2 A Scenario for Sustainable Electricity

Sustainability is a development that meets the needs of the present generation without compromising the ability of future generations to meet their own needs /Brundtland 1987/. It is a necessary strategy of survival of a growing humanity on a limited planet /Knies 2006/. With respect to power generation, the concept of sustainability implies that certain economic, social and environmental requisites are satisfied to provide affordable, secure and lasting energy. Those requisites can be summarised in the "Energy Policy Triangle" shown in Figure 2-1, which was used as guideline for the scenario developed within the TRANS-CSP project /BMU 2004-3/.

A strategy for sustainability must satisfy all aspects of the **Energy Policy Triangle**:

- low cost of energy
- low environmental impact
- low conflict potential
- low risk and vulnerability
- protection of resources
- fair access to energy
- economic stability
- energy supply security
- power on demand
- international cooperation

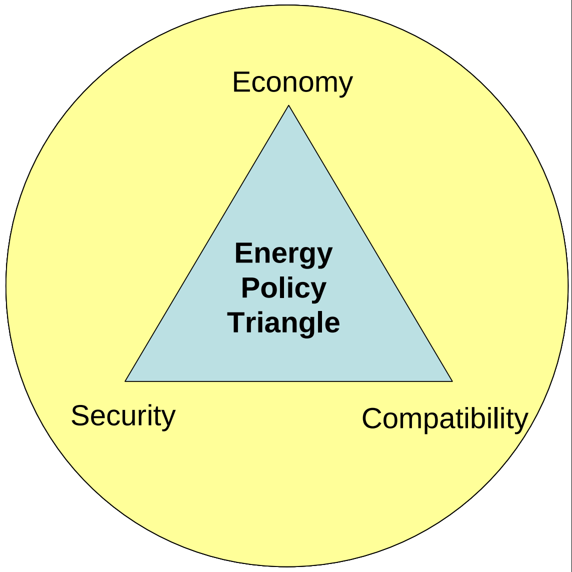


Figure 2-1: The principle of sustainability in the energy sector is represented by the energy policy triangle. This principle is applied to the electricity supply scenario of the TRANS-CSP study /BMU 2004-3/.

Compatibility

Almost all sustainability criteria are violated by our present electricity supply system, due to the un-damped exploitation of finite mineral fuel resources and the dumping of their residues in the biosphere. The negative impact of this attitude on the environment and society is well known, ranging from massive pollution of urban centres to the proliferation of plutonium and global climate change. This incompatibility to the natural and social environment is at present the main motivation for international efforts to reach sustainability.

Renewable forms of energy have impacts on the environment and society, too, but at a different level. While coal and nuclear plants massively risk the health of the population, a wind park mainly disturbs the visibility of the landscape.

Economy

Affordability is an even more immediate requisite for sustainability. The above mentioned incompatibilities take effect in the long term, but the immediate demand has often a higher priority in human acting and thinking. Long term necessary measures are not initiated if immediate needs are not satisfied. For this reason, most national economies rather subsidize their fossil and nuclear fuel based electricity sector and hide external costs for the sake of a seemingly secure and affordable supply /RIVM 2001/, /EEA 2004/. However, this is a self-delusion, as in this case, the real cost of power generation is not paid by the consumers of electricity, but by the health, environmental, military and disaster control sectors of the national economy. The external social costs of fuel based power generation have been generally accepted by the European Union to be in the order of about 3 - 8 cent/kWh in terms of electricity cost, without accounting for future, possibly irreversible damages to our habitat /ExternE 2003/, /EWEA 2002/.

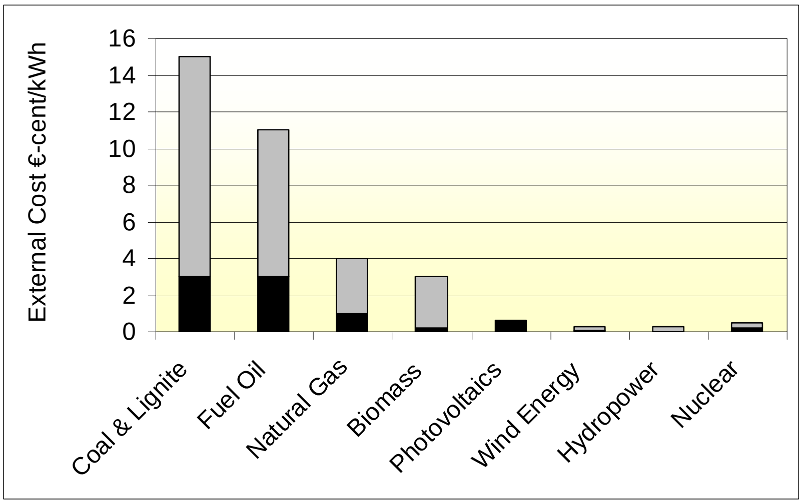


Figure 2-2: External cost range (minimum black, maximum grey bar) of electricity generation by different energy sources in the countries of the EU15 /ExternE 2003/

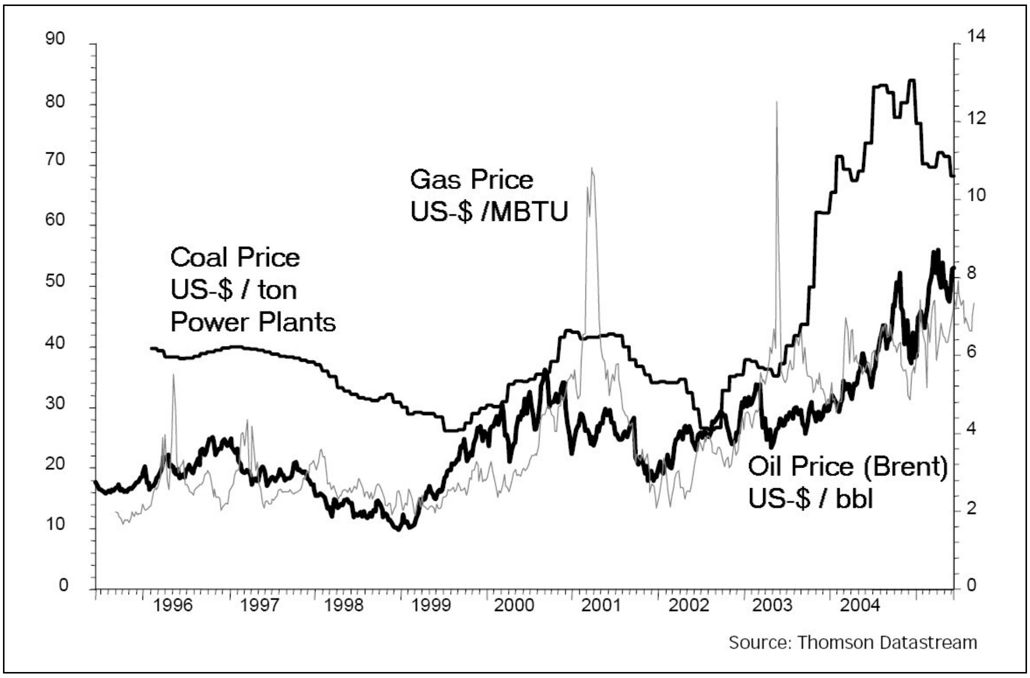


Figure 2-3: Spot prices of oil, coal (left scale) and gas (right scale) from 1995 to 2005. Source: /Thomson 2006/. For uranium prices see /Cameco 2006/

The price stability of conventional energy carriers assumed in the past has finally been unmasked as an illusion, too, with a cost escalation on the world market place of over 200 % in the past 5 years for coal, around 300 % for oil and gas, and close to 400 % for uranium (Figure 2-3). The access to affordable energy is more and more becoming a privilege of industrialised nations. This creates an increasing conflict potential in those countries that need affordable energy sources for their economical and infrastructural development.

Renewable forms of energy are the only energy sources that become cheaper with time (Table 2-1). Due to research and development and to the effects of mass production and larger unit scales, the cost of most renewable forms of energy is reduced by 10 to 20 % each time the installed capacity doubles /EXTOOL 2003/, /WETO 2003/. Wind, biomass and CSP plants are already today competitive with fuel oil at 50 $/barrel, and heading for competitiveness with natural gas and coal. As mentioned before, this cost reduction does not happen spontaneously, but requires continuous investment and extension of capacities on a global level. The initially higher cost of renewables is a necessary investment into a better and cheaper energy supply in the near term future, and pays back immediately once cost break even is achieved. Money spared in the past by not investing in renewables is spent today many times for escalating fuel prices and for the external costs of energy consumption. Compared to the fossil energy costs for power generation in the year 2000, which by that time were still expected to remain stable /IEA 2002/, the European electricity consumers and governments spend today additional 35-70 billion € per year or roughly 1-2 cent/kWh of consumed electricity, with increasing trend (also refer to /IEA 2004/).

Technology	Typical Characteristics	Typical Energy Costs (cents/kWh)	Cost Trends and Potential for Cost Reduction
Power Generation			
Large hydro	*Plant size:* 10 MW–18,000 MW	3–4	Stable.
Small hydro	*Plant size:* 1–10 MW	4–7	Stable.
On-shore wind	*Turbine size:* 1–3 MW *Blade diameter:* 60–100 m	4–6	Costs have declined by 12–18% with each doubling of global capacity. Costs are now half those of 1990. Turbine size has increased from 600–800 kW a decade ago. Future reductions from site optimization, improved blade/generator design, and electronics.
Off-shore wind	*Turbine size:* 1.5–5 MW *Blade diameter:* 70–125 m	6–10	Market still small. Future cost reductions due to market maturity and technology improvement.
Biomass power	*Plant size:* 1–20 MW	5–12	Stable.
Geothermal power	*Plant size:* 1–100 MW *Type:* binary, single-flash, double-flash, or natural steam	4–7	Costs have declined since the 1970s. Costs for exploiting currently-economic resources could decline with improved exploration technology, cheaper drilling techniques, and better heat extraction.
Solar PV (module)	*Cell type and efficiency:* single-crystal: 17%, polycrystalline: 15%, thin film: 10–12%	—	Costs have declined by 20% for each doubling of installed capacity, or by about 5% per year. Costs rose in 2004 due to market factors. Future cost reductions due to materials, design, process, efficiency, and scale.
Rooftop solar PV	*Peak capacity:* 2–5 kW	20–40	Continuing declines due to lower solar PV module costs and improvements in inverters and balance-of-system components.
Solar thermal power (CSP)	*Plant size:* 1–100 MW *Type:* tower, dish, trough	12–18 (trough)	Costs have fallen from about 44 cents/kWh for the first plants in the 1980s. Future reductions due to scale and technology.

Table 2-1: Costs and characteristics of renewables in 2004. Source: Renewables 2005 Global Status Report /REN 2005/

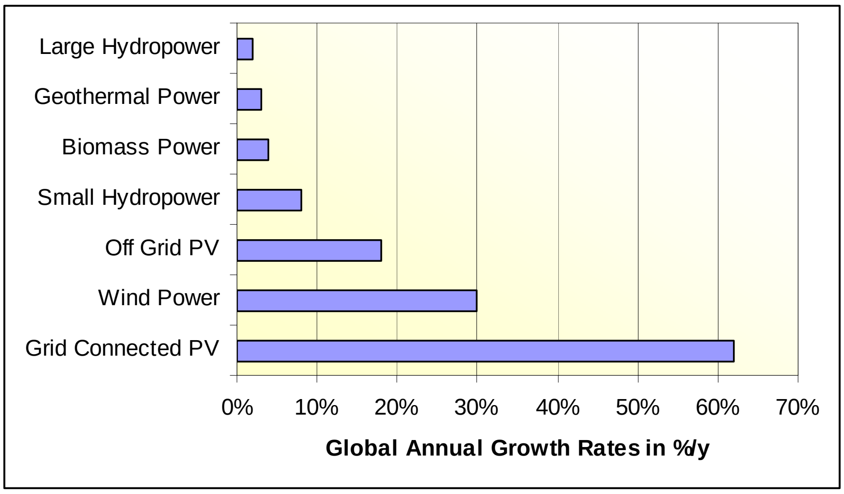


Figure 2-4: Average annual growth rates of global renewable power capacities 2000 – 2004 /REN 2005/

Today, there is a total of 3800 GW of installed power capacity worldwide. As a consequence of their economic advantages, renewables are increasingly gaining ground on the global power market. Existing renewable electricity capacity worldwide in 2004 totalled 720 GW for large hydropower and 160 GW for all other renewables, mainly small hydro and wind power, with very impressive growth rates (Figure 2-4). Today, renewables hold 20–25 percent of the global annual power sector investment of $110 – 150 billion per year with increasing trend /REN 2005/.

Security

It is a common belief that there is no alternative to fossil and nuclear energy to guarantee the security of supply required by modern economies. Security of supply implies long-term stable supply structures and, especially in the electricity sector, immediate satisfaction on demand. Only fossil and nuclear fuels can be used at any moment and to any extent as required for power generation, because they represent ideally stored primary energy. Only fossil and nuclear fuelled power plants can provide constant base load power around the clock, and only oil or gas fired plants can provide peaking electricity whenever required.

However, this belief is probably the most fatal error of our present energy supply system: like a squirrel eating in summer the nuts gathered for wintertime, we are burning our valuable fossil energy reserves for quotidian daily use, instead of using for this purpose those energy sources that are daily available like wind, solar, biomass and geothermal energy, and saving fossil fuels for the times when an ideally stored energy carrier is really needed.

In fact, there is no explicit need for power plants to operate at constant capacity. The electrical load is the sum of millions of dispersed, fluctuating and unpredictable consumers and in this sense, a phenomenon very much related to the fluctuating output of wind and PV plants. The electrical load of a country as a whole shows seasonal and daily fluctuations that fit much better to the time pattern of electricity supplied by a well balanced mix of wind, hydro, biomass and solar energy than to the constant output of a lignite or nuclear plant. For example, the seasonal and daily peak load caused by air conditioning systems naturally fits very well to the electricity yield of the concentrating solar power stations operating in California since 1986. Eventually remaining gaps between the load and the supply from renewables can be compensated by standard peaking power plants, while fossil and nuclear base load plants can be subsequently replaced by an adequate mix of renewables, as will be shown later in this Chapter.

Security is also a question of availability. Today, fossil energy reserves are burned at a high rate and becoming more and more concentrated in few regions of the world /HWWA 2005/. Today's developing countries increasingly claim for their share of the global energy cake to develop their economies, and the pressure on the remaining resources is dramatically increasing. It is hard to imagine that the MENA region, which in the year 2050 will have a similar energy demand as Europe, will satisfy this demand by the conventional oil and gas infrastructure it is used to today. While fossil resources become increasingly scarce and expensive, the primary solar energy potential in MENA equals a layer of crude oil of 0.25 meters thickness on the total land surface every year, of which only 1/1000 part harvested by concentrating solar power plants would suffice to cover the total regional demand even in 2050 /MED-CSP 2005/. Two parts out of 1000 of this potential would cover Europe's demand as well.

Interconnection is another very important security factor. Being interconnected gives the security of backup capacities and diversification in case of a local failure, and makes possible production, communication, marketing and trading even in remote regions. Missing infrastructure and interconnection always leads to excessive centralisation, as e.g. in the case of 25 % of the total Mexican population living in the country's capital Mexico City. On the other hand, the existence of infrastructure and interconnection allows global marketing even in the Black Forest of Germany. The closing of the electricity grid around the Mediterranean Sea described in Chapter 1 is another example of interconnection that serves to increase the security and redundancy of electricity supply in this region /EURELECTRIC 2003/.

Cooperation

In Europe, there is an increasing call for energy autonomy to avoid the obvious conflicts arising from our so called fossil fuel addiction. Representatives of renewable as well as nuclear power technologies both claim to have the solution for energy independency in Europe, on one side propagating large centralised nuclear breeders and fusion reactors, on the other hand opting for small renewable energy systems and decentralised, autonomous grid structures to achieve energy autonomy. Although having the same goal, both views of the world polarise in a controversial discussion, while the dependency on fossil fuels steadily increases. In fact, the autonomy goal – as well as the proposed solutions – is rather questionable in terms of ethics and sustainability: it propagates a Europe unaffected by the eventual future misery of its neighbours, and fosters the illusion of independency on a rather small and crowded planet.

In contrast to independency, inter-dependencies have always been a stabilising factor in international relations and policies. If based on a fair and eye-to-eye level cooperation, economic and social inter-dependencies are a guarantor for good neighbourhood and conflict prevention. The most delicate and at the same time the most rigorous inter-dependency of all cultures on earth is the biosphere, and it has become a global challenge to protect it in a sustainable way. It is obvious that such a global challenge can only be met by global cooperation. However, it is crucial that the goals of such an international cooperation do not remain global as well, but condense into very concrete projects /WBGU 2003/. The purpose of the study at hand is to provide the basis for such a policy for the electricity sector of the EUMENA region.

2.1 Outlook of Electricity Demand in Europe

Electricity demand was modelled for each of the European countries, taking into account the individual growth of population and economy. Empirical correlations derived from the analysis of the electricity demand of 25 countries over a 40 years time period between 1960 and 2000, served to assess the functional correlation of per capita economic growth and per capita electricity demand that was used for extrapolation to the future. The methodology is described in /MED-CSP 2005/, the used input data and the results for Europe are described here. The scenario assumes a rather moderate transformation of the power sector. Sharp changes of paradigm, like a quickly increasing use of electricity in the heat or mobility sector, e.g. for the production of hydrogen, is not considered. Such a scenario would further increase the electricity demand of the European countries beyond the limits shown here (Figure 2-5).

The total electricity demand of the 30 analysed countries starts with roughly 3500 TWh/y in the year 2000 and reaches a maximum of 4300 TWh/y in 2040. After that, it is reduced to shortly 4000 TWh/y, mainly due to stagnating and in some countries even retrogressive population and also due to an only moderate economic growth, although at high level. Moreover, efficiency gains lead to subsequent de-coupling of economic growth and electricity demand.

The outlook for the individual countries is very heterogeneous, ranging from a strong growth of electricity demand in Turkey and Serbia and Montenegro to stagnating or even retrogressive demand in countries like France and Belgium. For country details please refer to the Annex.

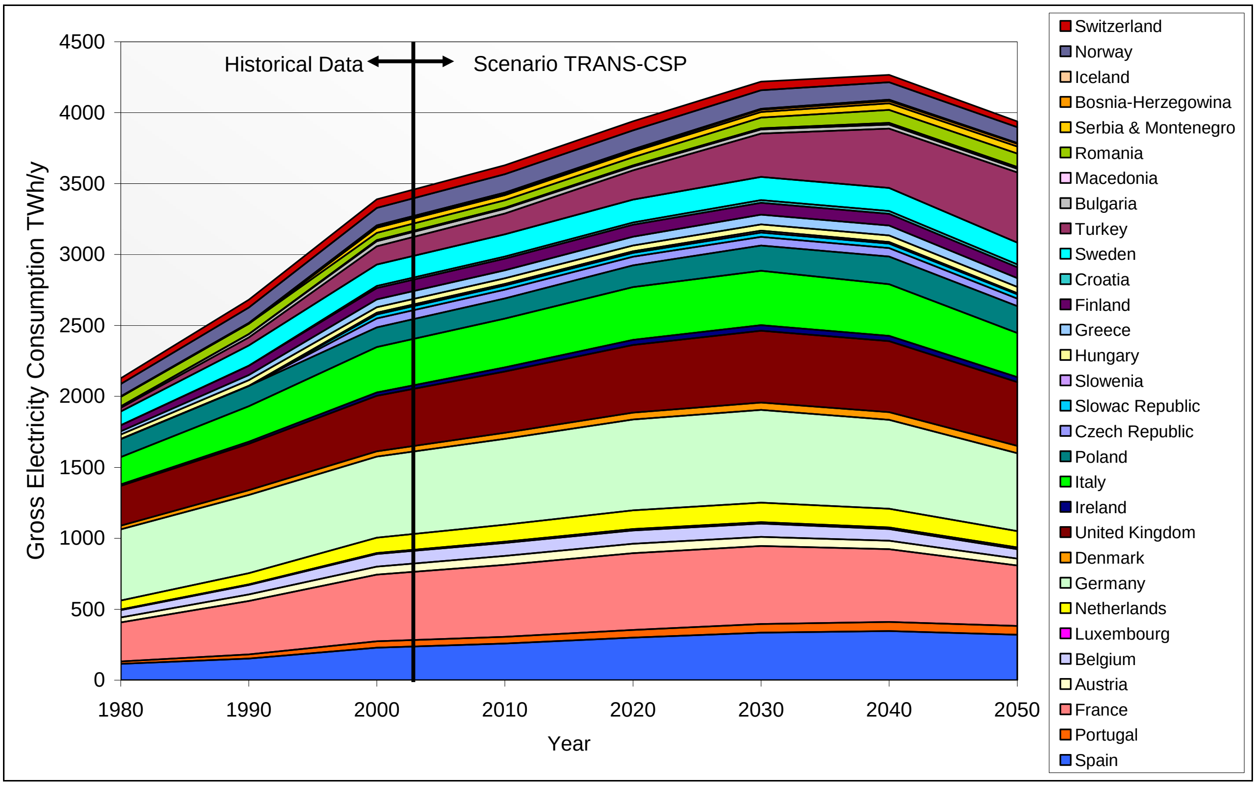


Figure 2-5: Electricity consumption of the European countries analysed within the TRANS-CSP study between 1980 and 2050. The data that served as basis for this analysis is described in this chapter.

The study shows that the electricity demand of Europe in 2050 will be only slightly higher than today. In the long term the strongly growing MENA region will achieve a demand in the same order of magnitude, as described in the MED-CSP study report. Thus, in terms of electricity demand, MENA will become an eye-to-eye neighbour for Europe by that time.

Figure 2-6 shows the average per capita growth rates of the Gross Domestic Product (GDP) for each of the analysed countries assumed in the TRANS-CSP scenario for the time span of 2000 to 2050. The four European regions expect economic growth rates ranging from 1.2 to 2.2 %/y in Western Europe and Scandinavia, and from 2.2 to 4.3 %/y in Eastern and South-Eastern Europe. These values reflect a convergence of the European economies and an overall average economic growth rate of about 2 %/y until 2050 for the region as a whole.

In the year 2000, the per capita GDP of the European economies ranged between 15,000 and 30,000 €/cap/year in Western Europe and Scandinavia, and between 4,000 and 15,000 €/cap/year in Eastern and South-Eastern Europe (Figure 2-9). In our scenario, by 2050, the Western and Scandinavian countries will have achieved a per capita GDP of 40,000 to 50,000 €/cap/y, while the Eastern and South-Eastern economies will range between 30,000 and 40,000 €/cap/y, considerably closing the present economic gap between the different regions. In view of a growing European Union and considering the present development of the European economies, this is both a feasible as well as a desirable scenario of economic development in Europe.

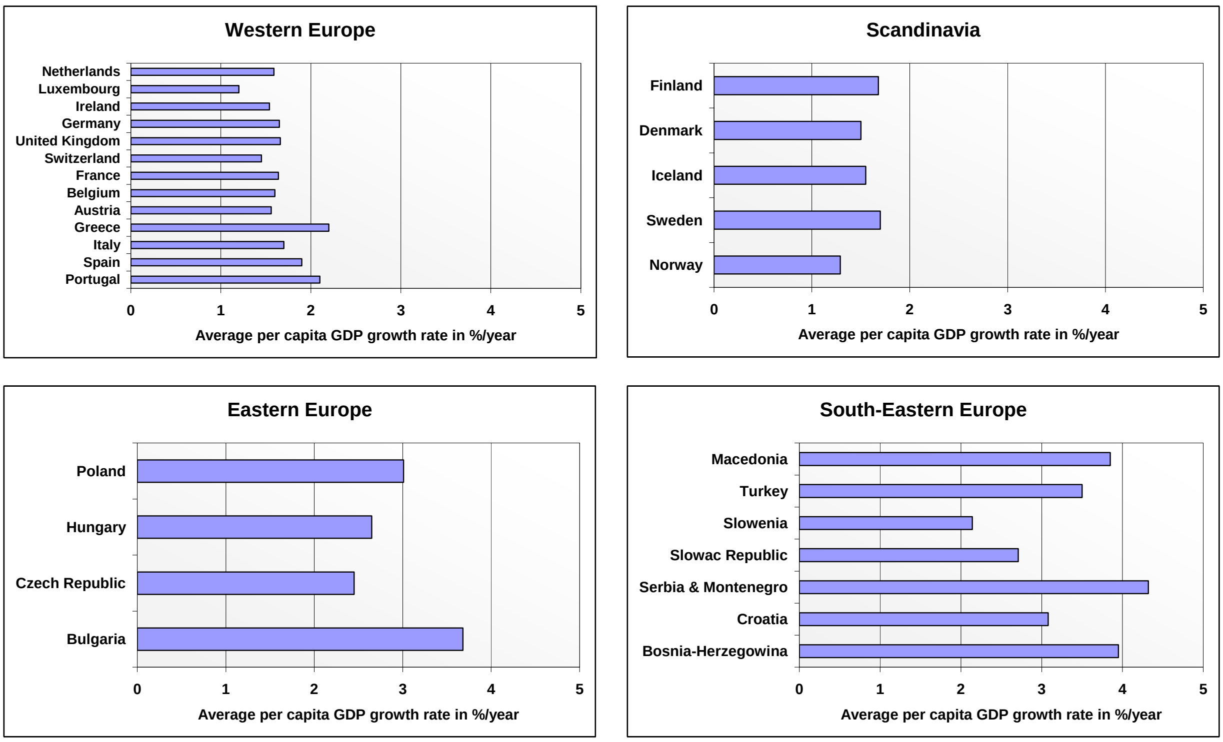


Figure 2-6: Average per capita GDP growth rate in the analysed countries for the time span from 2000 to 2050 assumed in the TRANS-CSP scenario. Strong economic growth at lower level in the South and East, slow growth at high level in the West and North of Europe.

