

# **EARTH & SPACE-BASED POWER GENERATION SYSTEMS A COMPARISON STUDY**

## **ANNEX**

**A Study for ESA Advanced Concepts Team**

Contract No: 17682/03/NL/EC To ESTEC

Final Report  
LBST Consortium



**TNO**



January 2005



## **Contractors**

Volker Blandow, Patrick Schmidt, Werner Weindorf, Martin Zerta, Werner Zittel  
**L-B-Systemtechnik GmbH**  
Ottobrunn / Germany  
[www.lbst.de](http://www.lbst.de)

Marco C Bernasconi  
**MCB Consultants**  
Dietikon / Switzerland

Patrick Q Collins  
**Space Future Consulting**  
Northampton / UK  
[www.spacefuture.com](http://www.spacefuture.com)

Thomas Nordmann, Thomas Vontobel  
**TNC Consulting AG**  
Erlenbach / Switzerland  
[www.tnc.ch](http://www.tnc.ch)

Joëlle Guillet  
**Université de Neuchâtel**  
Neuchâtel / Switzerland  
[www.unine.ch](http://www.unine.ch)



## ANNEX CONTENT

Annex Content.....	i
A1 System aspects.....	1-1
1.1 Solar potentials.....	1-1
1.1.1 Photovoltaics (PV).....	1-3
1.1.2 Solar thermal potentials.....	1-21
1.2 Power transmission .....	1-22
1.2.1 High voltage alternating current .....	1-22
1.2.2 High voltage direct current .....	1-23
1.3 Energy storage technologies.....	1-27
1.3.1 Batteries.....	1-27
1.3.2 Hydrogen .....	1-31
1.3.3 Pumped hydro storage.....	1-38
1.3.4 Compressed air storage .....	1-40
1.3.5 Flywheel .....	1-41
1.3.6 Super / ultra capacitors .....	1-42
1.3.7 Super-conducting magnetic energy storage.....	1-43
1.3.8 Thermal storage.....	1-44
A2 WP1 – Terrestrial and space background data.....	2-45
2.1 Terrestrial scenario data .....	2-45
2.1.1 Scenario 0.5 GW .....	2-45
2.1.2 Scenarios 5 GW.....	2-46
2.1.3 Scenario 10 GW .....	2-47
2.1.4 Scenario 50 GW .....	2-48
2.1.5 Scenario 100 GW .....	2-49
2.1.6 Scenario 500 GW .....	2-50
2.2 Space reference systems.....	2-51
2.2.1 Selection of 'Sun Tower' concept for 0.5 GW scenario.....	2-51
2.2.2 Selection of 'Solar Disk' concepts for 5 GW, 10 GW, 50 GW, 100	

	GW, 150 GW and 500 GW scenarios .....	2-54
	2.2.3 Costs split of SPS systems.....	2-56
A3	Launch – Fuel costs.....	3-59
	3.1 Hydrogen .....	3-59
	3.2 Oxygen .....	3-61
	3.3 Total fuel cost.....	3-62
A4	WP3 – Combination.....	4-63
	4.1 Substitution of terrestrial storage .....	4-63
A5	WP4 – Energy payback times.....	5-64
A6	Possible environmental impacts of effects from space transportation .....	6-77

## A1 SYSTEM ASPECTS

In this chapter, background data on system aspects are given.

### 1.1 Solar potentials

Sun zone 0 covers the countries along the Mediterranean coastal line of North Africa (Algeria, Egypt, Libya, Morocco, Tunisia). Sun zone 0 is the zone with the highest irradiation values in the course of a whole year. The annual solar irradiation of zone 0 countries is enlisted in Table 1-1.

Country	Solar Irradiation (Reference Data)	Source
Algeria	1700 - 2400 kWh/m <sup>2</sup> /a	[VanWijk 1994]
Egypt	1700 - 2400 kWh/m <sup>2</sup> /a	[VanWijk 1994]
Libya	1700 - 2400 kWh/m <sup>2</sup> /a	[VanWijk 1994]
Morocco	1700 - 2200 kWh/m <sup>2</sup> /a	[VanWijk 1994]
Tunisia	1700 - 1900 kWh/m <sup>2</sup> /a	[VanWijk 1994]

Table 1-1: Solar irradiation in sun zone 0 countries (North Africa)

Sun zone 1 comprises the countries in the European sunbelt – these are Portugal, Spain, Italy, Greece and Turkey. Especially Turkey provides large potentials on high solar irradiation.

Country	Solar Irradiation (Reference Data)	Source
Cyprus	1700 kWh/m <sup>2</sup> /a	[VanWijk 1994]
Malta	1700 kWh/m <sup>2</sup> /a	[VanWijk 1994]
Portugal	1700 kWh/m <sup>2</sup> /a	[VanWijk 1994]
Turkey	1700 kWh/m <sup>2</sup> /a	[VanWijk 1994]
Spain	1600 kWh/m <sup>2</sup> /a	[VanWijk 1994]
Greece	1500 kWh/m <sup>2</sup> /a	[VanWijk 1994]
Italy	1300 kWh/m <sup>2</sup> /a	[VanWijk 1994]

Table 1-2: Solar irradiation in sun zone 1 countries (European sunbelt)

Sun zone 2 subsumes the rest of Europe without the countries in the European sunbelt.

Country	Solar Irradiation (Reference Data)	Source
Romania	1400 kWh/m <sup>2</sup> /a	LBST/[PV-GIS]
Bulgaria	1300 kWh/m <sup>2</sup> /a	LBST/[PV-GIS]
Austria	1200 kWh/m <sup>2</sup> /a	[VanWijk 1994]
France	1200 kWh/m <sup>2</sup> /a	[VanWijk 1994]
Hungary	1200 kWh/m <sup>2</sup> /a	LBST/[PV-GIS]
Slovenia	1200 kWh/m <sup>2</sup> /a	LBST/[PV-GIS]
Switzerland	1200 kWh/m <sup>2</sup> /a	[VanWijk 1994]
Belgium	1000 kWh/m <sup>2</sup> /a	[VanWijk 1994]
Czech Republic	1000 kWh/m <sup>2</sup> /a	LBST/[PV-GIS]
Denmark	1000 kWh/m <sup>2</sup> /a	[VanWijk 1994]
Germany	1000 kWh/m <sup>2</sup> /a	[VanWijk 1994]
Ireland	1000 kWh/m <sup>2</sup> /a	[VanWijk 1994]
Latvia	1000 kWh/m <sup>2</sup> /a	LBST/[PV-GIS]
Lithuania	1000 kWh/m <sup>2</sup> /a	LBST/[PV-GIS]
Luxembourg	1000 kWh/m <sup>2</sup> /a	[VanWijk 1994]
Poland	1000 kWh/m <sup>2</sup> /a	LBST/[PV-GIS]
Slovakia	1000 kWh/m <sup>2</sup> /a	LBST/[PV-GIS]
The Netherlands	1000 kWh/m <sup>2</sup> /a	[VanWijk 1994]
UK	1000 kWh/m <sup>2</sup> /a	LBST/[PV-GIS]
Estonia	900 kWh/m <sup>2</sup> /a	LBST/[PV-GIS]
Finland	900 kWh/m <sup>2</sup> /a	[VanWijk 1994]
Norway	900 kWh/m <sup>2</sup> /a	[VanWijk 1994]
Sweden	900 kWh/m <sup>2</sup> /a	[VanWijk 1994]
Island	800 kWh/m <sup>2</sup> /a	[VanWijk 1994]

Table 1-3: Solar irradiation in sun zone 2 countries (rest of Europe)

### 1.1.1 Photovoltaics (PV)

As a first approach only the roof area has been considered for PV installations. In the course of this study the countries Portugal, Spain, Italy, Greece and Turkey (European sunbelt) have been selected for PV installations. The roof area was derived from [VanWijk 1994]. The total roof area in the selected countries is approximately 4,300 km<sup>2</sup> <sup>1</sup>.

Table 1-4 enlists basic data for each of the European sunbelt's country. The distribution of PV installations is performed according to these data sets.

	Portugal	Spain	Italy	Greece	Turkey
Area [km2]	92,345	504,782	301,336	131,957	779,452
Inhabitants [Mio]	10.0	41.1	57.9	10.6	66.2
<b>Distribution [%]</b>	<b>5.4</b>	<b>22.1</b>	<b>31.2</b>	<b>5.7</b>	<b>35.6</b>
Living in cities [%]	66	78	67	60	76
Living in cities [Mio]	6.6	32.1	38.8	6.4	50.3
<b>Distribution [%]</b>	<b>4.9</b>	<b>23.9</b>	<b>28.9</b>	<b>4.7</b>	<b>37.5</b>
BIP [Mia \$]	\$109	\$588	\$1,124	\$121	\$168
<b>Distribution [%]</b>	<b>5.2</b>	<b>27.9</b>	<b>53.3</b>	<b>5.7</b>	<b>7.9</b>
BIP/person [\$]	\$10,900	\$14,300	\$19,390	\$11,430	\$2,530
<b>Distribution [%]</b>	<b>18.6</b>	<b>24.4</b>	<b>33.1</b>	<b>19.5</b>	<b>4.3</b>
Electricity Demand [GWh/a]	38,300	220,100	320,900	53,500	125,600
<b>Distribution [%]</b>	<b>5.1</b>	<b>29.0</b>	<b>42.3</b>	<b>7.1</b>	<b>16.6</b>
Electricity Demand/person [kWh/Capita/a]	3,821	5,353	5,538	5,051	1,896
<b>Distribution [%]</b>	<b>17.6</b>	<b>24.7</b>	<b>25.6</b>	<b>23.3</b>	<b>8.8</b>
Roof area [km2]	246	780	1,690	271	1,337
<b>Distribution [%]</b>	<b>5.7</b>	<b>18.0</b>	<b>39.1</b>	<b>6.3</b>	<b>30.9</b>
Roof area/person [m2/Capita]	24.6	19.0	29.2	25.6	20.2
<b>Distribution [%]</b>	<b>20.7</b>	<b>16.0</b>	<b>24.6</b>	<b>21.6</b>	<b>17.0</b>

Table 1-4: Basic data of countries selected for PV installations [Eurostat 2003], [VanWijk 1994], [Weltalmanach 2004]

Table 1-5 shows the technical data of typical PV plants today and future projections for efficiency improvements. The performance ratio includes the efficiency of the DC/AC converter and other losses (e.g. caused by cabling). The performance ratio represents the average efficiency of the DC/AC inverter and the balance of system (BOS) components in the course of one year of operation.

