, gas turbines are used to reheat the compressed air. The efficiency is in range of 40-54 %, but alternative designs of cycles exist and result in improved efficiency rates [BNEF, 2011b]: CAES with recuperated cycle; CAES with combined cycle; CAES with steam-injected cycle; CAES with humidification.
- 2) Adiabatic CAES (AA-CAES), where the heat resulting from the compression process is stored and is reused when the compressed air is released. Heat can be stored in solid, fluid or molten salt solutions, at temperatures from 50 to over 600 °C [Bullough et al., 2004]. Compared with a diabatic system, the AA-CAES does not need additional gas co-firing, and the energetic process is more efficient (70 %).
- 3) Isothermal compression, which employs a thermo-dynamically reversible cycle, where the temperature is maintained constant by allowing continuous heat exchange during air compression and expansion. The process approaches a theoretical efficiency of 100 %.

Two CAES facilities are currently in operation, one in Germany in Huntorf built by Alstom Power in 1978, with a rated output power capacity of 320 MW and a discharge average of 3 hours per day [RWE, 2010]; and the second in Alabama, USA built by Dresser-Rand in 1991, with a rated power output of 110 MW and a discharge time up to 10 hours during weekends [Ibrahim et al., 2008]. Additional CAES facilities are under different stages of planning, construction or demonstration in USA (1 500 MW) [BNEF, 2011b], Germany (300 MW) [RWE, 2010], Italy (25 MW), Israel (300 MW), South Korea (300 MW), Morocco (400 MW), Japan and South Africa [Chen et al., 2009].

Life cycle emissions related to the construction of a CAES facility are in the order of 19 tCO₂/MWh of storage capacity [Denholm and Kulcinski, 2004]. However, the main source of emissions for CAES is linked to the natural gas consumption.

Main advantages of CAES are the large storage capacity, relatively fast time response and fast ramping rates, no self-discharge and long life time. CAES plants are designed to sustain frequent start-up/shut-down cycles, and can swing quickly from generation (discharge) to compression (charge) mode or can be designed to operate them simultaneously. The technology is therefore suitable for applications such as load following, time shifting, peak shaving, price arbitrage, frequency regulation (tertiary reserve), seasonal fluctuation regulation, grid decongestion, assets deferral, voltage control [EPRI, 2002]. One feature of the new generation of proposed CAES plants is that they may be closely integrated with wind farms, presenting a means of firming the capacity of wind energy [RRI, 2008].

The economic and technical performance of CAES plants, although based on mature components, is expected to continue to improve. This is mainly due to the possibility to use different designs for the basic process, such as different degrees of inter-cooling and humidification, and improved heat integration leading to a simplified high pressure turbo-expander design and less NO_x emissions [Baker, 2008]. There are also cross-synergies within the power sector due to the use of common components with gas turbines.

Improvements in the CAES operation are expected along with the identification of new locations, such as compressed air storage in vessels or above ground (CAS or SSCAES, i.e. Small Subsurface CAES). These are small-scale CAES systems, where the air is stored in fabricated high-pressure tanks. They are independent of geology, and they can hot start in seconds and cold start in minutes.⁷⁴

Further advances are to be noted for the adiabatic process, with the project ADELE in Germany [RWE, 2010], with 300 MW of generation and a storage capacity of 1 000 MWh, for daily charging and discharging operations. Expected improvements

⁷⁴ BNEF documents a project under discussion in USA of 1 MW, with a capital cost of \$10 800/kW and \$2 700/kWh, based on an isothermal process and targeted efficiency of 90% [BNEF, 2011b]. For comparison purposes, the German CAES power plant in Huntorf has a capital cost of \$485/kW and \$121/kWh, and a round-trip efficiency of 42 %.

are higher efficiency (70 %), no gas combustion and a longer lifetime, comparable with heat plants, 30-40 years. The cost is higher than for diabatic CAES (\$1 500/kW, \$380/kWh) [BNEF, 2011b]. Cost reductions are expected for the converter and the heat storage.

Hydrogen-based energy systems

Hydrogen can be produced using electricity via reversible water electrolysis. It can be stored and transformed back into electricity by means of a fuel cell or a combustion engine/turbine. The main components are the electrolyser unit which converts the power into hydrogen, the hydrogen storage system and the convertor which transforms hydrogen back into electricity [Chen et al., 2009]. Suitable large-scale storage locations are underground caverns, salt domes and depleted oil and gas fields.

The concept of hydrogen-based energy storage is currently in a demonstration phase with a focus to back-up wind farms in remote areas. The world's first-of-a-kind demonstration project was run in 2004 in Norway, in the Utsira Island, (Figure 16.2), in connection with a wind farm [Ulleberg et al., 2010]. Other demonstration projects in Europe based on wind-hydrogen hybrid systems can be found in Unst, Shetland Islands, UK, in Nakskov, Denmark, in Keratea, Greece; and in Galicia and Aragon, Spain.

Considering the main advantages such as the large energy capacity, high energy density and the very low self-discharge, the technology appears suitable in connection with very large wind farms, in support to power grids in isolated systems or in systems where grid reinforcement is very expensive. The main services provided are seasonal storage, wholesale

arbitrage, time-shifting, forecast hedging, secondary and tertiary reserve, grid bottleneck avoidance, and voltage support [EPRI, 2004; Chen et al., 2009].

The current lines of future technical progress are reducing the system cost, increasing the efficiency, scaling-up electrolyzer systems and increasing the fuel cell durability and lifetime [Ulleberg et al., 2010]. Important cost reductions and performance improvements for fuel cell systems are expected from synergies with the on-going research and demonstration efforts on hydrogen and fuel cell technologies in the transport sector.

Batteries

Electrochemical batteries store electricity through a reversible chemical reaction. The essential components are the container, the electrodes (cathode and anode) and the electrolyte. By charging the battery, the electricity is transformed into chemical energy, while during discharging, it is restored into electricity. Conventional batteries have a standard design (lead-acid, nickel-based batteries), while advanced batteries have higher performances (lithium-based, sodium-based batteries). Their storage and discharge take place in the same structure. By contrast, flow batteries (vanadium-based, zinc-bromine) present a different design where the electrolyte is stored in a separate container.

Conventional batteries

Lead-acid batteries (Pb-acid) have a mature technology base, suitable for large power quality applications. Nickel-cadmium batteries (NiCd) are also mature and popular systems, with a higher density and longer life than Pb-acid, but contain environmentally-unfriendly toxic metals. Nickel-metal hydride batteries (NiMH) are an alternative to NiCd, have no toxic material and have a higher density but also higher loss rates [Chen et al., 2009].

Most common applications are for power quality, such as grid reliability, frequency control, black start, uninterruptible power supply (UPS) systems, and also spinning reserve and peak shaving (EERA,

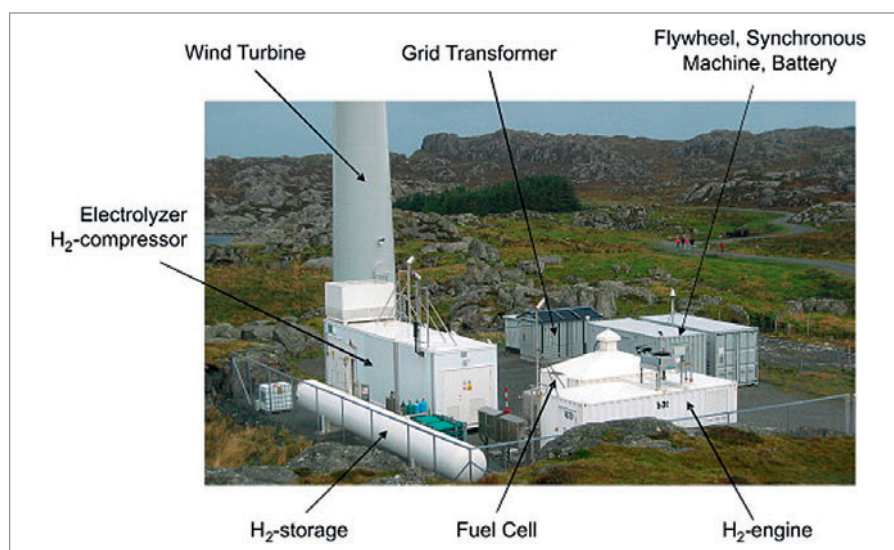


Figure 16.2: Photo of the Utsira wind/hydrogen demonstration plant [Ulleberg, 2010]

2011). If there is no restriction on volume and weight because of their low energy density, good candidates are lead-acid batteries because of their economic cost, and nickel-cadmium because of higher rates of charging/discharging capabilities. When energy density is important, NiMH is the suitable technology.

Lead-acid batteries are commonly used in stationary and automotive applications. Despite low energy density, moderate efficiency and in some cases, the need for maintenance, these batteries have a relatively long lifetime and robustness, in addition to low costs when compared to other types of battery. Several large stationary projects based on lead-acid batteries have been performed worldwide to improve grid performances, as for instance in Berlin from 1988 to 1997, for frequency regulation and spinning provision. Demonstration projects, such as the European FP6 programme DEMO-RESTORE, test the robustness of lead-acid batteries in support to PV systems.⁷⁵

Despite advantages of NiCd over Pb-acid batteries in terms of energy density and number of cycles, projects are limited because of the harmful environmental impact of cadmium. The European Directive on batteries and waste 2006/66/EC⁷⁶ prohibits batteries containing cadmium above a fixed threshold and introduces recycling measures. NiCd batteries need maintenance and have memory effect, which is much less significant in NiMH systems.

Advanced batteries

Different chemical types are currently being used for stationary applications, such as lithium-ion (Li-ion) and sodium-sulphur (NaS). Li-ion batteries have very high efficiency, high energy density, fast charging and light weight. They are therefore suitable for small-scale applications, mostly developed for consumers, PV support and vehicles. Whereas, NaS batteries are primarily suited for large-scale applications and long-daily cycles for energy management.

Lithium batteries rely on the properties of lithium metal, the most electropositive and lightest metal. Therefore, a high energy density storage device can theoretically be achieved in a more compact system. The advantage in using Li metal was first demonstrated in the 1970s and it is undergoing

important research development worldwide. Two types are available: Lithium-Ion (Li-ion) and Lithium-Polymer (Li-pol). Lithium-ion is the most mature lithium technology to date. Transport and mobile applications have so far been the main drivers for its development. However, the future prospect of PV energy has recently revived a strong interest in lithium-ion batteries.

The costs of lithium battery modules are still quite high. The deployment of Li-ion in support to renewables will require further cost reductions, particularly in research in materials and manufacturing techniques [Hall and Bain, 2008]. For instance, sodium-ion technology follows the same principle as Li-ion and is further investigated as an interesting alternative to lithium's scarcity and cost price increase [European Commission, 2011]. An alternative to lithium-ion technology is lithium-ceramic. The largest lithium ceramic battery in the world has been developed in Germany, with a power of 1 MW, storage capacity of 700 kWh, efficiency rate of 96 %, and very low self-discharge rate, see Figure 16.2.⁷⁷

Current research is ongoing on the development of new cathode and anode materials, on safe non-flammable electrolytes, on materials for new cells and battery designs and on the improvement of the temperature operating window [European Commission, 2011]. Further demonstration projects for large systems and also for small residential applications are necessary to validate the robustness of batteries in supporting renewables.

Sodium sulphur batteries consist of molten sulphur at the anode, molten sodium at the cathode, and a solid beta-alumina electrolyte membrane which allows the battery to function without self-discharge [Chen et al., 2009; Hall and Bain, 2008]. The battery is based on a high temperature electrochemical reaction between sodium and sulphur (~ 300 °C), which implies losses with heating. Therefore the technology is suitable for short-term storage with daily, long-cycle applications such as energy management, e.g. load-following and peak-shaving.

The main manufacturer is NGK Insulators (Japan). NaS batteries have significant potential to become cost-effective, modular and bulk medium-scale

⁷⁵ http://ec.europa.eu/research/energy/pdf/synopses_electricity_en.pdf

⁷⁶ Directive 2006/66/EC of the European Parliament and of the Council of 6 September 2006 on batteries and accumulators and waste batteries and accumulators and repealing Directive 91/157/EEC.

⁷⁷ <http://corporate.evonik.com/en/content/product-news/Pages/storing-the-sun.aspx>

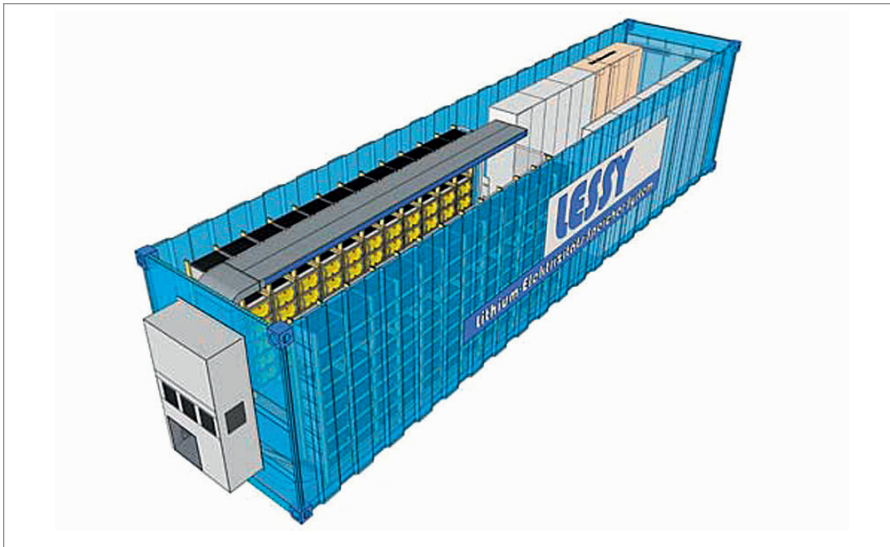


Figure 16.3: XXL lithium-ion batteries made by Evonik Industry. The technology stores solar energy and releases it when there is no sunlight. [Source: Evonik Industries⁷⁸]

storage deployed at a large scale, since no material constraint limits their manufacture [BNEF, 2011a]. The market is expected to grow from the current 316 MW to more than 1 GW by 2020 [BNEF, 2011a]. In Europe, several demonstration projects have been conducted in Germany (Berlin-Adlershof), Spain (Gran Canaria Facility) and France (Reunion Islands). Applications on islands, aim at optimizing the electrical mix, e.g. to support renewables integration and to reduce fossil-fuel-based technologies. Current research is ongoing on beta-alumina membrane and new electrolytes, and on reducing corrosion risks of container materials [European Commission, 2011].

Sodium-nickel-chloride (NaNiCl) or Zebra batteries are similar to NaS but are able to operate at a broader temperature range (-40 to +70 °C) and have better safety characteristics [Chen et al., 2009], presenting however lower density than NaS. Zebra batteries are produced by MES-DEA (Switzerland) and further research is conducted at its Beta R&D centre in the UK. Main services are in automotive and mobile applications, but also in stationary systems in support to PV and wind, for load levelling [EERA, 2011]. Although there are few applications to the grid, some projects are being tested in Europe, such as the Livorno Test Facility in Italy [Fastelli, 2010].