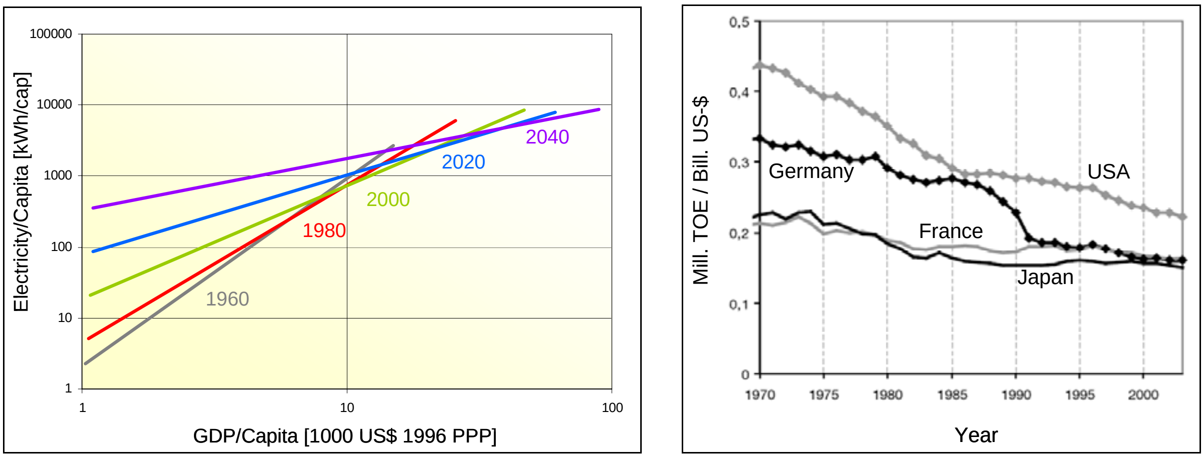


Figure 2-7: Left: The relation of per capita electricity consumption and per capita GDP as parameter for demand side modelling in the TRANS-CSP study. The curves from 1960 to 2000 are fitted to historical data of 25 countries, while the curves of 2020 and 2040 are extrapolated for the scenario analysis. Typically, a decoupling of GDP growth and energy demand growth can be observed, which is motivated by enhanced efficiency of power generation and distribution. For further details please refer to /MED-CSP 2005/. Right: Energy intensity in million tons of oil equivalent per billion US-$ gross domestic product /HWWA 2005/. The German experience after 1989 shows that targeted efforts can have a considerable effect on energy efficiency.

Analysing the historical data of many countries as described in /MED-CSP 2005/, there is evidence of a decoupling of economic growth and growth of electricity demand as shown in Figure 2-7. The reason for this is that growing economies increasingly invest into energy efficiency and enhanced infrastructure for distribution and rational use of energy, especially in the power sector. Such measures lead to increasing GDP but at the same time reduce power consumption. Thus, growing economies are not necessarily bound to a proportionally growing power demand, but usually achieve a lower growth rate for electricity than for their economy.

From the economic development represented by the growing GDP per capita (Figure 2-9) and the correlation of GDP growth and electricity consumption in Figure 2-7, a scenario for the specific per capita electricity consumption in each of the analysed countries can be developed. The result of this calculation for each country is shown in Figure 2-10.

Present per capita power consumption in Europe is rather heterogeneous. The general level of consumption is highest in the Scandinavian countries, ranging from 7,000 kWh/cap/y in Denmark, which is closer related to Central Europe, to more than 25,000 kWh/cap/y in Norway, which relies mainly on hydropower and additionally to the traditional power sector, uses electricity for room heating and many process heat applications. The high level of consumption in Scandinavia is in general maintained within the scenario, leading to similar values in 2050.

Lowest electricity consumption levels are detected today in South Eastern Europe, with about 2000 kWh/cap/y in Turkey and Romania, while Greece and Slovenia have a much higher level of 6000 kWh/cap/y. There is also a large band width of consumption in Western Europe, from about 4000 kWh/cap/y in Portugal to 8500 kWh/cap/y in Switzerland and Belgium. These numbers reflect the different economic situation and life style of the respective countries. In the non-Scandinavian countries, an approximation of the per capita electricity consumption to values between 5000 and 7000 kWh/cap/y can be detected from the scenario analysis. This again reflects the economic and technical convergence of the different European regions. The much higher level of electricity consumption of the Northern Scandinavian countries is due to their specific climatic situation, their extensive use of electricity for space heating, and to the availability of abundant renewable sources, mainly hydropower and biomass, for power generation.

The last step for calculating the total electricity consumption of each country is multiplying the per capita electricity consumption with the expected numbers of population, shown in Figure 2-11. Except for Turkey and the smaller South-Eastern countries, most countries in Europe show stagnating or even retrogressive population after 2030. Therefore, the main reason for a growing electricity consumption in Europe is the expected growth of economy. The calculation leads to the result in Figure 2-5 that was already discussed before.

Our scenario is based on the assumption that the development of the power sector is not hampered by very strongly escalating costs or by a severe shortage of primary energy for power generation. Such severe changes of paradigm are difficult to predict and their consequences for economy and the power sector are very difficult to quantify. Anyway, we do not see a high probability of such a scenario, as in case the fossil fuel reserves would become extremely scarce or expensive, renewables will take over most power services at a slightly higher speed than assumed here, stabilising energy costs and opening new ways of supply for Europe.

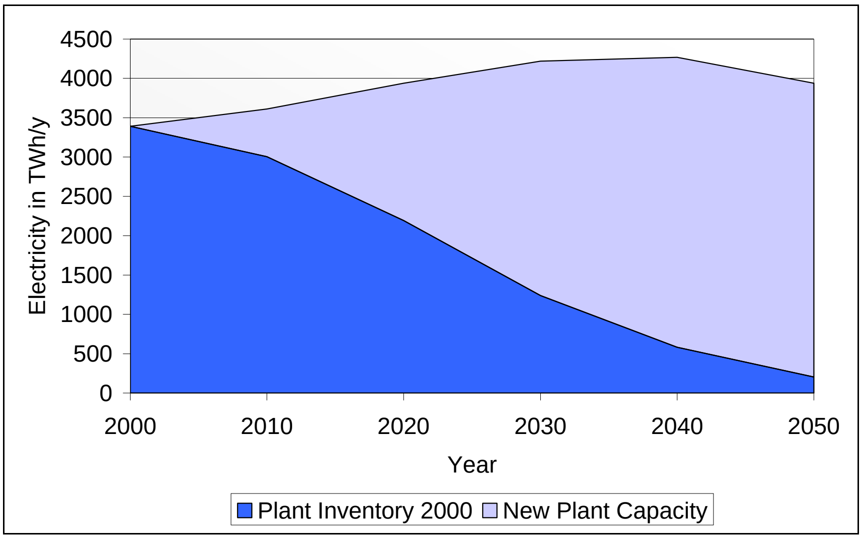


Figure 2-8: Life inventory of power plants existing in the year 2000. "New Plant Capacity" defines the difference between existing and subsequently decommissioned plants and the electricity demand. This gap must be filled with new supply systems, summing up new demand and replacement capacities for old plants. Hydropower plants are considered to be subsequently re-powered, and therefore are partially still existing in 2050. Based on data from /Platts 2004/.

The demand for new power plant capacity is defined by plant life and investment cycles. Figure 2-8 shows the opening gap between the presently existing (and subsequently decommissioned) plants and the growing power demand. It is based on the UDI world power plant inventory, assuming a lifetime of 20 years for gas turbines and combined cycles, 40 years for steam cycles and nuclear plants, 15 years for wind plants and 60 years for hydropower plants.

The demand for new power plant capacity will be partially covered by renewable and conventional power sources, as described in the following. All plants are assumed to operate for their full economic life time. That means that coal or natural gas fired plants installed in 2030 will still be operating in 2050 and beyond.

In view of the long life and investment cycles of power plants, it is obvious that any decision for or against a technical option today will significantly affect the mix of energy sources and its economic, environmental and social sustainability up to the middle of this century.

The window for changing to a sustainable scheme is open now, but will be closed by about 2020. Europe now has the chance to invest into a cost efficient, sustainable electricity scheme, or it will depend on and suffer under the costly and in the meantime obsolete supply structures of the past century.

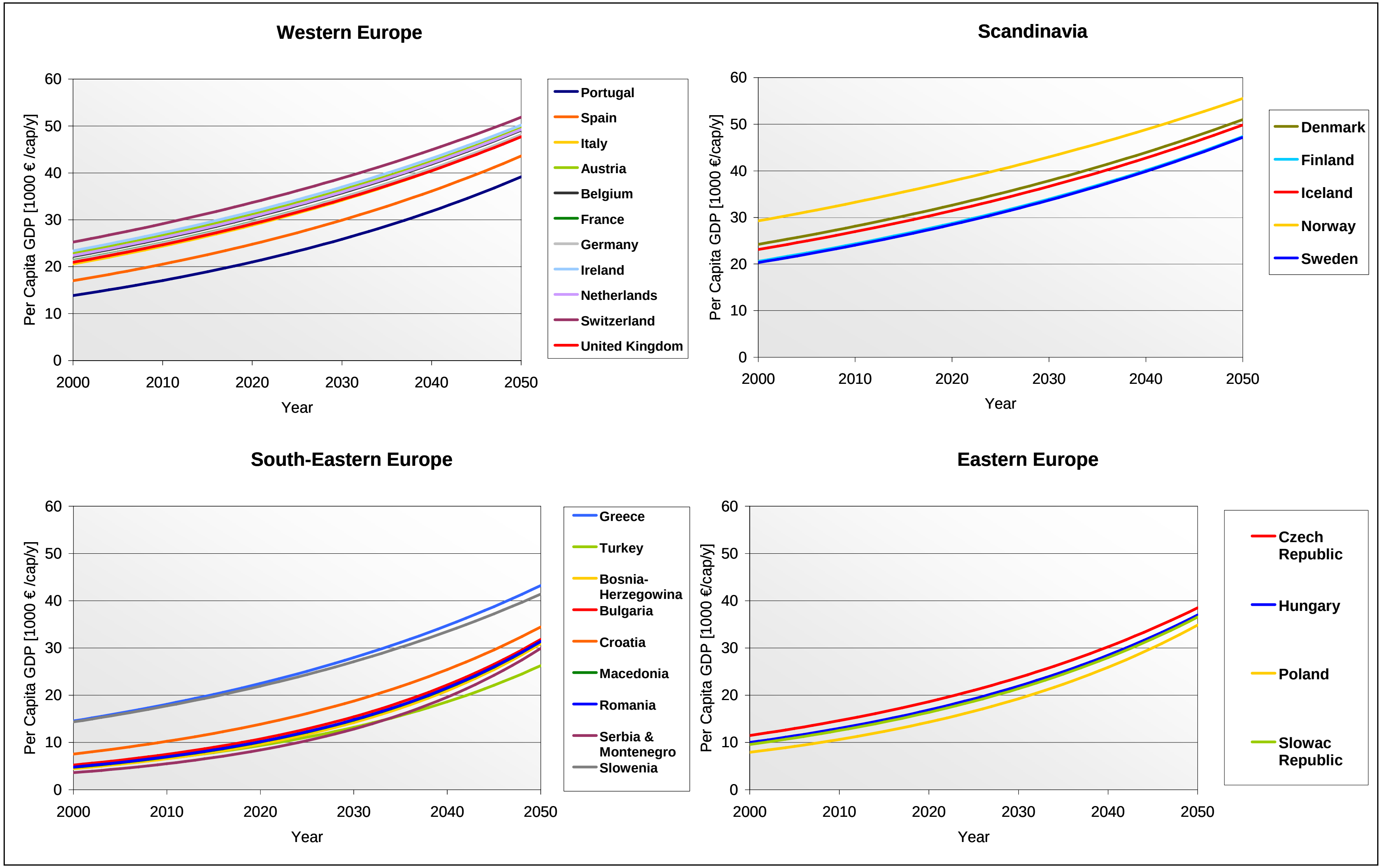


Figure 2-9: Economic development as driving force for electricity demand: the evolution of the per capita gross domestic product in the European countries in the TRANS-CSP scenario.

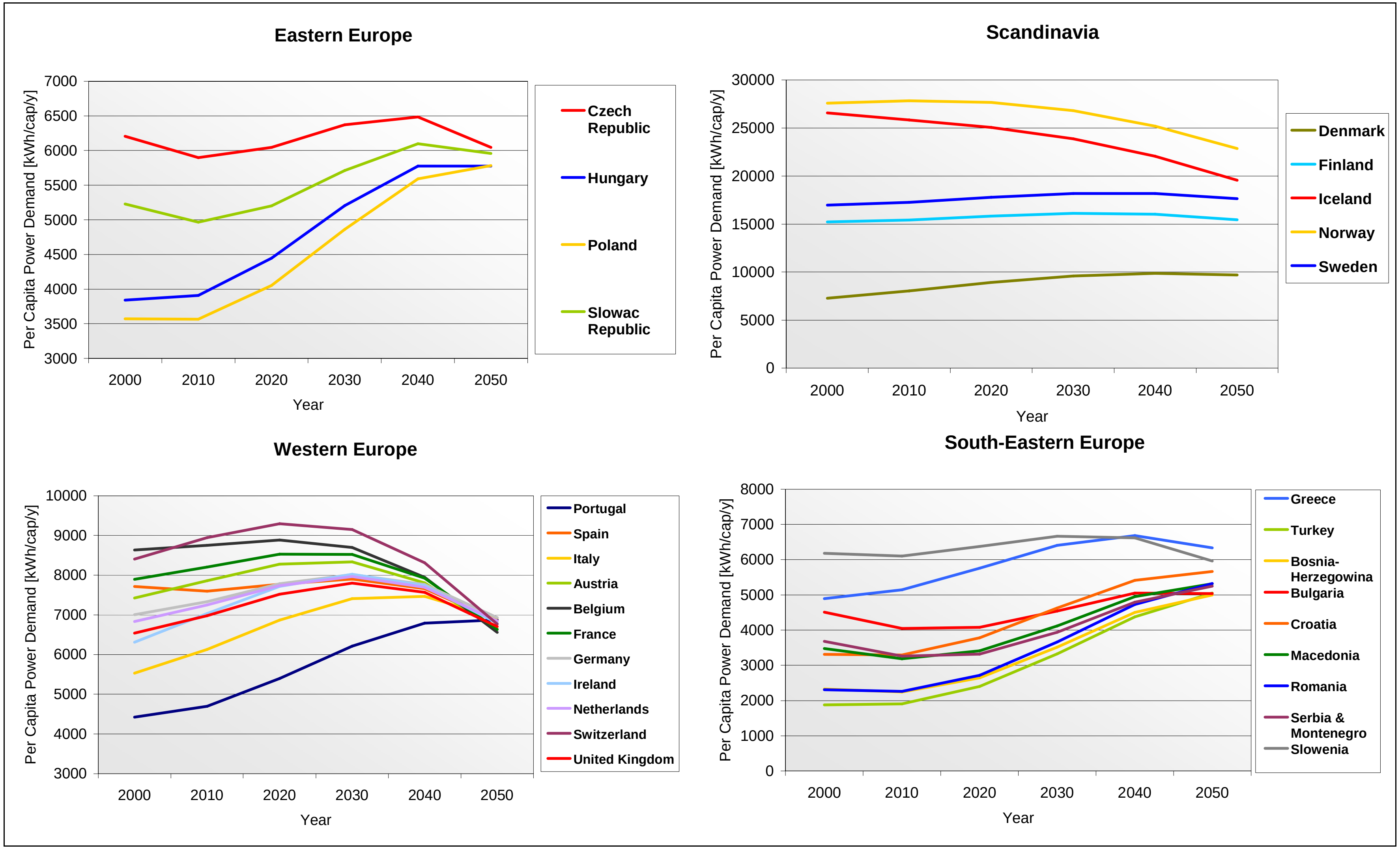


Figure 2-10: Per capita electricity consumption for the European countries until 2050 in the TRANS-CSP scenario

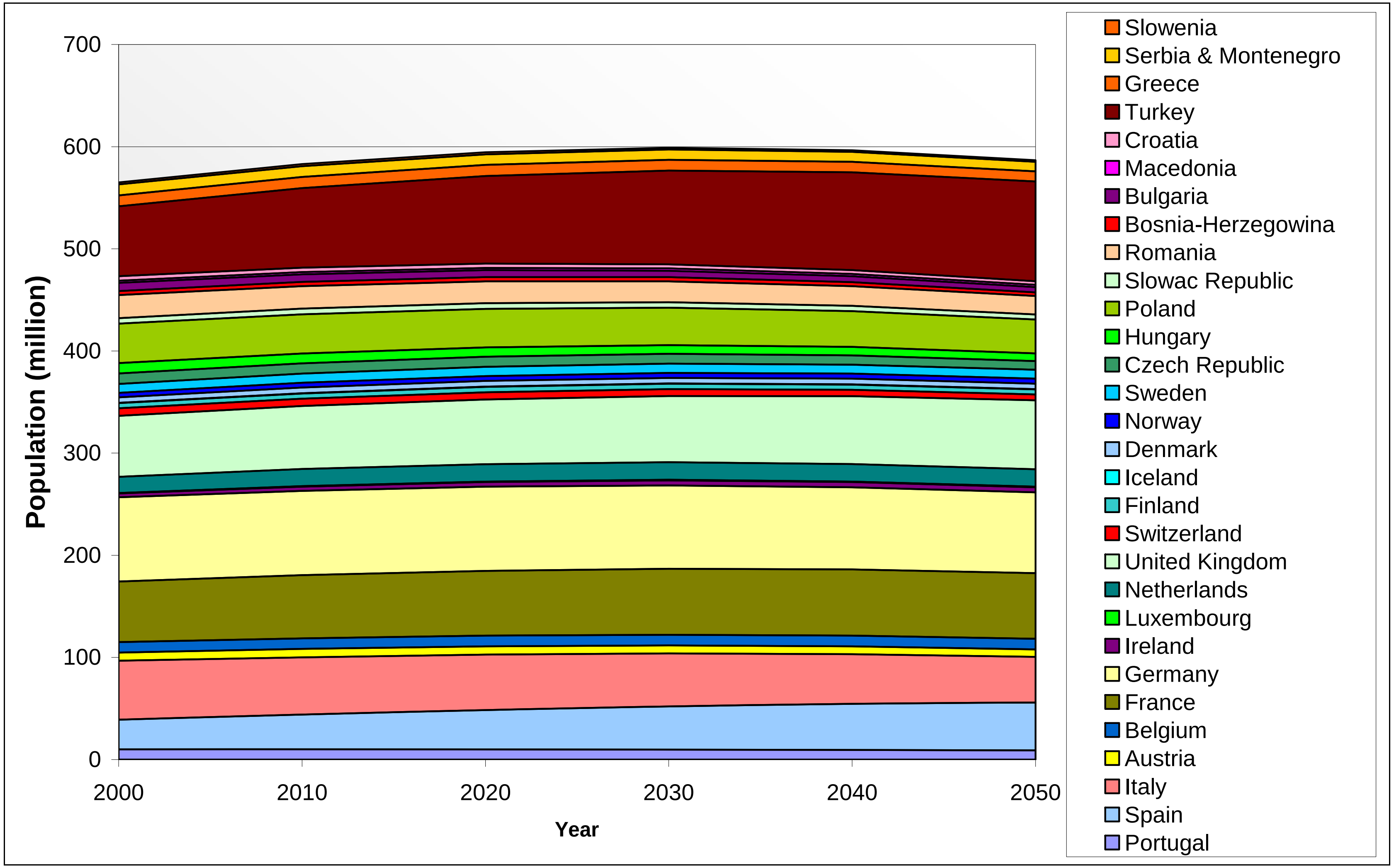


Figure 2-11: Population of European countries according to the UN medium growth scenario is a major driving force for electricity demand /SBA 2003/

2.2 Renewable Electricity Potentials in Europe

For Europe, reliable references are available to quantify the renewable energy potentials for wind, photovoltaics, concentrating solar power, geothermal, biomass, wave and tidal power (Figure 2-12). Those numbers already consider the availability of land area for the placement of the converters and other socio-economic and environmental restrictions. They can be considered as generally accepted /BMU 2004-3/.

The European renewable energy potential of about 40,000 PJ/y equals about twice the present electricity consumption and 75% of the present heat consumption in Europe. All in all it could supply 62 % of the present primary energy consumption in Europe. The use of those resources differs widely. About 80 % of the existing hydropower potential and 50 % of the biomass potential is already used today, while the other available resources are hardly used up to now.

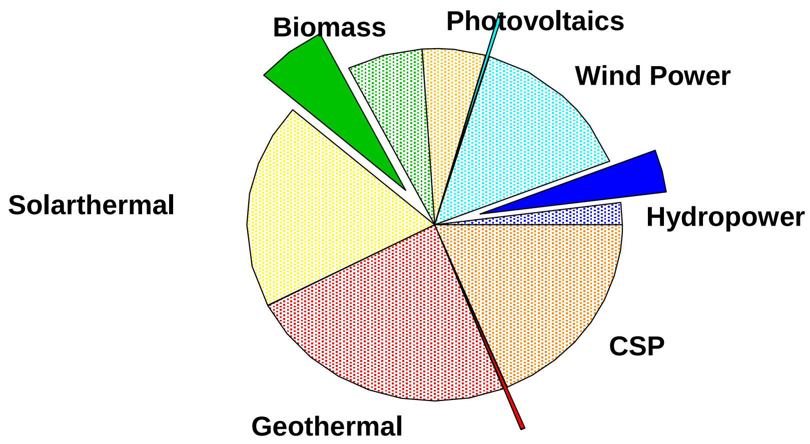


Figure 2-12: The technical potential of renewable energy in Western Europe amounts to approximately 40,000 PJ/y. Only 12 % of this potential are used at present, mainly hydropower and biomass /BMU 2004-3/

Once renewable energy technologies are well established, their potentials could be extended in the long term by making use of further resources and technologies. Here are some examples:

- Use of wind-offshore potentials along the European coast lines with a potential of roughly 2.000 TWh/y of electricity;
- Energy crops on additional agricultural areas, especially in Eastern Europe, with a potential of about 30 million hectares equalling 3.500 PJ/y of primary energy;
- Use of geothermal energy in Western Europe with a potential of up to 1.700 TWh/y;
- Importing solar electricity from concentrating solar power plants from the MENA region in the frame of a Mediterranean renewable energy partnership with a potential of several 100,000 TWh/y which is well beyond the European electricity demand.

This sums up to a total renewable energy potential which would more than suffice to cover the European energy needs. In the TRANS-CSP study, the renewable energy resources for power generation in Europe were assessed on the basis of different sources described later in this chapter. The direct normal irradiance (DNI) used by concentrating solar power systems was assessed by DLR's high resolution satellite remote sensing system /SOLEMI 2004/.