<sup>1</sup> In [VanWijk 1994] the horizontally projected roof area which is equivalent to the module area has been indicated for the selected countries. The horizontally projected roof area indicated in [VanWijk 1994] (1,350 km<sup>2</sup>) has been traced back to the total roof area (~4,300 km<sup>2</sup>) in the selected countries using the assumptions indicated in [VanWijk 1994]. The reason for this approach was that the assumptions such as inclination of the roofs and maximal allowable south west or south east orientation of the roofs used in this study are slightly different to those in [VanWijk 1994].

Module Type	2003				2030
	Efficiency <sup>2</sup> [%]	Performance Ratio (PR) [-]	Availability [%]	Solar irradiance @ STC [kW/m <sup>2</sup> ]	Efficiency <sup>2</sup> [%]
Mono- and Polycrystalline	14	0.7-0.8	95	1	21
Thin Film	8	0.7-0.8	95	1	14

Table 1-5: Technical data PV plants and future projections

If the efficiency of a state of the art crystalline PV module is assumed to be 14%<sup>2</sup> and the performance ratio ranges between 0.7 to 0.8 the net efficiency of the PV plant will be 9.8 to 11.1%. If the efficiency of a future crystalline PV module is assumed to be 21%<sup>2</sup> the net plant efficiency will range between 14.7 and 16.8%.

The inclination is corresponding to the latitude. The spacing between modules is required to evade shading. For the calculation of the required roof area the spacing between the modules have to be taken into account (flat roof: factor=2.5, sloped roof: factor=1.2). The ratio between flat roof area and sloped roof area is about 1:1 leading to an average spacing factor of 1.85. Further the inclination of the modules has to be considered which leads to a reduction of the spacing factor. Table 1-6 shows the calculation of the real spacing factor.

	Portugal	Spain	Italy	Greece	Turkey
Inclination of modules [°]	38	38	41	38	37
Reduction Factor for Area needed for modules because of inclination [-]	0.79	0.79	0.75	0.79	0.80
Factor for spacing between the modules [-]	1.85	1.85	1.85	1.85	1.85
Factor for spacing including the inclination of the modules [-]	1.46	1.46	1.40	1.46	1.48

Table 1-6: Calculation of the real spacing factor

---

<sup>2</sup>

as defined at the second workshop January 12, 2004 at ESTEC in Noordwijk

### Calculations:

All calculations for space requirements are based on assumptions made for 2003 (conservative approach). With the development of higher efficiencies, space requirements only decrease. Silicon PV technology as well as thin film PV technology were considered separately. The distribution factor for each country is calculated as follows:

$$f_i = \frac{1}{3} \cdot (X_{Pop} + X_{GDP} + X_{We})$$

Equation 1-1: Distribution of space requirements

where

$f_i$	distribution factor for country i
$X_{Pop}$	Share of population
$X_{GDP}$	Share gross domestic product
$X_{We}$	Share of electricity consumption

Having a look at the demand curve (Figure 1-1 shows the Turkey as example), it is clear that only if the production stays below the difference calculated of the relative maximum and the minimum it is possible to produce without having to use storage of any kind.

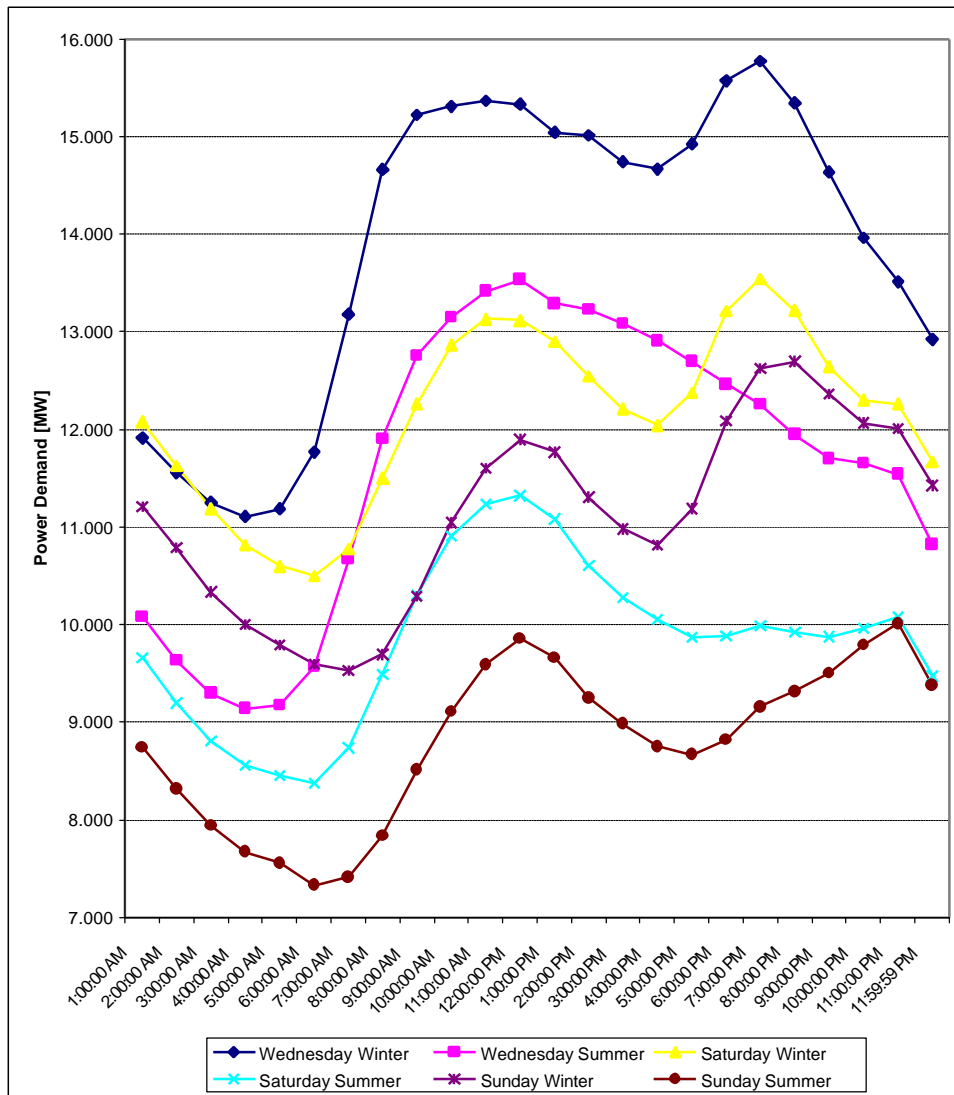


Figure 1-1: Example of hourly electricity demand in Turkey for various seasons and days of a week

The combination of the load curves lead to the load curve of the enlarged Europe in 2030 shown in Figure 1-2. The dotted lines mark the maximum hourly load minus the maximum power supply of the different scenarios.

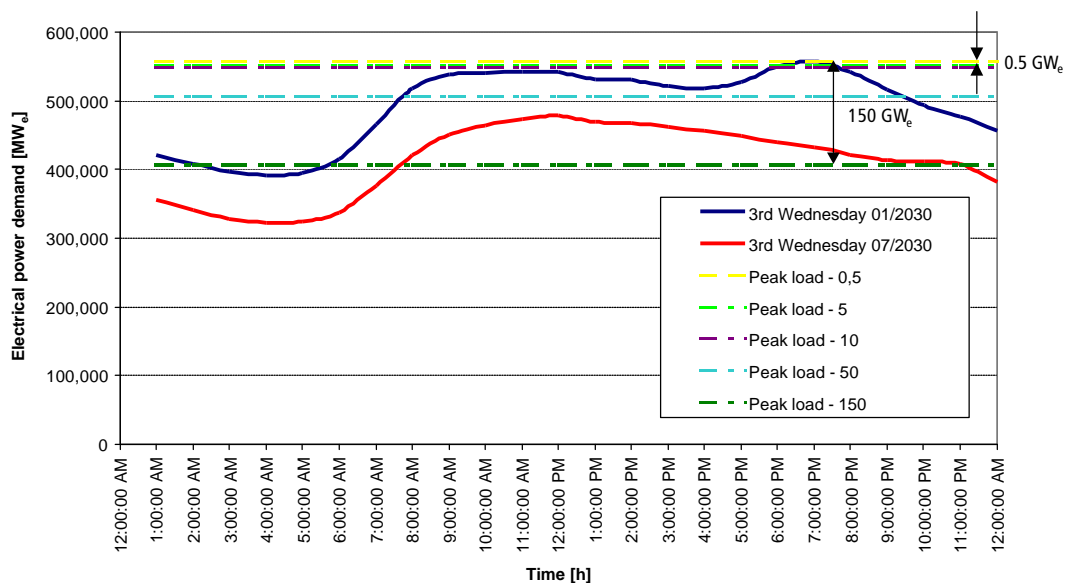


Figure 1-2: Hourly electricity demand 3<sup>rd</sup> Wednesday January and July of EU 2030 and non-base load scenario size

The equivalent full load period of power stations which supply non-base load electricity are very low. E.g. at 3<sup>rd</sup> Wednesday in January electricity would be supplied by the non-base load generation capacity only for less than one hour in case of the 0.5 GW peak load scenario.

To meet the electricity demand at any time, energy storage is required to level mismatches between supply and demand. Furthermore, the performance ratio of the PV plant has to be taken into account. Therefore the capacity of PV modules to be installed is different to that of the electric power requirement of the different scenarios. Figure 1-3 depicts the principles of dimensioning non-base load power plants.