Other advanced batteries, such as **Metal-Air** systems, are currently at different basic research stages. To date Zinc-Air and Lithium-Air are the most advanced. These are very compact systems and are therefore limited to small-scale applications. Research

initiatives are ongoing, as the German STROM programme [European Commission, 2011], and they focus on the improvement of the porous air design, electrical rechargeability and system safety.

Flow batteries

In flow batteries, the electrolyte is stored in a tank separated from the cell stack, decoupling thus the power system from the energy capacity. The storage capacity can be increased by adding more electrolytes

combined in series or in parallel [EERA, 2011]. Therefore, flow batteries could be easily scaled up to very large capacity. They have a large number of cycles and high discharge rates (~10 h), which make them suitable for large storage systems and high energy applications [Chen et al., 2009]. With low energy density, flow batteries are large and heavy, being more suitable for small-to-medium scale applications. Potential services are peak-shaving, back-up supply, power supply in remote areas, support to renewables, asset deferral. Fast response time, in order of sub-milliseconds [Beaudin et al., 2010], makes the technology a good candidate for power quality applications, UPS and voltage support.

Several flow battery types are under different stages of R&D, such as polysulphide bromine, vanadium-vanadium, vanadium-polyhalide, cerium-zinc, lead-lead, etc., but two main types raised more interest: zinc-bromine (Zn-Br) and vanadium-redox (VRB) flow batteries. Zn-Br batteries have a lower cost than VRB, while VRB are more efficient and have a longer life time.

Both Zn-Br and VRB batteries are in an early phase of commercialisation. European manufacturers for VRB include Cellstrom (Austria) and REDT (UK and Ireland). On the research side, the National Power Institute (UK) developed a system based on polysulphide-bromide (Regenesys) in the early 1990s. Demonstration projects in Europe are in Spain (La Gomera Facility), Ireland (Sorne Hill

⁷⁸ <http://corporate.evonik.de/en/content/product-stories/Pages/energy-source-of-the-future.aspx>

wind farm) and Denmark (Riso Research Institute). Further research focus, on increased energy density, improved membrane performance, new stack design and cost reduction [European Commission, 2011]. For VRB in particular, the replacement of vanadium media with vanadium bromide, the so-called second generation of VRB flow batteries, allowed to increase the energy density and to find further applications in mobile devices [EERA, 2011].

Flywheels

Flywheel systems store energy mechanically in the form of kinetic energy by rotating a mass around an axis. On charging, the flywheel is accelerated, and on power generation, it is slowed. The core element of a flywheel is a rotating mass which is connected to a main shaft (rotor) powered by an external source of energy. In revolving, the mass builds up inertial energy. In discharge mode, the kinetic energy is released when the rotor is switched off. The use of flywheels as an energy storage device was first proposed for electric vehicles and stationary power back-up in the 1970s. Flywheel systems are generally distinguished between low speed (up to 5 000 rpm) and high speed systems (up to 50 000 rpm) [Lazarewicz and Rojas, 2004].

Flywheel systems have the advantage of high cyclability, high energy efficiency and fast response time. The main applications are power related such as short time support in distributed power systems, including power quality for sags and surges lasting less than 5 seconds, UPS for outages lasting up to 10 minutes, voltage regulation, and support for flexible alternating current transmission systems (FACTS). Flywheels can provide ride-through power with generators, as well as short-time support for systems providing ancillary services such as spinning and standby reserves. They can be combined with batteries to cover short-duration events and save batteries life-time [EERA, 2011].

In Europe, the project SA2VE (Spain) tests the applications of flywheels in three sectors: stationary applications for railway transport, energy management in buildings and the quality of power supply.⁷⁹

Research and development aim at increasing the energy density, for instance through increased

angular velocity, and to reduce energy losses because the system has a quite high self-discharge rate. However, increasing the rotational speed of the flywheel poses severe constraints on the bearings. Hence, magnetic bearings are used, in addition to maintaining the flywheel housing under a partial pressure or vacuum to reduce the drag force due to high rotational energy. Research on low cost and high strength composite materials would influence the development of flywheels, such as high strength fibres and high temperature superconductors. Further research focuses on improved safety and design for the deployment in residential systems, along with cost reductions [EERA, 2011; European Commission, 2011].

Supercapacitors⁸⁰

The basic principle of a capacitor is to store the electricity in an electrostatic field formed between a pair of conductors (two electrodes of opposite polarity) separated by a dielectric or insulator layer. Main differences between conventional capacitors and supercapacitors are enlarged electrode surface areas, the use of a polymer membrane and of a liquid electrolyte instead of the dielectric solid material. In these electrochemical systems, the capacitive properties of the electrolyte-electrode interfaces, known as electrochemical double layers, are exploited to store energy [Hadjipaschalis et al., 2009; Chen et al., 2009; Naish et al., 2008].

Electrochemical capacitors are in different stages of R&D, although some devices are becoming commercially available. In Europe, demonstration projects are in Spain for ultracapacitors (STORE project in Canary Island, La Palma Facility in Los Guinchos) and for supercapacitors to optimize hydrogen-based systems (the EU FP6 project HyHeels).⁸¹

Supercapacitors have low maintenance needs, very fast charging and discharging times and they can stand many cycles. They are good candidates for frequency and voltage regulation, pulse power, factor correction, VAR support and harmonic protection. They have the potential for fast acting short term power back-up for UPS, transmission line stability (FACTS devices), and spinning reserve provision. They find applications in support to renewable energies and in smart grid systems [Beaudin et

⁷⁹ <http://www.aicia.es/2/sites/aicia.es/files/IA-AICIA-2007-ing.pdf>

⁸⁰ Terminology: Super capacitors are referred to also as electro-chemical capacitors, ultra-capacitors, ultra-high capacitance capacitors, and double layer capacitors [European Commission, 2011].

⁸¹ http://ec.europa.eu/research/transport/projects/items/eu_funded__hyheels__takes_new_approach_to_fuel_cells_en.htm

al., 2010]. Coupling supercapacitors with batteries is a prime option to extend both the peak power capacity of batteries and the energy density of supercapacitors.

The technology is also suitable for road transport applications to capture and store the energy from regenerative braking, and to supply acceleration power for electric vehicles. Other applications are in aerospace field, as they can withstand severe temperature conditions and power emergency events; and in cranes and elevators to capture energy along downward motion [EERA, 2011].

Research is currently on going on nano-carbon materials as a promising route to increase energy and power densities [Hadjipaschalis et al., 2009]. Efforts are on improved capacitance and control of pore sizes, to increase the cycle life and the charge-discharge operations. New electrolyte solutions are also tested (solvents/ salts/ ionic liquids) in synergy with research on batteries [European Commission, 2011].

Superconducting magnetic energy storage (SMES)

SMES stores energy in a magnetic field. Once a DC electric current is injected into a superconducting coil, it creates a magnetic field where the energy is stored. It is then released when this closed circuit is opened. Up to now, coils are mainly built from niobium-titanium (NbTi) and cooled by liquid helium [Wolsky, 2002]. Emissions incurred during the manufacture of SMES facilities are about 962 tCO₂/MWh stored [Hartikainen, 2007].

The capacity installed of SMES units is over 100 MW worldwide [EERA, 2011]. Research prototypes have been developed up to 1 MW in Italy, Germany, Finland and Spain; while successful demonstration projects operating at 20 K have been run in Germany, Finland, France, USA and South Korea [Hall and Bain, 2008]. The technology is at a mature development stage; however, only micro-SMES systems (1 to 10 MW) are commercialised.

A hybrid-storage type with a flywheel system is the Inertial Energy Storage system (INES). The basic principle consists in the rotation of a flywheel under levitating conditions with a self-stable magnetic bearing including bulk superconducting materials and magnets. The essential components are the flywheel, a power conditioning system and a vacuum vessel [European Commission, 2011].

A SMES stores electrical energy directly, without converting it into another form, so it can release the energy very quickly. The system has very high

efficiency, fast response and is suitable for power quality applications, to provide active and reactive power, voltage support for critical loads, static VAR compensations, transmission lines stability and smart grid applications [EPRI, 2004; EERA, 2011].

Main SMES disadvantages are that they require large installation surfaces, and that materials only become superconducting at extremely low temperatures (0–273 °C). A research topic is the development of larger systems with higher energy density. Research efforts concern low temperature superconductivity but also high temperature systems to can reduce the cost. Additional research on these high temperature materials is needed to increase the critical current and magnetic field and to develop manufacturing processes enabling high production volumes. More efficient cryogenic cooling systems, high magnetic field and mechanically secure structure are key for future SMES development [EERA, 2011].

16.3. Market and industry status and potential

The European industry has currently a strong market leadership in large-scale energy storage technology, but it needs to maintain this industrial excellence [SETIS, 2008]. Three market leaders for hydro-pumped storage are based in Europe, and among them one company alone owns 40 % of the market share worldwide. Although the European know-how is widely used around the world, international competitors, such as Chinese manufacturers, are entering the market at a fast pace. As for CAES technologies, although they are not widely deployed, one of the two plants currently in operation was built with European technologies, while European manufacturers are actively evaluating adiabatic CAES concepts [RWE, 2010]. However, it has to be noted that six other projects on advanced CAES systems (second generation and isothermal CAES) are under construction or planned in the US [BNEF, 2011b]. For fuel cell and hydrogen technologies, the establishment of a Joint Undertaking in 2008 is contributing to the development and strengthening of the European industry.

For small-to-medium scale technologies, the European industrial base is weaker, although dynamic. Despite world-class European manufacturers of batteries and supercapacitors, the overall battery market is dominated by Asian manufacturers. This contrasts with the excellence of European research at the origin of decisive breakthroughs, which enabled the commercialisation of lithium batteries over the

past 40 years. As this market is expected to grow significantly in the coming decades, accompanying the deployment of PV systems, for instance, now is the opportunity to strengthen the European industry. R&D programmes on advanced lithium storage, such as the Franco-German industrial project SOLION,⁸² are indicators of the potential of Europe to play a critical role in this field.

Storage units currently operating in Europe are mostly in the form of hydro-storage plants, but interest is growing for other storage technologies. Forecasting the future needs in storage capacity is strongly dependent – among others – on the developments of the future electricity technology mix, of the trans-European power network and of the electrification of transport. Compliance with grid code requirements for wind and solar technologies is one of the main influencing drivers for storage expansion [Martinez et al., 2007]. Grid codes setting the connection rules are constantly upgraded and several Member States, e.g. France and Germany, have revised them for high voltage and medium voltage levels, in order to account for the increasing penetration of renewables [Tsili et al., 2008]. Furthermore, unlike hydropower, there is no assessment of the potential for pumped storage in Europe. One of the main reasons is that a new pumped storage plant can be greenfield or based on existing reservoirs, out-of-use mines and quarries, the sea, etc.

Electrification of road transport provides an evident ground for synergies with power storage. R&D on batteries and fuel cells for the development of plug-in hybrid vehicles and fuel cell vehicles will reinforce the development of storage. Technological development in other areas, such as power electronics, ICT and smart grid technologies, can further drive storage evolution.

16.4. Barriers to large-scale deployment

The main barriers facing electricity storage belong to four categories: technological issues, market uncertainty, regulation and economics [EAC, 2008].

Technological issues: Performance is the most decisive for most technologies which are currently at different stages of development, as shown in Figure 16.1. Except for PHS, all the technologies require R&D efforts to improve their operational characteristics

and to reduce their costs. Simultaneously, installing more storage capacity depends on the availability of suitable geological formations (PHS, underground CAES and hydrogen) and on the access to materials and resources (batteries). At current extraction rates, some resources, e.g. zinc and lithium, could limit the large-scale development of technologies, such as Zn-Br and lead-acid batteries [European Commission, 2011; Beaudin et al., 2010]. Therefore, proper disposal and recycling are needed to ensure the sustainable development of storage.

Market uncertainty: Storage development faces uncertainties surrounding the power sector evolution, such as the level of variable renewables, the carbon price, the level of baseload technology deployment, e.g. nuclear power, and the level of demand side measure effectiveness in curbing and peak shaving energy consumption. Therefore it is urgent to advance the analytical framework by building scenarios on the future requirements for electricity storage.

Estimating the storage potential represents a key issue in the planning process of the transition of the European power system towards a low-carbon system and the investment in storage applications needs to be synchronised with the investment in electricity generation, as well as in transmission and distribution. For instance, the large Scandinavian hydropower storage potential can be further exploited in order to contribute with additional storage capacity to the whole European system, provided that grid connections are in place with Germany and UK, or reinforced with the Netherlands and Denmark [SETIS, 2009].

Regulation: The role of regulation is crucial for transmission and distribution utilities to help storage operators address their project specificities and for defining a clear business case [SETIS, 2008]. With the increasing penetration of distributed and variable energy sources, there is a need to further develop regulatory aspects on power quality at the European level and to contribute to integrate storage while defining grid extension planning and renewable integration targets. For example, in most of the Member States, storage is charged with grid fees both for power consumption and for generation. However, the regulation improves along with the constant increase in renewables. In Germany, the revision of the Energy Industry Act proposes to exempt new storage facilities from grid fees.⁸³

⁸² http://www.saftbatteries.com/SAFT/UploadedFiles/PressOffice/2008/CP_33-08_fr.pdf

⁸³ https://www.bmu.de/english/energy_efficiency/doc/print/47609.php

Economics: The capacity of electricity storage to provide multiple services to the power system is at the origin of the difficulty to assess its economics. In particular this is due to the fact that there is an overlap created between the levels to which storage contributes, i.e. generation, grid, end-user. For storage to be profitable, all multiple value streams need to be accumulated, and regulatory barriers must be removed. Establishing a framework to assess the economic potential of storage would enable the industry to take investment decisions and public authorities to support the development of electricity storage [SETIS, 2008].

The economic valuation of power storage in Europe faces the heterogeneity of power systems and power markets among Member States, since storage operation is strongly dependent on local conditions and regulation. However, outlining the framework of the market evaluation of storage represents one of the current priorities of the Information System of SET-Plan, SETIS [Loisel et al., 2010; 2011].

The development of a fully-integrated European power market takes into consideration all the options which can improve the flexibility of power supply and demand. Storage is clearly identified as part of the project and complements measures such as improved weather forecasting, new market-based approaches, demand control, cross-border interconnections, HVDC lines, power flow control technologies and smart meters [ETP, 2008]. Therefore strategic planning at the European level is required to inscribe storage technology and regulatory developments in the broader context of smart grid related activities and renewable energy integration.