	Hydro		Geo		Bio		CSP		Wind		PV		Wa/Ti	
	Tech.	Econ.	Tech.	Econ.	Tech.	Econ.	Tech.	Econ.	Tech.	Econ.	Tech.	Econ.	Tech.	Econ.
Austria	56,0	56,0	n.a.	4,1	n.a.	30,6	n.a.	n.a.	n.a.	3,0	n.a.	2,9	n.a.	n.a.
Cyprus	24,0	1,0	n.a.	n.a.	n.a.	0,6	23	20	n.a.	6,0	n.a.	0,1	n.a.	0,2
Denmark	0,0	0,0	n.a.	n.a.	n.a.	6,6	n.a.	n.a.	n.a.	55,0	n.a.	1,3	n.a.	2,2
Finland	20,0	20,0	n.a.	n.a.	n.a.	53,7	n.a.	n.a.	n.a.	27,0	n.a.	1,7	n.a.	2,0
France	72,0	72,0	n.a.	14,1	n.a.	79,1	n.a.	n.a.	n.a.	129,0	n.a.	23,4	n.a.	12,0
Czech Republic	4,0	3,0	n.a.	n.a.	n.a.	20,0	n.a.	n.a.	n.a.	5,8	n.a.	1,1	n.a.	n.a.
Belgium	0,3	0,5	n.a.	n.a.	n.a.	7,3	n.a.	n.a.	n.a.	13,0	n.a.	2,1	n.a.	0,2
Ireland	1,0	1,3	n.a.	n.a.	n.a.	6,2	n.a.	n.a.	n.a.	55,0	n.a.	1,1	n.a.	4,0
Luxembourg	n.a.	1,0	n.a.	n.a.	n.a.	0,4	n.a.	n.a.	n.a.	0,0	n.a.	0,8	n.a.	n.a.
Netherlands	0,1	0,1	n.a.	1,3	n.a.	9,6	n.a.	n.a.	n.a.	40,0	n.a.	4,3	n.a.	1,0
Sweden	130,0	90,0	n.a.	1,3	n.a.	80,4	n.a.	n.a.	n.a.	63,5	n.a.	3,7	n.a.	2,0
Switzerland	41,0	38,3	n.a.	n.a.	n.a.	8,0	n.a.	n.a.	n.a.	0,0	n.a.	3,7	n.a.	n.a.
United Kingdom	7,8	8,0	n.a.	0,3	n.a.	30,7	n.a.	n.a.	n.a.	344,0	n.a.	7,8	n.a.	60,0
Poland	14,0	7,0	n.a.	1,7	n.a.	52,1	n.a.	n.a.	n.a.	65,0	n.a.	3,1	n.a.	1,0
Bulgaria	15,0	12,0	n.a.	0,8	n.a.	7,7	n.a.	n.a.	n.a.	8,9	n.a.	2,0	n.a.	n.a.
Slowac Republic	7,0	6,0	n.a.	3,1	n.a.	10,7	n.a.	n.a.	n.a.	0,7	n.a.	2,0	n.a.	n.a.
Slowenia	9,0	8,0	n.a.	0,4	n.a.	6,3	n.a.	n.a.	n.a.	0,3	n.a.	1,0	n.a.	n.a.
Germany	26,0	26,0	120,0	28,2	n.a.	87,0	n.a.	n.a.	n.a.	262,0	n.a.	23,4	n.a.	7,0
Hungary	5,0	4,0	n.a.	51,9	n.a.	11,3	n.a.	n.a.	n.a.	1,3	n.a.	2,0	n.a.	n.a.
Greece	15,0	12,0	n.a.	9,4	n.a.	7,2	44	4	n.a.	49,0	n.a.	3,9	n.a.	4,0
Italy	105,0	65,0	n.a.	19,6	n.a.	46,1	88	7	n.a.	79,0	n.a.	17,6	n.a.	3,0
Malta	n.a.	n.a.	n.a.	n.a.	n.a.	0,1	2	2	n.a.	0,2	n.a.	0,1	n.a.	0,1
Portugal	33,0	20,0	n.a.	14,1	n.a.	15,2	436	142	n.a.	18,0	n.a.	3,9	n.a.	7,0
Spain	70,0	41,0	n.a.	28,2	n.a.	40,4	1646	1278	n.a.	93,0	n.a.	19,5	n.a.	13,0
Turkey	216,0	122,0	n.a.	300,1	n.a.	44,7	405	131	n.a.	110,0	n.a.	15,6	n.a.	n.a.
Macedonia	6,0	4,0	n.a.	n.a.	n.a.	2,6	n.a.	n.a.	n.a.	0,1	n.a.	0,6	n.a.	n.a.
Croatia	9,0	8,0	n.a.	1,1	n.a.	8,9	n.a.	n.a.	n.a.	2,6	n.a.	0,8	n.a.	3,0
Romania	36,0	18,0	n.a.	1,0	n.a.	40,9	n.a.	n.a.	n.a.	7,9	n.a.	2,0	n.a.	n.a.
Serbia & Montenegro	27,0	27,0	n.a.	4,1	n.a.	14,3	n.a.	n.a.	n.a.	0,3	n.a.	1,0	n.a.	2,0
Bosnia-Herzegowina	24,0	19,0	n.a.	n.a.	n.a.	9,5	n.a.	n.a.	n.a.	0,1	n.a.	0,6	n.a.	n.a.
Iceland	64,0	40,0	n.a.	182,4	n.a.	0,1	n.a.	n.a.	n.a.	1,0	n.a.	0,3	n.a.	10,0
Norway	200,0	178,0	n.a.	n.a.	n.a.	25,8	n.a.	n.a.	n.a.	76,0	n.a.	1,0	n.a.	10,0
Total		**908**		**667**		**764**		**1584**		**1517**		**154**		**144**

Table 2-2: Technical and economical renewable energy potential for electricity generation in Europe not including solar electricity import. The total potential of 5600 TWh/y exceeds by far the present and future electricity demand of around 3500 – 4000 TWh/y of the analysed countries.

The data for the other renewable energy options was taken from materials kindly provided by the renewable energy scientific community. We have taken into consideration the following renewable energy resources for power generation:

- Direct Solar Irradiance on Surfaces Tracking the Sun (Concentrating Solar Thermal Power Plants in Southern Europe and MENA)
- Direct and Diffuse (Global) Solar Irradiance on a Fixed Surface tilted South according to the Latitude Angle (Photovoltaic Power)
- Wind Speed (Onshore and Offshore Wind Power Plants)
- Hydropower Potentials from Dams and River-Run-Off Plants
- Heat from Deep Hot Dry Rocks (Geothermal Power)
- Biomass from Municipal and Agricultural Waste and Wood
- Wave and Tidal Power

Both the technical and economic potentials were defined for each renewable energy resource and for each country. The **technical potentials** are those which in principle could be accessed for power generation by the present state of the art technology (Table 2-2). For each resource and for each country, a **performance indicator** was defined that represents the average renewable energy yield with which the national potential could be exploited (Table 2-4). The **economic potentials** are those with a sufficiently high performance indicator that will allow new plants in the medium and long term to become competitive with other renewable and conventional power sources, considering their potential technical development and economies of scale.

The main characteristics of each technology with respect to its integration to the electricity supply system are given in Table 2-5. The renewable energy potentials for power generation differ widely in the countries analysed within this study. They are more or less locally concentrated and not available everywhere, but can be distributed through the electricity grid. The following analysis shows the quantity and the geographic distribution of the different renewable energy sources in Europe represented by the main performance indicators of each technology.

One of the pre-conditions of the electricity mix is that it must cover the power demand at any time, with a preset security margin of 25 % of minimum remaining reserve capacity. The different technologies of our portfolio contribute differently to secured power: fluctuating sources like wind and PV contribute very little, while fossil fuel plants contribute at least 90 % of their capacity to secure power on demand (Table 2-5). Hourly time series of resource data for wind and solar radiation have been used to estimate those limitations. Besides of the total demand of electricity of each country, also the secured coverage of peaking demand has been used as frame condition for the scenario. The individual country scenarios have been designed such that they satisfy this condition at any time of the year.

One of the consequences of renewable energy scenarios is that the ratio of the total installed power plant capacity to peak load increases, or in other words, the average capacity factor of the power park decreases. The increasing capacity overhead is due to the fluctuating supply from wind and PV plants that have a rather low capacity factor and that do not contribute substantially to secured power. However, this does not necessarily lead to an augmentation of fossil fuel based peaking duties, as there are a number of effects that compensate such fluctuations:

- temporal fluctuations of a large number of distributed wind or PV plants will partially compensate each other, delivering a much smoother capacity curve than single plants,
- temporal fluctuations of different, uncorrelated renewable energy resources will partially compensate each other, together delivering a much smoother capacity curve than one single resource
- fluctuations can be compensated by distribution through the electricity grid,
- biomass, hydro-, geothermal and solar thermal plants can deliver power on demand and be applied as renewable backup capacity for fluctuating inputs,
- load management can enhance the correlation of demand and renewable supply,
- fossil fuel fired peaking plants can be used for final adaptation to the load.

In effect, controlling many distributed, fluctuating and unpredictable elements within a power system is nothing new. Exactly the same occurs with the load induced by millions of consumers connected to the grid. All together deliver a relatively stable and predictable load curve. A large number of distributed renewable energy sources in a well balanced mix can even show a better adaptation to the time pattern of the load than nuclear or coal fired base load plants with a flat capacity curve, as shown later in this chapter.

Today lignite, nuclear and river runoff hydropower plants are typically used for base load, as they are rather expensive and cannot be quickly adapted to changing load patterns. Coal, oil and gas fired plants are used for intermediate load. Peaking load is covered by gas or oil fired plants and by hydropower storage. In 2050, the valuable fossil fuel resources will be only used for the purpose they are best suited for: peaking power, while base load will be provided mainly by renewables. The principle characteristics of the power mix of our scenario are described in the following:

Oil and Gas fired Power Plants

Oil and gas fired power plants are today the most applied resource for peaking power as they can react quickly to changing load patterns. They will take over the part of closing the gap between the fluctuating load and renewable power. Due to their priority on peaking duties, their average fossil fuel consumption and their CO_2 emissions will be reduced faster than their installed capacity. Due to their high cost, fuel oil fired plants will fade out in most countries after 2020.

Coal Steam Plants

Coal is an important primary energy for power generation in Europe. However, coal is also considered a heavy burden for climate stability. In our scenario, the capturing and sequestration of carbon dioxide (CCS) from the power plant's flue gases is therefore implemented in all new power plants in Europe after 2020. The model assumes an overall extraction of 85 % of CO_2 and an additional cost of 1.5 cent/kWh for plants using CCS. In the medium term, coal gasification may provide increasing shares of the gas demand of peaking power plants.

Nuclear Fission and Fusion

Nuclear fission is a fading technology with unsolved problems of nuclear waste disposal and very high environmental risks. The net present value of decommissioning of such plants is reported to be in the order of 1000 €/kW that must be added to the investment /WISE 2006/, /VDE 2006/. The nominal civil liabilities for decommissioning of nuclear plants in the United Kingdom are even reported to be in the order of 6000 €/kW /NDA 2002/. A number of European governments like Germany and Sweden have decided to fade out nuclear power plant operation within the coming decades. With present consumption – only 5 % of the world primary energy demand[1] is covered by nuclear energy today – the global uranium resources will not last longer than 50 years and are becoming more and more expensive /HWWA 2005/. Breeder technology could expand those resources but would lead to a dangerous proliferation of plutonium and increase the amount of nuclear waste materials by a factor of 10 compared to simple fission. At the moment, nuclear power has a share of global power sector investment of less than 1 % (for comparison: renewables had a share of 25 % in 2005).

In spite of R&D expenditures of more than a billion Euro per year spent by the OECD for several decades and scheduled to be spent also in the future, electricity from nuclear fusion is not expected to be available before 2050, and the outcome of this effort is not sure. The expected cost of commercial fusion reactors ranges between 8 – 12 €-cent/kWh /HGF 2001/, which would be much higher than the cost of renewables by that time. Nuclear plants are only economic if they are allowed to run at constant full capacity. However, as will be shown later in this chapter, there will be no functional window for such plants in the future energy mix. For all those reasons, nuclear power technologies cannot contribute considerably to climate stability or to sustainable development within the time span analysed in our study. In view of those limitations and unsolved problems, nuclear fission is not considered a serious alternative or complement for energy sustainability in our scenario and is consequently faded out, while nuclear fusion is not expected to function commercially within the analysed time span until 2050.

Wind Energy

Wind is a strongly fluctuating energy source that cannot be easily controlled by demand. However, distributed wind parks partially compensate each others fluctuations and show a relatively smooth transition of their total output. Depending on the different situation in each country, up to 15 % of the installed wind capacity can be considered as firm. Hourly wind data was taken for selected sites from the World Wind Atlas /WWA 2004/.

The European Wind Energy Association EWEA gives a wind energy onshore potential of 650 TWh/y for the EU15 and Norway in its report /EWEA 2002/. For the Eastern European and EBRD countries, the report gives a potential of a total of about 280 TWh/y that could be realised until 2020. In addition to that, an offshore potential of 460 – 560 TWh/y is available, while other sources even give an offshore potential of up to 3000 TWh/y for Europe.

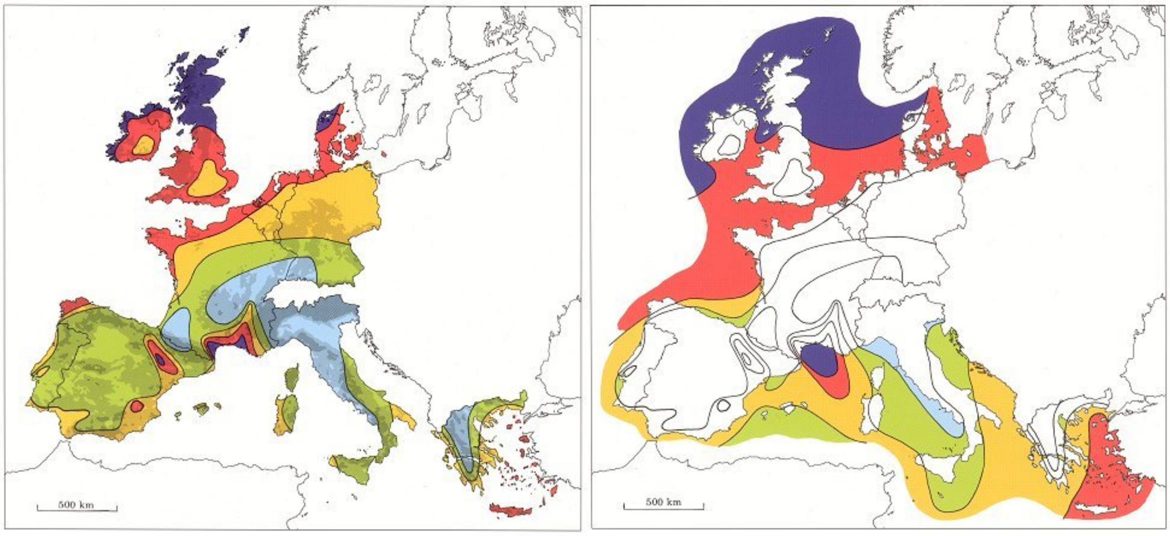
In the TRANS-CSP study, we have identified a total economic potential of about 1500 TWh/y for the analysed countries (Table 2-2). This includes both onshore and offshore potentials and

1 This value includes the waste heat of nuclear plants; considering electricity only, the global nuclear energy share is in the order of 2 %

was based on the literature mentioned above or calculated according to the methodology described in /MED-CSP 2005/. The geographic allocation of the potentials represented by the wind velocity 50 meters above ground can be estimated from the European Wind Atlas prepared by Risø National Laboratory, Denmark, shown in Figure 2-13.

Wind power plants use the kinetic energy of the wind to produce electricity. They have a typical unit capacity of several kW to about 5 MW for the largest plants available today (Table 2-5). Wind parks of several 100 MW capacity are possible. They can have an annual utilisation ratio – represented by the capacity factor – of about 15 % to over 50 % at the best available sites in offshore regions, equivalent to over 4500 full load operating hours per year. E.g. a capacity factor of 30 % indicates that the energy produced by a wind converter during the year equals full load operation of 2628 hours out of a total of 8760 hours per year.

However, those operating hours are statistically distributed during the year and not controllable by the operator. Wind energy is fluctuating, and only at very good sites with a very steady wind regime there is a considerable contribution to firm power capacity. Wind cannot supply peaking demand at all, as it is controlled by the resource and not by demand. However, at very good sites and considering a broad geographic distribution of wind converters in a country – that leads to a compensation of the fluctuations of single plants – its contribution to firm capacity can be up to 30 % of the installed capacity. This is represented by the "capacity credit" and must not be confused with the "capacity factor" that gives the average utilisation of the plants. The capacity factor and the capacity credit as function of the wind speed is given in /MED-CSP 2005/, pp. 46.



	Protected Terrain $m s^{-1}$	Open Plain $m s^{-1}$	Coast $m s^{-1}$	Offshore $m s^{-1}$	Mountains and Crests $m s^{-1}$
	> 6.0	> 7.5	> 8.5	> 9.0	> 11.5
	5.0-6.0	6.5-7.5	7.0-8.5	8.0-9.0	10.0-11.5
	4.5-5.0	5.5-6.5	6.0-7.0	7.0-8.0	8.5-10.0
	3.5-4.5	4.5-5.5	5.0-6.0	5.5-7.0	7.0- 8.5
	< 3.5	< 4.5	< 5.0	< 5.5	< 7.0

Figure 2-13: Wind velocity 50 m above ground in 5 different categories of terrain. Left Onshore, Right: Offshore. Source: European Wind Atlas, Risø National Laboratory, Roskilde, Denmark, /Risoe 1998/.

In our scenario, wind power technology is subsequently enhanced. The average annual full load hours increase in each country from the values reported in the year 2000 to a maximum performance indicator identified by the mapping of wind speed at 80 meters above ground which would be reached in the year 2050 (Table 2-4).

In the year 2000, the installed wind power capacity in the analysed countries was about 12 GW producing 23 TWh/y of electricity /Enerdata 2004/. This is equivalent to an average of 1900 full load hours per year. According to our analysis, the total wind electricity potential of the region amounts to 1500 TWh/y, of which 780 TWh/y (280 GW) could be exploited until 2050. According to this, the average performance indicator of the total wind power park in 2050 would increase to 2800 full load hours per year which is due to enhanced power plant efficiency and an increasing share of offshore capacities. In the TRANS-CSP scenario, wind power capacities will grow with an average rate of 6.5 %/y until 2050.

Photovoltaic Systems

PV power is strongly fluctuating and only available during daytime. There is no contribution to secured power, but a good correlation with the usual daytime power demand peak of most countries. PV is specially suited for distributed power supply. Hourly global irradiance on a fixed surface oriented south and tilted according to its latitude was taken from the Meteonorm database /METEONORM 2004/ to calculate the output of PV generators as a function of time.

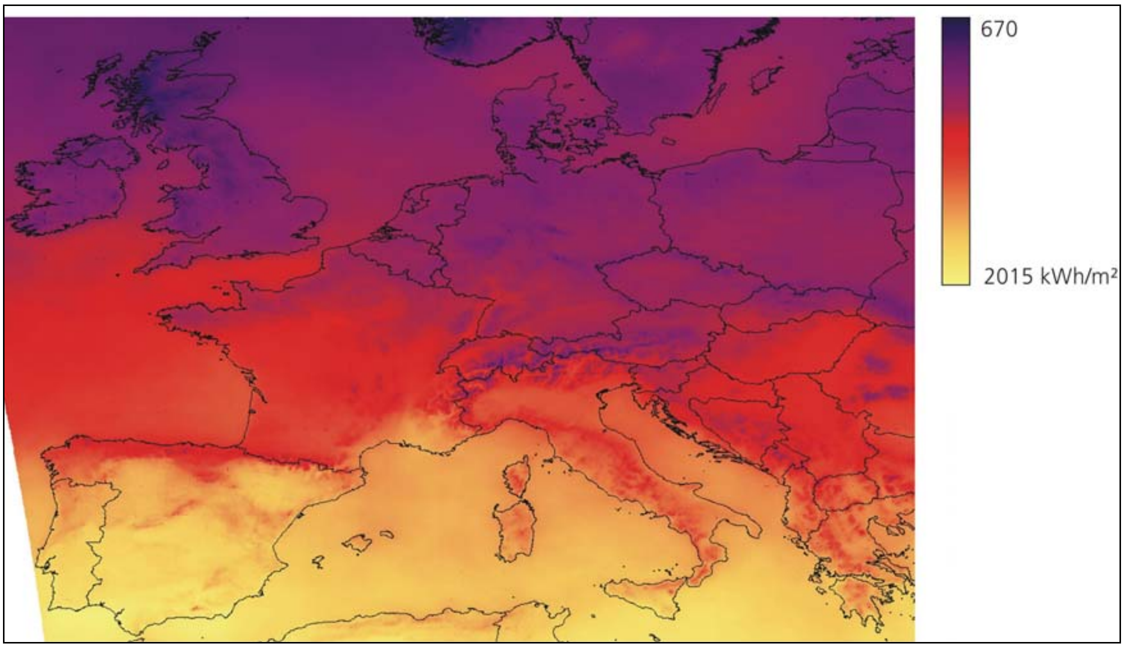


Figure 2-14: Annual sum of the global horizontal irradiance (kWh/m²/y) of the year 2004 in Europe as resource for non-concentrating PV systems. Source: Virtuelles Institut für Energiemeteorologie /vIEM 2006/.

Non-concentrating photovoltaic systems use the direct and diffuse (global) irradiance for electricity generation. PV systems can be installed anywhere and at any size, from 1 W stand alone systems to large grid connected plants of several 10 MW of capacity. PV systems cannot provide firm capacity due to the transient of clouds and to the diurnal cycle. Fluctuating electricity from PV systems can in principle be stored in pump storage, compressed air and batteries, however, storage capacities for electricity are limited and rather expensive. For Europe, literature gives extensive information of the potentials for PV expansion, ranging from optimistic /EU 2004/, /Greenpeace 2005/ to rather pessimistic expectations /EU 2003/, /WETO 2003/. The annual global irradiance increases from North to South (Figure 2-14), with typical 500 - 800 full load operating hours per year in Northern Europe and over 2000 h/y in the South, equivalent to capacity factors between 5 and 20 %.

The European solar energy atlas in Figure 2-14 explains the great difference of PV performance comparing Northern and Southern Europe. A fourfold output of PV systems in Southern Europe has of course a significant impact on the economic performance compared to the Northern European countries. Due to subsequently enhanced system efficiencies, the utilisation ratio of PV systems is expected to increase over time. This is represented by a steadily growing capacity factor as shown in Figure 2-15 for the different solar irradiance levels available in Europe. More information about the methodology is given in /MED-CSP 2005/, pp. 46.

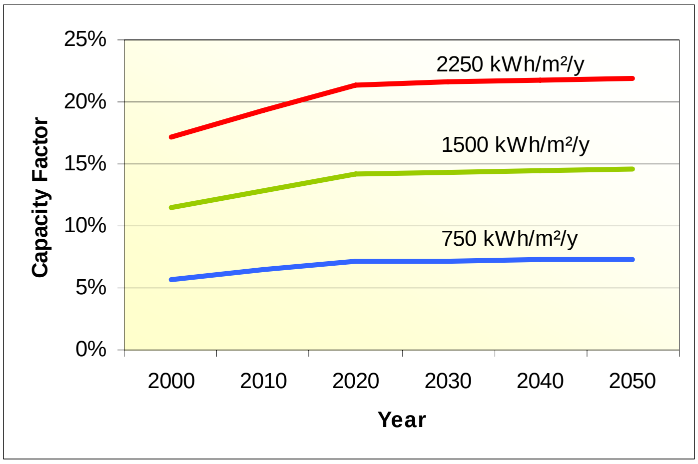


Figure 2-15: Capacity factor of grid connected PV systems as function of global irradiance on a surface tilted at latitude angle (kWh/m²/y) and the year of commissioning. There is no capacity credit for PV power.

In the year 2000, the total installed PV capacity in Europe amounted to about 190 MW producing 165 GWh/y of electricity. This is equivalent to an average of 870 full load hours per year. Most of this capacity was installed in Germany in the frame of the German Renewable Energy Act. According to our scenario, the PV capacity in the analysed countries will increase to 122 GW in the year 2050 producing about 155 TWh/y with an enhanced utilisation of 1270 full load hours per year. In spite of the relatively low level of solar irradiance and limited storability, PV will achieve a considerable share of 4 % of European electricity generation. Our scenario assumes an average PV growth rate of 14 %/y over the analysed time span of 50 years.

Hydropower

Hydropower from dams can be delivered on demand, but is usually subject to seasonal fluctuations. If used in times when PV and wind power are low, it acts like a natural complement and as a storage system for those resources. In our scenario, hydropower is increasingly saved when wind and PV energy is available and preferably used during peaking periods, while its annual capacity factor remains constant.

Hydropower technologies are well established since many years. There are large hydropower storage dams in Norway, Switzerland and Austria, and river run-off plants in most other European countries, ranging from large schemes with several 100 MW capacity to micro-hydropower systems with less than 1 kW capacity. Depending on the seasonal fluctuations and the available storage capacities of dams, the capacity factor of hydropower ranges between 10 and 90 %, while the capacity credit can be considered to range between 50 and 90 % (Table 2-5).

Hydropower potentials in Europe are well documented in the literature /WEC 2004/, /Horlacher 2003/. The annual full load hours are used as performance indicator. For the year 2000, they were calculated from the reported installed capacities and electricity generation in each country /Enerdata 2004/. The map in Figure 2-16 illustrates the geographic distribution, Table 2-2 quantifies the technical and economic potentials of hydropower.