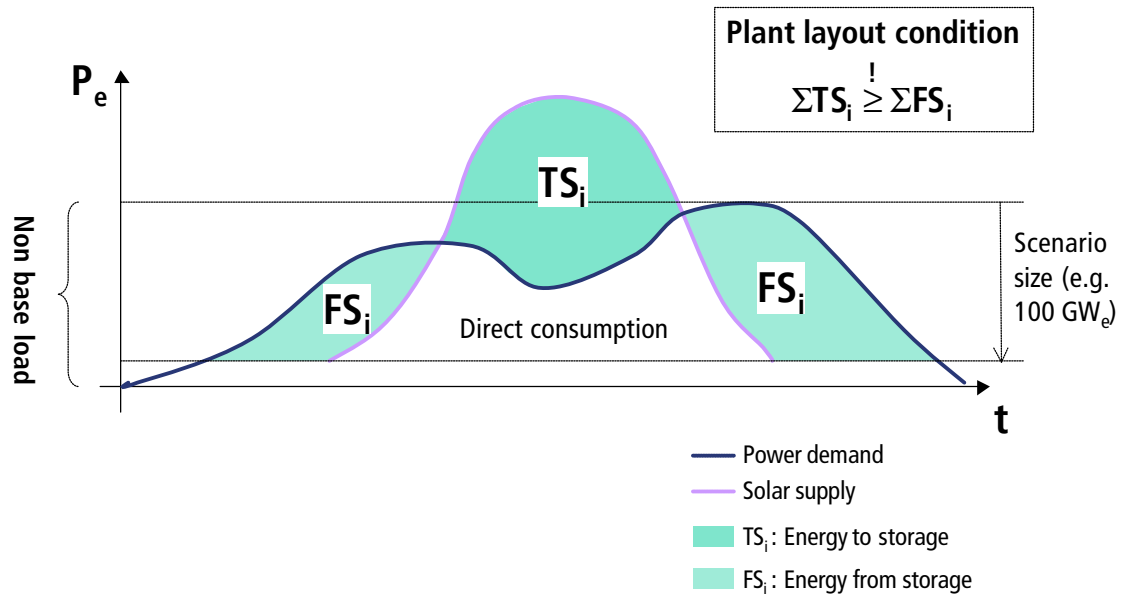


Figure 1-3: Principle of PV plant dimensioning for non-base load scenario calculation

a) **Non-base load scenario with hydrogen storage**

The results of non-base load PV plant dimensioning with hydrogen as energy storage are stated in Table 1-7.

Scenario size [GW]	Capacity fuel cell power plants [GW]	Capacity PV modules [GW <sub>p</sub> ]
0.5	0.5	0.0073
5	5	0.126
10	10	0.519
50	50	37
100	100	210
150	150	587

Table 1-7: Required PV capacity for the different scenarios with hydrogen storage

Regarding the 0.5 GW, 5 GW, 10 GW and 50 GW scenario the required PV capacity related to the output of the modules is lower than that of the power demand of the scenar-

ios because equivalent full load hours of the hydrogen fueled fuel cell is lower than that of the PV modules. The PV plants produce hydrogen at times when electricity demand is lower than the electricity supply. Hydrogen is then stored and converted back to electricity when electricity demand is below electricity supply.

Applying the country distribution factor leads to the required area for PV modules for each country in the European sunbelt as depicted in Table 1-8 and Table 1-9.

				Distribution-Factor for Portugal	Distribution-Factor for Spain	Distribution-Factor for Italy	Distribution-Factor for Greece	Distribution-Factor for Turkey
				0.05	0.26	0.42	0.06	0.20
		PV module		Thereof in Portugal [km2]	Thereof in Spain [km2]	Thereof in Italy [km2]	Thereof in Greece [km2]	Thereof in Turkey [km2]
Plant size [GW]	PV module total [m2]	area total [km2]						
Mono- and Polycrystalline Modules	0.0073	52,143	0.05	0.00	0.01	0.02	0.00	0.01
	0.126	900,000	0.90	0.05	0.24	0.38	0.06	0.18
	0.519	3,707,143	3.71	0.19	0.98	1.57	0.23	0.74
	37	264,285,714	264.29	13.76	69.61	111.66	16.29	52.97
	210	1,500,000,000	1,500.00	78.11	395.06	633.74	92.45	300.64
	587	4,192,857,143	4,192.86	218.33	1,104.28	1,771.46	258.42	840.37
Thin Film Modules	0.0073	91,250	0.09	0.00	0.02	0.04	0.01	0.02
	0.126	1,575,000	1.58	0.08	0.41	0.67	0.10	0.32
	0.519	6,487,500	6.49	0.34	1.71	2.74	0.40	1.30
	37	462,500,000	462.50	24.08	121.81	195.40	28.51	92.70
	210	2,625,000,000	2,625.00	136.69	691.35	1,109.05	161.79	526.13
	587	7,337,500,000	7,337.50	382.08	1,932.49	3,100.05	452.23	1,470.65

Table 1-8: Required module area to the different countries for the different scenarios with H<sub>2</sub> storage (efficiency mono and polycrystalline modules: 14%; efficiency thin film modules: 8%)

				Distribution-Factor for Portugal	Distribution-Factor for Spain	Distribution-Factor for Italy	Distribution-Factor for Greece	Distribution-Factor for Turkey
				0.05	0.26	0.42	0.06	0.20
		PV module		Thereof in Portugal [km2]	Thereof in Spain [km2]	Thereof in Italy [km2]	Thereof in Greece [km2]	Thereof in Turkey [km2]
Plant size [GW]	PV module total [m2]	area total [km2]						
Mono- and Polycrystalline Modules	0.0073	34,762	0.03	0.00	0.01	0.01	0.00	0.01
	0.126	600,000	0.60	0.03	0.16	0.25	0.04	0.12
	0.519	2,471,429	2.47	0.13	0.65	1.04	0.15	0.50
	37	176,190,476	176.19	9.17	46.40	74.44	10.86	35.31
	210	1,000,000,000	1,000.00	52.07	263.37	422.49	61.63	200.43
	587	2,795,238,095	2,795.24	145.55	736.19	1,180.97	172.28	560.25
Thin Film Modules	0.0073	52,143	0.05	0.00	0.01	0.02	0.00	0.01
	0.126	900,000	0.90	0.05	0.24	0.38	0.06	0.18
	0.519	3,707,143	3.71	0.19	0.98	1.57	0.23	0.74
	37	264,285,714	264.29	13.76	69.61	111.66	16.29	52.97
	210	1,500,000,000	1,500.00	78.11	395.06	633.74	92.45	300.64
	587	4,192,857,143	4,192.86	218.33	1,104.28	1,771.46	258.42	840.37

Table 1-9: Required module area to the different countries for the different scenarios with H<sub>2</sub> storage (efficiency mono and polycrystalline modules: 21%; efficiency thin film modules: 14%)

The inclination of the roof and the spacing between the modules lead to the required roof area presented in Table 1-10 and Table 1-11.

T O D A Y						
Capacity [GW]	Portugal [km <sup>2</sup> ]	Spain [km <sup>2</sup> ]	Italy [km <sup>2</sup> ]	Greece [km <sup>2</sup> ]	Turkey [km <sup>2</sup> ]	Total [km <sup>2</sup> ]
Mono and polycrystalline PV modules: efficiency: 14%						
0.0073	0.00	0.02	0.03	0.00	0.02	0.07
0.126	0.07	0.35	0.53	0.08	0.27	1.29
0.519	0.28	1.42	2.19	0.33	1.10	5.32
37	20.06	101.47	155.90	23.75	78.26	379
210	113.87	575.92	884.84	134.77	444.19	2,154
587	318.29	1,609.84	2,473.33	376.73	1,241.63	6,020
Thin film PV modules: efficiency: 8%						
0.0073	0.01	0.04	0.05	0.01	0.03	0.13
0.126	0.12	0.60	0.93	0.14	0.47	2.26
0.519	0.49	2.49	3.83	0.58	1.92	9.31
37	35.11	177.58	272.82	41.56	136.96	664
210	199.27	1,007.86	1,548.47	235.86	777.34	3,769
587	557.00	2,817.22	4,328.33	659.27	2,172.85	10,535

Table 1-10: Required roof area for the installation of PV modules when the spacing between the modules are taken into account with H<sub>2</sub> storage (today)

2 0 3 0						
Capacity [GW]	Portugal [km <sup>2</sup> ]	Spain [km <sup>2</sup> ]	Italy [km <sup>2</sup> ]	Greece [km <sup>2</sup> ]	Turkey [km <sup>2</sup> ]	Total [km <sup>2</sup> ]
Mono and polycrystalline PV modules: efficiency: 21%						
0.0073	0.00	0.01	0.02	0.00	0.01	0.05
0.126	0.05	0.23	0.35	0.05	0.18	0.86
0.519	0.19	0.95	1.46	0.22	0.73	3.55
37	13.37	67.65	103.93	15.83	52.18	253
210	75.91	383.95	589.89	89.85	296.13	1,436
587	212.19	1,073.23	1,648.89	251.15	827.75	4,013

2 0 3 0						
Capacity [GW]	Portugal [km <sup>2</sup> ]	Spain [km <sup>2</sup> ]	Italy [km <sup>2</sup> ]	Greece [km <sup>2</sup> ]	Turkey [km <sup>2</sup> ]	Total [km <sup>2</sup> ]
Thin film PV modules: efficiency: 14%						
0.0073	0.00	0.02	0.03	0.00	0.02	0.07
0.126	0.07	0.35	0.53	0.08	0.27	1.29
0.519	0.28	1.42	2.19	0.33	1.10	5.32
37	20.06	101.47	155.90	23.75	78.26	379
210	113.87	575.92	884.84	134.77	444.19	2,154
587	318.29	1,609.84	2,473.33	376.73	1,241.63	6,020

Table 1-11: Required roof area for the installation of PV modules when the spacing between the modules are taken into account with H<sub>2</sub> storage (2030)

Table 1-12, Table 1-14 and Table 1-14 shows the required usable roof area per capita in the different countries for the different scenarios.