16.5. RD&D priorities and current initiatives

Current initiatives on storage development are undertaken at the industry level, at the Member State level and at the European level. Two time-perspectives can be framed, as a function of their development stage. Short-to-medium term initiatives aim at attaining the commercial maturity and at accelerating the transition to mass commercialisation, while long-term actions consist in boosting the fundamental research on new technologies, new materials and new components.

The European Association for Storage of Energy (EASE), created in 2010 and launched officially in 2011, aims at building a common industry and stakeholders vision.⁸⁴ EASE objectives are to build a

European platform for sharing information on storage and to help advance technological development, in connection with similar associations in USA, Japan, Australia and China.

With focus on the research and innovation, the European Energy Research Alliance (EERA)⁸⁵ includes a chapter “Smart Grids. Task 4.1 Electric Energy Storage technologies”. It provides a review of storage technologies aimed at gaining a deeper knowledge in storage applications and capabilities to respond to grid needs from economic and technical viewpoints. In a later stage, the objective is to offer solutions which can be embedded in industry-driven research.

Focussed on batteries, the Association of European Automotive and Industrial Battery Manufacturers gathers more than 85 % of European industrial actors in the field and joins their R&D efforts in developing new solutions in areas such as electrical vehicles and renewable energy storage.⁸⁶

The European Fuel Cells and Hydrogen Joint Technology Initiative aims to accelerate the development and the deployment of hydrogen-based technologies in a cost effective way through applied research programmes and demonstration projects.⁸⁷

Ongoing or planned European projects financed under FP6 and FP7 programmes consist in creating networks of excellence to consolidate the European research in a particular field. For instance, the FP6 European virtual research centre ALISTORE⁸⁸ gathers 23 European research organisations structuring R&D activities on lithium systems and promoting nanomaterials. The FP7 European project MESSIB⁸⁹ focuses amongst others on solutions which reduce the energy consumption in buildings by advancing the research on materials, on phase change slurries, flywheels and VRB batteries. The FP7 project HESCAP⁹⁰ aims to develop a new generation high-energy supercapacitor based system. For the longer term perspective, EU research funding could focus on key components, i.e. for battery development, such as electrolytes, additives, new solvent solutions, new cells designs and post-lithium ion systems [European Commission, 2011].

⁸⁴ http://www.iea.org/work/2011/storage/Item11_EDF.pdf

⁸⁵ <http://setis.ec.europa.eu/about-setis/technology-roadmap/european-energy-research-alliance-eera>

⁸⁶ <http://www.eurobat.org/>

⁸⁷ <http://www.fch-ju.eu/>

⁸⁸ http://www.u-picardie.fr/alistore/alistore_presentation.htm

⁸⁹ <http://www.messib.eu/>

⁹⁰ <http://www.hescap.eu/>

All storage technologies need sustained RD&D efforts through demand pull and supply push actions. Demand pull policies can send a market signal to researchers and investors that there is a potential need for the technology (e.g. re-designed ancillary services markets). However, these measures mainly stimulate innovation through deployment and may lead to low amounts of additional R&D expenditure. Dedicated funds for research programmes, the

creation of public-private partnerships, cost-sharing schemes, loan guarantees and prizes for achieving policy goals, are examples of supply push actions that would further stimulate innovation by providing additional expenditure. Industrial-scale demonstration projects for near-to-market deployment are necessary to build the industrial trust and to gain field experience in storage technologies [SETIS, 2008].

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17. Energy Efficiency and CO₂ Emission Reduction in Industry

17.1. The Cement Industry

17.1.1 Introduction

Cement is a binder, a substance which sets and hardens independently, and can bind other materials together; its most important use is the production of concrete. Concrete is the most-used, man-made material in the world, almost three tonnes of concrete are produced in the world per person, twice as much as the rest of materials together, including wood, steel, plastics and aluminum.

Energy needs accounts for an important share of the variable cost of cement production (around 40 %). This energy requirement is split between process heat and electrical energy, the latter accounts for around 20 % of the cement energy needs [European Commission, 2007]

Most of the CO₂ emissions and energy use of the cement industry are related to the production of the clinker. Clinker, the main component of cement, is obtained throughout the calcination of limestone. Up to 63 % of the CO₂ emissions emitted during the fabrication of cement come from the calcination process, while the rest (37 %) is produced during the combustion of fossil fuels to feed the calcination process [BREF, 2010]. The CO₂ emissions from the cement industry in Europe peaked in 2007 with 173.6 Mt CO₂ [Ecofys, 2009], whereas in 2008, CO₂ emissions fell back to 2005 values (157.4 Mt CO₂ in 2005 and 157.8 Mt CO₂ in 2008 [Ecofys, 2009]).

17.1.2 Technological state of the art and anticipated developments

Four processes are currently available to produce the clinker: wet, semi-wet, semi-dry and dry. The main steps in the production of cement are: i) preparing/grinding the raw materials; ii) producing an intermediary clinker; and iii) grinding and blending clinker with other products to make cement.

The heat consumption of a typical dry process is currently 3.38 GJ/t clinker [WBCSD/CSI, 2009], where 1.76 GJ/t clinker is the minimum energy consumption for the thermodynamical process, about 0.2 to 1.0 GJ/t clinker is required for raw material drying (based on a moisture content of 3 to 15 %), and the rest are thermal losses [WBCSD/CSI-ECRA, 2009]. This amount (3.38 GJ/t clinker) is a little more than half of the energy consumption of the wet process (6.34 GJ/t clinker) [WBCSD/CSI, 2009]. According to the BREF⁹¹, the best available techniques (BAT) value

for the production of clinker range between 2.9-3.3 GJ/t (under optimal conditions). It is noted that these values have been revised recently as in the previous version of the BREF document, a consumption of 3.0 GJ/t clinker was proposed [BREF, 2001] (based on a dry process kiln with multi-stage preheating and pre-calcination). This broadening of the energy consumption range for clinker production is due to the recognition that there is a realistic difference between short term and annual average values of 160 to 320 MJ/t clinker, depending on kiln operation and reliability (e.g. number of kiln stops) [Bauer and Hoenig, 2009]. The average heat consumption of the EU industry was 3.69 GJ/t clinker in 2006 [WBCSD/CSI, 2009]. The average thermal energy value in 2030 can be expected to decrease to a level of 3.3 to 3.4 GJ/t of clinker; this value can be higher if other measures to improve overall energy efficiency are pursued (cogeneration of electric power may need additional waste heat) [WBCSD/CSI-ECRA, 2009]. The percentage of the dry process use in the EU production in the cement industry has increased from 78 % in 1997 to 90 % in 2008 [BREF, 2010; CEMBUREAU, 1999]. In the rest of the world, this process is gaining ground progressively but not at the same pace. The general trend is towards a progressive phasing out of wet process facilities, nevertheless individual cases will provide exceptions to this trend. [Grydgaard, 1998; Kappahn and Burkhard, 2009].

The current European average of electrical consumption is 111 kWh/t cement [WBCSD/CSI, 2010], most of it (around 80 %) consumed for grinding processes. The main users of electricity are the mills (grinding of raw materials, solid fuels and final grinding of the cement) that accounts for more than 60 % of the electrical consumption [WBCSD/CSI-ECRA, 2009] and the exhaust fans (kiln/raw mills and cement mills) which together with the mills, account for more than 80 % of electrical energy usage [CEMBUREAU, 2006]. However, the energy efficiency of grinding is typically only 5 to 10 % [Taylor et al., 2006]. From 1990 to 2006, the global weighted average of electrical consumption of the participants in the project "Getting the numbers right" (GNR) [WBCSD/CSI, 2009] has decreased from 115 kWh/t cement to 111 kWh/t cement; without the adoption of "Carbon Capture and Storage" (CCS) technologies, the electrical consumption in

⁹¹ BREFs are the main reference documents on Best Available Techniques. They are prepared by the European Integrated Pollution Prevention and Control (IPPC) Bureau and are used by competent authorities in Member States when issuing operating permits for the installations that represent a significant pollution potential in Europe.

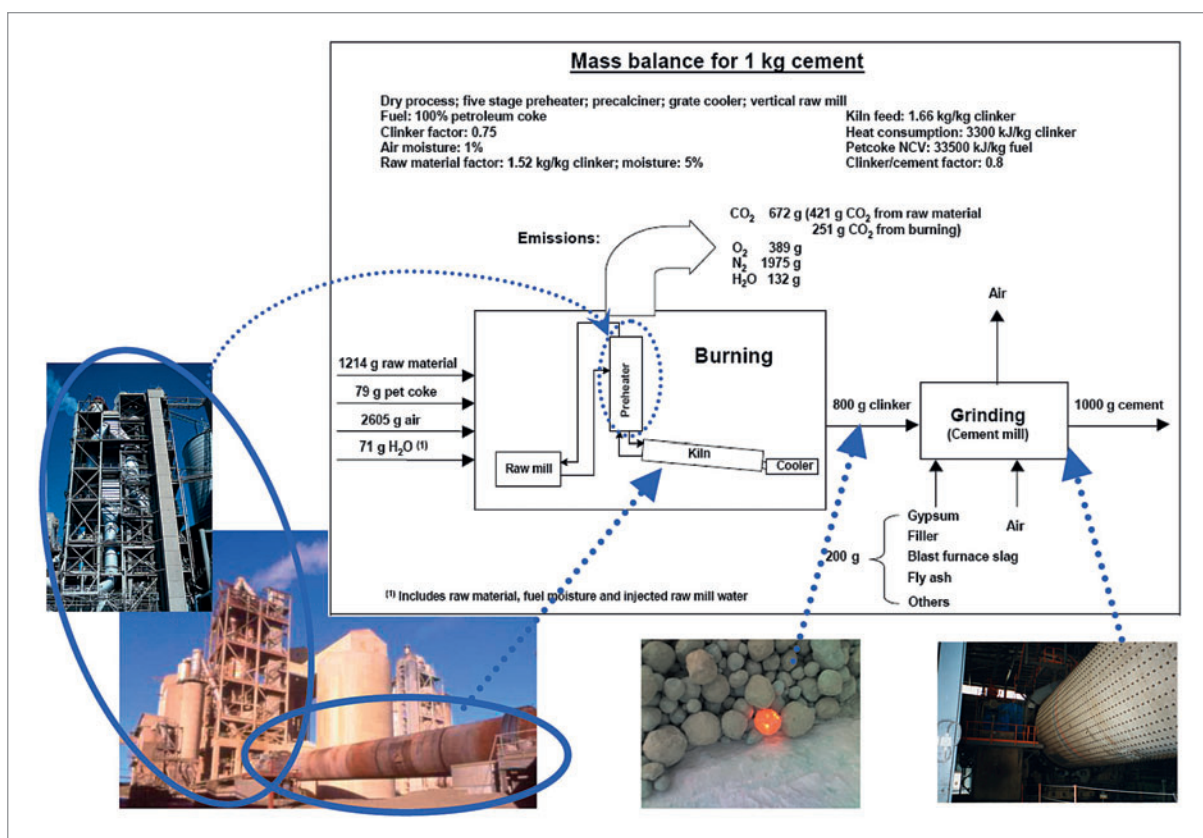


Figure 17.1.1: Main processes involved in the manufacture of cement, with typical mass balances for the manufacture of 1 kg of cement with a clinker-to-cement ratio of 0.75 [BREF, 2010]

2030 could decrease to a level of about 105 kWh/t cement. The uptake of CCS technology by the cement industry would mean a significant increase in power consumption [WBCSD/CSI-ECRA, 2009].

As a mature industry, no breakthrough technologies in cement manufacture are foreseen that can reduce significantly thermal energy consumption. Alternative technologies are currently being researched such as the fluidised bed technology. However, although improvements can be expected, it is not foreseen that such technologies will cover the segment of large kiln capacities [WBCSD/CSI-ECRA, 2009]. On the other hand, CCS has been identified as a prominent option to reduce CO₂ emissions from cement production in the medium term. Currently, the main evolution of the sector to improve its energy and environmental performance is towards higher uses of clinker substitutes in the cement, higher use of alternative fuels such as waste and biomass and the deployment of more energy efficiency measures. A significant number of energy efficiency measures are currently being proposed, however their deployment is quite site-specific, rendering difficult an assessment of the gains that can be expected. It is noted that many thermal energy reducing measures can increase the power consumption. [WBCSD/CSI-ECRA, 2009].

17.1.3 Market and industry status and potential

Production in the EU-27 in 2006 (267.5Mt) represented 10.5 % of the total world production, decreasing in 2008 to 9 % of world production (254.7Mt) [BREF, 2010; CEMBUREU, 2009b]. Cement consumption in Europe peaked in 2006 with 265.9Mt, but decreased in 2008 to around the 2005 level (246.6Mt) [CEMBUREU, 2009b]. The overall EU consumption per capita in the future can be expected to remain around 450 kg per capita [Gielen, 2008], despite the fact that there will be differences between countries. Assuming such numbers would lead to cement production in Europe of around 234 Mt by 2030.

The EU-27 thermal energy consumption for cement production in 2007 was 0.76 EJ (18.1 Mtoe). The alternative fuels consumption increased from 3 % of the heat consumption in 1990 to almost 18 % in 2006 [CEMBUREAU, 2009a]. If the current trends remain similar, the substitution rate could reach 36 % in 2020 and 49 % in 2030, with a saving of 0.23 EJ (5.6 Mtoe) in 2020 and 0.30 EJ (7.3 Mtoe) in 2030.

The achievement of a clinker-to-cement ratio of 0.73 and 0.70 in 2020 and 2030 (possible if current trends are held) would mean a saving of 0.033 EJ (0.8 Mtoe) in 2020 and 0.054 EJ (1.3 Mtoe) in 2030.

The main source of CO₂ emission reduction is the decrease of the proportion of clinker in the cement (clinker-to-cement ratio), where the process emissions in the manufacture of the clinker – coming from the calcination of

the raw material are governed by chemistry - 526 gCO₂/kg of clinker [BREF, 2010]. From 1990 to 2005, this ratio decreased from 0.81 to 0.77 [WBCSD/CSI, 2009]. If this trend is sustained, this ratio would reach 0.73 in 2020 and 0.70 in 2030. If that is the case, the reduction in CO₂ emissions with respect to current practices would be 4.7 Mt CO₂ in 2020 and 8.0 Mt CO₂ in 2030.

The use of alternative fuels avoids emissions in the disposal of the waste treated by the cement industry as fuels, and at the same time saves fossil fuels. The amount of CO₂ emissions savings from the use of alternative fuels would be 18 Mt of CO₂ in 2020 and 23.5 Mt of CO₂ in 2030 if current trends in fuels substitution hold. This is an indirect saving of CO₂, because if the cement industry had not used some wastes as alternative fuels, then they would have produced that amount of CO₂ in their disposal elsewhere.