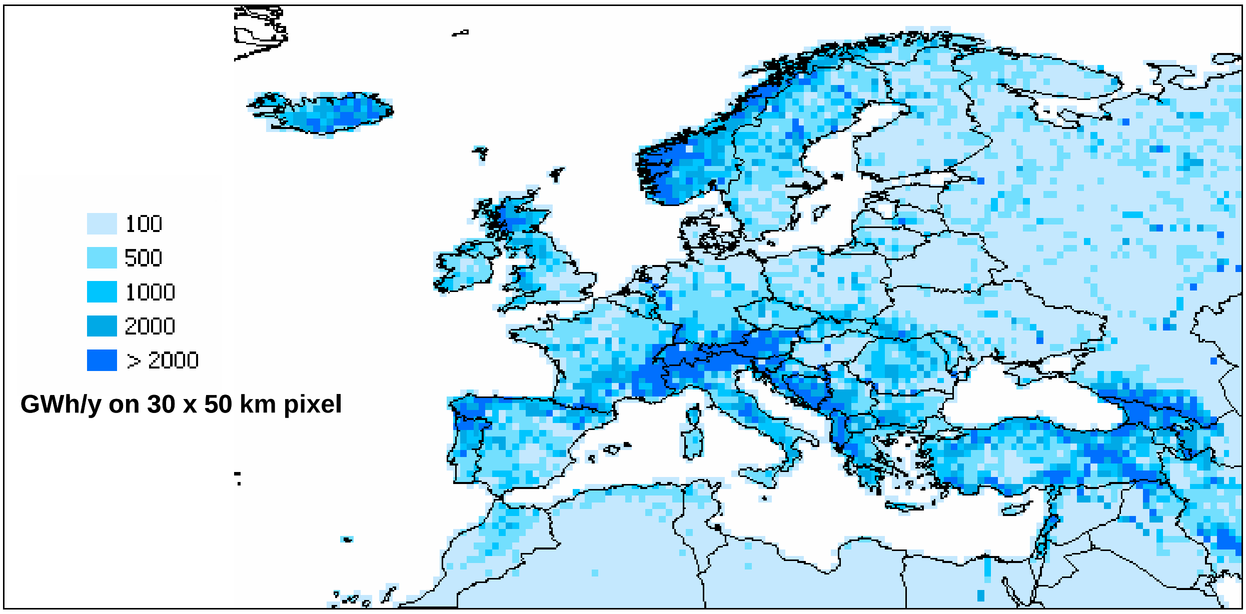


Figure 2-16: Gross physical hydropower potentials in Europe in GWh/y for unit elements of 30 km x 50 km size. Source: WaterGap, /Lehner et al. 2005/.

The total economic hydropower potential of all countries analysed in the TRANS-CSP study amounts to roughly 910 TWh/y. In the year 2000, European hydropower schemes produced 615 TWh/y of electricity with an installed capacity of 190 GW in 3250 full load operating hours per year. The numbers scheduled for 2050 in the TRANS-CSP scenario are 235 GW of installed capacity producing 750 TWh/y, respectively.

There is certain evidence that climate change is having an increasing impact on hydropower generation with the possibility of reductions of up to 25 % in the long term in the Southern European countries, /Lehner et al. 2005/. Although we have not quantified such impacts in the study we believe that this is a serious concern that should be taken into account in energy planning. Efficiency of hydropower use should be enhanced systematically in order to counteract at least partially such effects. Due to the already extensive use of hydropower in Europe, the expected growth rates until 2050 are rather moderate, with an average of around 0.5 %/y.

Geothermal (Hot Dry Rock)

Geothermal power can be delivered on demand as base, intermediate or peaking power using the earth as natural storage system. It can be used to compensate the fluctuations from wind and PV-power. Geothermal heat at over 200 °C can be delivered from up to 5000 m deep holes to operate organic Rankine cycles or Kalina cycle power machines. Unit sizes are about 1 MW today and limited to about 100 MW maximum in the future. Geothermal energy is often used for the co-generation of heat and power. Geothermal power plants are used all over the world where surface near geothermal hot water or steam sources are available, like in USA, Italy and the Philippines. In Europe those conventional geothermal potentials are significant in Island, Italy, Turkey and the Balkan region. Conventional geothermal resources were taken from literature /GEA 2004/, /WEC 2004/. Medium term geothermal power potentials are described in /EU 2004/. Those potentials are small in comparison to the Hot Dry Rock potentials and are not quantified separately in the study. In the year 2000, about 6 TWh/y of electricity were generated by conventional geothermal power plants, mainly in Iceland and Italy.

The Hot Dry Rock technology aims to make geothermal potentials available everywhere, drilling deep holes into the ground to inject cold water and receive hot water from cooling down the hot rocks in the depth /IGA 2004/. However, this is a rather new though promising approach and its technical feasibility must still be proven. Geothermal power plants provide power on demand using the ideal storage of the earth's hot interior as reservoir. They can provide peak load, intermediate load or base load electricity. Therefore, the capacity factor of geothermal plants is defined by the load and their operation mode. Assuming a plant availability of 90 %, their capacity credit would have that same value.

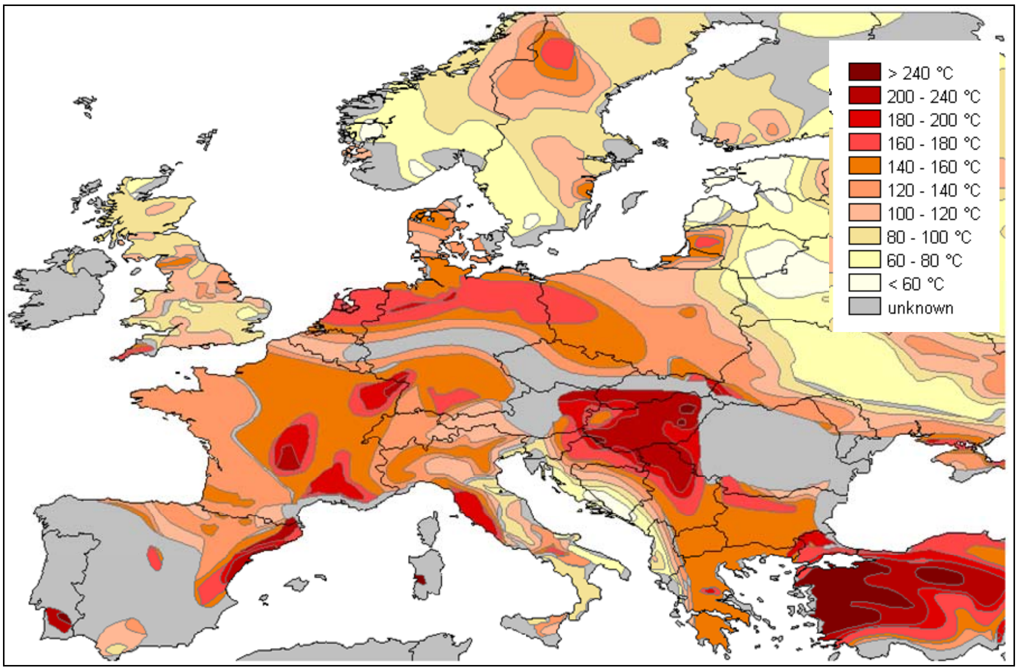


Figure 2-17: Rock temperatures in 5000 meters depth as indicator for HDR electricity potentials in Europe /Bestec 2004/.

A map of subsoil temperatures at 5000 m depth was taken to assess the total areas with temperatures higher than 180°C as economic potential for Hot Dry Rock technology (Figure 2-17). It was assumed that a layer with 2 km thickness in 5000 m depth was used as heat reservoir /BMU 2003-2/, /GGA 2000/. The total heat in place was then calculated from that volume with the temperature range available in each country according to the methodology described in /MED-CSP 2005/, pp. 47 and pp. 63. The resulting potentials for each country are given in Table 2-2. In 2050, a total potential of 200 TWh/y with a capacity of 41 GW could be activated by this technology, if the presently ongoing efforts of research and development are successful.

Biomass

Biomass can deliver power on demand as it is easily storable. However, biomass is subject to seasonal fluctuations. As a strategic guideline, biomass can be supplied in times when wind and PV power is low in order to compensate those sources, and shut down when wind and PV power is available to save the scarce biomass resources. It will also be used for cogeneration.

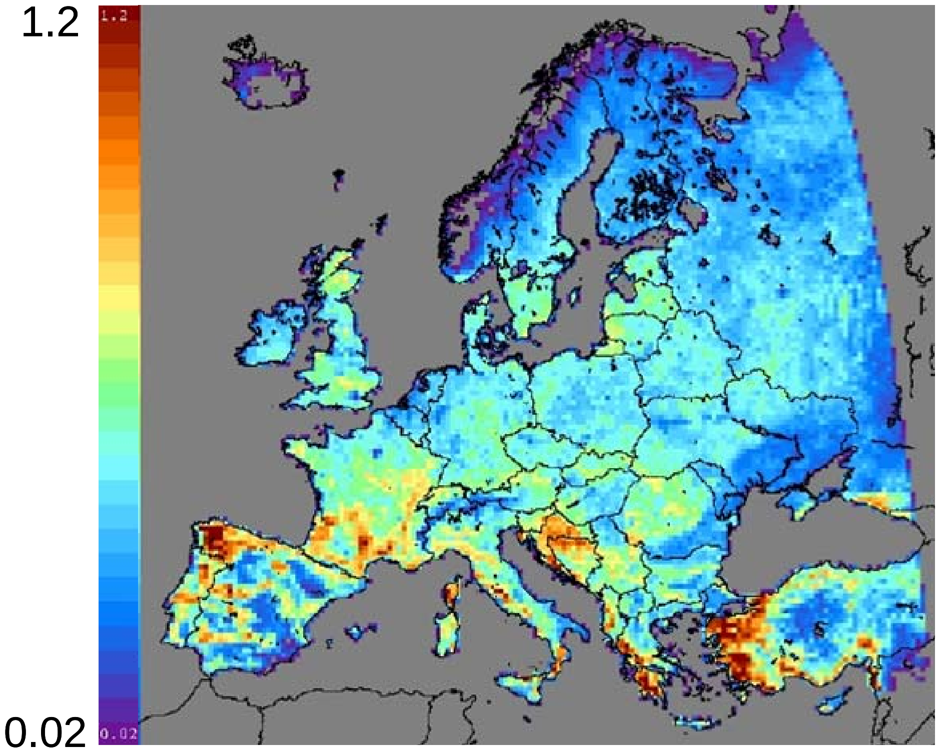


Figure 2-18: Net primary production of the total biomass by photosynthesis in million tonnes of carbon units per year on land surface units (pixel) of 27,5 x 27,5 km in the year 1998 (to obtain dry matter please multiply by 2) /WDC 2006/

There are a number of potential sources to generate energy from biomass: biogas can be produced by the decomposition of organic materials like municipal liquid waste, manure or agricultural residues. Biogas reactors require large quantities of water. The calorific value of biogas is about 6 kWh/m³. Biogas can be used in combustion engines or turbines for electricity generation and for co-generation of heat and power. Landfill gas can be used in a similar way.

Solid biomass from agricultural or municipal residues like straw, cane trash and wood can be used to generate heat and power. From every ton of dry solid biomass about 1.5-2.5 MWh of heat or 0.5-1.0 MWh of electricity can be generated in steam cycle power plants /BMU 2004-1/.

There is also the possibility to raise crops specifically for energy purposes. However, this option has been neglected in the TRANS-CSP scenario as there will be probably a priority to use energy crops for the transport sector (biofuels) rather than for electricity generation /UBA 2004/.

The size of biomass plants ranges from some kW (combustion engines) to about 25 MW. Biomass can be stored and consumed on demand for power generation. However, there are often seasonal restrictions to the availability of biomass. Typical power plants using biomass in co-generation have capacity factors between 0.4 and 0.6 that are equivalent to 3500 – 5500 full load hours per year. They are usually operated to provide intermediate or peaking power but seldom for base load. The availability of biomass plants is high at 90 % and so is their capacity credit.

If used for co-generation of electricity and heat, biomass electricity must be considered part of the base load segment of the power market, as it is not controlled by electricity demand, but usually by the heat load.

Electricity generation from biomass is calculated with the methodology described in /MED-CSP 2005/, pp. 49 and pp. 65. and compared to potentials given in the literature /EU 2004/ and /Greenpeace 2005/. The results of the study are given in Table 2-4 and Table 2-2.

In the year 2000, a total capacity of 11 GW was installed in Europe producing 49 TWh/y of electricity. In the TRANS-CSP scenario, the European biomass electricity potential was estimated to be in the order of 764 TWh/y of which 495 TWh/y could be used until 2050, with an installed capacity of 135 GW. The tenfold increase until 2050 is equivalent to an average growth rate of power generation from biomass of 5 %/y over the total time span.

	2050						2000	2010	2020	2030	2040	2050
	Max	Agr.Res.	Agr.Res.	Forest	Prod.	Wood	Mun.Waste	Mun.Waste	Mun.Waste	Mun.Waste	Mun.Waste	Mun.Waste
	TWh/y	1000 t/y	TWh/y	1000 km²	t/ha/y	TWh/y	TWh/y	TWh/y	TWh/y	TWh/y	TWh/y	TWh/y
Austria	30,62	10610	10,61	39	4,8	18,72	1,42	1,42	1,41	1,38	1,34	1,29
Cyprus	0,58	280	0,28	1	1,7	0,17	0,10	0,11	0,12	0,12	0,13	0,13
Denmark	6,62	3500	3,50	5	4,4	2,20	0,93	0,95	0,96	0,95	0,94	0,92
Finland	53,68	11200	11,20	219	1,9	41,61	0,91	0,92	0,93	0,92	0,90	0,87
France	79,15	26600	26,60	153	2,7	41,31	10,38	10,82	11,13	11,30	11,34	11,24
Czech Republi	19,98	6000	6,00	26	4,8	12,48	1,80	1,78	1,74	1,68	1,60	1,50
Belgium	7,29	2000	2,00	7	5	3,50	1,79	1,82	1,84	1,84	1,82	1,79
Ireland	6,25	1800	1,80	7	5,1	3,57	0,67	0,74	0,80	0,84	0,86	0,88
Luxembourg	0,44	270	0,27	0	5	0,05	0,08	0,09	0,10	0,11	0,12	0,12
Netherlands	9,57	5000	5,00	4	4	1,60	2,78	2,90	2,97	3,01	3,01	2,97
Sweden	80,35	16500	16,50	271	2,3	62,33	1,55	1,57	1,58	1,58	1,56	1,52
Switzerland	8,03	1250	1,25	12	4,8	5,76	1,25	1,24	1,21	1,16	1,10	1,02
United Kingdo	30,68	8500	8,50	26	4	10,40	10,46	10,80	11,10	11,37	11,59	11,78
Poland	52,14	16600	16,60	93	3,2	29,76	6,77	6,73	6,62	6,42	6,14	5,78
Bulgaria	7,74	2750	2,75	37	1,1	4,07	1,42	1,31	1,21	1,11	1,01	0,92
Slowac Republ	10,75	3000	3,00	20	3,44	6,88	0,94	0,95	0,95	0,93	0,91	0,87
Slowenia	6,25	2350	2,35	11	3,3	3,63	0,35	0,34	0,33	0,32	0,30	0,27
Germany	87,00	25000	25,00	107	4,5	48,15	14,40	14,44	14,40	14,29	14,11	13,85
Hungary	11,35	4800	4,80	18	2,9	5,22	1,75	1,67	1,59	1,51	1,42	1,33
Greece	7,24	3000	3,00	36	0,7	2,52	1,91	1,91	1,90	1,86	1,80	1,72
Italy	46,05	14200	14,20	100	2,4	24,00	10,08	9,84	9,50	9,05	8,50	7,85
Malta	0,07	2	0,00	0	0	0,00	0,06	0,07	0,07	0,07	0,07	0,07
Portugal	15,16	1000	1,00	37	3,4	12,58	1,75	1,76	1,74	1,71	1,65	1,58
Spain	40,40	13500	13,50	144	1,3	18,72	5,09	5,94	6,74	7,41	7,90	8,18
Turkey	44,74	13200	13,20	102	1,7	17,34	7,86	9,53	11,05	12,39	13,50	14,20
Macedonia	2,58	1300	1,30	3	3	0,90	0,35	0,37	0,38	0,39	0,39	0,38
Croatia	8,93	2900	2,90	18	3	5,40	0,78	0,76	0,73	0,70	0,67	0,63
Romania	40,91	15000	15,00	65	3,5	22,75	3,94	3,84	3,72	3,56	3,38	3,16
Serbia & Monte	14,34	4000	4,00	29	3	8,70	1,85	1,84	1,81	1,77	1,71	1,64
Bosnia-Herzeg	9,52	2000	2,00	23	3	6,90	0,70	0,73	0,74	0,73	0,69	0,62
Iceland	0,06	0	0,00	0	1,1	0,00	0,05	0,05	0,06	0,06	0,06	0,06
Norway	25,77	8000	8,00	89	1,9	16,91	0,78	0,82	0,84	0,85	0,86	0,86
Total	764		226			438	95	98	100	101	101	100

Table 2-3: Summary of the biomass electricity potential from agricultural and municipal waste and wood in Europe according to the methodology described in /MED-CSP 2005/, based on data from /WEC 2004/, /UBA 2004/ and /EU 2004/. Municipal waste potentials consider demographic and technical development.

Concentrating Solar Power

A major advantage of concentrating solar thermal power plants is their capability for thermal energy storage and hybrid operation with fossil or bio-fuels, allowing them to provide firm power capacity on demand. The principle of operation is drafted in Figure 2-19 for the cogeneration of heat and power. The use of a simple power cycle for electricity is of course possible as well. In the future European mix of energy sources for power generation, CSP can serve to cover base load, intermediate load or peaking load and even to compensate the fluctuations of PV and wind power. From the point of view of a grid operator, CSP behaves just like any conventional steam cycle power station, thus being an important factor for grid stability and control. CSP plants can be designed from 5 MW to several 100 MW capacity.

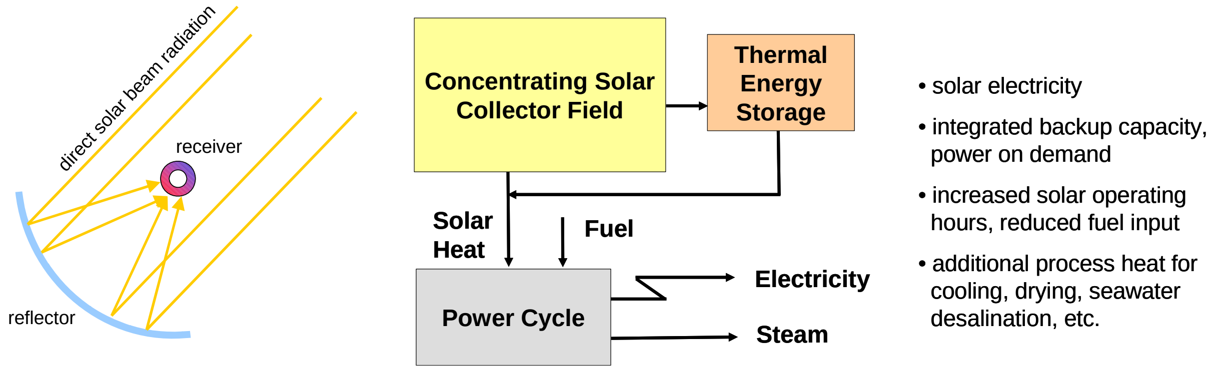


Figure 2-19: Principle of a concentrating solar collector (left) and of a concentrating solar thermal power station for co-generation of electricity and process heat (right).

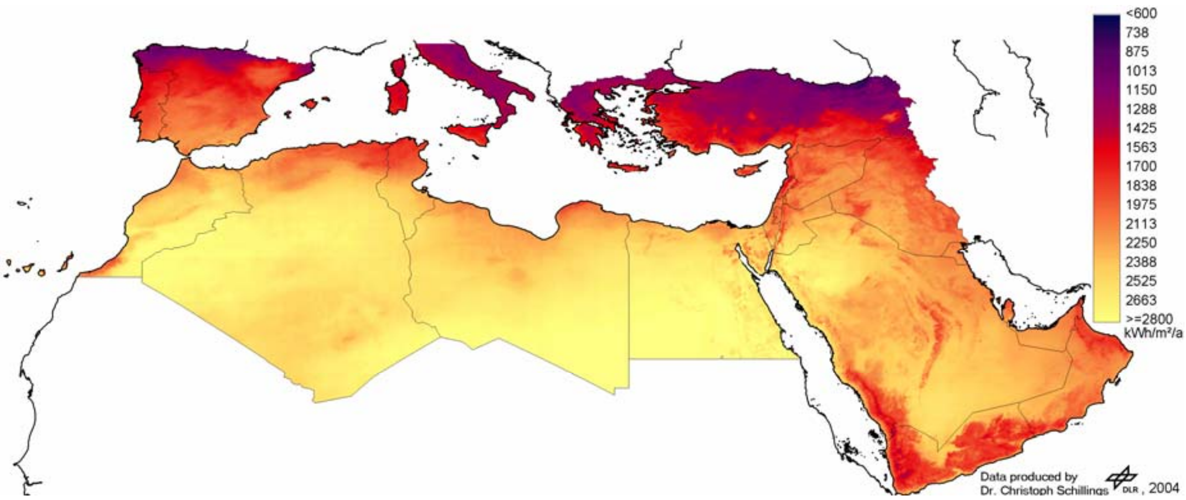


Figure 2-20: Annual direct normal irradiance in kWh/m²/y. In terms of primary energy, the direct solar irradiance in North Africa equals a layer of crude oil of 0.25 meters thickness on the total land surface every year. This gigantic resource is several orders of magnitude larger than the global energy demand. A small part could be harvested by concentrating solar thermal power stations and exported to Europe via High Voltage Direct Current interconnections /MED-CSP 2005/

A reasonable economic performance of concentrating solar power plants is given at an annual direct solar irradiance of more than 2000 kWh/m²/y. The economic potential of CSP in Europe has been assessed in /MED-CSP 2005/, pp. 58 and pp. A-11. It is limited to Spain, Portugal, Greece, Turkey and the Mediterranean Islands and amounts to 1580 TWh/y of which 1280 TWh/y are located in southern Spain (Table 2-2). Although there is a relatively large CSP potential in Europe, more attractive sites are located south of the Mediterranean sea, with an annual direct solar irradiance of up to 2800 kWh/m²/y (Figure 2-20).

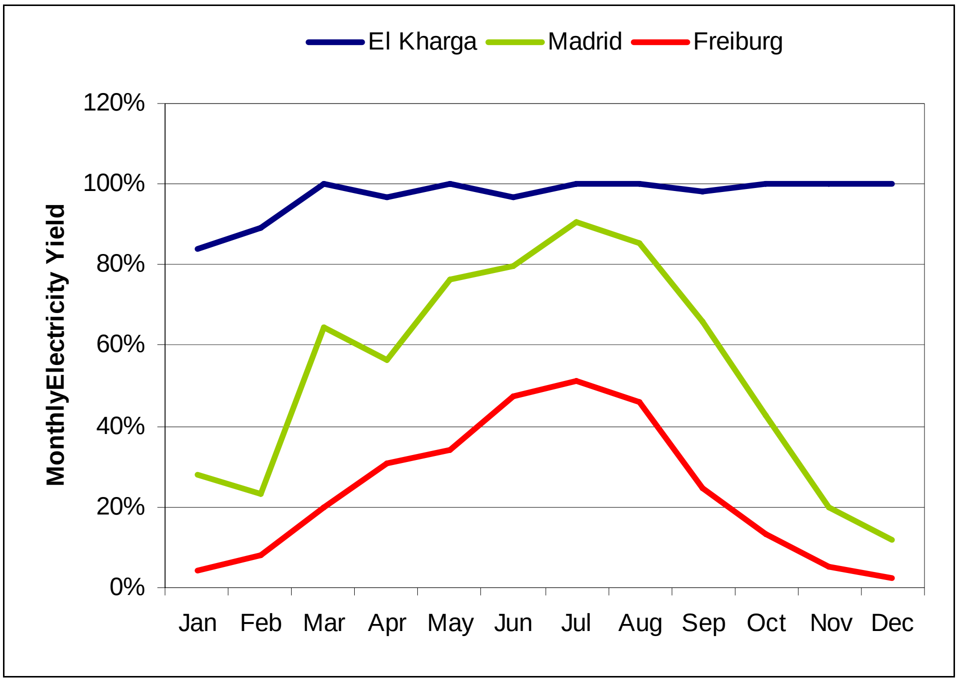


Figure 2-21: Simulation of the relative monthly electricity yield of a solar thermal power plant with 24 hour storage at sites with different annual solar irradiance and latitude. Solar only operation without fuel input. Equivalent annual full load hours: Freiburg (Germany) 2260 h/y, Madrid (Spain) 5150 h/y, El Kharga (Egypt) 8500 h/y /May 2005/.