Mono-/polycrystalline (T O D A Y)   Tthin film (2 0 3 0)					
Capacity PV modules [GW <sub>p</sub> ]	Portugal [m <sup>2</sup> /capita]	Spain [m <sup>2</sup> /capita]	Italy [m <sup>2</sup> /capita]	Greece [m <sup>2</sup> /capita]	Turkey [m <sup>2</sup> /capita]
0.0073	0.00	0.00	0.00	0.00	0.00
0.126	0.01	0.01	0.01	0.01	0.00
0.519	0.03	0.03	0.04	0.03	0.02
37	2.00	2.47	2.69	2.24	1.18
210	11.36	14.01	15.27	12.73	6.71
587	31.75	39.15	42.68	35.57	18.75

Table 1-12: Required useable area per capita for the installation of state-of-the-art mono and polycrystalline PV modules, respectively thin film PV modules with 2030 efficiencies for the different scenarios (either module efficiency: 14%)

Mono-/polycrystalline (2 0 3 0)					
Capacity PV modules [GW <sub>p</sub> ]	Portugal [m <sup>2</sup> /capita]	Spain [m <sup>2</sup> /capita]	Italy [m <sup>2</sup> /capita]	Greece [m <sup>2</sup> /capita]	Turkey [m <sup>2</sup> /capita]
0.0073	0.00	0.00	0.00	0.00	0.00
0.126	0.00	0.01	0.01	0.01	0.00

Mono-/polycrystalline (2 0 3 0)					
Capacity PV modules [GW <sub>p</sub> ]	Portugal [m <sup>2</sup> /capita]	Spain [m <sup>2</sup> /capita]	Italy [m <sup>2</sup> /capita]	Greece [m <sup>2</sup> /capita]	Turkey [m <sup>2</sup> /capita]
0.519	0.02	0.02	0.03	0.02	0.01
37	1.33	1.65	1.79	1.49	0.79
210	7.57	9.34	10.18	8.48	4.47
587	21.17	26.10	28.45	23.71	12.50

Table 1-13: Required useable roof area per capita for the installation of mono and polycrystalline PV modules in 2030 for the different scenarios (module efficiency: 21%)

Thin film (2 0 3 0)					
Capacity PV modules [GW <sub>p</sub> ]	Portugal [m <sup>2</sup> /capita]	Spain [m <sup>2</sup> /capita]	Italy [m <sup>2</sup> /capita]	Greece [m <sup>2</sup> /capita]	Turkey [m <sup>2</sup> /capita]
0.0073	0.00	0.00	0.00	0.00	0.00
0.126	0.01	0.01	0.02	0.01	0.01
0.519	0.05	0.06	0.07	0.06	0.03
37	3.50	4.32	4.71	3.92	2.07
210	19.88	24.51	26.72	22.27	11.74
587	55.57	68.52	74.69	62.25	32.81

Table 1-14: Required useable roof area per capita for the installation of thin film PV modules for the different scenarios (module efficiency: 8%)

The roof area per capita indicated above (Table 1-4) includes roofs looking to the north, east and the west. It has been assumed that only flat roofs and roofs looking to the south with a maximum deviation of +/- 15 degree. Then the share of the sloped roof area suitable for PV installations can be expected to be 1/12. It has been assumed that 50% of the roofs are flat roofs. To calculate the total roof area from the usable roof area the not usable roof area has to be taken into account by multiplying the usable roof area with  $1/(0.5+0.5*1/12)$ .

The roof area including the not usable roof area as shown in Table 1-15, Table 1-16 and Table 1-17 can be compared with the available roof area indicated in Table 1-4. The numbers for the required roof area per capita which are above the available roof area are marked **yellow**.

Mono-/polycrystalline (T O D A Y)   Thin film (2 0 3 0)					
Capacity PV modules [GW <sub>p</sub> ]	Portugal [m <sup>2</sup> /capita]	Spain [m <sup>2</sup> /capita]	Italy [m <sup>2</sup> /capita]	Greece [m <sup>2</sup> /capita]	Turkey [m <sup>2</sup> /capita]
0.0073	0.00	0.00	0.00	0.00	0.00
0.126	0.01	0.02	0.02	0.01	0.01
0.519	0.05	0.06	0.07	0.06	0.03
37	3.69	4.56	4.97	4.14	2.18
210	20.97	25.86	28.19	23.49	12.38
587	58.62	72.28	78.80	65.67	34.61

Table 1-15: Required roof area per capita for the installation of state-of-the-art mono and polycrystalline PV modules, respectively thin film PV modules in 2030 for the different scenarios including not usable roofs (either module efficiency: 14%):

Mono-/polycrystalline (2 0 3 0)					
Capacity PV modules [GW <sub>p</sub> ]	Portugal [m <sup>2</sup> /capita]	Spain [m <sup>2</sup> /capita]	Italy [m <sup>2</sup> /capita]	Greece [m <sup>2</sup> /capita]	Turkey [m <sup>2</sup> /capita]
0.0073	0.00	0.00	0.00	0.00	0.00
0.126	0.01	0.01	0.01	0.01	0.00
0.519	0.03	0.04	0.05	0.04	0.02
37	2.46	3.04	3.31	2.76	1.45
210	13.98	17.24	18.79	15.66	8.25
587	39.08	48.19	52.53	43.78	23.07

Table 1-16: Required area per capita for the installation of mono and polycrystalline PV modules in 2030 for the different scenarios including not usable roofs (module efficiency: 21%)

Thin film (2 0 3 0)					
Capacity PV modules [GW <sub>p</sub> ]	Portugal [m <sup>2</sup> /capita]	Spain [m <sup>2</sup> /capita]	Italy [m <sup>2</sup> /capita]	Greece [m <sup>2</sup> /capita]	Turkey [m <sup>2</sup> /capita]
0.0073	0.00	0.00	0.00	0.00	0.00
0.126	0.02	0.03	0.03	0.02	0.01
0.519	0.09	0.11	0.12	0.10	0.05
37	6.47	7.97	8.69	7.24	3.82
210	36.70	45.25	49.33	41.11	21.67
587	102.58	126.49	137.90	114.92	60.57

Table 1-17: Required area per capita for the installation of thin film PV modules for the different scenarios including not usable roofs (module efficiency: 8%)

The need of roof area per capita would exceed the available roof area for the 150 GW peak load scenarios with hydrogen storage for all types of PV modules. In case of today's thin film modules the requirement of roof area per capita would exceed the available roof area per capita for the 100 GW and for the 150 GW scenario. For state of the art crystalline silicon modules the available roof area per capita is sufficient for the 0.5 GW, 5 GW, 10 GW and the 50 GW scenario. In case of the 150 GW scenario the available roof area per capita in Spain would slightly be exceeded if state of the art crystalline silicon PV modules were used. For future crystalline silicon modules the available roof area is sufficient for the 0.5 GW, 5 GW, 10 GW, 50 GW and 100 GW scenario. As a result for the 150 GW scenario with hydrogen storage further areas have to be employed for PV installations such as noise barriers along of highways in any case.

**b) Non-base load scenario with pumped hydro storage**

In case of pumped hydro the requirement of PV capacity is lower because of the higher efficiency of electricity storage. The results of the dimensioning are stated in Table 1-18.

Scenario size [GW]	Capacity hydro electric turbine [GW]	Capacity PV modules [GW <sub>p</sub> ]
0.5	0.5	0.0031
5	5	0.053
10	10	0.218
50	50	17.6
100	100	107
150	150	306

Table 1-18: Required PV capacity for the different scenarios with pumped hydro storage

For the 0.5 GW, 5 GW, 10 GW and 50 GW scenario the required PV capacity related to the output of the modules is lower than that of the power demand of the scenarios because equivalent full load hours of the hydrogen fueled fuel cell is lower than that of the PV modules. The PV plants produce hydrogen which is stored and converted back to electricity when electricity is required.

Using the distribution factor (calculation see above) for the different countries leads to the required area for PV modules to the different countries as shown Table 1-19 and Table 1-20.

		Distribution-Factor for Portugal	Distribution-Factor for Spain	Distribution-Factor for Italy	Distribution-Factor for Greece	Distribution-Factor for Turkey		
		0.05	0.26	0.42	0.06	0.20		
Plant size [GW]	PV module area total [m <sup>2</sup> ]	PV module area total [km <sup>2</sup> ]		Thereof in Portugal [km <sup>2</sup> ]	Thereof in Spain [km <sup>2</sup> ]	Thereof in Italy [km <sup>2</sup> ]	Thereof in Greece [km <sup>2</sup> ]	Thereof in Turkey [km <sup>2</sup> ]
Mono- and Polycrystalline Modules	0.0031	22,143	0.02	0.00	0.01	0.01	0.00	0.00
	0.053	378,571	0.38	0.02	0.10	0.16	0.02	0.08
	0.218	1,557,143	1.56	0.08	0.41	0.66	0.10	0.31
	17.6	125,714,286	125.71	6.55	33.11	53.11	7.75	25.20
	107	764,285,714	764.29	39.80	201.29	322.91	47.11	153.19
	306	2,185,714,286	2,185.71	113.81	575.66	923.45	134.71	438.08
Thin Film Modules	0.0031	38,750	0.04	0.00	0.01	0.02	0.00	0.01
	0.053	662,500	0.66	0.03	0.17	0.28	0.04	0.13
	0.218	2,725,000	2.73	0.14	0.72	1.15	0.17	0.55
	17.6	220,000,000	220.00	11.46	57.94	92.95	13.56	44.09
	107	1,337,500,000	1,337.50	69.65	352.26	565.09	82.43	268.07
	306	3,825,000,000	3,825.00	199.18	1,007.40	1,616.04	235.75	766.64

Table 1-19: Required module area to the different countries for the different scenarios with pumped hydro storage (efficiency mono and polycrystalline modules: 14%; efficiency thin film modules: 8%)

		Distribution-Factor for Portugal	Distribution-Factor for Spain	Distribution-Factor for Italy	Distribution-Factor for Greece	Distribution-Factor for Turkey	
		0.05	0.26	0.42	0.06	0.20	
Plantsize [GW]	PV module		Thereof in Portugal [km <sup>2</sup> ]	Thereof in Spain [km <sup>2</sup> ]	Thereof in Italy [km <sup>2</sup> ]	Thereof in Greece [km <sup>2</sup> ]	Thereof in Turkey [km <sup>2</sup> ]
	PV module area total [m <sup>2</sup> ]	area total [km <sup>2</sup> ]					
Mono- and Polycrystalline Modules							
0.0031	14,762	0.01	0.00	0.00	0.01	0.00	0.00
0.053	252,381	0.25	0.01	0.07	0.11	0.02	0.05
0.218	1,038,095	1.04	0.05	0.27	0.44	0.06	0.21
17.6	83,809,524	83.81	4.36	22.07	35.41	5.17	16.80
107	509,523,810	509.52	26.53	134.19	215.27	31.40	102.12
306	1,457,142,857	1,457.14	75.88	383.77	615.63	89.81	292.05
Thin Film Modules							
0.0031	22,143	0.02	0.00	0.01	0.01	0.00	0.00
0.053	378,571	0.38	0.02	0.10	0.16	0.02	0.08
0.218	1,557,143	1.56	0.08	0.41	0.66	0.10	0.31
17.6	125,714,286	125.71	6.55	33.11	53.11	7.75	25.20
107	764,285,714	764.29	39.80	201.29	322.91	47.11	153.19
306	2,185,714,286	2,185.71	113.81	575.66	923.45	134.71	438.08

Table 1-20: Required module area to the different countries for the different scenarios with pumped hydro storage (efficiency mono and polycrystalline modules: 21%; efficiency thin film modules: 14%)

The inclination of the roof and the spacing between the modules lead to the required roof area presented in Table 1-21 and Table 1-22.