Taking into account all these trends, [Pardo et al., 2011] estimate that between 2006 and 2030, the cost effective implementation of remaining technological innovation can reduce the thermal energy consumption by 10 % (see Figure 17.1.2) and 4 % CO₂ emissions. The value for the specific thermal energy consumption in 2030 (around 3350 MJ/t clinker) is in line with the expected value in 2030 (3400 MJ/t clinker) used in the IEA Cement Technology Roadmap [Tam and van der Meer, 2009].

It is noted that the deployment of CCS could reduce significantly CO₂ emissions in the sector. However, a wide deployment of this technology in the cement industry is not foreseen before 2020. Assuming no

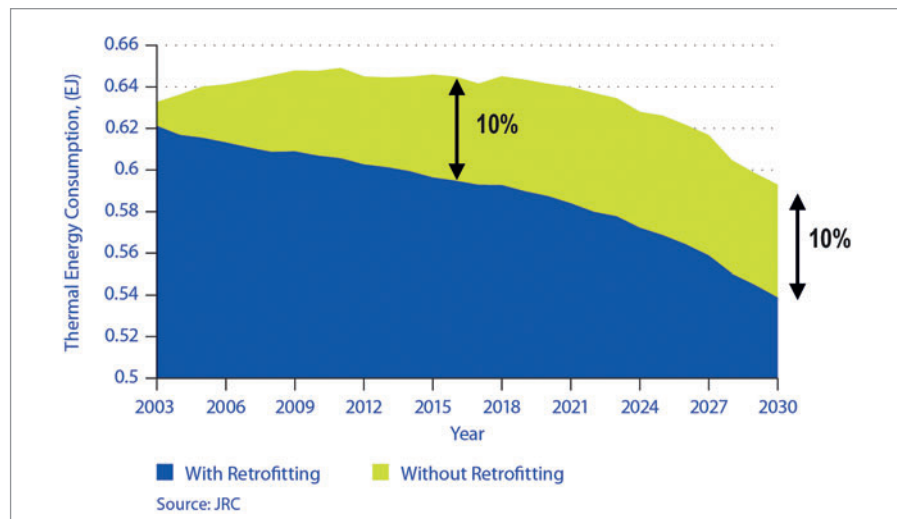


Figure 17.1.2: Evolution of the total thermal energy consumption modelled, precluding the retrofitting of existing facilities (upper area), and allowing cost effective retrofittings (lower area) [Pardo et al., 2011].

CCS deployment, the specific electricity demand of cement production could decrease from 110 kWh/t cement in 2006 to 105 kWh/t cement in 2030 [WBCSD/CSI-ECRA, 2009].

The number of people employed in 2005 in the EU-27 was about 54 000 [BREF, 2010]. The average price of cement in Europe varies broadly between countries. Despite an historical tendency to produce and consume cement locally, as this is a product with a relative low price, around €70 on average in the EU, compared to its transport price (transport costs are around €10 per tonne of cement per 100km by road and around 15€ to cross the Mediterranean Sea) [Climate Strategies, 2007],

Three out of the five world's largest cement producers are sited in the EU-27, Lafarge (France), HeidelbergCement (Germany) and Italcementi (Italy). The other two are Holcim (Switzerland) and Cemex (Mexico) [BREF, 2010]. This means that the European cement industry has a truly global presence enjoying a market share of 95 % in Europe and 70 % in North America [IEA, 2008]. In addition to the production of cement, these companies have also diversified into other sectors of building materials.

17.1.4 Barriers to large-scale deployment

The industry has pointed out the risks of carbon leakage under the terms of the previous EU Greenhouse Gas Emission Trading System (EU ETS) [EC, 2003]. In the EU-27 in 2006, 38 Mt of cement were imported and 32 Mt exported. These figures include trade among EU countries [BREF, 2010]. The

revised Directive [EC, 2009b] provides for 100 % of allowances allocated free of charge, at the level of the benchmark to the sectors exposed. The sectors exposed were determined by the Commission in December 2009 [EC, 2009a]; the cement industry is among them. The benchmarking values, proposed by the European Commission, were adopted in April 2011 [EC, 2011]. The Commission has launched the Sustainable Industry Low Carbon (SILC) initiative to help the industry to achieve specific GHG emission intensity reductions in order to maintain their competitiveness [SILC, 2011].

One of the main barriers to the deployment of energy efficiency measures and CO₂ mitigation technologies in the cement industry in Europe is related to energy prices. High energy price favours investment in energy efficiency and CO₂ emissions abatement. However, at the same time, higher energy prices may lead towards more and more imports from non-EU countries to the detriment of a European production. There are energy efficiency improvements that the EU industry is currently not following, due to, among other factors, low energy prices. For example, concerning heat waste recovery nowadays in China there are 120 cement plants equipped with cogeneration systems with a total capacity of 730MW [Rainer, 2009], whereas the number of EU-27 plants recovering waste heat are very limited.

The market penetration of cements with a decreasing clinker-to-cement ratio will depend on six factors: i) availability of raw materials; ii) properties of those cements; iii) price of clinker substitutes; iv) intended application; v) national standards; and vi) market acceptance [WBCSD/CSI-ECRA, 2009]. It is noted that cement that can be fit for purpose in one country can often not be placed in another country due to differences in national application documents of the European concrete standard [Damtoft and Herfort, 2009]. Therefore a way to encourage the use of these cements would be the promotion of standards harmonisation at the EU level.

17.1.5 RD&D priorities and current initiatives

The main needs of the cement industry can be summarised as follows: i) promotion of current state-of-the-art technologies; ii) encourage and facilitate an increased use of alternative fuels; iii) facilitate and encourage clinker substitution; iv) facilitate the development of CCS; v) ensure predictable, objective and stable CO₂ constraints and an energy framework on an international level; vi) enhance research and development of capabilities, skills, expertise and innovation; and vii) encourage international collaboration and public-private partnerships. [Tam and van der Meer, 2009]

Among the conclusions of the cement roadmap of the IEA [Tam and van der Meer, 2009] is that the options available today (BAT, alternative fuels and clinker substitutes) are not sufficient to achieve a meaningful reduction of CO₂ emissions. Hence there is a need for new technologies, CCS and new types of cements. To achieve this goal, a step increase in RDD&D is required.

The Cement Industry shows great potential for the use of CCS as CO₂ emissions are concentrated in few locations and at the same time the concentration of CO₂ in the flue gas is twice the concentration found in coal-fired plants (about 14-33 % compared to 12-14 %) [IPCC, 2005]. Nonetheless, according to the latest research, the deployment of CCS technologies currently being considered (oxy-combustion and post-combustion) can double the price of the cement. Therefore, along with significant R&D efforts, the application of CCS technologies will demand the development of a stable economic framework able to compensate the increased costs [WBCSD/CSI-ECRA, 2009].

17.1.5 References

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17.2. The Iron and Steel Industry

17.2.1 Introduction

The GHG emissions from the Iron and Steel industry during the period 2005 to 2008 on average amounted to 252.5 Mt of CO₂ eq [Ecofys, 2009]. In Europe, about 80 % of CO₂ emissions related to the integrated route originates from waste gases. These waste gases are used substantially within the same industry to produce about 80 % of its electricity needs [EUROFER, 2009].

Part of the steep decrease in energy consumption in the European industry over the 40 years (by about 50 %) has been due to the increase of the recycling route at the expense of the integrated route (the share has increased from 20 % in the 1970's to around 40 % today). However, a prospective shift to recycling is confined by scrap availability and its quality.

In the EU-25, the number of people directly employed in the sector in 2005 was about 350 000 people [BREF, 2009]. Steel is a direct supplier for and part of a value chain representing the best of European industry and contributing annually revenues in excess of EUR 3 000 billion and employing 23 million people [ESTEP, 2009].

17.2.2 Technological state of the art and anticipated developments

There are two main routes to produce steel. The first route is called the “integrated route”, which is based on the production of iron from iron ore. The second route called “recycling route”, using scrap iron as the main iron-bearing raw material in electric arc furnaces. In both cases, the energy consumption is related to fuel (mainly coal and coke) and electricity. The recycling route has a much lower energy consumption (about 80 %).

The “integrated route” relies on the use of coke ovens, sinter plants, blast furnaces (BF) and Basic Oxygen Furnace (BOF) converters. Current energy consumption for the integrated route is estimated to lie between 17 and 23 GJ/t of hot-rolled product [SET-Plan, 2010]. The lower value is considered by the European sector as a good reference value for an integrated plant. A value of 21 GJ/t is considered as an average value throughout the EU-27 [SET-Plan, 2010]. It is noted that a fraction of this energy consumption may be committed to downstream processes. The fuels applied are fully exploited, first for their chemical reaction potential (during which they are converted into process gases) and then for their energy potentials by capturing, cleaning and



Figure 17.2.1: Overview of the steel making process and variety of products manufactured. [Source: World Steel Association]⁹²

⁹² <http://www.worldsteel.org/?action=publicationdetail&id=83>

combusting these process gases within production processes and for the generation of heat and electricity. It is an important characteristic of this “cascadic fuel use” that increased energy efficiencies in the use of the process gases do not reduce the overall energy consumption, related to the use of primary fuels for the chemical reactions.

The “recycling route” converts scrap iron in electrical arc furnaces. Current energy consumption for this route is estimated to lie between 3.5-4.5 GJ/t of hot-rolled product [SET-Plan, 2010]. The lower value corresponds to a good reference plant. The higher value corresponds to today’s average value within the EU-27. In Figure 17.2.1, the “integrated route” and the “recycling route” are shown at the left hand side and right hand side, respectively.

Alternative product routes to the two main routes are provided by direct-reduced iron technology (which produces substitutes for scrap) or smelting reduction (which like the blast furnace produces hot metal). The advantage of these technologies compared with the integrated route is that they do not need raw material beneficiation, such as coke making and sintering and that they can better adjust to low-grade raw materials. On the other hand, more primary fuels are needed, especially natural gas for direct reduced iron technology and coal for smelting reduction. In the latter, 20-25 % savings in CO₂ emissions [De Beer et al., 1998] can be achieved, if the additional coal is transformed into process gases which are captured and used to produce heat and electricity for exports to the respective markets for heat and electricity. So far and for this reason, the expansion of these technologies occurs in developing countries with weak energy supply infrastructures or countries with low fuel resources. In 2006, this represented about 6.8 % of worldwide production [BREF, 2009]. There is only one plant using direct-reduced iron technology in EU-27 (in Germany) and none of the 8 facilities of smelting reduction operating in the world are sited in Europe. The possible gap for direct-reduced iron technology could come in the EU-27 if increase capacity of hot metal is required [BREF, 2009] and if the necessary, additional primary fuel demands could be satisfied at low cost. The opportunity for smelting reduction is harder to assess due the lack of detailed information available today but should be governed by the same boundary conditions.

17.2.3 Market and industry status and potential

The production of crude steel in the EU in 2008 was 198 Mt, representing 14.9 % of the total world production (1 327 Mt of crude steel) [Worldsteel, 2009]. Ten years earlier, with a slightly lower production (191 Mt of crude steel), the share of the same European countries was 24.6 %. The main difference is that the Chinese production has grown more than fourfold over this period (from 114 Mt to 500 Mt of crude steel) [Worldsteel, 2009]. In these 10 years, the European consumption of finished-steel products rose from 157 Mt to 182 Mt [Worldsteel, 2009]. In 2009, with the financial crisis, the production level in Europe dropped by 30 % compared to the previous three years. Partial recovery of production has been achieved in the first half of 2010, but it is not expected to reach the pre-crisis output level before 2012.

The growth of the EU-27 iron and steel production can be estimated to be 1.18 % per year up to 2030 [European Commission, 2007]. This would imply a production of around 260 Mt of crude steel in 2030. The increase in the production is estimated to be covered mainly by an increase in the recycling route. The production from the integrated route will stay around their current values [European Commission, 2007].

Today, over 40 % of steel is traded internationally and over 50 % is produced in developing countries [Worldsteel, 2009]. The world’s largest producer in 2008 was a European company (ArcelorMittal). The production of the eighth world producer (Tata Steel) includes the production of Corus but the third largest European producer (Riva) was ranked 16th in the 2008 world production, the fourth largest producer (ThyssenKrupp) was ranked 18th and the fifth largest producer (Techint) was ranked 27th.

To achieve the potential identified in the 2009 Technology Map for wind power generation [JRC-SETIS, 2009], the annual consumption of steel in the wind industry by 2020 and by 2030 could amount to 3 Mt and 6.3 Mt, respectively. These annual amounts of steel would be needed to achieve 230 GW of wind energy in 2020 (180 GW onshore and 40 GW offshore) and 350 GW in 2030 (200 GW onshore and 150 GW offshore).⁹³

⁹³ The turbine data used to obtain these estimates is based on an analysis of the mass of 8 offshore and onshore wind turbines (Vestas V90-3.0 and V120; Multibrid M5000, REpower 5M, Enercon E-126, Siemens SWT-3.6-107, GE Energy 3.6s); and on data from the alpha-ventus experimental offshore wind farm (M5000 & 5M). The mass of the foundations was estimated with data from alpha-ventus, Vestas, and Vattenfal. Assumptions had been made on the possible evolution of the weight vs. capacity relationship according to technological evolution, to 2015/2020/2030, in turbines, towers, and foundations. The turbine sizes assumed are 3 MW for onshore and 6 MW for offshore by 2020 and 3 MW for onshore and 8 MW for offshore by 2030.

In thermal power plants, the development of new steel grades will increase temperature and pressure and will contribute to the improvement of energy efficiency (a realistic medium-term target is the development of types of steels able to operate at pressures and temperatures up to 32.5 MPa and 650 °C, respectively). In advanced supercritical plants with steam conditions up to 600 °C and 30 MPa it should be possible to reach net efficiencies between 46 and 49 %, whereas, plants with steam conditions of 600 °C and 25 MPa have efficiencies in the range 40-45 % [JRC-SETIS, 2009]. Older pulverised coal plants, with subcritical steam parameters, operate with efficiencies between 32-40 %. Each %-age point efficiency increase is equivalent to about 2.5 % reduction in tonnes of CO₂ emitted [JRC-SETIS, 2009]. Therefore, major retrofitting of old subcritical power plants with supercritical steam cycles or retiring old plants and their replacement with new plants is essential to minimise CO₂ emissions in the power sector. Further developments of Ni-base alloys may allow steam with temperatures up to 700 °C [ESTEP, 2005].

In gas transportation, the development of very high strength steels will contribute to safe and efficient transportation of natural gas, H₂ and CO₂ (CCS technologies). Historically, since 1996, a fundamental effort of the EU, focusing on smoothing out the workings of the internal energy market, was the Trans European Networks for Energy [European Commission, 2010a]. Recently, the European Energy Programme for Recovery has allocated almost EUR 4 billion to leverage private funding in gas and electricity structure. A good example of the active role of the European Commission in support of this kind of project is the Baltic Energy Market Interconnection Plan (BEMIP) [European Commission, 2010b] or the Southern Corridor (including Nabucco [European Commission, 2008]). Currently, the EU is setting out new measures to safeguard the security of gas supply in Europe with a new Energy Infrastructure Package.