Figure 2-21 shows the monthly electricity yield of a solar thermal power plant with 24 hour storage capacity at different locations in Europe and North Africa. The site El Kharga in Egypt represents the best case of all. Throughout the whole year the energy yield stays at almost 100 %, just in January and February it declines to about 85 %. The more the plant is located to the North, the lower is its monthly electricity yield. In Madrid and Freiburg values of less than 20 % are achieved in wintertime, and nether achieves 100 % in summer.

For this reason, the TRANS-CSP study investigates the feasibility of activating part of the valuable and powerful solar energy resources of North Africa for export to Europe by means of High Voltage Direct Current power transmission (HVDC) as complement to the European renewable energy sources. There is an economic potential of 1584 TWh/y, of which 111 TWh/y (19 GW) would be used until 2050, with a growth rate of 9 %/y.

Resource	Hydro	Geo	Bio	CSP	Wind	PV	Wa/Ti
Indicator	Flh	THDR	FLh	DNI	FLh	GTI	FLh
Unit	h/y	°C	h/y	kWh/m²/y	h/y	kWh/m²/y	h/y
Austria	3608	200	4500	820	1176	1380	0
Cyprus	0	100	3500	2200	3423	2100	4000
Denmark	2818	100	5000	950	3304	1180	4000
Finland	4933	100	5500	950	3310	1180	4000
France	2838	200	4500	1060	2618	1560	4000
Czech Republic	1100	100	4500	760	1789	1130	0
Belgium	4466	100	4500	700	2449	1140	4000
Ireland	2264	100	4500	700	3260	1120	4000
Luxembourg	789	100	4500	700	1176	1130	0
Netherlands	2432	180	4500	700	3413	1120	4000
Sweden	4852	180	4500	1070	2638	1240	4000
Switzerland	2894	100	4500	990	1176	1170	0
United Kingdom	1857	180	4500	660	3733	1100	4000
Poland	1881	180	4500	790	2355	1140	4000
Bulgaria	1667	180	5500	1070	1176	1510	0
Slowac Republic	2000	180	4500	750	1176	1430	0
Slowenia	4419	180	4500	860	1176	1250	4000
Germany	3667	180	4500	900	3459	1260	4000
Hungary	3771	220	4500	1100	1176	1370	0
Greece	1331	213	3500	1900	2252	1730	4000
Italy	2502	200	3500	2000	2289	1800	4000
Malta	0	100	3500	2000	2095	2150	4000
Portugal	2589	213	3500	2100	2862	1910	4000
Spain	1705	213	4500	2250	2494	2020	4000
Turkey	2762	281	3500	2000	2235	1900	4000
Macedonia	2667	100	4500	1100	1176	1450	4000
Croatia	2823	180	4500	940	1176	1400	4000
Romania	3086	190	4500	1200	1176	1500	0
Serbia & Montenegro	3715	220	4500	1250	1176	1550	4000
Bosnia-Herzegowina	3091	100	4500	1100	1176	1450	4000
Iceland	6038	400	4500	810	2708	970	4000
Norway	5164	100	5000	580	2708	850	4000

Table 2-4: Performance indicators of the different renewable energy sources in Europe. The resource indicators quantify the average performance quality of the economic potential in each country. Flh: Full Load Hours per year, THDR Temperature of Hot Dry Rocks in 5000 m depth, DNI Direct Normal Irradiance, GTI Global Irradiance on surfaces Tilted according to latitude. Wa/Ti Wave and Tidal Power.

	Unit Capacity	Capacity Credit *	Capacity Factor **	Resource	Applications	Comment
Wind Power	1 kW – 5 MW	0 – 30 %	15 – 50 %	kinetic energy of the wind	electricity	fluctuating, supply defined by resource
Photovoltaic	1 W – 5 MW	0 %	5 – 25 %	direct and diffuse irradiance on a tilted surface	electricity	fluctuating, supply defined by resource
Biomass	1 kW – 25 MW	50 - 90 %	40 – 60 %	biogas from the decomposition of organic residues, solid residues and wood	electricity and heat	seasonal fluctuations but good storability, power on demand
Geothermal (Hot Dry Rock)	25 – 50 MW	90 %	40 – 90 %	heat of hot dry rocks in several 1000 meters depth	electricity and heat	no fluctuations, power on demand
Hydropower	1 kW – 1000 MW	50 - 90 %	10 – 90 %	kinetic energy and pressure of water streams	electricity	seasonal fluctuation, good storability in dams, used also as pump storage for other sources
Solar Chimney	100 – 200 MW	10 to 70 % depending on storage	20 to 70 %	direct and diffuse irradiance on a horizontal surface	electricity	seasonal fluctuations, good storability, base load power
Concentrating Solar Thermal Power	10 kW – 200 MW	0 to 90 % depending on storage and hybridisation	20 to 90 %	direct irradiance on a surface tracking the sun	electricity and heat	fluctuations are compensated by thermal storage and (bio)fuel, power on demand
Gas Turbine	0.5 – 100 MW	90 %	10 – 90 %	natural gas, fuel oil	electricity and heat	power on demand
Steam Cycle	5 – 500 MW	90 %	40 – 90 %	coal, lignite, fuel oil, natural gas	electricity and heat	power on demand
Nuclear	>500 MW	90 %	90 %	uranium	electricity and heat	base load power

Table 2-5: Some characteristics of contemporary power technologies. * Contribution to firm capacity. ** Average annual utilisation.

2.3 Outlook for Electricity Supply in Europe

Comparing the expected future electricity demand in Europe with the economic renewable energy potentials shows that in principle enough potentials are available to cover the demand with a surplus of 45 % (Table 2-6). However, it must be taken into account that about 30 % of the analysed countries show considerable deficits, while on the other hand considerable surpluses are concentrated in only 7 countries. Roughly one quarter of the potential is represented by one single resource in one single country, that is concentrating solar power in Spain.

Unit: TWh/y	Demand 2050	Total Ren. Econ. Pot.	Coverage in 2050
Austria	49,0	96,6	197%
Cyprus	5,0	27,9	558%
Denmark	51,1	65,1	127%
Finland	76,4	104,3	137%
France	426,0	329,7	77%
Czech Republic	51,7	29,9	58%
Belgium	67,0	23,2	35%
Ireland	34,0	67,6	199%
Luxembourg	10,9	2,2	20%
Netherlands	116,0	56,3	48%
Sweden	153,7	240,9	157%
Switzerland	39,4	50,0	127%
United Kingdom	451,2	450,8	100%
Poland	190,9	129,9	68%
Bulgaria	26,5	31,4	119%
Slowac Republic	29,5	22,5	76%
Slowenia	9,3	16,0	171%
Germany	548,8	433,6	79%
Hungary	43,9	70,5	161%
Greece	62,1	89,5	144%
Italy	310,6	237,2	76%
Malta	2,4	2,3	95%
Portugal	62,0	220,1	355%
Spain	320,1	1513,1	473%
Turkey	494,1	723,4	146%
Macedonia	11,5	7,3	63%
Croatia	20,3	24,4	120%
Romania	96,1	69,8	73%
Serbia & Montenegro	49,2	48,8	99%
Bosnia-Herzegowina	17,8	29,2	164%
Iceland	6,6	233,8	3567%
Norway	112,0	290,7	259%
Total	3945	5738	145%

Table 2-6: Electricity demand in 2050 compared to the total economic renewable electricity potential of the analysed countries without solar electricity imports. Red indicates those countries where the domestic renewable electricity potential is smaller than the expected demand, green indicates sufficiently high potentials to cover the expected demand.

The available potentials will probably not cover by 100 % the total European electricity demand in 2050, for the following reasons:

- About 60 % of the economic renewable electricity potential in Europe is represented by wind and solar energy, both highly fluctuating resources that cannot deliver power on demand. As explained in Figure 2-21, even concentrating solar thermal power (CSP) must be considered a fluctuating resource under European conditions. Biomass and hydropower resources are not submitted to short term, but to seasonal fluctuations. Therefore, a 100 % coverage of the annual electricity demand would ether require the installation of considerable over-capacities by a factor 2 or 3 /Quaschning 2000/ or the use of conventional fossil backup power, consequently reducing the renewable energy share to less than 100 %. The same would result from the use of hybrid CSP plants.
- Most renewables except hydropower and wind energy are not yet visible in the European energy mix today. To grow to considerable shares requires time, defined by the growth rates of the respective industrial production capacities. Although growing quickly today, with spectacular rates of 25-60 %/y for wind and PV, a considerable share of renewables will not become visible in the total energy mix before 2020. To cover the power demand until renewables can really take over the core of electricity supply, and considering the demand for new power capacities as shown in Figure 2-8, new fossil fuel based power capacities will have to be installed from here to 2050. Once installed, those capacities will not be decommissioned before their economic lifetime is over, thus still blocking the respective market segment in 2050 and afterwards.
- The economic learning curves of renewable energy technologies will require a certain time span to come to a competitive level. Geothermal (HDR) plants still require considerable R&D efforts, while the economic performance of PV plants is limited by the rather low solar irradiance in northern Europe. Public concern is increasingly pushing wind power to offshore regions, and hydropower plants are subject to increasing environmental constraints, creating additional challenges for each technology that still must be overcome and will take time to be solved.
- Public support of renewables must balance the expectations of private investors with adequate incentives for cost reduction to achieve an optimal allocation of funds. Therefore, only a support exactly fitting to the real cost level of each technology and subsequently reduced over time will induce optimal learning and development. Nether scarce nor excessive funding would be helpful to achieve that goal. Renewables will need time to come to overall electricity costs comparable to the starting point of the scenario in the year 2000, but on the other hand, only renewables have the potential to come back to that level at all, while fossil generation is already far beyond that point.

The scope of our study was to find a well balanced mix of domestic and imported, fossil and renewable sources to provide compatible, secure and affordable electricity for each of the analysed European countries, not to maximise renewable electricity generation.

To calculate the TRANS-CSP scenario we have followed the methodology described in /MED-CSP 2005/, pp. 111 ff, which is guided by the energy policy triangle. We must point out again that a scenario is not a prediction of future events, but a consistent path to the future that will require efforts to become reality. The scope of a scenario analysis is to identify a viable and consistent future situation, to evaluate its desirability and to provide the necessary data base for the finding of strategies for its achievement.

Frame Parameters for the Scenario

The frame conditions and assumptions used to narrow down the set of viable paths to the future have been selected to be plausible and "conservative" in terms of the expansion of renewables, assuming e.g. a relatively low cost escalation for fossil fuels. There can be different scenarios based on more optimistic or more pessimistic assumptions. We think that the frame parameters chosen here are within a reasonable range of possibilities. The TRANS-CSP scenario was calculated under the following economic assumptions (Figure 2-22):

- Oil price: 25 $/bbl in 2000 rising to 80 $/bbl in 2050.
- Gas price starting with 3.5 $/GJ in 2000 escalating to 10 $/GJ in 2050.
- Coal price rising from 48 $/ton to 80 $/ton.
- Capture and sequestration of 85 % of the carbon dioxide emitted from new fossil fuel fired plants starting in 2020 with average 1.5 ct/kWh additional electricity cost.
- Real discount rate 5 %/y.
- Average exchange rate of € / US$ = 1.

The following potential barriers and frame conditions have also been taken into account to narrow down the course of market development of renewable forms of energy in the scenario:

- existing grid infrastructure
- growth rates and market shares of renewable energy technology production
- annual electricity demand
- peaking power demand and firm reserve capacity
- replacement of old plants
- cost of electricity in comparison to competing technologies
- opportunities of finance
- policies and energy economic frame conditions

All those parameters are not treated as static constants, but are analysed in their dynamic transition towards a sustainable energy scheme.

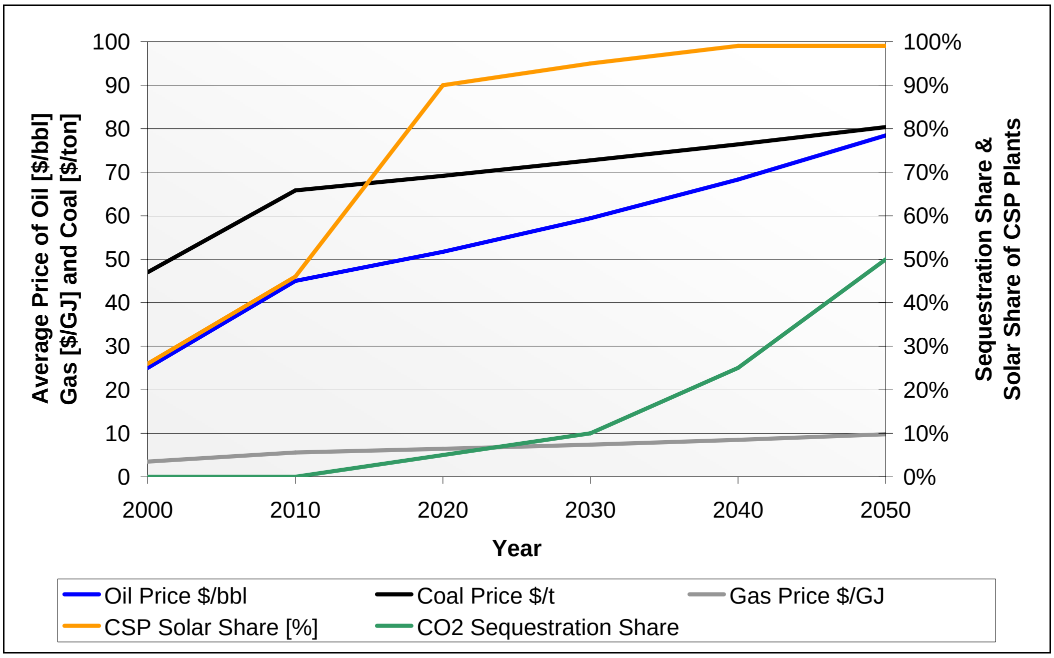


Figure 2-22: Energy economic frame parameters and assumptions used for the TRANS-CSP scenario calculations.

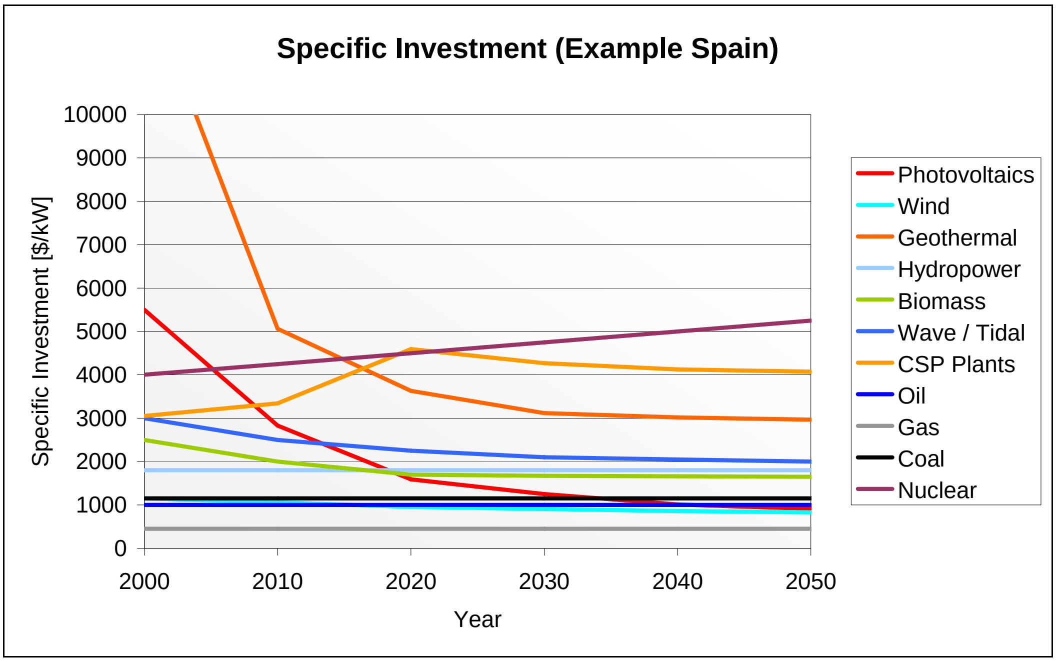


Figure 2-23: Specific investment of power technologies in the TRANS-CSP scenario, including the costs of decommissioning depreciated with a discount rate of 5%/y over the economic lifetime. CSP plants are subsequently built with larger collector fields and thermal storage, therefore, their specific investment increases proportionally to their solar operating time. The investment of all other plants is reduced with time according to their specific learning curves. Nuclear power investments include subsequently higher costs for security and nuclear waste disposal (+25 % until 2050).

Our scenario assumes that the European countries will introduce CO_2-capturing and sequestration after 2020, and will reach a sequestration share of 50 % of their conventional power generation capacity by 2050. Carbon capture will increase the cost of conventional power generation of newly installed plants by a minimum of 1.5 cents/kWh. We consider this a rather optimistic estimate to describe the cost of carbon capture technology /NREL 2004/.

All technologies analyzed within this study are subject to technology development and economies of scale. While renewables have still a rather elevated investment cost, they are in a phase of fast technological progress with market growth rates of over 25 % per year, which will lead to a significant cost reduction in a relatively short time (Figure 2-23). This has been observed in the past and will continue in the future – although slowing down with increasing market presence /EXTOOL 2003/, /WETO 2003/.
On the contrary, fossil and nuclear power technologies are mature since many years and are massively applied world wide. Investment cost reductions are hardly noticeable at present, although existent. However, many cost reductions have been compensated by the necessity of adding measures for security and the protection of the environment, like e.g. filters and chemical flue gas treatment, and nuclear waste disposal. Moreover, the primary energy sources used by those technologies are not for free and everlasting like solar or wind energy, but increasingly becoming scarce, expensive and burdened by severe environmental constraints like e.g. global climate change.

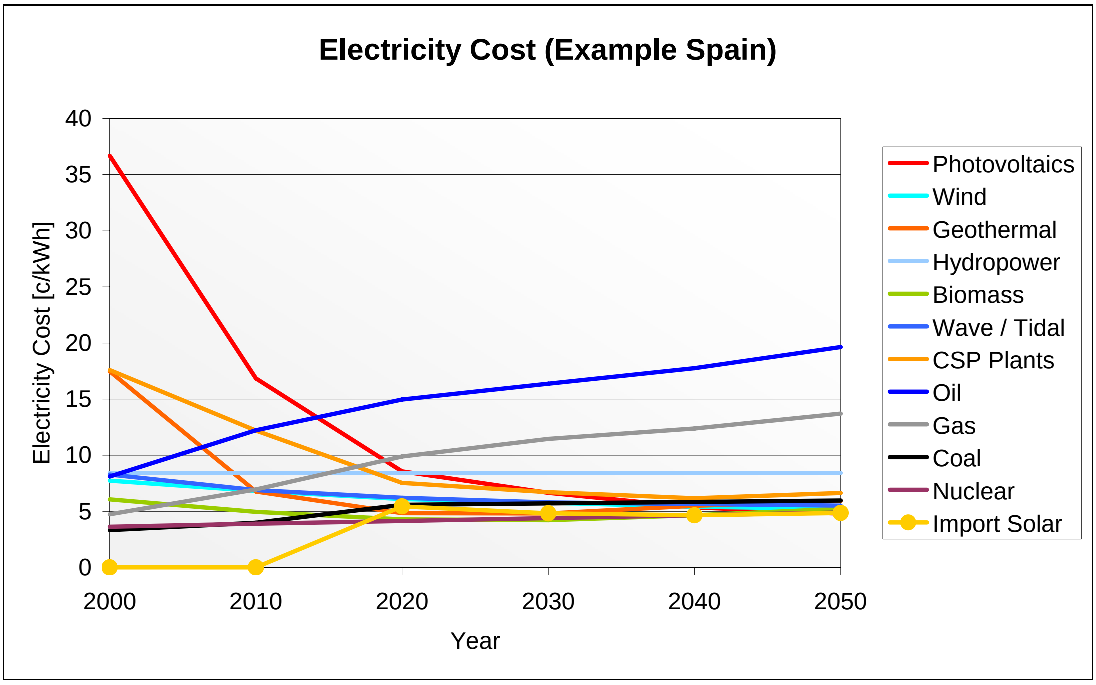


Figure 2-24: Electricity generation cost of new plants resulting from the specific investment (Figure 2-23) and from the performance indicators of each country and source in Table 2-4. In the long term, renewables are not only the more valuable, but also the least cost option for power.

The cost of renewables will strongly depend on the meteorological conditions in each country, which may widely differ. The electricity cost scenario was calculated with an average real discount rate of 5 %/year. All numbers are given in real values of €-2000. The electricity cost of renewable sources is calculated as function of the performance indicators described before and taking into consideration realistic learning effects by economies of scale and technical progress. The electricity cost of all power technologies is calculated by the following equation:

$$C_{el} = \frac{Inv \cdot FCR + O\,\&\,M + F}{E_{year}}$$

C_{el} cost of electricity in €-2000/kWh

Inv investment cost in €-2000

FCR fixed charge rate as function of interest rate and economic lifetime (annuity)

O&M annual cost of operation and maintenance, personnel, insurance, etc.

F annual fuel expenses

E_{year} electricity generated per year = installed capacity (MW) · full load hours (h/y)

	Economic Life years	Efficiency % *	Fuel Price Escalation %	Operation & Maintenance % of Inv./y	Annual Full Load Hours hours/year*
Steam Coal Plants	40	40%	1.0%	3.5%	5000
Steam Oil Plants	30	40%	1.0%	2.5%	5000
Combined Cycle Natural Gas	30	48%	1.0%	2.5%	5000
Wind Power	15			1.5%	2000
Solar Thermal Power	40	37%	1.0%	3.0%	8000
Hydropower	50	75%		3.0%	2600
Photovoltaics	20	10%		1.5%	1800
Geothermal Power	30	13.5%		4.0%	7500
Biomass Power	30	35%		3.5%	3700

* vary for different countries and sites

Table 2-7: Example of parameters used for the calculation of the electricity cost.

A set of parameters used for the calculation of the electricity cost as a function of time is given in Table 2-7, showing some parameters that vary for each country and site and others that are assumed to be equal for all countries within the scenario calculation. The cost of solar import electricity is calculated on the basis of the CSP performance parameters in North Africa and includes the investment and operation cost of the HVDC transmission lines as well as the electricity losses caused by transmission as described in Chapter 1.

A Well Balanced Energy Mix

Coal (inclusive lignite) and nuclear power are the main sources for electricity in Europe in the starting year 2000, followed by hydropower and natural gas (Table 2-8), (Figure 2-25). The installed power capacity is dominated by coal and hydropower, followed by natural gas and nuclear plants (Table 2-9), (Figure 2-26). The present electricity mix violates a number of requisites for sustainability as described in Figure 2-1. The past and present carbon emissions of the power sector are a major cause for climate change, the valuable fossil energy resources – especially those existing in Europe – are gradually depleted, import dependency of the European power sector is increasing, and the world market price of all primary energy sources used for power generation has become today more than three times that of the year 2000, with a persisting trend upwards. Today European electricity consumers are already paying approximately 35-70 billion €/y more for fuels for power generation than in the year 2000.

Year	2000	2010	2020	2030	2040	2050
Wind	23,2	172,8	496,4	667,4	743,0	780,7
Photovoltaics	0,2	4,1	26,4	78,9	118,3	153,8
Geothermal	5,9	10,2	29,3	76,0	130,5	200,6
Biomass	49,3	84,8	156,4	223,7	371,3	495,4
CSP Plants	0,0	3,2	14,6	53,5	87,5	111,5
Wave / Tidal	0,0	2,6	10,4	24,1	42,6	66,7
Hydropower	615,8	642,3	668,8	695,3	721,8	748,3
Oil	195,4	152,2	111,8	58,0	8,8	0,0
Gas	528,9	720,0	797,6	910,2	823,5	431,9
Coal	1000,6	1031,5	1031,1	955,6	744,0	362,0
Nuclear	970,1	804,2	537,5	259,7	62,3	0,0
Import Solar	0,0	0,0	60,0	231,0	473,0	707,5
Total	**3389**	**3628**	**3940**	**4233**	**4327**	**4058**

Table 2-8: Electricity generation in TWh/y in the analysed countries in the TRANS-CSP scenario

Year	2000	2010	2020	2030	2040	2050
Wind	12,8	73,9	196,3	254,0	272,5	276,6
Photovoltaics	0,2	3,7	21,5	63,5	94,6	122,3
Geothermal	0,8	1,4	4,1	12,0	24,3	41,2
Biomass	10,8	19,0	35,6	52,7	95,4	138,6
CSP Plants	0,0	0,8	2,3	8,2	13,8	18,8
Wave / Tidal	0,0	0,6	2,6	6,0	10,6	16,7
Hydropower	190,3	203,5	214,1	224,1	228,8	235,7
Oil	64,0	55,0	42,8	29,6	3,3	0,0
Gas	136,9	197,6	261,7	314,3	328,7	259,4
Coal	210,4	205,7	192,0	171,1	127,7	58,6
Nuclear	137,8	115,0	77,5	37,3	8,7	0,0
Import Solar	0,0	0,0	11,5	38,7	69,3	102,2
Total Capacity	**763,9**	**876,3**	**1062,0**	**1211,4**	**1277,7**	**1270,0**

Table 2-9: Installed capacity in GW in the analysed countries in the TRANS-CSP scenario

The external costs caused by the damages of power generation to health and the environment are accepted to be in the order of 3-8 cents/kWh with increasing trend, together with the expenses for military and intelligence to secure the remaining global fossil energy resources mainly in the Middle East and North Africa, and to protect the highly vulnerable energy supply infrastructure in Europe. External costs and direct energy subsidies for fossil and nuclear fuels add another 80 billion €/y to the real cost of fossil fuels for power generation in Europe (Chapter 4).