T O D A Y						
Capacity [GW]	Portugal [km <sup>2</sup> ]	Spain [km <sup>2</sup> ]	Italy [km <sup>2</sup> ]	Greece [km <sup>2</sup> ]	Turkey [km <sup>2</sup> ]	Total [km <sup>2</sup> ]
Mono and polycrystalline PV modules: efficiency: 14%						
0.0031	0.00	0.01	0.01	0.00	0.01	0.03
0.053	0.03	0.15	0.22	0.03	0.11	0.54
0.218	0.12	0.60	0.92	0.14	0.46	2.24
17.6	9.54	48.27	74.16	11.30	37.23	180
107	58.02	293.45	450.85	68.67	226.33	1,097
306	165.92	839.20	1,289.33	196.39	647.25	3,138
Thin film PV modules: efficiency: 8%						
0.0031	0.00	0.01	0.02	0.00	0.01	0.06
0.053	0.05	0.25	0.39	0.06	0.20	0.95
0.218	0.21	1.05	1.61	0.24	0.81	3.91
17.6	16.70	84.47	129.78	19.77	65.15	316
107	101.53	513.53	788.98	120.17	396.07	1,920
306	290.36	1,468.60	2,256.34	343.68	1,132.70	5,492

Table 1-21: Required roof area for the installation of PV modules when the spacing between the modules are taken into account with pumped hydro storage

2030						
Capacity [GW]	Portugal [km <sup>2</sup> ]	Spain [km <sup>2</sup> ]	Italy [km <sup>2</sup> ]	Greece [km <sup>2</sup> ]	Turkey [km <sup>2</sup> ]	Total [km <sup>2</sup> ]
Mono and polycrystalline PV modules: efficiency: 21%						
0.0031	0.00	0.01	0.01	0.00	0.00	0.02
0.053	0.02	0.10	0.15	0.02	0.07	0.36
0.218	0.08	0.40	0.61	0.09	0.31	1.49
17.6	6.36	32.18	49.44	7.53	24.82	120
107	38.68	195.63	300.56	45.78	150.89	732
306	110.61	559.47	859.56	130.92	431.50	2,092
Thin film PV modules: efficiency: 14%						
0.0031	0.00	0.01	0.01	0.00	0.01	0.03
0.053	0.03	0.15	0.22	0.03	0.11	0.54
0.218	0.12	0.60	0.92	0.14	0.46	2.24
17.6	9.54	48.27	74.16	11.30	37.23	180
107	58.02	293.45	450.85	68.67	226.33	1,097
306	165.92	839.20	1,289.33	196.39	647.25	3,138

Table 1-22: Required roof area for the installation of PV modules when the spacing between the modules are taken into account with pumped hydro storage

Table 1-23, Table 1-24 and Table 1-24 shows the required usable area per capita in the different countries for the different scenarios.

Mono-/polycrystalline (T O D A Y)   Thin film (2 0 3 0)					
Capacity PV modules [GW <sub>p</sub> ]	Portugal [m <sup>2</sup> /capita]	Spain [m <sup>2</sup> /capita]	Italy [m <sup>2</sup> /capita]	Greece [m <sup>2</sup> /capita]	Turkey [m <sup>2</sup> /capita]
0.0031	0.00	0.00	0.00	0.00	0.00
0.053	0.00	0.00	0.00	0.00	0.00
0.218	0.01	0.01	0.02	0.01	0.01
17.6	0.95	1.17	1.28	1.07	0.56
107	5.79	7.14	7.78	6.48	3.42
306	16.55	20.41	22.25	18.54	9.77

Table 1-23: Required useable roof area per capita for the installation of state-of-the-art mono and polycrystalline PV modules, resp. thin film PV modules in 2030 for the different scenarios (either module efficiency: 14%)

Mono-/polycrystalline (2 0 3 0)					
Capacity PV modules [GW <sub>p</sub> ]	Portugal [m <sup>2</sup> /capita]	Spain [m <sup>2</sup> /capita]	Italy [m <sup>2</sup> /capita]	Greece [m <sup>2</sup> /capita]	Turkey [m <sup>2</sup> /capita]
0.0031	0.00	0.00	0.00	0.00	0.00
0.053	0.00	0.00	0.00	0.00	0.00
0.218	0.01	0.01	0.01	0.01	0.00
17.6	0.63	0.78	0.85	0.71	0.37
107	3.86	4.76	5.19	4.32	2.28
306	11.03	13.61	14.83	12.36	6.52

Table 1-24: Required useable roof area per capita for the installation of mono and polycrystalline PV modules for the different scenarios (module efficiency: 21%)

Thin film (T O D A Y)					
Capacity PV modules [GW <sub>p</sub> ]	Portugal [m <sup>2</sup> /capita]	Spain [m <sup>2</sup> /capita]	Italy [m <sup>2</sup> /capita]	Greece [m <sup>2</sup> /capita]	Turkey [m <sup>2</sup> /capita]
0.0031	0.00	0.00	0.00	0.00	0.00
0.053	0.01	0.01	0.01	0.01	0.00
0.218	0.02	0.03	0.03	0.02	0.01
17.6	1.67	2.05	2.24	1.87	0.98
107	10.13	12.49	13.62	11.35	5.98

Thin film (T O D A Y)					
Capacity PV modules [GW <sub>p</sub> ]	Portugal [m <sup>2</sup> /capita]	Spain [m <sup>2</sup> /capita]	Italy [m <sup>2</sup> /capita]	Greece [m <sup>2</sup> /capita]	Turkey [m <sup>2</sup> /capita]
306	28.97	35.72	38.94	32.45	17.10

Table 1-25: Required useable roof area per capita for the installation of thin film PV modules for the different scenarios (module efficiency: 8%)

The roof area per capita indicated above (Table 1-4) includes roofs looking to the north, east and the west. It has been assumed that only flat roofs and roofs looking to the south with a maximum deviation of +/- 15 degree. Then the share of the sloped roof area suitable for PV installations can be expected to be 1/12. It has been assumed that 50% of the roofs are flat roofs. To calculate the total roof area from the usable roof area, the not usable roof area has to be taken into account by multiplying the usable roof area with  $1/(0.5+0.5*1/12)$ .

The roof area including the not usable roof area as shown in Table 1-26, Table 1-27 and Table 1-28. The numbers for the required roof area per capita which are above the available roof area are marked yellow.

Mono-/polycrystalline (T O D A Y)   Thin film (2 0 3 0)					
Capacity PV modules [GW <sub>p</sub> ]	Portugal [m <sup>2</sup> /capita]	Spain [m <sup>2</sup> /capita]	Italy [m <sup>2</sup> /capita]	Greece [m <sup>2</sup> /capita]	Turkey [m <sup>2</sup> /capita]
0.0031	0.00	0.00	0.00	0.00	0.00
0.053	0.01	0.01	0.01	0.01	0.00
0.218	0.02	0.03	0.03	0.02	0.01
17.6	1.76	2.17	2.36	1.97	1.04
107	10.69	13.18	14.36	11.97	6.31
306	30.56	37.68	41.08	34.23	18.04

Table 1-26: Required roof area per capita for the installation of state-of-the-art mono and polycrystalline PV modules, respectively thin film PV modules in 2030 for the different scenarios including not usable roofs (either module efficiency: 14%)

Mono-/polycrystalline (2 0 3 0)					
Capacity PV modules [GW <sub>p</sub> ]	Portugal [m <sup>2</sup> /capita]	Spain [m <sup>2</sup> /capita]	Italy [m <sup>2</sup> /capita]	Greece [m <sup>2</sup> /capita]	Turkey [m <sup>2</sup> /capita]
0.0031	0.00	0.00	0.00	0.00	0.00
0.053	0.00	0.00	0.00	0.00	0.00
0.218	0.01	0.02	0.02	0.02	0.01
17.6	1.17	1.44	1.58	1.31	0.69
107	7.12	8.78	9.58	7.98	4.21
306	20.37	25.12	27.38	22.82	12.03

Table 1-27: Required area per capita for the installation of mono and polycrystalline PV modules for the different scenarios including not usable roofs (module efficiency: 21%)

Thin film (T O D A Y)					
Capacity PV modules [GW <sub>p</sub> ]	Portugal [m <sup>2</sup> /capita]	Spain [m <sup>2</sup> /capita]	Italy [m <sup>2</sup> /capita]	Greece [m <sup>2</sup> /capita]	Turkey [m <sup>2</sup> /capita]
0.0031	0.00	0.00	0.00	0.00	0.00
0.053	0.01	0.01	0.01	0.01	0.01
0.218	0.04	0.05	0.05	0.04	0.02
17.6	3.08	3.79	4.13	3.45	1.82
107	18.70	23.06	25.14	20.95	11.04
306	53.48	65.94	71.88	59.91	31.57

Table 1-28: Required area per capita for the installation of thin film PV modules for the different scenarios including not usable roofs (module efficiency: 8%)

Under the scenario conditions given, the need of roof area per capita would exceed the available roof area for the 150 GW non-base load scenarios with pumped hydro storage in case of state of the art crystalline silicon modules and future thin film modules except in Turkey. If the module efficiency were increased to 21% the available roof area would sufficient to meet the 150 GW scenario except in Spain. As a result the roof potential in case of the use of improved crystalline silicon PV modules almost can meet the demand for the 150 GW scenario. Only in Spain a few PV capacity installed on other areas than roofs would have to be added if improved crystalline silicon modules were used.