The development of new grades (lightweight alloys) for the automotive industry can decrease steel consumption (energy consumption) and at the same time improve the efficiency of the final products; lighter cars will be more efficient. If the body structures of all cars produced worldwide were made of Advanced high-Strength Steel instead of conventional steel, 156 Mt CO₂eq would be avoided [Wordsteel, 2011]. The savings which are typically achieved today correspond to a total vehicle weight reduction of 9 %. For every 10 % reduction in vehicle weight fuel, its economy is improved between 1.9 % and 8.2 % [Wordsteel, 2011a]. When applied to a

typical five-seater passenger family car, the overall weight of the vehicle is reduced by 117 kg, the savings produced during the whole lifetime of the vehicle is 2.2 t CO₂eq [Geyer and Bren, 2006].

17.2.4 Barriers to large-scale deployment

Further increases in the recycling rate beyond the 60 % in 2030 will be stifled by the availability of scrap. Such high recycling values will increase the impurities and reduce the overall steel quality. Recycling has high emissions of heavy metals and organic pollutants due to the impurities of scrap [ETC/RWM, 2005]. These issues will become a more pressing issue to be solved urgently.

According to EUROFER, for the reduction of CO₂ emissions with the conventional integrated route (BF and BOF), the thermochemical efficiency of current blast furnaces is very close to the optimum. CO₂ emissions are linked to the chemical reaction for the reduction of iron ore. No significant advance to decrease CO₂ emissions is possible without the development of breakthrough technologies, as proposed by ULCOS.

The main lever of energy savings for steel production is led by further increases in the recycling rate. For the integrated route, the BF and BOF of existing “good reference plants” are very close to the optimum, so there are very few possibilities of additional energy savings in this area. The best performers are at 17 GJ/t of hot-rolled product when the average is at around 21 GJ/t of hot-rolled product. Not all the European operators are best-in-class and thus more potential to save energy is available by bringing them up to the level of the best performers: dissemination of best practices and best available technologies (BAT) identified in the BREFs documents for the Iron and Steel industries [BREF, 2009]. In addition, there is some room for improvement for the best performers and others, especially for the downstream processes, with a better energetic valorisation of process gases in excess, wastes and by-products. A recent roadmap addressing the strategy of the steel industry in the fields of sustainability, CO₂, energy and environment [ESTEP, 2010], proposes new areas for R&D for energy efficiency in the steel production. Thus, recovery of waste heat (including mean and low level temperatures), improving the valorisation of process gases, use of renewable energies, ICT integrated approach for the plant energy management, recovery of wastes and residues are some of the topics where the industry needs support for research, pilots and demonstrators.

The industry has pointed out the risks of carbon leakage under the terms of the former EU Greenhouse Gas Emission Trading System (EU ETS) [EC, 2003]. According to Worldsteel's figures [Worldsteel, 2009], trade within the EU-25 in 2007 amounted to 127 Mt of crude steel, with 41 Mt imported from outside the EU-25 and 34.1 Mt exported to other non-EU-27 countries. Excluding the intra-EU-27 trade, the EU is ranked as first as world importer and as third as world exporter. When looking at individual countries of the EU-27, the variability in trade behaviour clearly stands out. In 2007, Spain, Italy and Poland imported 16.9 Mt whereas Belgium-Luxembourg, Austria, Germany and the Netherlands exported 14.5 Mt (these latter figures include intra-EU-27 trade). The revised EC Directive [European Commission, 2009a] provides for 100 % of allowances allocated free of charge, at the level of the benchmark to the sectors exposed. The sectors exposed were determined by the Commission in December 2009 [European Commission, 2009b]; the iron and steel industry is among them. The benchmarking values, proposed by the European Commission, were adopted in April 2011 [European Commission, 2011].

Other social challenges to the industry come from the increasing average age structure of its workforce: more than 20 % will retire from 2005 to 2015 and close to 30 % during the following 10 years. Therefore, the industry has the challenge to attract, educate and secure more qualified people [ESTEP, 2005].

17.2.5 RD&D priorities and current initiatives

During the period 2005 to 2008, direct emissions from the integrated route were on average 2.3 tCO₂/t of rolled products and 0.21 tCO₂/t of rolled products for the recycling route [Ecofys, 2009]. Taking into account the indirect emissions from electricity production in the case of the recycling route, of around 452 kgCO₂ /t of rolled products⁹⁴ should be added to the 210 kgCO₂/t of rolled products reported. The resulting amount remains well below the reference values emitted for the integrated route (on average 2300 kgCO₂/t of rolled products).

⁹⁴ This value has been obtained using an average emission factor for electricity of 0.465 tCO₂/MWh [Capros et al., 2008] for the overall EU electrical production and 3.5 GJ/t needed as a good reference value for the production of the recycling route [SET-Plan, 2010].

The data collection for the purposes of the implementation of the revised Emissions Trading Directive indicates a potential for reductions of direct CO₂ by applying best practice to the extent of 10 % of the current absolute and direct emission of the parts of the sector covered by the revised Emissions Trading Directive (roughly equivalent to 27 Mt of CO₂ per year). This potential however relies strongly on a substitution of local raw materials with increased imports of best performance raw materials from outside the EU (especially ores and coal). The EU Commission has launched the Sustainable Industry Low Carbon (SILC) initiative to help the industry to achieve specific GHG emission intensity reductions in order to maintain their competitiveness [SILC, 2011].

According to the IEA, the savings potential in 2005 for the industry, based on best available technologies are around 2.12 GJ/t for the European countries of the OECD [IEA, 2008]. This value is around 15 % of the average consumption (combined production of the integrated route and the recycling route) [SET-Plan, 2010]. In the EU-27, such savings would have meant 0.40 EJ (9.5 Mtoe) in 2005.

The expected increase in the share of recycling route for the total production from 42 % in 2005 to 56 % in 2030 [European Commission, 2007] could result in an increase of only 7 % in CO₂ emissions. This means an improvement of the CO₂ emissions per tonne of crude steel of around 20 %.

An early market roll out after 2020 of the first technology considered in the Ultra low CO₂ steelmaking project (ULCOS project, supported by the EU) could further reduce the CO₂ emissions. The ULCOS project is the flagship of the industry to obtain a decrease of over 50 % of CO₂ emissions in the long term. The first phase of ULCOS had a budget of EUR 75 million. As a result of this first phase, four main processes have been earmarked for further development:

- 1 **Top gas recycling blast furnace** is based on the separation of the off-gases so that the useful components can be recycled back into the furnace and used as a reducing agent and in the injection of oxygen instead of preheated air to ease the CO₂ capture and storage (CCS). The implementation of the Top gas recycling blast furnace with CCS will cost about EUR 590 million for an industrial demonstrator producing 1.2 Mt hot metal per year [SET-Plan, 2010]. A proposal, for an existing steel plant in France, has been submitted within the NER-300 allowances funding as a CCS flagship

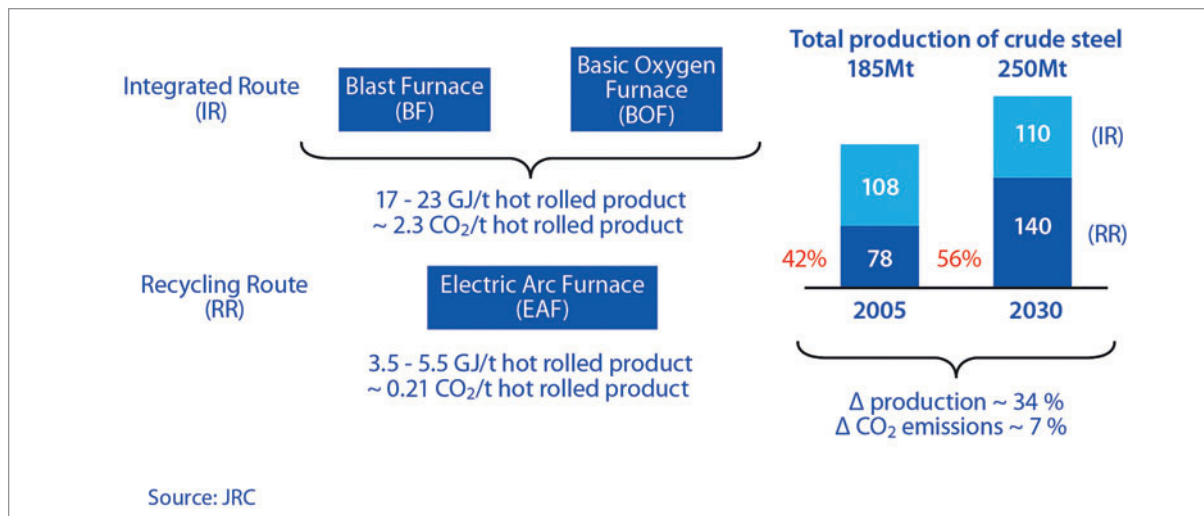


Figure 17.2.2: Combining the expected increased share of the recycling route by 2030, the specific energy consumption and CO₂ emissions of both routes and the expected increase of the production (around 34 %) will mean an increase of only 7 % in total CO₂ emissions. [Source: JRC]

demonstrator. The tentative timeline to complete the demonstration programme is about 10 years, allowing further market roll-out post-2020 [EECRsteel, 2011a].

- 2 The **Hisarna** technology combines preheating of coal and partial pyrolysis in a reactor, a melting cyclone for ore melting and a smelter vessel for final ore reduction and iron production. The market roll-out is foreseen for 2030. Combined with CCS, the potential reduction of CO₂ emissions of this process is 70-80 % [SET-Plan, 2010]. A pilot plant (8 t/h without CCS) is being commissioned during 2011 in Ijmuiden, Netherlands [EECRsteel, 2011b].
- 3 The **ULCORED** (advanced Direct Reduction with CCS) direct-reduced iron is produced from the direct reduction of iron ore by a reducing gas produced from natural gas. The reduced iron is in solid state and will need an electric arc furnace for melting the iron. An experimental pilot plant is planned in Sweden, with market roll-out foreseen for 2030. The potential reduction of CO₂ emissions from this process is 70-80 %.
- 4 **ULCOWIN** and **ULCOSYS** are electrolysis processes to be tested on a laboratory scale. There is a clear need to support this ULCOS research effort with a high share of public funds, and to lead the global framework market towards conditions that ease the prospective deployment of these breakthrough technologies.

It is important to notice that, compared to the conventional blast furnace, the first two breakthroughs ULCOS-BF and HISARNA would result in a reduction of CO₂ emissions of 50-80 % and at the same time a reduction of energy consumption by 10-15 %. One important synergy in the quest to curb prospective CO₂ emissions through the ULCOS project is the share of innovation initiatives within the power sector or with any other (energy-intensive) manufacturing industries that could launch initiatives in the field of CCS (e.g. cement industry) [ZEP, 2010; ESTEP, 2009].

Exploiting the advantages of the recycling route (an order of magnitude lower of direct CO₂ emissions than the integrated route) will demand an outstanding end-of-life management to make sure that all steel contained in scrap can be recycled in an effective way.

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17.3. The Pulp and Paper Industry

17.3.1 Introduction

Pulp and paper is an energy-intensive industry. On average, energy costs are 16 % of the production costs [BREF, 2010] and in some cases up to 30 % [CEPI, 2011b].⁹⁵ This industry is the largest user and producer of renewable energy (around 50 % of the primary energy consumption comes from biomass) [BREF, 2010]. At the same time, in 2008, the bioenergy consumption in the European pulp and paper industry represented more than 16 % of the bioenergy consumed in Europe [AEBIOM, 2010; EUBIONET3, 2010]. In the quest for energy efficiency measures, the industry has invested heavily in combined heat and power generation (CHP). In 2008, its electricity production from CHP was 46 % of the electrical consumption [CEPI, 2009]. Also, half of the paper produced comes from recycled fibre. This evolution has resulted in that, from 1990 to 2008, direct absolute CO₂ emissions have decreased by 4.4 %, whereas the pulp and paper production has increased by 50 % and 22 %, respectively [CEPI, 2009]. The CO₂ emissions from the sector in 2008, around 38 million tonnes, represented 2 % of the emissions under the EU Emission Trading System.

In 2008 in Europe, the sector had a total turnover of EUR 83 billion, employing some 240 000 people directly [CEPI, 2009]. Many mills operate in rural areas, making them particularly relevant to regional employment – 60 % of employment in the European pulp and paper industry is located in rural areas.

17.3.2 Technological state of the art and anticipated developments

There are two main routes to produce different types of pulp: from virgin wood or from recycled material. The pulp produced in either way is subsequently processed into a variety of paper products. For virgin pulp making, two main kinds of processes are used – chemical and mechanical pulp making. Virgin pulp can be produced alongside paper, on the same site. In Europe, about 18 % of all mills are integrated mills producing both virgin pulp and paper [Ecofys, 2009].

Recycled fibres are the starting point for the recycling route. Europe has one of the highest recovery and utilisation rates of fibres in the world (66.7 % in 2008) [CEPI, 2009].⁹⁶ Except for a small number of deinked market pulp mills, pulp production from recycled fibres is always integrated alongside paper production.

The pulp and paper industry is one of the most energy-intensive sectors of the EU. Pulp and paper production requires the use of power and steam/heat. There are large variations on the energy profiles for different technologies. Raw wood use differs by almost four times between the different paper grades and energy use differs by a factor of two [JRC-IPTS, 2006]. However, in general terms, it can be said that mechanical pulp making is more electricity-intensive and less heat intensive than chemical pulping. The electricity/steam consumption ratio at paper mills enables an efficient use of co-generation of heat and power (CHP). On the overall European balance, the industry in 2008 bought 72 TWh of electricity, sold 9 TWh of electricity and produced 53 TWh of electricity [CEPI, 2009], that is, its electricity production amounts to almost 46 % of its electrical consumption.

Specific primary energy consumption in 2008 was 13.4 GJ/t, based on the overall totals of energy and production data [CEPI, 2009]. This specific consumption includes 2.04 GJ/t of specific net bought electricity. Half of the energy used by the industry (54.4 % in 2008) comes from biomass and approximately 38 % from natural gas [CEPI, 2009]. Therefore, although the industry is energy-intensive, its carbon-intensity is not comparable with other sectors.

From 1990 to 2008, the improvement in specific primary energy and electricity consumption has been 16.6 % and 16.1 %, respectively [CEPI, 2009]. In a business-as-usual scenario, there is still some room for improvement because the average values of the 10 % of best performers (benchmark levels) have 50 % and 30 % lower specific CO₂ emissions than the highest values and the average, respectively [SET-Plan, 2010]. However, tapping this potential improvement requires the replacement of today's machines by new ones and due to the high cost of new machines, this will take time and is dependent on

⁹⁵ CEPI is the Confederation of European Paper Industries (CEPI) and its mission is to promote the member's business sector by taking specific actions, notably by monitoring and analysing activities and initiatives in the areas of industry, environment, energy, forestry, recycling, fiscal policies and competitiveness in general [CEPI, 2011a].