At the same time, many industrial countries as well as the strongly growing economies in transition, specially in Asia, exert an increasing pressure on the global fossil fuel resources, claiming their share of those energy reserves and driving prices further up. Some analysts predict a cost of 120 $/bbl for crude oil until 2030, and there is evidence that considerable cost escalation will affect the other primary energy sources as well /HWWA 2005/.

Escalating fossil fuel costs as well as European policies to reduce climate change will accelerate the expansion of renewable energy sources. Starting with 20 % renewables and 80 % fossil and nuclear power in the year 2000, the TRANS-CSP scenario leads to a transition to 20 % fossil fuels and 80 % renewables within the electricity supply of the year 2050 (Figure 2-25). By that time, the risky use of nuclear power will not be necessary any more.

The European countries show rather large potentials of hydropower, wind power and biomass and less potential for solar and geothermal power generation. This is due to the fact that PV, CSP and geothermal HDR production capacities are still very small today, and once they become visible after 2020, the electricity demand in Europe is already stagnating or retrogressive. Also, in comparison to the large power demand of this region, economic solar power potentials are relatively limited. Hydropower potentials are already used to a considerable extent today, and there is only a moderate growth for this technology in view. Biomass potentials are large in Europe, however there will be competing biomass applications in the heat and mobility sector, thus reducing the potentials for power generation. Wind power is a very strongly growing technology today, with several GW of capacity installed every year in Spain and Germany alone. By 2050 it will have the same share of electricity generation as hydropower.

Comparing the results of TRANS-CSP to the trends under current policies published recently by the European Commission's Greenpaper on Sustainable, Competitive and Secure Energy (Figure 2-27), we see a slightly lower growth of electricity demand in our scenario which is due to a higher exploitation of the potentials of rational use of energy and energy efficiency, specially in the new European countries.

We also have a higher content of renewables and natural gas in the year 2030, and less coal and nuclear power. This is due to the fact that increased shares of renewables – specially wind and PV – will primarily substitute base load capacities from nuclear and coal (non-regulative power), while on the other hand existing and additional intermediate/peaking capacities using natural gas will be required for the complementation of these resources.

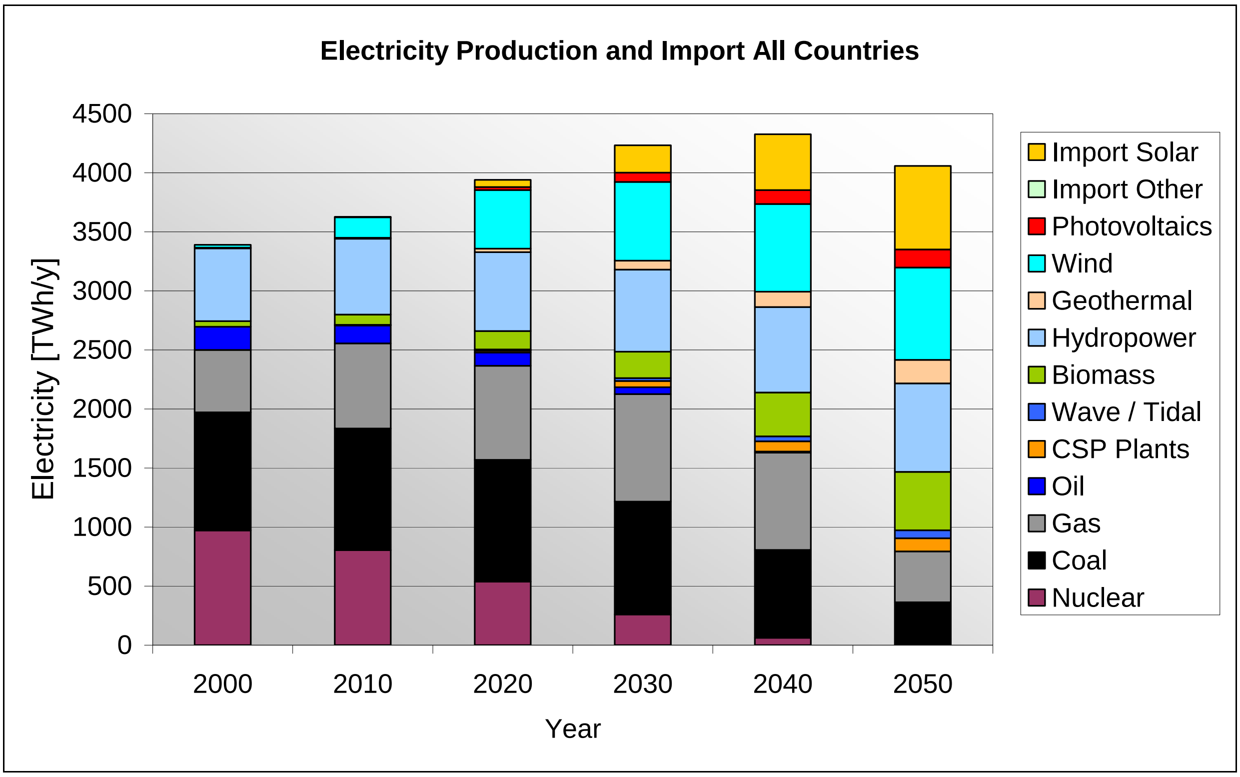


Figure 2-25: TRANS-CSP scenario of gross electricity production and import for the analysed European countries until 2050

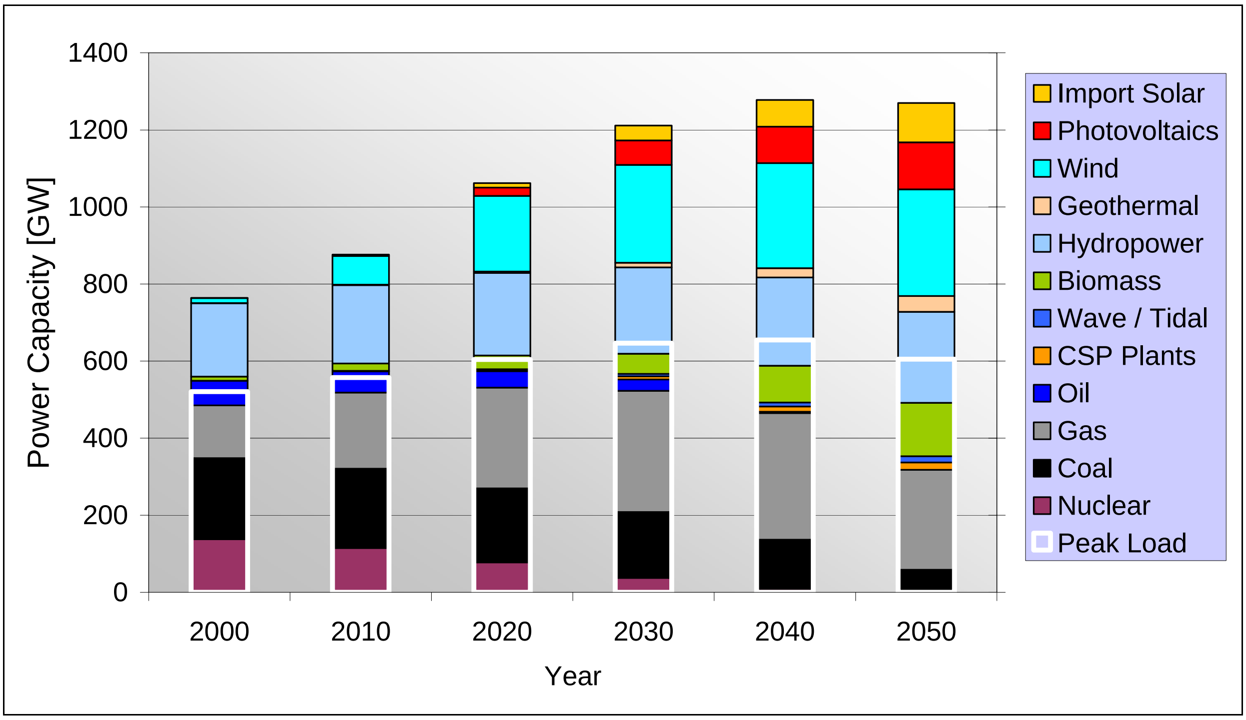


Figure 2-26: TRANS-CSP scenario for installed capacities and peak load for the analysed European countries

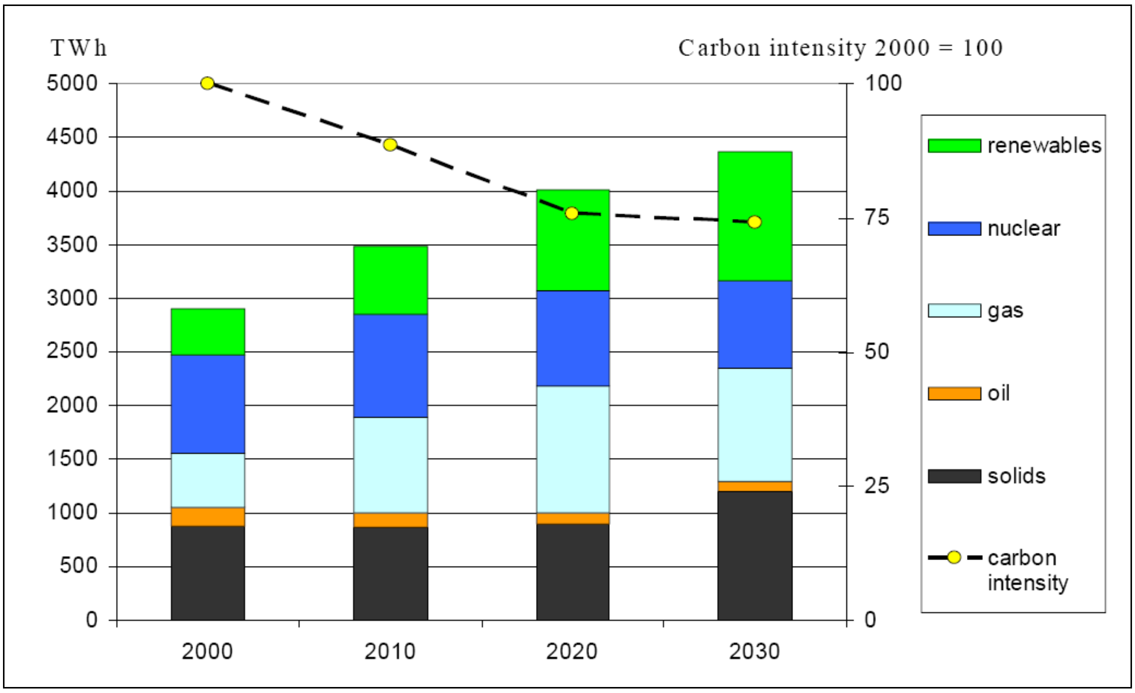


Figure 2-27: Electricity production by fuel and trends under current policies in the EU 25 according to the EU-Greenpaper for sustainable, competitive and secure energy /EU 2006/

European energy import dependency is a factor often discussed in the context of sustainability e.g. in the EU Green Paper /EU 2006/. Due to the subsequent depletion of the European domestic fossil and nuclear primary energy sources, imports are steadily growing, and concerns for the security of supply increase. Nuclear power is often mentioned as the solution of this dilemma, however European uranium resources are depleting as well – the EU 15 reserves are close to zero – and import dependency is expected to increase (Figure 2-28). This trend is reversed by the TRANS_CSP scenario after 2020 due to the improved use of domestic renewable energy sources. This will not only reduce the necessary energy imports, but will also prolong the useful lifetime of the remaining domestic fossil fuel resources in Europe.

The Need of Firm Power Capacity

To achieve the annual electricity production in Figure 2-25 the capacities shown in Figure 2-26 must be installed. It can be noted that the share of PV and wind capacities is higher in terms of installed capacity than in terms of electricity, which is due to the relatively low capacity factor (annual utilisation) of those technologies. For example, the installed PV capacities are comparable to those of biomass, but their annual electricity yield is only 20 % compared to that of the biomass plants. As a consequence, the ratio of the total installed capacity to peak power demand for the total power plant park increases from 1.5 in the year 2000 to 2.1 in the year 2050. Reserve capacities of about 25 % with respect to peak load are usually necessary to have enough reserves for the case of overhaul and failure of power plants in the present energy mix, but with the increasing use of wind and PV power, the over-capacities increase to 110 %.

The subsequently growing over-capacities in the scenario are due to the low capacity credit of PV and wind power, requiring other renewable or fossil backup plants to provide the necessary minimum firm capacity, which we have set to 125 % of the peaking demand in order to have a 25 % reserve.

It is a common misbelieve that for every wind park a conventional power plant of the same capacity must be installed and operated. The necessary peaking capacities remain more or less the same for the whole period until 2050. That means that the necessary peaking capacities to compensate the fluctuations of the PV and wind parks scheduled in the scenario already exist today. No considerable extra capacities must be installed, but the existing peaking capacities must be maintained. From the point of view of a peaking plant, it does not make any difference if the load fluctuates (as usual) or if the power delivered by another power plant fluctuates. The transients that must be compensated by peaking plants are just the same (Figure 2-29 and Figure 2-30), they just occur at another time. However, it is true that wind and PV plants do not replace other power plant capacities, they just reduce their fuel consumption. Wind and PV plants reduce the necessary operation time of other power plants, but they cannot replace their firm capacity.

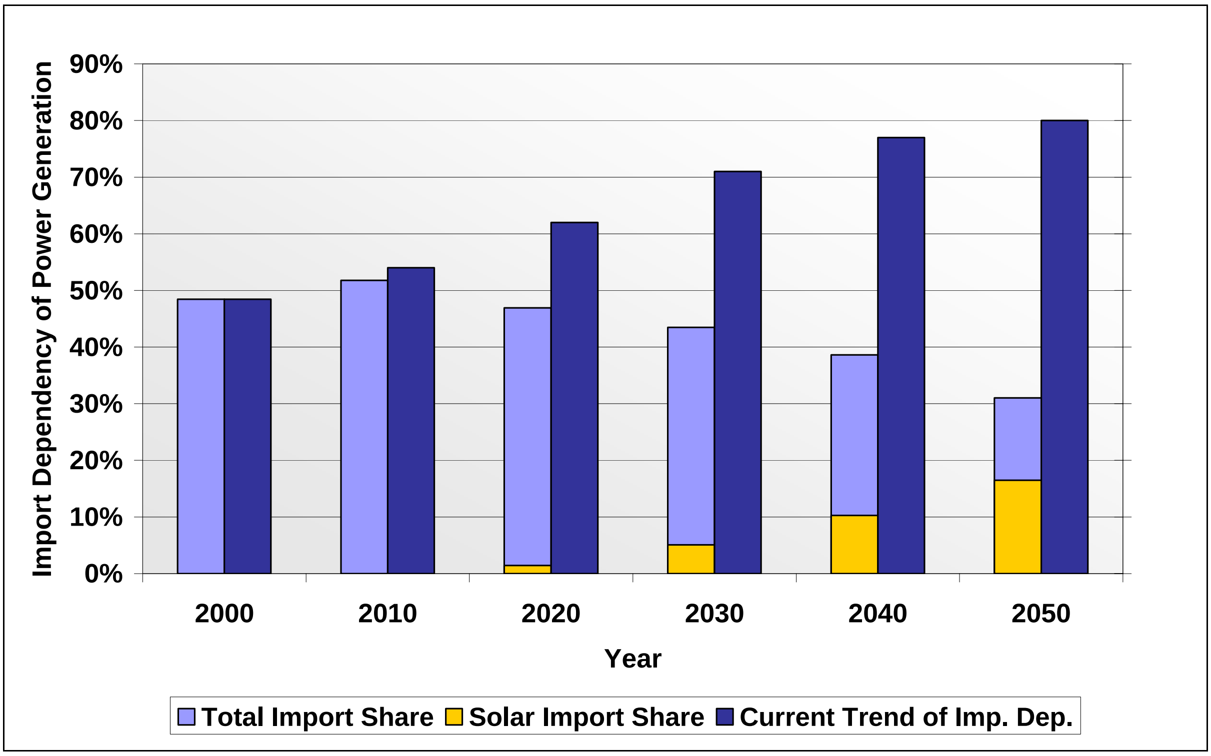


Figure 2-28: Total import share of power generation inclusive import from concentrating solar power from MENA in the TRANS-CSP scenario, versus the currently projected trend of import dependency of power generation in the EU according to /EU 2006/.

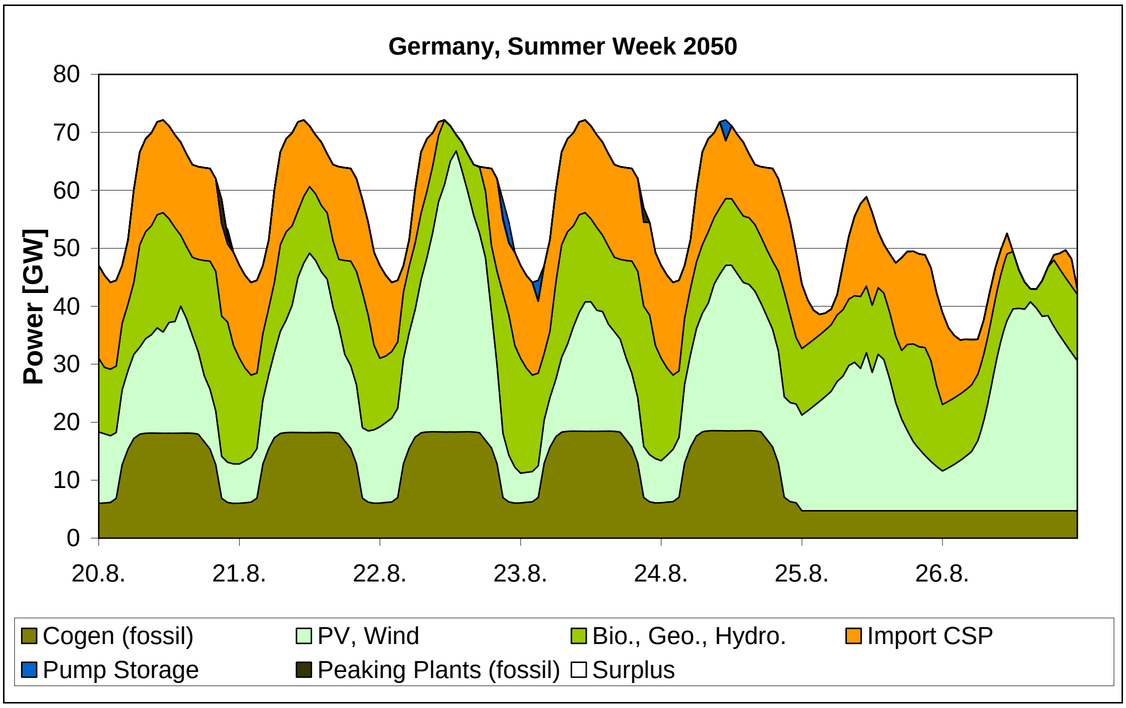


Figure 2-29: Hourly time series of power generation during a summer week in the year 2050 in Germany modelled in the TRANS_CSP scenario. For the other countries please refer to the Annex. Base load electricity is provided by cogeneration plants and by renewable sources. Fossil fuelled power is only required for peaking purposes. There is no functional window for conventional base load plants with constant capacity.

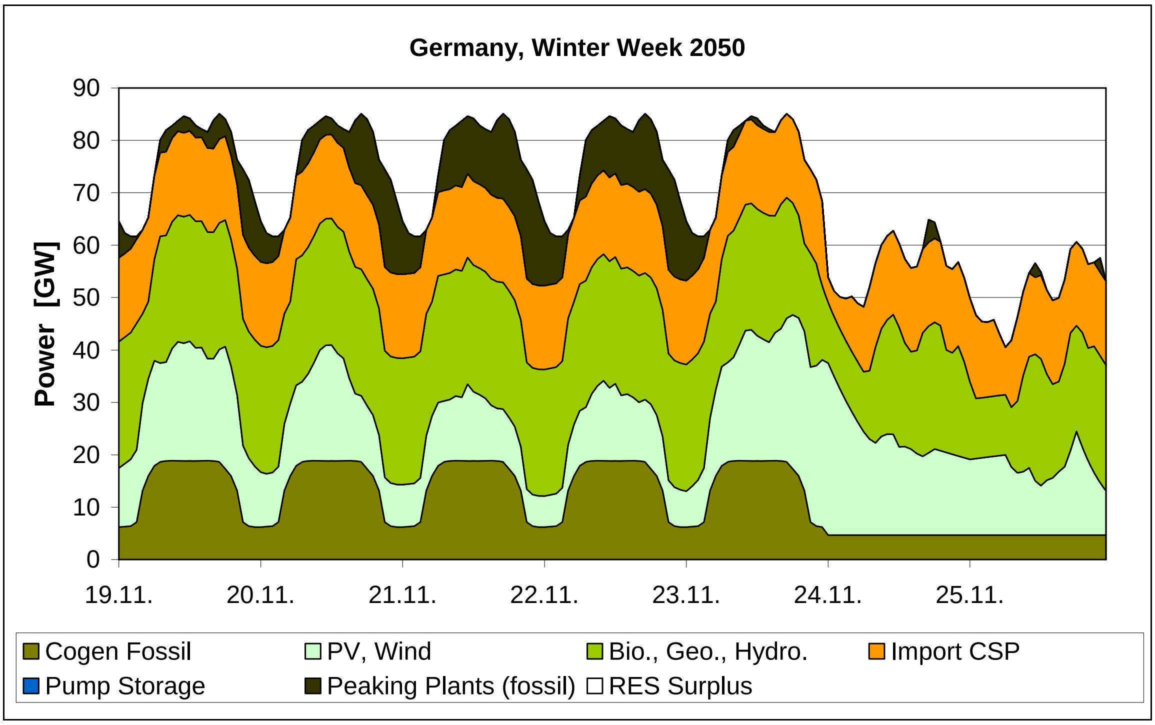


Figure 2-30: Hourly time series of power generation during a winter week in the year 2050 in Germany modelled in the TRANS-CSP scenario. For other countries please refer to the Annex. Base load electricity is provided by cogeneration plants and by renewable sources. Fossil fuelled power is only required for peaking purposes. There is no functional window for base load plants operating at constant power capacity.

As a consequence of the increasing share of renewable electricity generation, the need and usability of constant capacity base load plants will subsequently disappear until 2050 (Figure 2-29, Figure 2-30 and Figure 2-31). Base load demand will be covered mainly by co-generation, wind power, CSP import and photovoltaics, following the daily load curve instead of providing flat constant power.

Intermediate power will be supplied by hydropower storage, biomass, geothermal power, CSP and solar electricity imports. Peaking demand will be satisfied by pump storage, hydropower storage and fossil fuel based peaking plants. In the future, peaking times will differ significantly from the present peaking time defined solely by the load. Future peaking periods will rather be defined by the difference between load and fluctuating renewable electricity supply.

The conventional, fossil fuel fired power capacities remaining in 2050 will exclusively serve peaking duties and co-generation of heat and power. This is in line with the initially mentioned strategy of using those valuable, ideally storable primary energy sources exclusively for what they are best suited for, and not wasting them for quotidian use. Flat capacity base load plants fuelled by nuclear fission, fusion or lignite will not be able to function within such a mix, as they are not capable of following the transients to fill the gap between the partially fluctuating supply from cogeneration and renewables and the otherwise fluctuating demand. Gas driven plants will be the preferred choice for this purpose /Brischke 2004/.