### 1.1.2 Solar thermal potentials

Solar thermal potentials in the Mediterranean area was examined by [Klaiß 1992]. With reference to the definition of so called sun zones (see 4.2), the resulting solar thermal potentials are enlisted in the following tables:

Country	Potential [TWh]	Potential 8760 h/yr [GW <sub>e</sub> ]	Potential (8760 h/yr – losses H2 path) [GW <sub>e</sub> ]
Greece	180	21	14
Italy	288	33	22
Portugal	72	8	6
Spain	864	99	66
Turkey	3,240	370	249
<b>Total</b>	<b>4,644</b>	<b>530</b>	<b>357</b>

Table 1-29: Solar thermal potentials in the European sunbelt (sun zone 1); derived from [Klaiß 1992]

Country	Potential [TWh]	Potential 8760 h/yr [GW <sub>e</sub> ]	Potential (8760 h/yr – losses H2 path) [GW <sub>e</sub> ]
Egypt	14,959	1,708	1,095
Algeria	2,340	267	171
Libya	11,148	1,273	816
Morocco	9,321	1,064	682
Tunisia	1,080	123	79
<b>Total</b>	<b>38,848</b>	<b>4,435</b>	<b>2,844</b>

Table 1-30: Solar thermal potentials in North Africa (sun zone 0); derived from [Klaiß 1992]

The following areas are excluded from the potentials stated in Table 1-29 and Table 1-30:

- Forests
- Agriculture land

- Grass land
- Sandy deserts
- Areas with a gradient angle above 5%

Furthermore, [Klaiß 1992] considered the following restrictions:

- only locations less or equal 50 km from existing electricity grid
- only locations less or equal 50 km from existing roads
- only locations with irradiation of more than 1,700 kWh/m<sup>2</sup>/yr

The above stated potentials therefore represent rather conservative values.

## 1.2 Power transmission

### 1.2.1 High voltage alternating current

High voltage alternating current is (HVAC) mostly applied for electricity transmission by means of overhead lines. Underground cables are only used for short-distance HVAC power transmissions due to higher losses.

Typical voltage and power levels for long-distance power transmission are shown in Table 1-31.

Voltage level	Maximum transmission distances
110,000 V	several dozens of km
220,000 V	several hundred km
380,000 V	< 1,000 km
500,000 V	~ 1,000 km

Table 1-31: Typical data of HVAC power transmission overhead lines

A great advantage of HVAC transmission over HVDC is that they may easily be expanded in terms of numbers of consumers connected to the transmission line.

Most of the European grid consists of HVAC lines. By 2002, Austria, Belgium, Bosnia & Herzegovina, Bulgaria, Croatia, Czech Republic, Denmark, France, Germany, Greece, Hungary, Italy, Luxembourg, Macedonia, Poland, Portugal, Romania, Slovakia, Slovenia, , Serbia, Spain, Switzerland and The Netherlands are connected to the European grid. In the

end of 2003 through the networks of the UCTE, about 450 million people have been supplied with electric energy; annual electricity consumption totals approximately 2300 TWh [UCTE 2003]. Their transmission system operators are members of the UCTE.

Regarding the upper end of the scenarios considered (100 - 500 GW<sub>e</sub>), the required transmission capacities (several GW<sub>e</sub>) and distances (> 1,000 km) exceed the economic viability of HVAC transmission lines. Thus, HVDC transmission lines are applied in this study (see the following chapter).

### 1.2.2 High voltage direct current

A high voltage direct current (HVDC) electricity transmission system consists of a DC line with a head station (also called converter or terminal station) at each of the line's ends (an AC/DC converter and a DC/AC converter).

HVDC transmission lines are applied for long-distance, point to point power transmission due to the high costs of the head stations and the transmission losses. Another application of HVDC lines is making a short connection between two non synchronized power systems or two power systems with different nominal frequencies.

Figure 1-4 and Figure 1-5 depict simplified block diagrams of two different system architectures of HVDC systems.

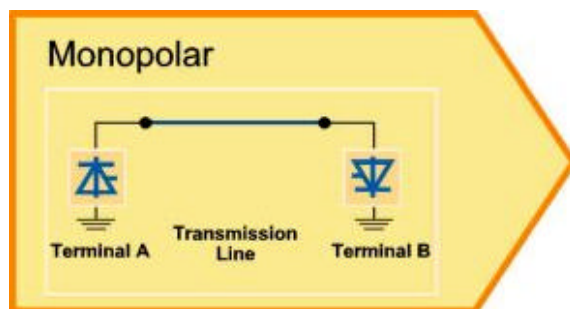


Figure 1-4: Simplified block diagram of a monopolar HVDC line [Siemens 2004]

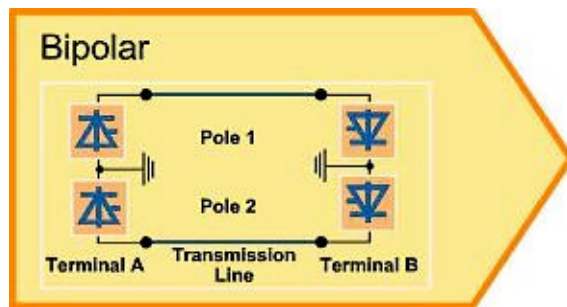


Figure 1-5: Simplified block diagram of a bipolar HVDC line [Siemens 2004]

Monopolar HVDC lines are cheaper as the ground is applied as electrical back-channel. A bipolar HVDC system architecture provides a higher operational reliability. In case of a failure in a single line or in one of the converter stations, the bipolar HVDC system architecture may continue to operate with 50% power capacity.

Cause of losses at the converter station are stated in Table 1-32.

COMPONENT	CONVERTER LOSSES	
	@ No Load (Standby)	@ Rated Load
Filters:		
▪ AC-Filters	4%	4%
▪ DC-Filters	0%	< 0.1%
Converter Transformers, 1 phase, 3 windg.	53%	47%
Thyristor Valves (Switching and Parasitic Losses)	10%	36%
Smoothing Reactor	0%	4%
Auxiliary Power Consumption:		
▪ Cooling System, Converter Valves	4%	3%
▪ Cooling System, Converter Transformer	4%	1%
▪ Air-conditioning System	15%	4%
▪ Others	10%	1%
<b>Total Losses @ 20°C</b>	<b>100%</b>	<b>100%</b>
<b>Specific Losses (<math>P_{Loss}/P_{Nom}</math>)</b>	<b>0.11%</b>	<b>0.7%</b>

Table 1-32: Split of losses which occur at the converter station [Siemens 2004]

HVDC is an established technology, though with further potential for technological improvement. Currently, some 90 HVDC installations exist worldwide. The overall capacity sums up to approximately 70,000 MW [Grotelüschen 2004]. The three major companies in the field are ABB (> 50% market share), Areva and Siemens. An overview over selected HVDC applications is given in Figure 1-6.

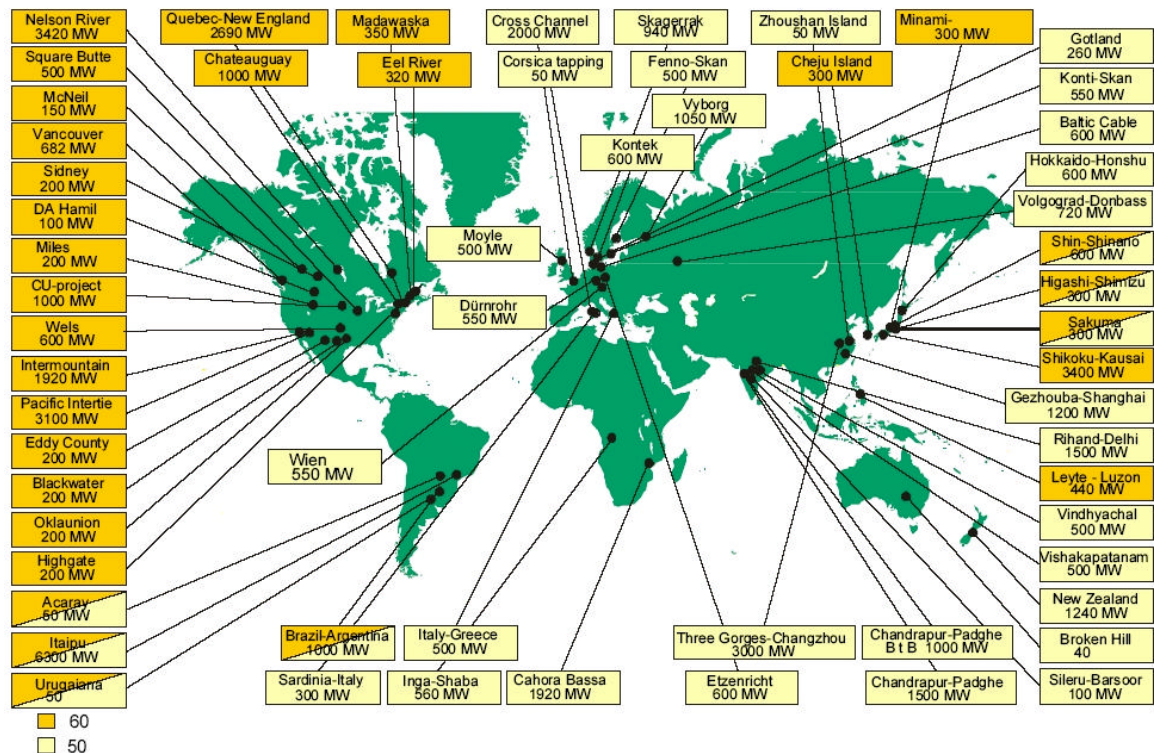


Figure 1-6: HVDC lines worldwide [ABB 2000]

Due to the technologies' cost structure, the break-even between HVAC and HVDC power lines for bulk power transmission is around 1,000 km. Above this distance, HVDC becomes more cost effective than HVAC.

For physical construction, one to three years is required from contract to commissioning depending on the system size [ABB 2000]. Maintenance effort is comparable to conventional AC lines. According to [ABB 2000] the recommended shut down time for routine maintenance is one week per year which is equal to an average availability of 98%. Newer systems even do not require any scheduled maintenance in the first two years. If a bipolar line is applied as depicted in Figure 1-5, only half of the transmission capacity has to be shut down for maintenance at the same time. Depending on the system design, the second line may even carry some of the other line's load.

Today, the maximum rated power capacity of HVDC line is some 4 GW<sub>e</sub> (bipolar line). On a single truss a maximum of 10 GW<sub>e</sub> (two 2030 bipole HVDC lines) may be transmitted. The maximum power capacity per head stations is 10 GW<sub>e</sub>.