⁹⁶ Recycling rate: "Recovered Paper Utilization + Net Trade", compared to Paper and Board Consumption [CEPI, 2009]

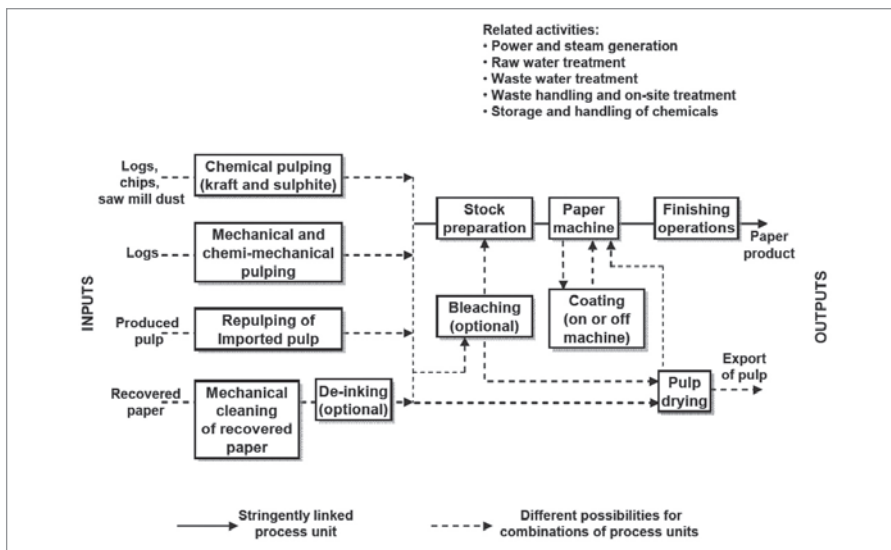


Figure 17.3.1: Main processes involved in the production of pulp and paper in integrated and non-integrated mills. [Source: [BREF, 2010]].

machine age, investment cycles, sector developments and availability of capital. The prime candidates for improvements are the boilers, followed by the most energy-intensive part of the paper production, the drying of the paper. There exist several potential breakthrough technologies, see Section 17.3.5, that have not managed to demonstrate market viability yet.

17.3.3 Market and industry status and potential

In 2008, the EU paper and board production (reported by the 19 CEPI-associated countries)⁹⁷ was 25.3 % (98.9Mt) of world production (North America 24.5 % and Asia 40.2 %). Europe also represents about 21.6 % (41.6 Mt) of the world's total pulp production [CEPI, 2009].

From 1991 to 2008, the EU pulp and paper production (in CEPI countries) had an average annual growth of 0.4 % and 1.9 % for pulp and paper respectively, whereas the number of pulp and paper mills has decreased around 40 % [CEPI, 2009]. This process of consolidation of the sector has led to fewer and larger companies with a large number of relatively small plants specializing in niche markets. The current total number of pulp and paper mills (all grades) in Europe is 203 and 944, respectively [BREF, 2010].

Sweden and Finland are the countries with the highest number of pulp mills (around 35 each),

followed by Germany (19) [BREF, 2010]. Their production share in 2008 was 28.8, 27.8 and 6.9 %, respectively [CEPI, 2008]. The two countries with the highest number of paper mills are Italy and Germany with around 170 mills each, followed by France, with around 95 paper mills [BREF, 2010] with a production share in 2008 of 9.6, 23.6 and 9.5 %, respectively [CEPI, 2008]. Other countries (such as Sweden and Finland), with a lower number of

paper mills (around 40 each) have a higher share of the production, 11.8 and 13.3 %, respectively [CEPI, 2008]. This is because a small amount of new mills are able to account for most of the production (i.e. for wood-free machines, the 10 % most efficient of the paper machines produce roughly 40 % of the total production [CEPI, 2009; JRC-IPTS, 2006]).

In 2008, the amount of pulp exported and imported to third countries (outside the EU) were 2.1 and 7.8 Mt, respectively, whereas for the paper, the figures of the exported and imported paper amounted to 17.5 and 5.4 Mt [CEPI, 2008].

Since the mid-1990s, the sector has invested annually 6-8 % (around EUR 5 billion) of its annual revenue to improve its capacity. The turnover in 2007 was EUR 82 billion, and between 2007 and 2010, due to the financial crisis, production decreased by 7 % and turnover by 3 %. The European pulp and paper industry has partially recovered. However, it has not reached the pre-crisis levels yet. For certain grades (e.g. newsprint), production is not expected to come back to pre-crisis levels [SET-Plan, 2010]. Overall, the sector keeps growing at a steady pace with a changing product mix and new grades developing as a consequence of long-term societal changes (tissue, because of the ageing population and hygiene needs, packaging, etc.). The situation of the sector in the future will also depend largely on the extent to which export markets advance, e.g. the competitiveness of the sector on a global perspective.

⁹⁷ The 19 CEPI countries are: Austria, Belgium, Czech Republic, Finland, France, Germany, Hungary, Italy, The Netherlands, Norway, Poland, Portugal, Romania, Slovak Republic, Slovenia, Spain, Sweden, Switzerland and the United Kingdom.

17.3.4 Barriers to large-scale deployment

In the short- and long-term perspectives, the availability of raw materials (wood and recycled fibre) will be crucial for the pulp and paper industry. Currently, there is an increasing pressure on biomass availability. For their main virgin feedstock, wood, the pulp and paper industry is competing with other bioenergy producers, almost 5 % of the EU gross energy demand is covered by biomass resources. In fact, biomass was almost two thirds (65.6 %) of all renewable primary energy consumption in 2007 [JRC-SETIS, 2009]. At the same time, waste paper is exported on a large scale, mainly to China, where new large paper mills have been built. This leads to shortages in recycled fibres for some European paper producers.

R&D in many innovative technologies is nearly stalled. This is related to the fact that many of the already available innovative technologies have not yet been able to demonstrate market viability. Most of the potential emerging technologies are currently in a “valley of death”, unable to achieve market deployment. Large-scale demonstration plants could help the breakthrough technologies to cross or leave this “valley of death” and demonstrate market viability. If the emerging technologies are not deployed, the expected improvement of the sector in energy consumption and emissions is roughly estimated at about 25 % by 2050, achievable through the deployment of BATs in two investment cycles from now to 2050.

Despite the high penetration of the cogeneration in the pulp and paper industry, it is estimated that only 40 % of CHP potential capacity has been installed in this industry [ASPAPPEL, 2011]. The barriers that the sector faces to further expansion of CHP are similar to the ones that the rest of the industry sector encounters [ASPAPPEL, 2011]. One of the main barriers is the ‘spread price’ [SET-Plan, 2010], the difference between the price of the fuel used by the CHP and the price of the electricity generated. Priority grid access and dispatch for CHP electricity sold back to the national grid might improve quicker and wider implementation. Also, the trend by many municipalities to decrease the availability of waste to be recycled by the energy intensive industries may further hamper reaching higher levels of efficiency.

The industry has pointed out the risks of carbon leakage under the terms of the former EU Greenhouse Gas Emission Trading System (EU ETS) [European Commission, 2003]. Sensitive to these concerns, the revised Directive [European Commission, 2009a]

stipulates that industrial sectors exposed to carbon leakage receive free emissions allowances equivalent to 100 % of benchmark values. The sectors exposed were determined by the European Commission in December 2009 [European Commission, 2009b]; the pulp and paper industry is among them. The benchmarking values proposed by the European Commission, were adopted in April 2011 [European Commission, 2011]. The EU Commission has launched the Sustainable Industry Low Carbon (SILC) initiative [SILC, 2011] to help the industry to achieve specific GHG emission intensity reductions in order to maintain their competitiveness.

Furthermore, the lack of detailed and consolidated information about consumptions and emissions of most of the pulp and paper technologies is a barrier in itself. Potential policy measures need to be justified and prioritised on sound data and robust impact calculations. The SILC initiative could also contribute to alleviate this issue.

17.3.5 RD&D priorities and current initiatives

In general terms, and as similar to other energy intensive industries, the pulp and paper industry devotes around 1-2 % of its turnover to R&D. However, many companies focus their R&D investments mainly on new products, leaving most of the investment in R&D regarding technology and processes to a small number of specialised machine and equipment suppliers [SET-Plan, 2010]. Although Europe is the global technology leader, the technology suppliers mainly develop modular-based solutions for the EU pulp and paper industry that operates in a stable market, whereas the suppliers focus on Asia and South America for the development of new mill concepts.

There are potential emerging and breakthrough technologies, although most are currently at a standstill. These can be grouped in the following families:

- The **bio-route** is the route towards integrated bio-refinery complexes producing bio-pulp, bio-paper, bio-chemicals, biofuels, bioenergy and possibly bio-Carbon Capture and Storage (bio-CCS). Some of the bio-route concepts are in the European Industrial Bioenergy Initiative (EIBI). In fact, as part of this initiative, there is a first large-scale demonstrator, a bio-DME (dimethyl ether) plant connected to a pulp mill, under construction in Sweden [Bio-DME, 2011] (see Figure 17.3.2). Also, one of the flagships

planned for this Initiative is led by a Finnish pulp and paper company [EIBI, 2011; UPM, 2011]. Part of this route is also the further development of gasification of black liquor, which aims at producing a combustible mixture of raw gases on the one hand and separating out the inorganic pulping chemicals on the other hand for their subsequent use in the pulping processes. **Lignoboost**, another bio-route concept, is a complete system that extracts lignin, a component of wood from kraft black liquor. This lignin can be used as a biofuel with a relatively high heating value and could also be used as feedstock to produce innovative chemicals.

- **Innovative drying technologies.** Some drying technologies, “impulse drying”, the “Condebelt” process or the “steam impingement drying” have only had a first-of-a-kind implementation and have not been replicated. The first European commercial facility with a condebelt® process entered in operation in 1996 at the Pankaboard mill in Pankakoski, Finland. There was a second case of implementation of this technology in 1999 in South Korea [Åsblad et al., 2001]. R&D regarding innovative drying technologies seems to be at a standstill.
- **Mechanical pulping.** There is ongoing work, at the laboratory level, to optimise the production of mechanical pulp focusing mainly on the wood yield preparation and more efficient refiner plates (less energy consumption at the same productivity levels).

The aggregated nature of the information available at the EU-sector level makes it difficult to assess the impact that individual technologies for the pulp and paper industry could have at the energy system level. Nevertheless, the IEA Technology Perspectives [IEA, 2010] and the Horizon 2050 study published by CAN Europe [CAN, 2010] give first estimates of savings potentials that could be achieved through a larger scale deployment of the above listed breakthrough technologies.

Under the European Commission’s Sustainable Bio-refineries Call, the EU is co-funding four projects: Star-COLIBRI, SUPRABIO, EuroBioRef and BIOCORE [Start-COLIBRI, 2011] for EUR 51.6 million of a total budget of EUR 79.1 million. Also, part of the support needed to develop the bio-route can be channelled through the European Industrial Bioenergy Initiative [EIBI, 2011] with projects such as [Bio-DME, 2011] and [UPM, 2011]. However, the large investments needed to jump from pilot plant to full-scale application may require an additional push to allow the industry to leave the apparent “valley of death” in which a lot of research finds itself. A number of these investments bring financial risks that mills cannot take on in the current economic conditions and for which assistance is needed. Furthermore, several large-scale technologies are competing in the same field, where it is not clear yet which one will be the winning technology. For those commercially-available drying technologies, the market seems to doubt their potential, since very few new machines have been

deployed. Next to the investment cost factor, trust or reliability of new technologies seems to be an issue.

One important synergy in the quest to curb CO₂ emissions could be exploited through sharing innovation initiatives with the power sector or with any other (energy-intensive) manufacturing industry that could launch initiatives in the field of CCS (e.g. iron and steel industry, cement industry...) [ZEP, 2010; ESTEP, 2009].



Figure 17.3.2: Photomontage of a gasification plant producing green fuels dimethyl ether (DME), ether and methanol at Domsjoe Fabriker. The plant is expected to be ready in 2013. [Source: CHEMREC]⁹⁸

⁹⁸ <http://www.chemrec.se/Page228.aspx>

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18. Energy Performance of Buildings

18.1. Introduction

About 37 % of final energy consumption is taken by the building sector (households and services). A gradual shift over the last five years has been observed from fossil fuels to renewable energy sources, such as solar energy, wind power and bio-energy. By means of Directives [EPBD, 2010; EESD, 2006; EESD, 2011; RESD, 2009], Recommendations and Regulations, the European Commission is giving direction to the future of sustainable energy use and supporting the low-carbon energy policy.

Energy performance of buildings and efficient energy end-use are the important topics of interest. European standardisation facilitates exchange of goods, information and services to ensure a competition in a single European market.

The Energy Performance of Buildings Directive [EPBD, 2010] concerns the residential and the tertiary sector (offices, public buildings, etc.). Member States must apply minimum requirements as regards the energy performance of new and existing buildings. A common calculation methodology should include all the aspects which determine the final and primary energy consumption of the building. This integrated approach should take into account aspects such as heating and cooling installations, lighting, the position and orientation of the building, heat recovery and the application of renewable energy. The Member States are responsible for setting the minimum standards for buildings that are calculated on the basis of the above methodology.

At present, roughly two thirds of the energy consumption in buildings is used for space conditioning

(temperature and ventilation) while the remaining one third, see Figure 18.2, is mostly electricity used for installations and appliances [Bloem, 2011]. The trend is that by energy saving, the thermal energy is decreasing while at the same time electricity consumption is increasing making the need evident for more efficient energy consuming apparatus.

Renewable Energy takes a more and more important share in the final energy supply. The 2010 data provided by the evaluation of the National Renewable Energy Action Plan reports give an estimated share of 11.6 %, this corresponds to more than a doubling in 10 years whereas the 2020 target is an overall share in Europe of 20 %.

The philosophy that supports the reduction of energy consumption in buildings is presented in three priority steps:

1. Energy saving (improve insulation),
2. Increase energy efficiency (building installations),
3. Use renewable energy resources (solar energy, etc.).

18.2. Technological state of the art and anticipated developments

Energy Performance of buildings⁹⁹ can be classified in three consumption categories:

- **Building energy needs (savings)**. This is directly related to indoor (comfort level of temperature, air quality and light) and outdoor climate conditions (temperature, solar radiation and wind) for working and living in buildings. The heat transfer through

the building envelope and the ventilation define importantly the building energy needs. Minimum energy performance requirements are set for insulation levels of walls, roof, floor and windows, etc.