There is a persistent myth claiming that renewables cannot provide base load electricity, as they are highly dispersed, fluctuating and unpredictable. The contrary is true: river-run-off, PV and wind plants can only provide base load capacity, but no peaking power. However, a well balanced mix of renewable and fossil plants can provide secure power on demand and at the same time save valuable fossil fuels that anyway should only be used for peaking. Considering that the electric load is the result of many dispersed, fluctuating and unpredictable elements - the consumers - it is little surprising that renewables and electric load fit fairly well to each other: they are related phenomena. Thus, inflexible, constant capacity base load plants fired by nuclear energy or lignite will totally disappear, as they will not be able to serve the remaining peaking demand. As their economic lifetime is about 40 years, this must be considered seriously for today’s investment decisions.

As described in /DENA 2005/, local problems may occur if e.g. large wind capacities are fed into a weak grid infrastructure, like e.g. at the coast line in Northern Germany. It must be considered that a wind park is a large centralised installation just like a hydropower, nuclear or coal plant, and of coarse such large amounts of electricity cannot be fed into a remote part of the grid, but must be connected to the large centres of demand via adequate transmission lines. This will be the case for large offshore and onshore wind parks as well as for large hydropower and solar schemes, just as it is the case for large nuclear, lignite or coal plants today. As described in

Chapter 1, this will be (and is already) solved by introducing HVDC technology to transfer power e.g. from large wind parks to the closest centres of demand.

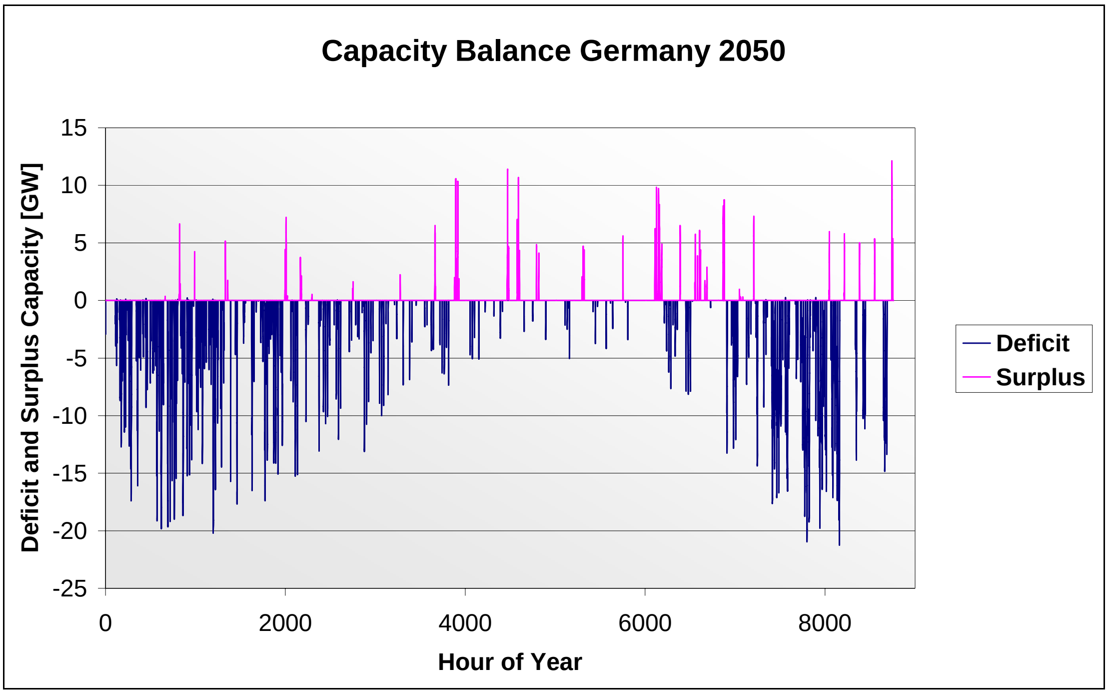


Figure 2-31: Balance of electricity load and renewables including co-generation for the German power park in 2050 calculated on the basis of hourly time series for the TRANS-CSP scenario. The surpluses are due to PV and wind power. A maximum deficit of about 22 GW must be covered by fossil fuelled peaking plants. At present, the available peaking capacity in Germany is about 35 GW.

With respect to sustainability, our scenario leads to a desirable goal, which is characterised by

- low cost of energy,
- low environmental impact,
- low conflict potential,
- access to new energy sources,
- fair distribution and access to energy,
- low risk and vulnerability,
- prolongation of fossil fuel resources,
- reduced energy import dependency,
- cost stability,
- enhanced energy supply security,
- enhanced international cooperation.

The wide-spread argument that renewables are too expensive has been proven wrong: in fact, they are the least cost option for energy sustainability. Initial investment is required to achieve a better and more affordable energy mix and to get rid of the open and hidden subsidisation of the power sector. An outstanding portfolio of technologies is available today to achieve that goal, and it is due time to initiate the broad application and expansion of those technologies in order to profit from their benefits as soon as possible, instead of subsequently burdening the national economies by the exploding costs of the obsolete energy supply schemes of the past century.

The scenario shows, that a sustainable mix of energy sources for power generation is possible not only for Europe as a total, but also for each of its single member states (ref. to Annex). The transition from today's fossil and nuclear fuel driven power schemes will take time. In spite of a fairly strong initial growth of renewables, considerable renewable electricity shares will not become visible before 2020 (ref. Figure 2-32 to Figure 2-34). However, as soon as industrial production capacities will have grown to a mature level, the share of renewable sources of energy will quickly increase, not only due to environmental concerns, but mainly due to economical reasons and security of supply. By 2050, a renewable electricity share of 80 % will be easily achieved, stabilizing electricity costs and relieving the environment, the global climate and the national economies from further pollution and subsidies. This development has already started in a few but not yet in all countries of Europe.

Table 2-10 quantifies the market volumes for fossil and renewable energy in the TRANS-CSP scenario. From the total demand and the total and renewable plant inventory in the year 2000, the market shares of renewable and fossil energy are calculated. The free market volume is the capacity of new plants that can be installed in the respective time span of 10 years, which is limited by new demand, replacement capacities and by the renewable and fossil capacities installed in the respective prior decade. The market share of renewables in 2004 accounted for 25 % /REN 2005/. Starting with 10 % in 2000, the scenario achieves relatively stable renewable market shares of around 50 % after 2020. On average, the renewable electricity market share grows by about 200 TWh/y each decade, reaching a market share of newly installed capacity of almost 1000 TWh/y equivalent to 80 % of the total power plant market volume in 2050.

Year		**2000**	**2010**	**2020**	**2030**	**2040**	**2050**
Total Plant Inventory 2000	TWh/y	3390	3004	2193	1239	581	203
Total Demand	TWh/y	3390	3628	3940	4233	4327	4058
Total Market Volume	TWh/y		624	1747	2994	3745	3855
Free Market Volume	TWh/y		624	1123	1247	1375	1233
Renewables Inventory 2000	TWh/y	695	695	695	695	581	203
Ren. Market Share	TWh/y		225	539	598	729	969
Ren. Market Share	%	**10%**	**36%**	**48%**	**48%**	**53%**	**79%**
Total Renewable Share	TWh/y	695	920	1459	2057	2672	3264
Total Renewable Share	%	**21%**	**25%**	**37%**	**49%**	**62%**	**80%**
Fossil Market Share	TWh/y		399	584	648	646	264
Fossil Market Share	%	**90%**	**64%**	**52%**	**52%**	**47%**	**21%**
Total Fossil Share	TWh/y	2695	2708	2481	2176	1654	795
Total Fossil Share	%	**79%**	**75%**	**63%**	**51%**	**38%**	**20%**

Table 2-10: Market statistics of the TRANS-CSP scenario. Renewable energy market shares in 2004 were reported 25 % of total electricity investment /REN 2005/.

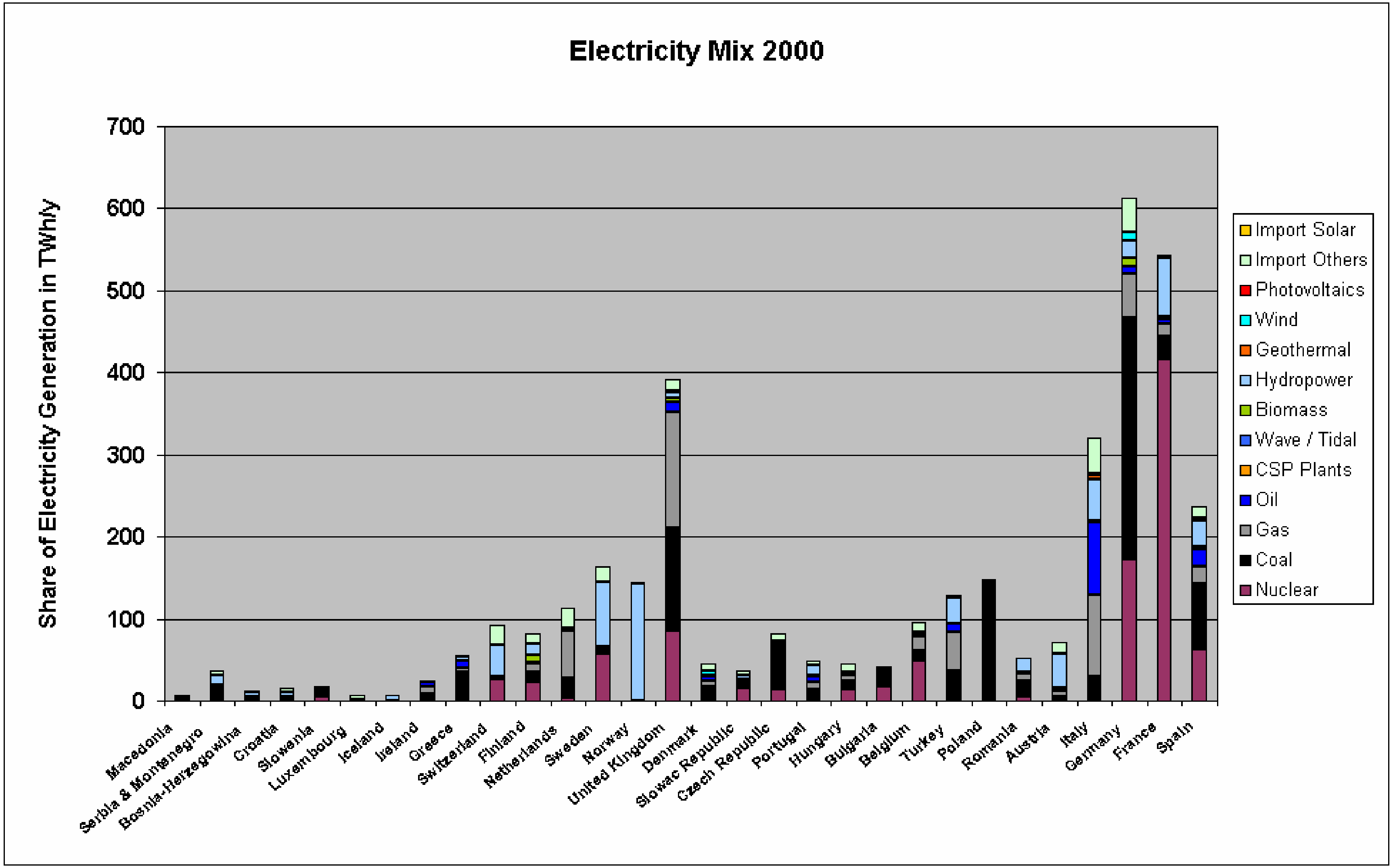


Figure 2-32: Starting point for the scenario: electricity generation in the analysed European countries in the year 2000 by resources /enerdata 2004/

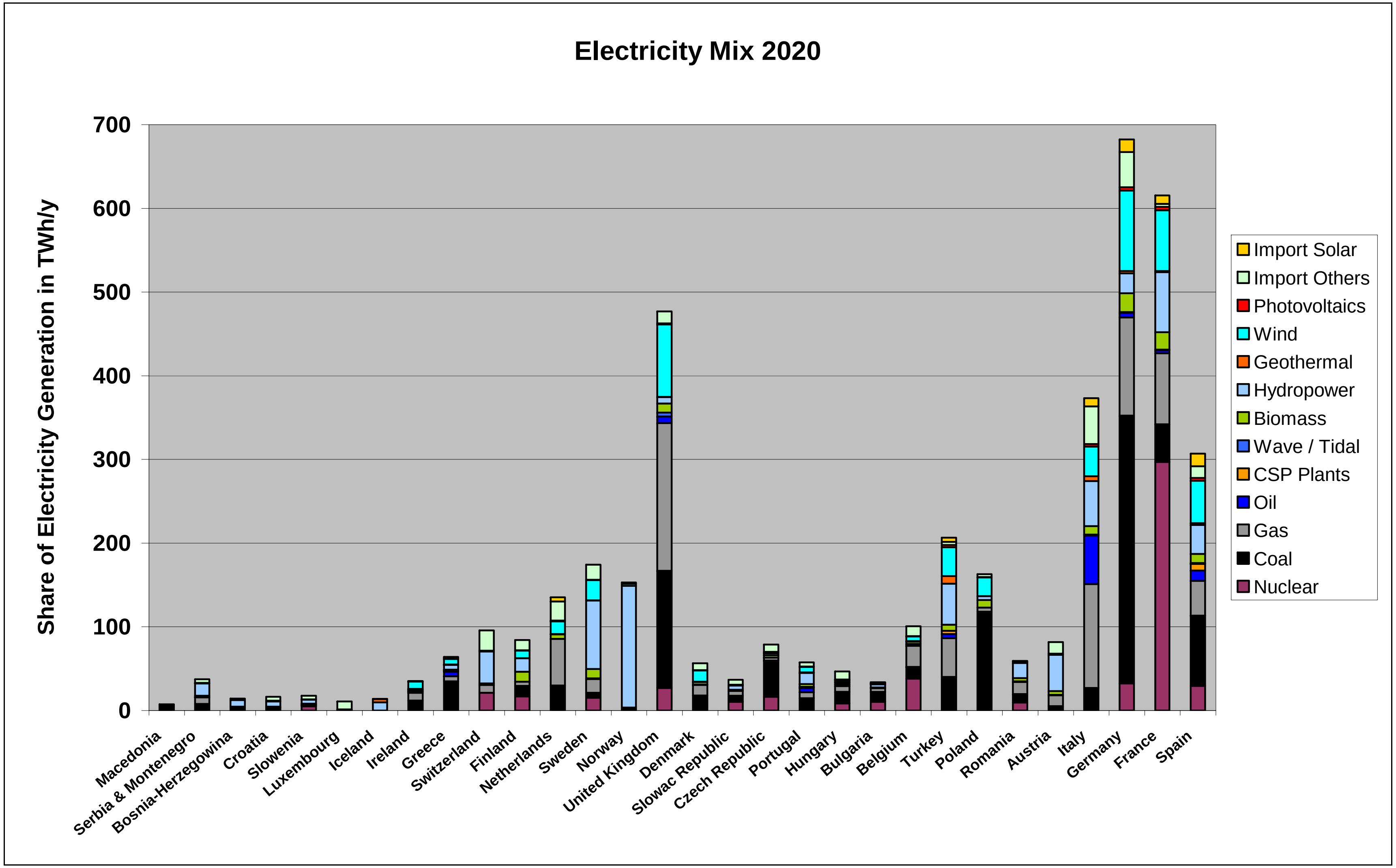


Figure 2-33: European electricity mix in 2020 in the TRANS-CSP scenario.

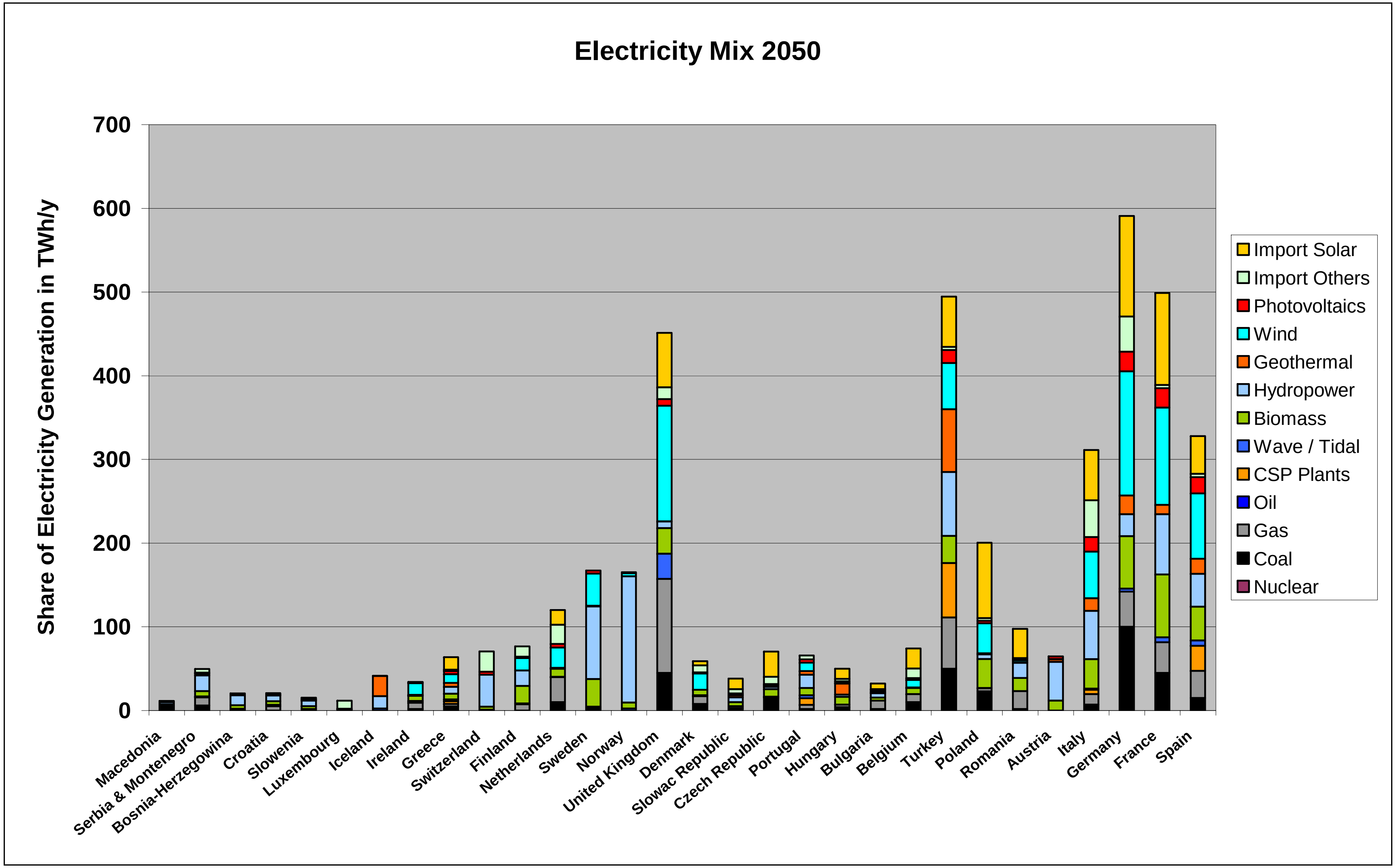


Figure 2-34: European electricity mix in 2050 in the TRANS-CSP scenario.

2.4 Market Potential for Solar Import Electricity

Solar electricity imports from North Africa to Europe through the conventional Alternate Current (AC) electricity grid will have only minor importance. With a transmission capacity of today 0.5 GW and a maximum 1-2 GW by 2020, such an interconnection would be capable of transmitting not more than about 5-10 TWh/y, which can be neglected in view of the total European electricity demand of roughly 3500 TWh/y.

For the transmission of large amounts of solar electricity from MENA to Europe, for the use of the hydropower storage capacities of Scandinavia and the Alps, as well as for the integration of large offshore wind parks, an intercontinental High Voltage Direct Current (HVDC) grid infrastructure will be necessary. Such a HVDC grid will interconnect the best sites for renewable electricity with the largest centres of demand. From there, electricity will be further distributed through the conventional AC grid. The planning and the international agreements necessary for such a large Trans-European infrastructure will easily take 15 to 20 years of time. Therefore, a transfer of solar electricity from MENA to Europe through HVDC cannot be expected considerably before 2020. Table 2-11 gives the potential of solar electricity imports of all countries analysed in the study (please refer to the Annex for country details).

Year		2020	2030	2040	2050
Transfer Capacity GW		2 x 5	8 x 5	14 x 5	20 x 5
Electricity Transfer TWh/y		60	230	470	700
Capacity Factor		0.60	0.67	0.75	0.80
Turnover Billion €/y		3.8	12.5	24	35
Land Area km x km	CSP HVDC	15 x 15 3100 x 0.1	30 x 30 3600 x 0.4	40 x 40 3600 x 0.7	50 x 50 3600 x 1.0
Investment Billion €	CSP HVDC	42 5	143 20	245 31	350 45
Elec. Cost €/kWh	CSP HVDC	0.050 0.014	0.045 0.010	0.040 0.010	0.040 0.010

Table 2-11: Main indicators of the total EUMENA High Voltage Direct Current (HVDC) interconnection and Concentrating Solar Power (CSP) capacities from 2020 – 2050 according to the TRANS-CSP scenario. In the final stage in 2050, 20 lines with a capacity of 5 GW each will transmit about 700 TWh/y of electricity from 20 different locations in the Middle East and North Africa (MENA) to the main centres of demand in Europe.

In the TRANS-CSP scenario we have assumed that the HVDC interconnections will be realised in units of 5 GW each. Connecting to those lines, power lines with lower capacity would be used. They will interconnect different sources of solar power generation in MENA with different centres of demand in Europe, as described in Chapter 1. In 2050, about 20 major links could be installed, with a total transfer capacity of 100 GW, equivalent to 7 % of the total installed power capacity in Europe by that time. With an average use of 7000 full load operating hours per year, these lines would transfer 700 TWh/y of solar electricity to Europe, with a value of 35 billion €/y at an average cost of 5 cents/kWh.

This cost is composed of 4 cents/kWh for solar electricity production by CSP plants in MENA and 1 cent/kWh for the transmission to Europe including electricity losses, capital cost and cost of operation, and assuming a discount rate of 5 %/y as for the other technologies. The total investment of this infrastructure would be 395 billion € between 2020 and 2050, that is an average of 10 – 15 billion € per year over that time span. The annual performance with 7000 full load hours per year and the specific investment including decommissioning of 4000 €/kW are both similar to the cost and performance of equivalent nuclear power plants. The relative land area consumed in MENA and Europe by the CSP and HVDC infrastructure is in the order of 0.03 %. Other environmental impacts are also low as described in Chapter 5.

As shown in the example in Figure 2-24, solar import electricity is one of the least cost options for electricity in Europe. It is attractive in terms of both economical and technological integration to the power park, as it provides firm power capacity for grid stability and control at very low cost. Just like natural gas or fuel oil, it can be used for base, intermediate and peaking power, in this context clearly beating other technologies like wind, PV and even nuclear power, that may be cheaper under very good conditions, but are also less worth.

The analysis shows that CSP electricity imports from MENA through HVDC lines are a valuable supplement of the future European power supply system. It will require considerable efforts in terms of finance, technology and international cooperation to realise such a large infrastructure, but similar to the introduction of interstate highways for transport and mobility, a Trans-European HVDC grid will create manifold synergetic effects for the benefit of the total European community and its neighbours in the South and East. Besides of being a requisite for the use and distribution of the best renewable energy sources of the region, such a grid will enhance the stability, capacity and redundancy of the European power supply system with considerable benefits for each of its member countries. Furthermore, it could be the physical basis for a Euro-Mediterranean Free Trade Area for Renewable Energy as described in Chapter 3.

For the analysis of the market potential of solar thermal electricity imports from MENA to Europe, it is important to define the market segments that shall be covered by this resource. Looking at a typical daily electricity load curve as in Figure 2-35, base load is traditionally covered by river run-off hydropower, nuclear power, lignite and coal (lately also gas fired combined cycle systems are used for this purpose), intermediate power is delivered by coal and gas fired plants and peaking load is covered by oil, gas and pump storage. Industrial power is fed to the grid if public load and industrial surplus – often from co-generation – coincide, it can therefore be considered as part of the base load segment, comparable to the slightly fluctuating, only partially controllable input of river run-off plants.

The base load segment summarises those sources that cannot easily be adapted to fluctuating load conditions, e.g. flat capacity nuclear and lignite plants, part of the coal plants, and river run-off plants. Intermediate load plants are turned on and shut down once per day, using for this purpose usually coal or gas plants and partially, if available, stored hydropower.