[Häusler 1999] states the following economic figures for HVDC lines:

Cost element	Investment costs
HVDC line – land (2 double bipole, simple terrain)	700 kEUR/1000km <sub>land</sub>
HVDC line – land (2 double bipole, complicated terrain)	1,400 kEUR/1000km <sub>land</sub>
HVDC line – sea (7 bipole cables)	13,300 kEUR/1000km <sub>sea</sub>
HVDC head station (1,000 MW <sub>e</sub> )	94 million EUR/unit
HVDC head station (2,000 MW <sub>e</sub> )	133 million EUR/unit
HVDC head station (4,000 MW <sub>e</sub> )	247 million EUR/unit

Table 1-33: Investment costs of HVDC transmission systems with a capacity of 10 GW in 1999 according to [Häusler 1999]

## 1.3 Energy storage technologies

### 1.3.1 Batteries

A battery converts chemical energy into electrical energy through an electrochemical process. A single cell of a battery consists of a positive metal electrode (cathode) and a negative metal electrode (anode) suspended in an electrolyte. The electrodes consist of active material that take part in the electrochemical reactions. During discharging the anode is oxidized while the cathode is reduced. During charging the positive electrode is oxidized and turns into the anode whereas the negative electrode is reduced and is turned into a cathode. The electrolyte must be a non-conductor for electrons in order to avoid self-discharging of the cell. When a rechargeable battery system is recharged all these reactions are reversed and the cells are restored.

Batteries can be of either primary or secondary type. Primary batteries are designed for a single discharge cycle only, this means they are not rechargeable. Secondary batteries are designed to be recharged, typically from 200 to 1,000 times. Secondary/rechargeable batteries are lead-acid, NiCd, Ni-metal hydride and lithium ion batteries.

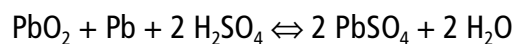
Some general information on batteries for electricity storage is given in Table 1-34. Further details on various battery technologies are stated in the following subchapters. Finally, the different types are compared in Table 1-35 regarding a relevant set of technological parameters.

Energy and power density	20 – 100 Wh/kg depending on type, target 170 Wh/kg; power levels for very short power pulses exceed most requirements; 150 W/kg and target of 400 W/kg. Energy to power ratio is a design characteristic and only small variations are possible.
Cost/economy of scale	Most battery types with economic potential are already produced in large quantities. The cost of material and processing are the driving factors. For power batteries in hybrid applications, the cost target is most crucial and is 100 EUR/kWh
Lifetime	Mostly application dependent but perfectly acceptable for most conventional applications under laboratory conditions. Particular problems exist for energy batteries in RES and power batteries in hybrid vehicle applications
Monitoring and control	Complex, no adequate solution exists
Efficiency	Higher than 90 % in some PV applications, very sensitive to application, standby losses in most batteries are negligible

Table 1-34: Technology profile for batteries [EC 2001]

#### a) Lead-acid battery

For stationary applications e.g. for uninterruptible power supply (UPS) or storing renewable electricity in remote locations without access to the electricity grid usually lead acid batteries are used (typically of the OPz type). In all lead acid batteries the same active materials work. At the positive electrode lead dioxide (PbO<sub>2</sub>) is converted to lead sulfate (PbSO<sub>4</sub>) during the discharge of the battery. The electrolyte is a dilute mixture of sulfuric acid (H<sub>2</sub>SO<sub>4</sub>) that provides the sulfate ion for the discharge reaction. Thin sheets of porous insulators ("separators") are used to isolate the positive and negative electrodes (or plates) from each other. The overall reaction is:



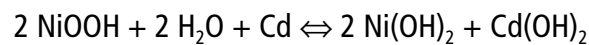
The open circuit voltage of the cell is around 2.1 V at room temperature (25°C) when the battery is fully charged. The working voltage is lower (1.85 V).

Lead acid batteries of the OPz which are designed for a maximum useful lifetime and low self-discharge achieve up to 1,000 loading/unloading cycles (unloading until 30% of

nominal capacity) and have a useful lifetime of approximately 12 years (typically) [AGTAR 2004].

**b) Nickel-cadmium battery**

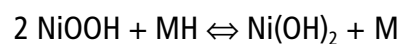
The nickel-cadmium (NiCd) battery comprises a nickel hydroxy-oxide (NiOOH) positive electrode and a metallic cadmium negative one. The electrolyte is a concentration solution of potassium hydroxide (typically 240 g/l). The electrolyte also contains lithium hydroxide (about 50 g/l) which exerts a stabilizing effect to the nickel electrode during the charging/discharging cycle. Sheets of polypropylene can be used as separators between the positive and the negative electrode. The overall reaction is:



In the fully discharged state the open circuit voltage of one cell is 1.3 V. During discharge the voltage of one cell is 1.2 V. The disadvantage is the so called "memory effect". This means that the storage capacity decreases when the battery only is discharged partially. There NiCd Batteries can not be used to compensate fluctuations of electricity demand and supply.

**c) Nickel-metal hydride battery**

Nickel hydroxy-oxid (NiOOH) is the active material of the positive electrode in the nickel-metal hydride (Ni-MH) battery. Hydrogen is absorbed in a metal alloy (metal hydride) is used as negative active material. Two types of metallic alloys are used, number one based on lanthanum and nickel and number two is consisting of titanium and zirconium. An aqueous solution of potassium hydroxide is used as electrolyte which may also contain a lithium hydroxide (LiOH) additive. The overall reaction is:



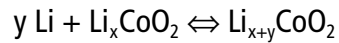
where M = metal

The cell has an open circuit voltage in the range of between 1.25 and 1.35 V. The working voltage (nominal voltage) is 1.2 V.

**d) Rechargeable lithium ion battery**

Lithium ion batteries are physically constructed with three main layers. These are the positive electrode plate, the negative electrode plate and a separator. The basic operation of a lithium ion battery consists of the movement of only a lithium ion from one electrode to the other. The anode contains a compound that receives the ions during discharge and gives up the ions during charge. The cathode operates in reverse, giving up the ions during discharge and receiving them during charge. The positive electrode uses compounds

such as lithium cobalt oxide, lithium nickel oxide or lithium manganese oxide. The negative electrode typically uses graphite or amorphous carbon. The overall chemical reaction—of a lithium ion battery is:



The open circuit voltage is 4.2 to 4.3 V.

#### e) Comparison

The technical properties of the different types of batteries are compiled in Table 1-35 for comparison reasons.

	Lead acid	NiCd	Ni-MH	Lithium
Energy density [kWh/kg]	0.025 to 0.035	0.035 to 0.057	0.050 to 0.080	0.100 to 0.150
Power density [kW/kg]	0.075 to 0.130	0.050 to 0.020	0.150 to 0.250	~0.300
open circuit voltage [V]	2.1	1.3	1.3	4.3
Cycle life	200 to 400 <sup>1)</sup>	800 to 2,000	600 to 1,500	400 to 2,000
Operating temperature [°C]	-18 to +70	-40 to +60	0 to 60	-20 to +60
Self-discharging rate [% per month]	2 to 3	10 to 20	20 to 30	6 to 10

<sup>1)</sup> up to 1000 when a decrease of to 80% of rated storage capacity is accepted

Table 1-35: Technical data for different types of batteries [AGTAR 2004], [ThermoAnalytics 2001], [XICOR 1999]

Only the self-discharging rate of the lead acid batteries (2-3% per month) might be acceptable for electricity storage. All other types of batteries have extremely high self-discharge rates (up to 30% per month).

The material requirement for the storage of large amounts of electricity via batteries is extremely high. The material requirement (mainly lead) is approximately 29 to 40 kg per

kWh of storage capacity. If it is assumed that 24 hours have to be bridged and power requirement is 500 GW about 343 to 480 million t lead would be required. The total amount of lead available in the world is 65 million t. The annual world lead production in 1997 was 2.6 million t [DIW 1999]. Therefore batteries are not considered for electricity storage in this study.

### 1.3.2 Hydrogen

#### Electrolysis

Electrolytic decomposition of water into hydrogen and oxygen is a proven technology since more than 100 years. Large-scale industrial use of alkaline electrolyzers is practiced since more than 70 years.

Conventional alkaline water electrolyzers are always suitable if electricity is provided in a more or less continuous form without too large timely fluctuations in operating regimes within several seconds or minutes. For such applications which are typical especially for stand-alone renewable power generation schemes new and more innovative electrolyzer technologies have been applied. Characteristics of such technologies are improved catalytic coatings of the electrodes, more efficient separation diaphragms/ membranes, pressurization of gas generation and delivery. Several of these improved technologies are available from companies as e.g. GHW, Norsk Hydro Electrolysers, Vandenborre Hydrogen Systems (which is a subsidiary of Stuart Energy)

Conventional alkaline electrolyzers have proven 15-20 years of operation without major overhaul efforts. Advanced more innovative technologies have not yet proven such long operating experiences without replacement of certain components but are continuously simplified and improved in order to enable long operating periods at low maintenance efforts as well. First units for distributed onsite hydrogen generation as replacement of merchant hydrogen trailer delivery are proving steadily increasing reliability since more than half a decade (in particular Vandenborre Hydrogen Systems and Norsk Hydro Electrolysers). These units typically are in the 30-60 Nm<sup>3</sup>/h capacity range. Gradually also advanced electrolyzer units with a higher capacity are under development (e.g. by GHW for unit sizes of between 200 and 800 Nm<sup>3</sup>/h).

Based on these products several manufacturers (Norsk Hydro/ GHW, Vandenborre Hydrogen Systems) are conceiving electrolysis based hydrogen refueling stations for the supply of compressed gaseous hydrogen to road vehicles within the coming years.

	Vandenborre Hydrogen Systems	Norsk Hydro	Giovanola	GHW
Model	H <sub>2</sub> IGen	HPE Series		
Unit size [Nm <sup>3</sup> H <sub>2</sub> /h]	1-120	60	110-760	200-800
Pressure (H <sub>2</sub> ) [MPa]	1.1-2.6	1.6	3.0	3.0
Electricity consumption [kWh/kWh <sub>H<sub>2</sub></sub> ]	1.6	1.6	1.43-1.53	1.54
Efficiency (LHV) [%]	62-63	62	65-70	65

Table 1-36: Pressurized alkaline electrolyzers

Today the investment for a 60 Nm<sup>3</sup> alkaline pressurized electrolyzer unit is indicated with about 6,850 EUR per Nm<sup>3</sup>/h [Hydrogen Systems 2000]. The future investment for electrolyzers with a capacity of 200 to 800 Nm<sup>3</sup>/h is expected to be about 1,500 EUR per Nm<sup>3</sup>/h [GHW 2003].