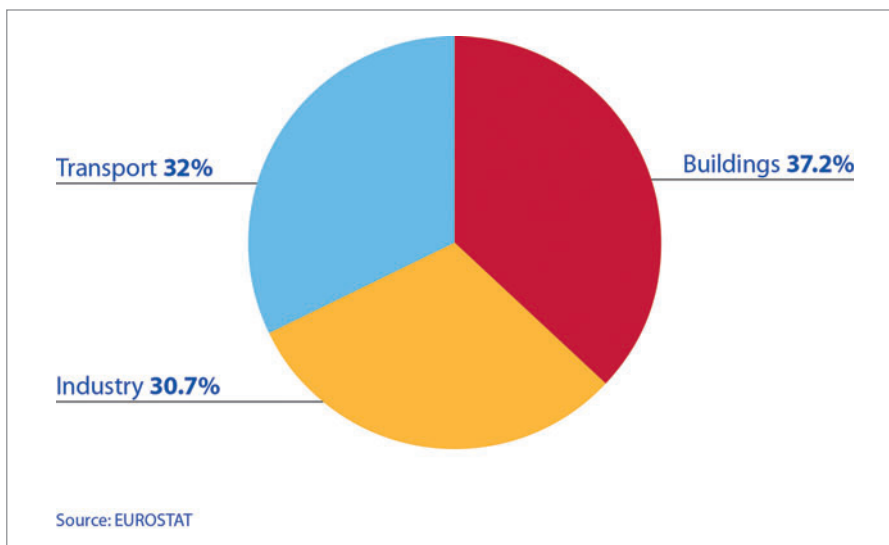


Figure 18.1: Final Energy Consumption 2008 [Source: Eurostat]

⁹⁹ Build-Up. The European portal to Energy Efficiency in Buildings: <http://www.buildup.eu>

- **Building systems energy (efficiency).**

The combined efficiency of the installations for heating, cooling, ventilation, hot water and electricity are the relevant factors in the end-use energy consumption. The EU harmonises national measures relating to the publication of information on the consumption of energy and of other essential resources by household appliances, thereby allowing consumers to choose appliances on the basis of their energy efficiency.

- **Occupancy energy consumption (behavioural).**

The remaining use of energy depends on how the occupant makes use of the building. Household appliances, such as washing machines, refrigerators, etc. and entertainment apparatus, such as TV and computers, consume mainly electricity that is converted for a great part into auxiliary heat. Occupancy behaviour is covering also variable aspects as the opening of windows, temperature setting, etc.

The EPBD requests for nearly-zero energy buildings, taking into account the possible positive impact of renewable energy technologies. Solar, wind and bioenergy are the technologies progressing most rapidly. Solar and wind develop for electricity generation, whilst bioenergy (biomass) remains dominant for the heating sector. In more detail, the renewable energy covered by solar energy, bioenergy and to a smaller extent by geo- and aero-thermal, is:

- Solar energy can be distinguished in:
 - **Passive solar** by means of building design (and orientation) for energy saving,
 - **Solar electrical**; roof-top photovoltaic installations produce energy electricity,
 - **Solar thermal**; solar collectors produce hot water for domestic use and space heating.
- Bio-mass products such as wood logs, pellets etc. are used as fuel for space heating installations.
- Geo- and aero-thermal energy: heat pumps are often used in buildings for ground coupled and air-

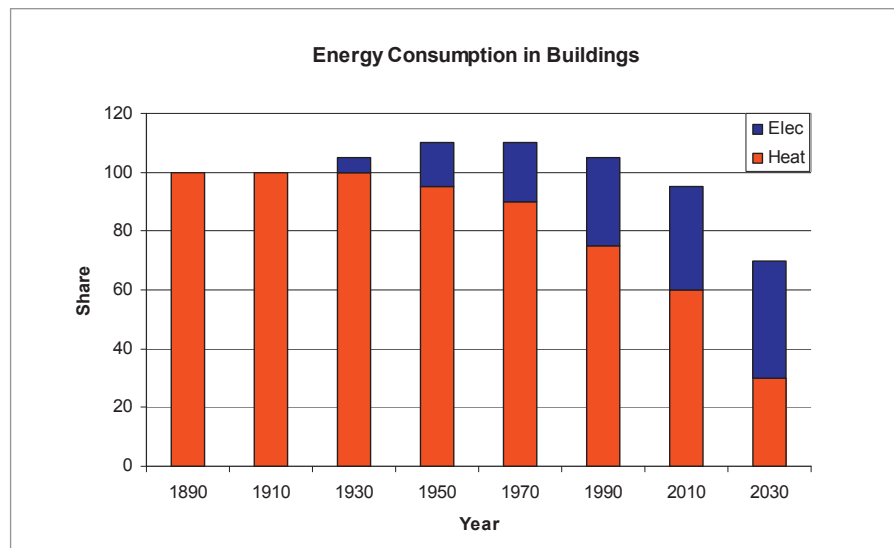


Figure 18.2: Energy consumption trend. [Source: [Bloem, 2011]]

to-air heat exchange. This conversion technology offers the possibility of efficient energy use both for space heating and cooling.

Numerous applications for innovation and requested technologies for the built environment offer opportunities to reduce the energy consumption and to control the energy demand/supply balance through intelligent management (ICT). The building will be considered as the cornerstone of the future energy system in our society. Proper integration of renewable energy technologies and electrical vehicles in this built environment will lead to a more efficient use of available energy resources.

18.3. Market and industry status and potential

The building construction sector knows a wide area of technologies, for which a brief overview is given below, in the context of low energy buildings. In line with the energy performance requirements, the market is focused on more sustainable construction techniques, materials and building components that will enter the market. Innovative integrated technologies (ventilated facades and windows, solar chimney and new insulation materials) will contribute to a decrease in overall energy consumption.

Low-energy buildings can become reality when the design process takes into account the energy flows from passive solar and landscape design (orientation and immediate environment, including soil) integrated with architectural design, see Figure 18.3. This design will have to incorporate technologies that are related to:

- The envelope (ambient exposed surface area) and space (volume contained by the envelope):
 - New insulation materials and techniques for construction materials, windows and doors are available for new buildings and refurbishment. Air tightness and thermal bridges of the whole construction receives more attention than before to reduce overall energy consumption.
- The operational energy installations (boiler, ventilation, etc.):
 - High efficiency boilers for space heating and hot water demand are entering rapidly the market. Efficient heat exchange ventilation is recognised as an integrated design requirement for low-energy buildings. Installations such as, heat pump floor heating and air conditioning.
- The gains from appliances, human behaviour and solar in particular:
 - The sun as source of our energy system could be utilised effectively in a passive solar and landscape design. In low-energy buildings, the gains will influence much more the dynamic response of operational energy installations. Note that most of the electrical consumed energy is converted into heat.

Other technologies to mention are:

- Renewable energy technologies, in particular solar thermal for domestic hot water and biomass for space heating, and
- Smart technologies entering the built environment ranging from automisation for control to smart metering devices for interaction with utilities.

Member States have minimum performance requirements for building insulation and ventilation that are defined in national building codes and regulation. Differences occur due to climate, construction technique and culture. For low-energy buildings, the following indicators are given of feasible insulation levels:

- Low U-values (high thermal resistance) can be reached of 0.1-0.15 W/m²K,
- Triple pane, low emissivity and gas-filled windows in warm-edged frames can reach 0.7 – 0.9 W/m²K, and
- Air tightness of the building, in combination with heat recovery ventilation systems can obtain levels of 0.4 – 0.6 ACH (air changes per hour) with an energy efficiency of the installation over 80 %.

18.4. Barriers to large-scale deployment

The low number of new buildings compared to the existing building stock is the reason that the potential energy savings are not leading to the desired overall energy savings. Operational energy in residential or commercial buildings to be renovated should be the first aspect to be taken into account when considering the improvement of the energy performance of building stocks. To ensure efficient life-cycle performance of the building, life-cycle responsibility and effective commissioning processes are required. The high investment costs involved, the lack

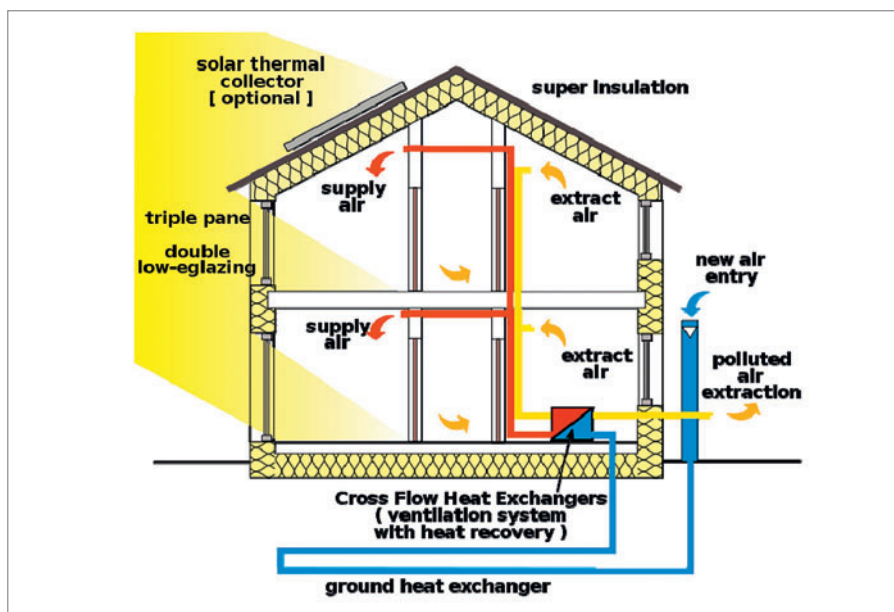


Figure 18.3: Passive house technologies [Source: Passivhaus Institut]

of information on energy-efficient solutions at all levels and scarce availability of solutions to specific conditions, are considered as the major barriers to the implementation of energy-efficiency measures in buildings as identified by a cost-optimal methodology.

The development in the construction market [EUROSTAT, 2010] reflects the impact of the economic and financial crisis, the oversupply of construction and reduced confidence, see Figure 18.4. The building energy related industry is directly affected by this development, however it will challenge the development and marketing of innovative building products supported by the EPBD.

Two important Energy Directives, the recast of the EPBD and the new EESD, should give a new impetus to an increase of energy savings and energy efficiency in order to reach the targets set by the EU for 2020. At present, a 9 % saving is expected, well below the target of 20 %. Problems with the implementation of the Directives into national regulations (and in relation to European standards) are seen as an additional barrier.

Hesitant investment in the implementation of energy efficient measures is considered as a barrier also. Confidence has to return in the financial and economic markets to stimulate the construction industry and therewith, the investment in the energy related markets.

18.5. RD&D priorities and current initiatives

The requirement of nearly-zero energy buildings from 2018-2020, as mentioned in the EPBD, will need the development of a new design approach, based more on energy flows in buildings. The trend for energy consumption in buildings is a decrease of thermal energy for space conditioning and an increase of electricity for installations and appliances. A much more design-based dynamic methodology (calculation tools), and test installations for innovative and energy-complex building elements are required to support building designers.

Major renovation is seen as an important option to reduce energy consumption. The integration

of renewable energy technologies in the built environment is a valuable option to support the reduction of energy consumption and in particular in the reduction of GHG emission.

Storage is considered as an important technological option to reduce overall energy consumption in buildings. Major renovation of buildings and new building design has to take into account the impact of thermal mass. Dynamic evaluation and simulation models are required to study carefully the impact on the overall energy balance of a building within the energy system, ranging from an hourly/daily up to a seasonal/annual time base. Opportunities for distributed electricity storage are innovative technologies, such as batteries, compressed air storage, thermal energy storage and vehicle-to-grid, will compete in this market. Benefits of electric storage installations are improved reliability and power quality, meeting peak demand, reduced need for added generation capacity and reduction of CO₂ emissions. Storage is particularly applicable to variable solar and wind power installations.

Designers and architects should become acquainted with these new technologies in order to find new and low energy buildings in our future society. Development programmes based on awareness, as well as technological knowledge, should be integrated in academic programmes.

The JRC Institute for Energy and Transport is supporting the European legislation [CEN] by assessing technical requirements for standardisation in relation to energy performance of buildings. Under review at present are the energy standards relevant

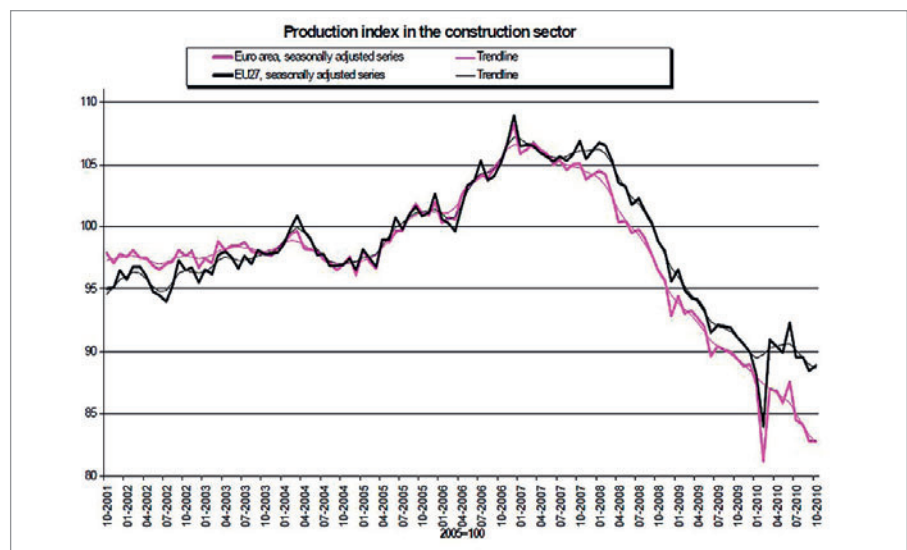


Figure 18.4: Development of the production index in the construction sector [Source: Eurostat 2010]

for the EPBD 2010/31/EU. A holistic calculation method for final and primary energy consumption is under development at CEN. This process includes harmonisation of climate data and overall energy calculation methodology.

Among other topics for harmonisation are:

- Assessment of solar yield for solar installations; energy produced by photovoltaic, as well as solar thermal collectors;
- Calculation and simulation methods for low energy buildings, considering also passive and solar gain and the application of dynamic calculation methods.