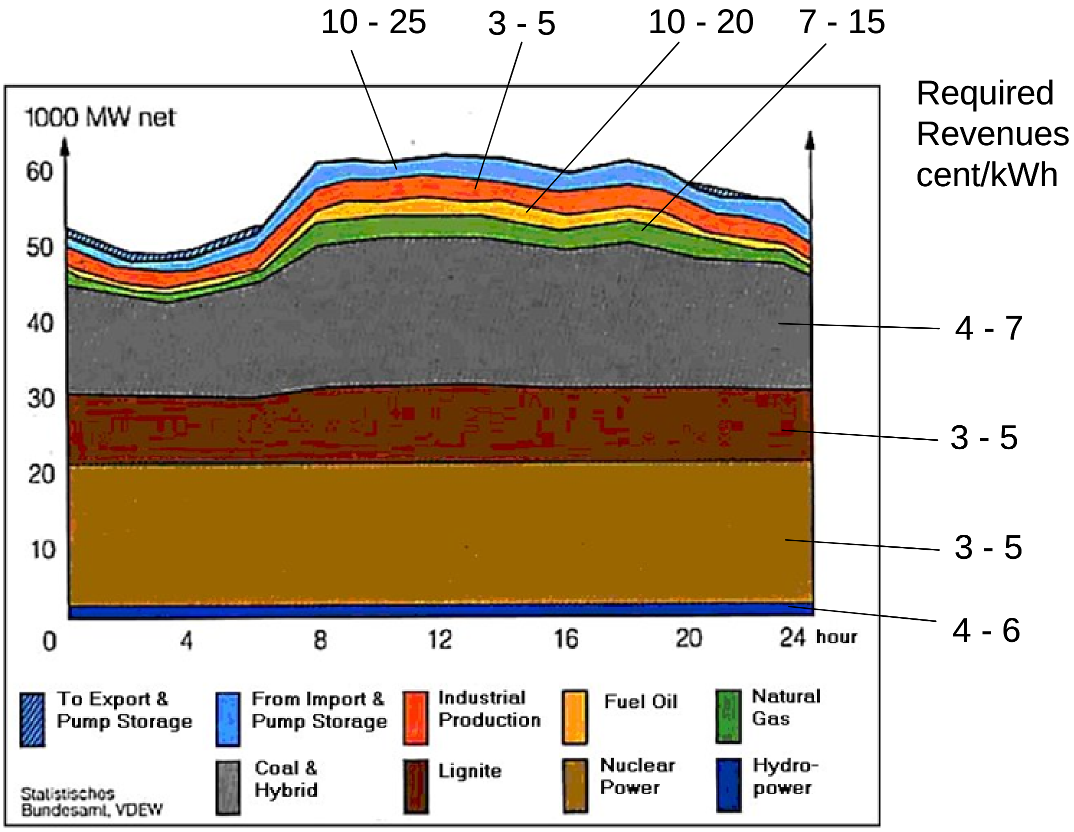


Figure 2-35: Coverage of a typical national daily load curve by conventional power technologies /VDEW 1990/ and the typical range of required revenues of each technology considering today's level of world market prices of oil (50 $/bbl), coal (65 $/t), natural gas (6 $/GJ), the different capacity factors in each market segment as explained in the text and a discount rate of 5 %/y (own calculations).

Peaking plants must react quickly to cover the remaining gap between the load and the other sources. Only hydro pump and dam storage, gas and oil plants are suited for this purpose.

The three market segments differ by their annual capacity factor and time of operation: peaking plants operate from several 100 to about 2000 hours per year, with a high share of part load operation, intermediate plants work 2000 to 5000 h/y, and base load plants typically 6000 to over 8000 h/y, mainly under full load conditions. Due to their different utilisation time, the electricity cost of peaking plants is usually much higher than that of base load plants, and so is their typical required revenue (Figure 2-35).

Spec. Invest. €/kW	2000	2010	2020	2030	2040	2050
Wind	1150	1058	956	908	859	832
Photovoltaics	5500	2830	1590	1250	1010	910
Geothermal	13093	5063	3631	3120	3018	2966
Biomass	2500	2000	1700	1670	1660	1650
CSP Plants	3052	3341	4595	4269	4125	4075
Wave / Tidal	3000	2500	2250	2100	2050	2000
Hydropower	1800	1800	1800	1800	1800	1800
Oil	1000	1000	1000	1000	1000	1000
Gas	450	450	450	450	450	450
Coal	1150	1150	1150	1150	1150	1150
Nuclear	4000	4250	4500	4750	5000	5250
Import Solar CSP			4200	3750	3550	3500
Import Solar HVDC			500	500	450	450

Table 2-12: Investment cost of power technologies including decommissioning discounted over lifetime

Electricity Cost c/kWh	2000	2010	2020	2030	2040	2050
Wind	7,7	6,8	6,1	5,8	5,4	5,2
Photovoltaics	36,7	16,9	8,6	6,6	5,3	4,8
Geothermal	17,5	6,8	4,8	4,8	5,5	5,9
Biomass	6,1	4,9	4,3	4,2	4,7	5,2
CSP Plants	17,6	12,2	7,5	6,7	6,2	6,6
Wave / Tidal	8,3	6,9	6,2	5,8	5,6	5,5
Hydropower	8,4	8,4	8,4	8,4	8,4	8,4
Oil	8,1	12,2	15,0	16,4	17,8	19,6
Gas	4,7	7,0	9,9	11,5	12,4	13,7
Coal	3,3	4,0	5,6	5,7	5,8	6,0
Nuclear	3,6	3,9	4,1	4,4	4,6	4,9
Solar Import Electricity			5,4	4,8	4,6	4,9
TRANS-CSP Average	**4,8**	**5,9**	**6,9**	**6,7**	**6,8**	**6,6**
Electricity Mix 2000	**4,8**	**5,7**	**6,8**	**7,2**	**7,6**	**8,0**

Table 2-13: Development of the electricity cost of new plants of different power technologies in the example of Spain on the basis of the investment cost development in Table 2-12 and the different performance indicators representing each technology in each country following the TRANS-CSP scenario until 2050. From 2030 onwards, biomass, geothermal and CSP plants subsequently take over peaking duties, which is the reason for their cost elevation. Peaking power is also supplied by natural gas fired plants. Coal and gas fired combined cycle plants are mainly used for cogeneration. Oil and nuclear plants are faded out in most countries. For comparison a business as usual scenario was calculated, assuming that the growing demand is covered by an electricity mix like in the year 2000.

Looking at the different market segments of electricity, each technology competes with a certain set of competing technologies, as shown in Table 2-14. Applicability in different market segments is an advantage, as it allows for higher revenues for a specific technology, and also for a larger potential market. In the long term CSP imports achieve the same cost as nuclear power, in spite of the fact that nuclear power is scheduled to operate 8400 h/y in flat base load, while CSP is operating only an average 5600 h/y, subsequently taking over increasing peak load duties in the electricity mix, which is not possible by nuclear power.

Segment	Source / Technology	Min. Rev. ct/kWh	Max. Rev. ct/kWh
Peak Power	Pump Hydro Storage	10	25
	Fuel Oil		
	Gas Turbine		
	Biomass		
	Geothermal		
	CSP		
Intermediate Power	Coal	5	12
	Gas Combined Cycle		
	CSP		
	Biomass		
	Geothermal		
Base Load	Coal	3	6
	Lignite		
	Nuclear		
	River Run-Off		
	Gas Combined Cycle		
	Co-generation		
	Wind		
	Photovoltaics		
	CSP		
	Geothermal		

Table 2-14: Technologies and range of required revenues in the different electricity market segments

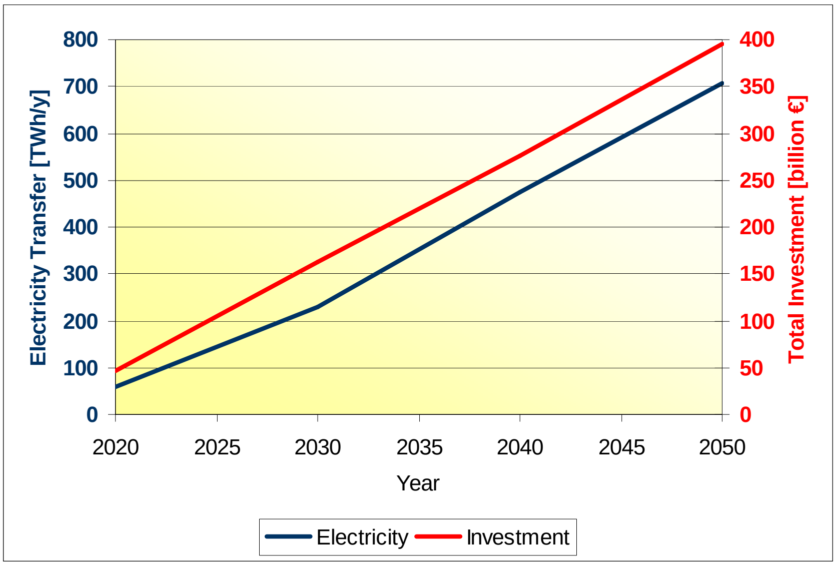


Figure 2-36: European market potential for solar import electricity from MENA based on CSP generation and HVDC transmission as described in Chapters 1 and 2.

With the exception of the vast hydropower storage resources in Norway, CSP imports and geothermal (HDR) power plants are the only renewable sources that can operate in all three segments of the power market, while others like lignite, nuclear, PV and wind power can only operate within the base load segment. The only conventional sources capable of operating in all three segments, too, and thus the natural competitors of CSP imports and geothermal power would be natural gas and oil, both being clearly more expensive by that time, even under the conservative cost estimate for oil and gas assumed here.

Solar import electricity is the best option to fill the respective market segment. If not realised in the proposed time, this market segment will have to be covered by fossil resources due to the need of firm power capacity in the electricity mix. Once installed, fossil plants will block that market segment for their lifetime beyond 2050. Wind, European CSP and PV power will not be able to cover the demand for firm capacity. Hydropower, biomass and geothermal power potentials are already used to a large extent, and doubling their electricity output would require the exploitation of all three resources completely up to their limits. Due to the fact that many of the hydropower and geothermal resources are relatively concentrated in a few regions, especially in Iceland, this will also require to connect those regions via HVDC to the European centres of demand /Knies et al. 1999/. This would be a reasonable complement, but not a realistic substitute for solar electricity imports from MENA. The higher diversity of supply, the extensive solar electricity potential and its low cost remain very good reasons for solar power import.

2.5 Solar Power for Europe – Water and Development for MENA

As proposed recently by the Trans-Mediterranean Renewable Energy Cooperation /TREC 2006/, concentrating solar thermal power stations in MENA could be used for export electricity to Europe as well as for providing regional freshwater from combined thermal desalination of sea water. The electricity produced in CSP plants can be used for domestic needs and export, as well as for additional desalination of sea water through reverse osmosis (RO), if required (Figure 2-37). The design of such combined solar power and desalination plants can be flexibly adapted to any required size and need. The advantages of this concept lay at hand:

- outstanding overall conversion efficiency of over 80 % for both solar heat and fuel,
- outstanding economic efficiency through the second valuable product freshwater,
- energy, water and income for the sustainable development of arid regions.

This concept may provide a key solution for the pressing freshwater deficits in the Middle East and North Africa, as reported by many sources /MED-CSP 2005/, /FAO 2003/, /Al-Zubari 2002/. In this chapter, we have analysed the potential of combining CSP exports to Europe with local sea water desalination for the MENA region.

At present, the countries of the Middle East and North Africa suffer from a freshwater deficit of about 60 billion cubic meters per year, equivalent to the average annual volume of the Nile River. In view of the growing population and economy of the MENA region, this deficit will increase to about 165 billion m^3/y by 2050, if no measures are taken at time to prevent such a disastrous situation (Figure 2-38).

Today, this deficit is poorly covered by over-exploitation of groundwater resources and by the desalination of sea water using fossil fuel resources (Figure 2-39). It is a question of only one or two decades, that most groundwater resources will be depleted and desalination by fossil fuels will have become too expensive for quotidian use. The only solution is the extended desalination of sea water by a sustainable and affordable energy source, supported by enhanced water management and by a more efficient use of water with increased reuse of wastewater and enhanced municipal water treatment.

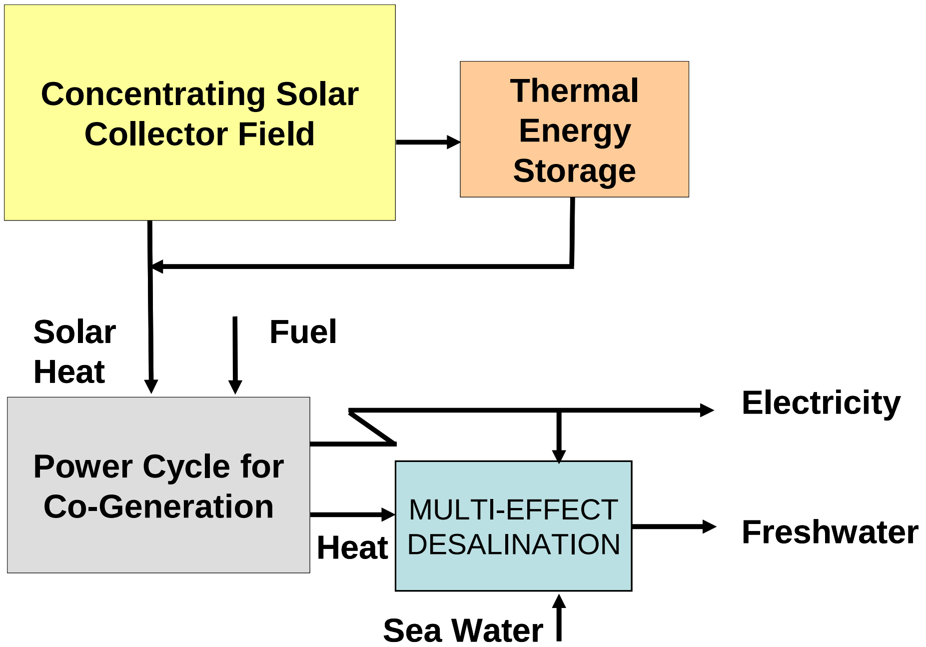


Figure 2-37: Principle of a concentrating solar power station with combined thermal sea water desalination. The generated electricity can be used for domestic needs, export and for desalination via reverse osmosis.

Nether energy nor water are scarce in MENA, looking at the large seawater bodies and the infinite solar energy resources available in this region. The use of CSP for combined power and desalination is economically attractive, as recently confirmed by a first pilot project of this type in Jordan /SolWater 2006/. The cost of desalted water from such plants will range between 1.5 and 0.5 €/m³.

Combined solar power and desalination plants will not only be able to tackle the challenges related to a sustainable energy supply at low cost, but also those related to clean water and to the conservation of productive soils. In the world's arid regions, such plants could become the nucleus of a totally new social paradigm: the conservation and recuperation of land endangered by desertification, comparable to the conservation and recuperation of land flooded by the sea in the Netherlands. Providing power, water, shadow and foreign exchange from the export of green power and revived agriculture, such multi-purpose plants could provide all what is needed to effectively combat desertification and to regain land for human settlement and agriculture that otherwise would be lost to the desert (Figure 2-40, Figure 2-41).

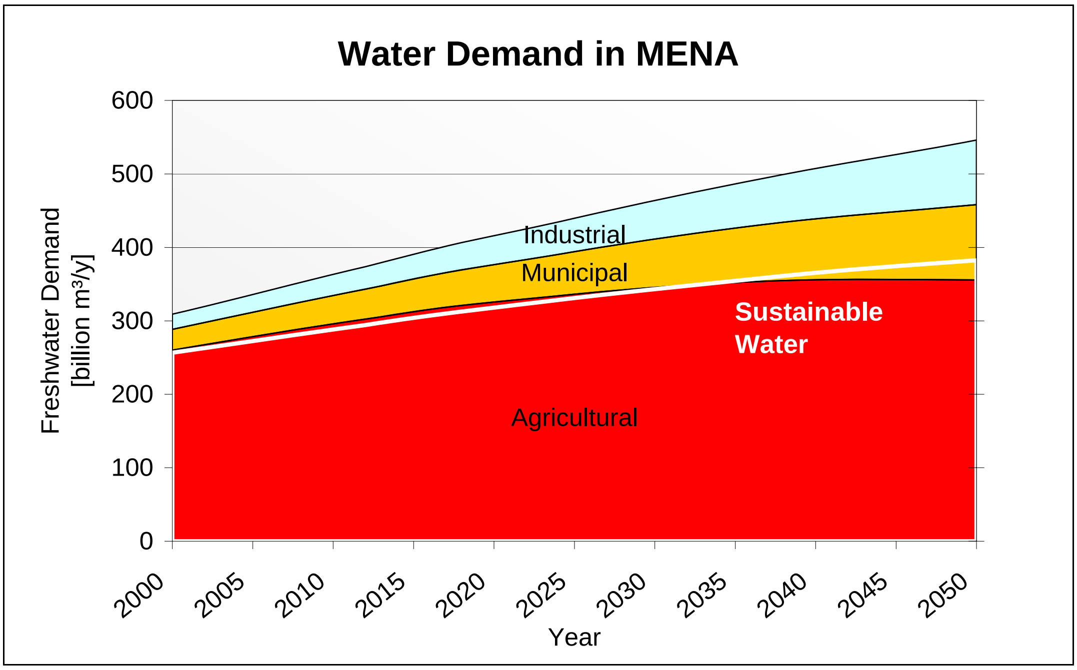


Figure 2-38: Freshwater demand for agriculture, industrial and municipal use in MENA in comparison to the renewable freshwater resources available in this region (white line). At present, the deficit of roughly 60 billion cubic meters per year is covered by overexploitation of groundwater resources and by desalination using fossil fuels /MED-CSP 2005/.

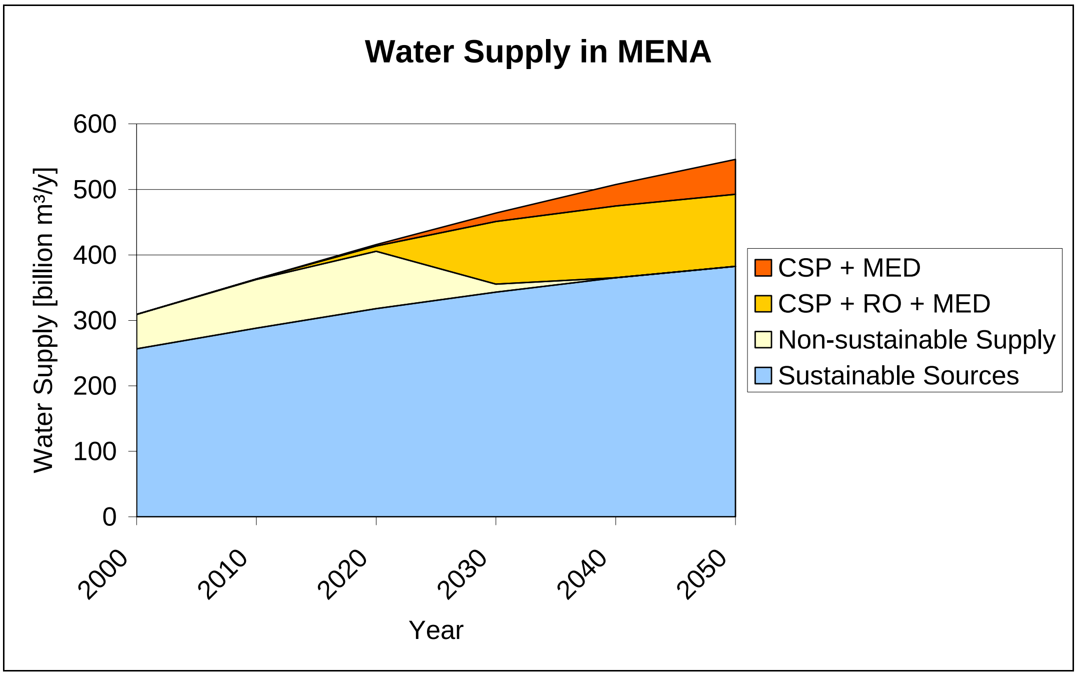


Figure 2-39: Water supply scenario for MENA /MED-CSP 2005/. Non-sustainable supply is based on over-exploitation of groundwater and desalination based on fossil fuel. The present deficit will augment until 2020. Then, CSP production capacities will be large enough to take over part of the necessary demand, partially by multi-effect thermal desalination combined with domestic and export electricity (CSP + MED), and mainly by CSP plants designed exclusively for water desalination, using electricity for Reverse Osmosis (RO) and combined heat for thermal Multi-Effect Desalination (CSP + RO + MED).

Arable land resources in the MENA region and globally are disappearing at a speed of several hectares per minute /IUCN 2006/. Concentrating solar multipurpose plants in the margins of the desert could generate solar electricity for domestic use and export, freshwater from seawater desalination, and in addition provide shade for agriculture and other human activities. Such plants could turn waste land into arable land and create labour opportunities in the agriculture and food sector. Tourism and other industries could follow. Desertification could be stopped. Other decentralised renewable energy sources could also come to use in those newly developed regions, like e.g. photovoltaics, solar thermal collectors, wind energy and biomass.

Solar energy and salt water are unlimited resources if used in a way compatible with environmental and socio-economic constraints. The economic figures of most renewable forms of energy indicate clearly that within a manageable time span they will become much more cost effective than fossil fuels. Renewable energy sources are the least cost option for energy and water security in the MENA region. With increasing electricity intensity in a developing world, their importance will steadily grow, being only limited by demand, and not by resources.

The combination of export solar electricity with sea water desalination will have only a moderate contribution to the coverage of the water deficit, because CSP exports will start relatively late, compared to the extremely pressing situation in the water sector (Figure 2-39). Therefore, CSP plants exclusively producing water with reverse osmosis (RO) and thermal multi-effect desalination (MED) will provide the core of the desalination capacity in MENA.

In the year 2050, a maximum 30 billion m^3/y could be desalted by about 40 % of the installed CSP export plants, covering roughly 20 % of the freshwater deficit. 25 billion m^3/y would be desalted by domestic CSP plants, while 110 billion m^3/y must be desalted by exclusive CSP desalination plants with RO and MED, and by other sustainable sources, that have not been quantified here separately. A detailed evaluation of the CSP desalination potential in MENA will be assessed in the AQUA-CSP study scheduled for 2006/2007, commissioned by the German Federal Ministry for the Environment and projected as a follow up investigation on the MED-CSP and TRANS-CSP studies.

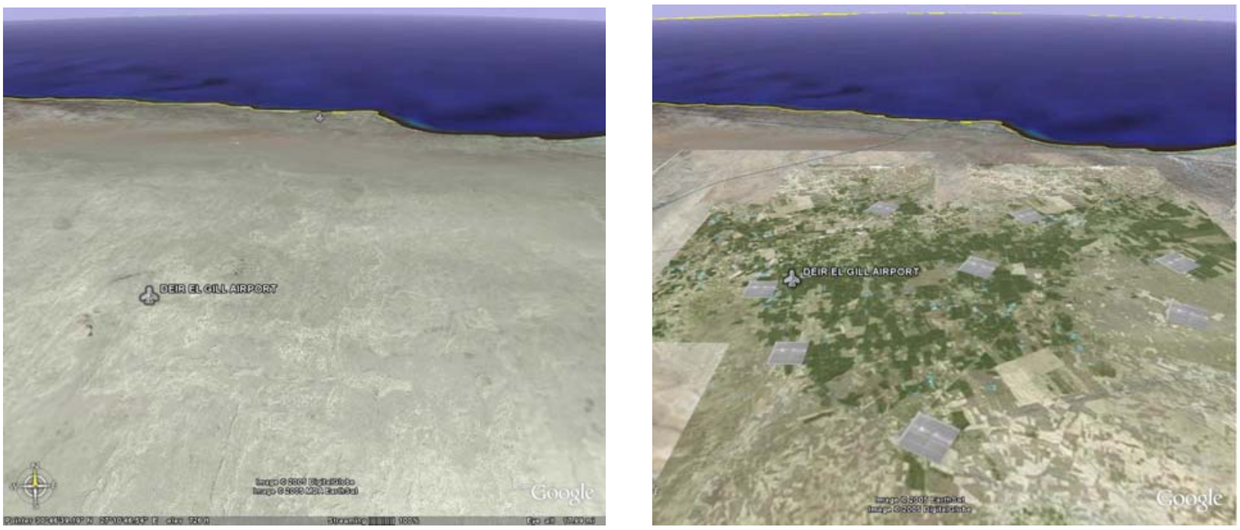


Figure 2-40: Left: typical region at the Mediterranean coast in Northern Egypt from Google Earth (left). Right: artist impression of the same region with large CSP plants for power and desalination connected to the national utility grid and to a trans-continental HVDC link that could be a key for the economic development of desert regions along the coasts of the Mediterranean Sea, the Red Sea and the Persian Gulf.

Figure 2-41: Photo of the top of a Linear Fresnel Concentrating Solar Collector and artist view of a greenhouse installed underneath to protect the plants from excessive irradiance and evaporation. This could be a concept for multi-purpose plants for power, water and horticulture. Other local uses include shade for parking and the production of steam for cooling and process heat. Source: Solarmundo, DLR)