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Abbreviations and Acronyms

ABWR	Advanced Boiling Water Reactor	CENELEC	Comite Europeen de Normalisation Electrotechnique (European Committee for Electrotechnical Standarization)
AA-CAES	Adiabatic Compressed Air Energy Storage	CEPI	Confederation of European Paper Industries
ACER	European Agency for the Cooperation of Energy Regulators	CF	Capacity Factor
ACH	Air Changes per Hour	CFB	Circulating Fluidised Bed
AD	Anaerobic Digestion	CHHP	Combined production of Hydrogen, Heat and Power
ADDRESS	Active Distribution networks with full integration of Demand and distributed energy RESourceS	CHP	Combined Heat and Power
AEBIOM	European Biomass Association	CHPDH	Combined Heat and Power District Heating
AFC	Alkaline Fuel Cell	CNY	Chinese Yuan
ALISTORE	Advanced Lithium Energy Storage Systems	COE	Cost of Electricity
AMSC	American Superconductors	CoE	Cost of Energy
APU	Auxiliary Power Unit	COP	Coefficient of Performance
ASPAPPEL	Asociacion Espaniola de Fabricantes de Pasta, Papel y Carton (Spanish Association of Pulp and Paper Manufacturers)	CPV	Concentrated Photovoltaics
		CSI	Cement Sustainability Initiative
		CSIRO	Commonwealth Scientific and Industrial Research Organisation
BAT	Best Available Techniques	CSLF	Carbon Sequestration Leadership Forum
BEMIP	Baltic Energy Market Interconnection Plan	CSP	Concentrated Solar Power
BERR	UK Department for Business, Enterprise and Regulatory Reform	CT	Carbon Trust
BEV	Battery Electric Vehicles	CTD	Critical Technology Development
BF	Blast Furnace	CTF	Clean Technology Fund
BIG/CC	Biomass Integrated Gasification/ Combined Cycle	CV	Calorific Value
BIOFRAC	Biofuels Research Advisory Council	CVPP	Commercial Virtual Power Plant
BNEF	Bloomberg New Energy Finance	CWEA	Chinese Wind Energy Association
BOF	Basic Oxygen Furnace	DCFC	Direct Carbon Fuel Cell
BOKU-IFA	Universitaet fur Bodenkultur- Interuniversitaeren Department fur Agrarbiotechnologie	DCNS	Direction des Constructions Navals
BP	British Petroleum	DEMO	Demonstration Power Plant
BREF	BAT Reference documents	DER	Distributed Energy Resources
BSW-Solar	Bundesverband Solarwirtschaft	DESS	Distributed Energy Storage Systems
BTG	Biomass Technology Group	DFIG	Doubly Fed Induction Generator
BTL	Biomass-to-Liquid	DG	Directoire General
BTN	Biotechnologie Nordhausen	DG	Distributed Generation
BWEA	British Wind Energy Association	DH	District Heating
		DLR	Deutsches Zentrum für Luft- und Raumfahrt (German Aerospace Center)
CAES	Compressed Air Energy Storage	DME	Dimethylether
CAGR	Compound Annual Growth Rate	DMFC	Direct methanol fuel cell
CAN	Climate Action Network	DNI	Direct Normal Insolation
CapEx	Capital Expenditures	DoE	Department of Energy
CAT	Carbon Abatement Technologies	DSM	Demand Side Management
CCBIS	China Construction Bank International Securities	D-STATCOM	Distribution Static Compensator
CCGT	Combined Cycle Gas Turbine	DTI	Department of Trade and Industry
CCS	Carbon Capture and Storage	EAC	Electricity Advisory Committee
CDM	Clean Development Mechanism	EACI	European Executive Agency for Competitiveness and Innovation
CEN	Comite Europeen de Normalisation (European Committee for Standarization)	EADS	European Aeronautic Defence and Space Company
		EASE	European Association of Energy Storage

EBIT	Earnings Before Interest and Taxes	EU-OEA	European Ocean Energy Association
EBTP	European Biofuels Technology Platform	EV	Electrical Vehicles
EC	European Commission	EWEA	European Wind Energy Association
ECRA	European Cement Research Academy	EWI	European Wind Initiative
EDEMO	Early Demonstration Power Plant	FACTS	Flexible AC Transmission Systems
EDSO ₄ SG	European Distribution System Operators for Smart Grids	FAO	Food and Agriculture Organisation
EEA	European Environmental Agency	FBC	Fluidised Bed Combustion
EECRsteel	1st International Conference and Exhibition on Energy Efficiency and CO ₂ Reduction in the Steel Industry	FC	Fuel Cell
EEGI	European Electricity Grid Initiative	FCEV	Fuel Cell Electric Vehicle
EEPR	European Energy Programme for Recovery	FCH	Fuel Cells and Hydrogen
EER	Emerging Energy Research	FCH-JU	Fuel Cells and Hydrogen Joint Undertaking
EERA	European Energy Research Alliance	FFV	Flexible Fuels Vehicles
EESD	Energy, end-use Efficiency and Energy Services Directive	FiT	Feed in Tariff
EFDA	European Fusion Development Agreement	FLP	Florida Power & Light
EGEC	European Geothermal Energy Council	FOM	Fixed Operations & Maintenance
EGS	Enhanced Geothermal System	FTE	Full time equivalent
EIB	European Investment Bank	GDP	Gross Domestic Product
EIBI	European Bioenergy Industrial Initiative	GFR	Gas-cooled Fast Reactor
EII	European Industrial Initiative	GHG	Greenhouse Gases
EISA	Energy Independence and Security Act	GHP	Geothermal Heat Pump
EMG	Electromagnets	GIF	Generation IV International Forum
ENEF	European Nuclear Energy Forum	GNR	Getting the Numbers Right
ENGINE	Enhanced Geothermal Innovative Network for Europe	GPS	Global Positioning System
ENTSO-E	European Network of Transmission System Operators for Electricity	GSHP	Ground-Source Heat Pump
EOR	Enhanced Oil Recovery	GWEC	Global Wind Energy Council
EPBD	Energy Performance of Buildings Directive	HCE	Heat Collection Item
EPC	Engineering, Procurement and Construction	HESCAP	New Generation, High Energy and Power Density Supercapacitor Based Energy Storage System
EPIA	European Photovoltaic Industry Association	HiPER	High Power laser Energy Research facility
EPR	European Pressurised Reactor	HP	Heat Pump
EPRI	Electric Power Research Institute	HS	High Speed
EREC	European Renewable Energy Council	HT-PEMFC	High Temperature-Proton Exchange Membrane Fuel Cell
ESNII	European Sustainable Nuclear Industrial Initiative	HTR	High Temperature Reactor
ESTELA	European Solar Thermal Electricity Association	HVAC	High Voltage Alternating Current
ESTEP	European Steel Technology Platform	HVDC	High Voltage Direct Current
ETBE	ethyl-tertiary-butyl-ether	HVO	Hydrotreated Vegetable Oil
ETC/RWM	European Topic Center/Resource and Waste Management	IAEA	International Atomic Energy Agency
ETP	European Technology Platform	IATA	International Air Transport Association
ETS	Emissions Trading Scheme	IBSC	Intermediate Band Solar Cell
ETSAP	Energy Technology Systems Analysis Program	ICE	Internal Combustion Engine
ETSI	European Telecommunications Standards Institute	ICOE	International Conference on Ocean Energy
		ICT	Information and Communication Technology
		IDDP	Icelandic Deep Drilling Project
		IEA	International Energy Agency
		IEA HPP	International Energy Agency Heat Pump Program
		IEA-ETSAP	International Energy Agency-Energy Technology Systems Analysis Programme

IEC	International Electrotechnical Commission	MIT	Massachusetts Institute of Technology
IFEU	Institut für Energie- und Umweltforschung Heidelberg GmbH	MML	Mott McDonald
IFMIF	International Fusion Materials Irradiation Facility	MS	Medium Speed
IFPRI	International Food Policy Research Institute	MS	Member States
IGCC	Integrated Gasification Combined Cycle	MSW	Municipal Solid Wastes
IGFC	Integrated Gasification Fuel Cell	NCV	Net Calorific Value
ILUC	Indirect Land Use Changes	NEA	Nuclear Energy Agency
INES	Inertial Energy Storage Systems	NEDO	New Energy and Industrial Technology Development Organisation
IPCC	Intergovernmental Panel For Climate Change	NEEDS	New Energy Externalities Developments for Sustainability
IPHE	International Partnership for Hydrogen and Fuel Cells in the Economy	NEO	Nuclear Energy Outlook
IPPC	Integrated Pollution Prevention and Control	NER	New Entrant's Reserve
IPR	Intellectual Property Rights	NERA	National Economic Research Associates
IPTS	Institute for Prospective Technological Studies	NGO	Non Governmental Organisation
IRR	Internal Rate of Returns	NHA	National Hydrogen Association
ITER	International Thermonuclear Experimental Reactor	NIMBY	not in my back yard
JARI	Japan Automotive Research Institute	NMP	Nanosciences, Nanotechnologies, Materials and new Production Technologies
JET	Joint European Torus	NREAP	National Renewable Energy Action Plan
JHFC	Japan Hydrogen and Fuel Cells demonstration project	NREL	National Renewable Energy Laboratory
JRC	Joint Research Centre	O&G	Oil and Gas
KETEP	Korea Institute of Energy Technology Evaluation and Planning	O&M	Operation and Maintenance
KIC	Knowledge and Innovation Community	OECD	Organisation for Economic Cooperation and Development
LCA	Life Cycle Analysis	OEDU	Ocean Energy Development Unit
LCOE	Levelized Cost of Electricity	OEM	Original Equipment Manufacturer
LDV	Light Duty Vehicle	OES-IA	Ocean Energy Systems Implementing Agreement
LFR	Lead-cooled Fast Reactor	ORC	Organic Rankine Cycle
LHP	Large Hydropower Plant	OTEC	Ocean Thermal Energy Conversion
LHV	Lower Heating Value	OWC	Oscillating Water Columns
LPG	Liquified Petroleum Gas	OWCGS	Offshore Wind Capital Grant Scheme
LS	Low Speed	PAFC	Phosphoric Acid Fuel Cell
LS-EMG	Low Speed Electromagnet Generator	PC	Pulverized Coal
LT-PEM	Low Temperature-Proton Exchange Membrane	PEGASE	Pan European Grid Advanced Simulation and state Estimation
LV	Low Voltage	PEM	Proton Exchange Membrane
LWR	Light Water Reactor	PEMFC	Polymer Electrolyte Membrane Fuel Cell
MAIP	Multi-Annual Implementation Plan	PES	Primary Energy Savings
MCFC	Molten Carbonate Fuel Cell	PHES	Pumped Hydro Energy Storage
MEA	Monoethanolamine	PHEV	Plug-in Hybrid Electric Vehicles
MENA	Middle East and North Africa	PHS	Pumped Hydro Storage
MESSIB	Multi-source Energy Storage System Integrated in Buildings	PMG	Permanent Magnet Generator
MHT	Medium Hydropower Plant	PMU	Phasor Measurement Unit
		PR	Progress Ratio
		PV	Photovoltaic

PWR	Pressurised Water Reactor		
QD	Quantum Dot	SNG	Technology Platform Synthetic Natural Gas
R&D	Research and Development	SOFC	Solid Oxide Fuel Cell
RCS	Regulations, Codes and Standards	SRA	Strategic Research Agenda
RD&D	Research, Development and Demonstration	SRC	Short Rotation Coppice
RDD&D	Research, Development, Demonstration & Deployment	SRF	Short Rotation Forestry
REALISEGRID	REseArch, methodoLogies and tchnologieS for the effective development of pan-European key GRID infrastructures to support the achievement of a reliable, competitive and sustainable electricity supply	SRF	Solid Recovered Fuel
REN	Redes Energeticas Nacionais (National Energy Networks)	SSCAES	Small Surface Compressed Air Energy Storage
REN21	Renewable Energy Policy Network for the 21st Century	TEN-T EA	Trans-European Transport Network Executive Agency
RES	Renewable Energy Sources	TES	Thermal Energy Storage
RESD	RES Directive (Directive on Promotion of the Use of Energy from Renewable Sources)	TPV	Thermo-photovoltaic
RES-E	Renewable-Electricity	TPWind	Wind Technology Platform
RFS	Renewable Fuels Standard	TVPP	Technical Virtual Power Plant
ROR	run-of-the-river	ULCOS	Ultra Low CO ₂ Steelmaking
RRI	Research Reports International	UPS	Uninterruptible Power Supply
RTFO	Renewable Transport Fuel Obligation	USC	Ultra Supercritical
RWE	Rheinisch-Westfälisches Elektrizitätswerk	USD	US Dollars
		UTPB-CEED	University of Texas of the Permian Basin-Center for Energy & Economic Diversification
SA2VE	Sistemas de Almacenamiento AVanzado de Energía	V2G	Vehicle to Grid
SC	Supercritical	VHTR	Very High Temperature Reactor
SCADA	Supervisory Control and Data Acquisition	VOM	Variable Operations & Maintenance
SCIG	Single Cage Induction Generator	VPP	Virtual Power Plant
SEAI	Sustainable Energy Authority of Ireland	VRB	Vanadium Redox Battery
SEGS	Solar Energy Generating Systems	VVER	Vodo-Vodyanoi Energeticheskoy Reactor (Water-Water Energetic Reactor)
SEIA	Solar Energy Industries Association	WAMS	Wide Area Monitoring System
SEII	Solar Europe Industry Initiative	WB	The World Bank
SERF	Socio-Economic Research on Fusion	WBCSD	World Business Council for Sustainable Development
SETIS	Strategic Energy Technology Information System	WEII	Wind European Industrial Initiative
SET-Plan	Strategic Energy Technology Plan	WERATLAS	European Wave Energy Atlas
SFR	Sodium Fast Reactor	WFD	European Waste Framework Directive
SHP	Small Hydropower Plant	WID	European Waste Incineration Directive
SILC	Sustainable Industry Low Carbon	WNA	World Nuclear Association
SMES	Superconducting Magnetic Energy Storage	WRIG	Wound Rotor Induction Generator
SMR	Small and Medium-sized Reactors	ZEP	Zero Emissions Platform
SMR	Steam Methane Reforming		
SNETP	Sustainable Nuclear Energy		

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Abstract

The Technology Map is one of the principal regular deliverables of SETIS. It is prepared by JRC scientists in collaboration with colleagues from other services of the European Commission and with experts from industry, national authorities and academia, to provide:

- a concise and authoritative assessment of the state of the art of a wide portfolio of low-carbon energy technologies;
- their current and estimated future market penetration and the barriers to their large-scale deployment;
- the ongoing and planned R&D and demonstration efforts to overcome technological barriers; and,
- reference values for their operational and economic performance, which can be used for the modelling and analytical work performed in support of implementation of the SET-Plan.

This third edition of the Technology Map, i.e. the 2011 update, addresses 20 different technologies, covering the whole spectrum of the energy system, including both supply and demand technologies, namely: Wind Power Generation, Solar Photovoltaic Electricity Generation, Concentrated Solar Power Generation, Hydropower, Geothermal Energy, Marine Energy, Cogeneration or Combined Heat and Power, Carbon Capture and Storage in Power Generation, Advanced Fossil Fuel Power Generation, Nuclear Fission Power Generation, Nuclear Fusion Power Generation, Smart Grids, Bioenergy - Power and Heat Generation, Biofuels for the Transport Sector, Fuel Cells and Hydrogen, Electricity Storage in the Power Sector, Energy Efficiency and CO₂ Emission Reduction in Industry (The Cement Industry, The Iron and Steel Industry, The Pulp and Paper Industry) and Energy Performance of Buildings.

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