Electrolyzers employing a proton exchange membrane (PEM) are also under development (Proton Energy Systems) but until now the efficiency is below that of pressurized alkaline electrolyzers.

Progress towards direct solar-powered generation of hydrogen through solar cell-driven electrolysis has reached 12% efficiency, and offers promise of direct production of hydrogen fuel from sunlight, thereby raising the efficiency of hydrogen storage of solar energy.

### **Hydrogen storage**

The most common methods for hydrogen storage are compressed gaseous hydrogen (CGH<sub>2</sub>), liquid hydrogen (LH<sub>2</sub>) and metal hydrides. These hydrogen storage technologies are described in brief in the following subchapters.

#### **a) Liquefied hydrogen (LH<sub>2</sub>)**

LH<sub>2</sub> is not useful for seasonal hydrogen storage. Since there is always some heat entry into the cryogenic vessel small amounts of LH<sub>2</sub> are vaporized (~0.1% per day in case of large stationary cryogenic vessels). This leads to a pressure increase until the maximum pressure is exceeded and the hydrogen has to be released for safety reasons. The time until the maximum pressure is exceeded amounts to a few days for cryogenic vehicle tanks, and up to a few weeks for large stationary cryogenic vessels. The released hydrogen can be used for electricity and heat generation or can be compressed and stored in pressure vessels as CGH<sub>2</sub>. Another disadvantage of LH<sub>2</sub> is the additional electricity requirement for

hydrogen liquefaction which leads to a lower overall efficiency. The electricity consumption of large state of the art hydrogen liquefaction plants is about 0.30 kWh per kWh of hydrogen related to the lower heating value (LHV) of the delivered hydrogen. The electricity consumption of an optimized liquefaction process can be lowered down to about 0.21 kWh per kWh of hydrogen [LBST 2001].

**b) Metal hydrides (MH)**

Metal hydrides are usually applied for the storage of small amounts of hydrogen. There are low temperature metal hydrides ( $< 100^{\circ}\text{C}$ ), medium metal hydrides ( $100\text{-}250^{\circ}\text{C}$ ) and high temperature metal hydrides ( $> 250^{\circ}\text{C}$ ). When charging low temperature metal hydrides heat is released. Vice versa, heat is required to discharge low temperature metal hydrides. The required heat input amounts to approximately 12% of the energy content of the delivered hydrogen. The hydrogen storage capacity is indicated with some 1.5 wt-% which is about 0.5 kWh hydrogen per kg of metal hydride. Furthermore the mass of the vessels has to be taken into account (vessel for a 100 kg metal hydride: ~60 kg). The investment for the storage of 500 Nm<sup>3</sup> hydrogen in low temperature metal hydrides is indicated with some 190,000 EUR or 380 EUR per Nm<sup>3</sup> of hydrogen storage capacity [GfE 2001]. Current research activities in the field focus on new medium temperature metal hydrides compounds (so called Alanate) which are very promising regarding their weight specific hydrogen storage capabilities. Primary promoter is the automotive industry and their quest for an optimal hydrogen storage system by both volume and weight. Whether the R&D efforts lead to a commercially viable product cannot be foreseen by now. Metal hydrides are thus not considered in this study.

**c) Compressed gas hydrogen (CGH<sub>2</sub>)**

In the framework of this study hydrogen is stored as compressed gaseous hydrogen. For large amounts of hydrogen compressed hydrogen could be stored in depleted natural gas fields or caverns. But depleted natural gas fields or suitable caverns are not available everywhere. Another possibility is to store hydrogen in spherical pressure vessels. Spherical pressure vessels is a widespread technology to store gases like natural gas and hydrogen.



Figure 1-7: Spherical pressure vessel (CBI – Chicago Bridge & Iron Company N.V.)

The maximum pressure of large commercial available spherical pressure vessels ranges between 0.8 and 2 MPa. In this study a spherical pressure vessel with a maximum pressure of 2 MPa has been selected. Table 1-37 shows different spherical pressure vessels.

Volume [m <sup>3</sup> ]	Max. pressure [MPa]	Min. pressure [MPa]	Storage ca- pacity [Nm <sup>3</sup> ]	Investment [EUR]	Spec. Investment [EUR/Nm <sup>3</sup> ]
300	1.2	0.1	3,000	230,000	76
300	2.0	0.1	5,200	307,000	59
1,000	0.8	0.1	6,400	383,000	60
1,000	2.0	0.1	17,400	844,000	49
3,000	0.8	0.1	19,300	971,000	50
3,000	2.0	0.1	52,100	1,917,000	37

Table 1-37: Technical and economic data of spherical pressure vessels

Since the electrolyzer delivers hydrogen at a pressure above 2 MPa no hydrogen compression is required.

### **Fuel cells**

Fuel cells are high-efficient, electrochemical energy conversion devices. The chemical energy resulting from the oxidation of a fuel (e.g. hydrogen or hydrocarbons) is directly converted into electrical energy. In contrary to this fuel cell process, a conventional power

generator utilizes an indirect, thermo-mechanical process in which heat steam is produced by burning a fuel. A turbine converts the steam's energy content into mechanical energy. A power generator then converts this mechanical energy into electrical energy.

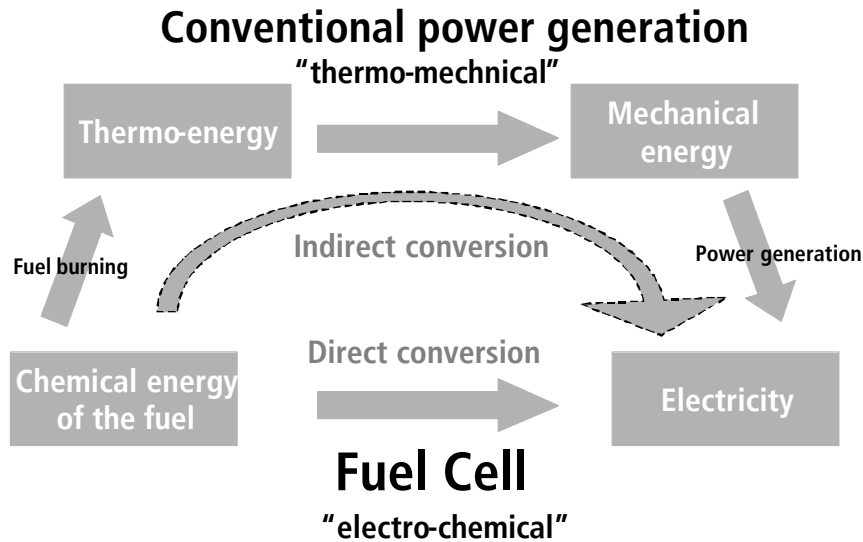


Figure 1-8: Comparison of energy conversion principles for the purpose of electricity generation by means of fuel cell and conventional power plant

In the electrochemical reaction of a fuel cell, the fuel is converted directly into electricity without the need of a thermo-mechanical process which respectively is limited by irreversible heat and mechanical losses.

The theoretically maximum of efficiency of a reversible fuel cell (idling with zero current) is defined as:

$$h_{FuelCell\_reversible} = \frac{\Delta G}{\Delta H}$$

with:  $\Delta H$  = Given enthalpy of the reaction in kJ/mol (fuel) ( $p, T = \text{constant}$ )

$\Delta G$  = Free enthalpy of the reaction in kJ/mol ( $p, T = \text{constant}$ )

The free enthalpy  $\Delta G$  is defined as:

$$\Delta G = \Delta H - T * \Delta S \quad (p, T = \text{constant})$$

with:  $T$  = Temperature in K

$\Delta S$  = Entropy of the reaction ( $p, T = \text{constant}$ )

$T \cdot DS$  represents the amount of energy by which the reaction enthalpy  $DH$  is reduced due to losses.  $\Delta G$  represents the maximum of electricity which can be gained from a given feed fuel in a fuel cell.

The theoretically maximum of efficiency  $\eta_{\text{fuel cell, reversible}}$  of a fuel cell converting pure hydrogen and pure oxygen into water under standard ambient conditions ( $p= 0.1013 \text{ MPa}$ ,  $T=298 \text{ K}$ ) is 83 % respectively 94 %, depending on the state of aggregation (liquid or gaseous) of the reaction product [Heuser 1995]

In contrary to an ideal, reversible fuel cell process without any losses, respectively providing a constant, theoretical output voltage – in contrary to this, the voltage of a real fuel cell decreases with an increase of the current/power output.

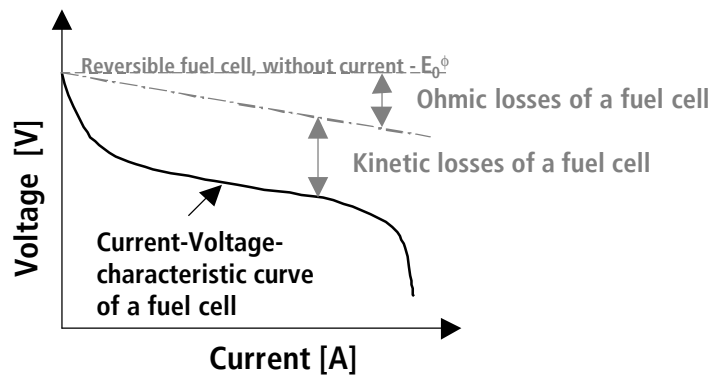


Figure 1-9: Scheme of a current-voltage-characteristic curve of a fuel cell

If a fuel cell is connected to an electrical load, kinetic losses (mass-transport-effects, reaction conversion rates) and ohm resistive losses in the cells cause a decrease of the fuel cell voltage with an increase of the current.

Fuel cell type	Electrically efficiency	Temperature
AFC: Alkaline Fuel Cell	Cell: 50 – 70 %: (H <sub>2</sub> /O <sub>2</sub> )	~70°C
PEMFC: Polymer Electrolyte Fuel Cell or Proton Exchange Membrane Fuel Cell	Cell: 50 – 65 %: (H <sub>2</sub> /O <sub>2</sub> ) 35 – 55 %: (H <sub>2</sub> /air)	60-120°C
PAFC: Phosphoric Acid Fuel Cell	Cell: 35 - 50 %: (H <sub>2</sub> /air)	160-200°C
MCFC: Molten Carbonate Fuel Cell	System: 45 - 50 %: (natural gas/air) with downstream steam turbine: up to 65%	600-650°C
SOFC: Solid Oxide Fuel Cell	System: 45 – 50 % (natural gas / air) with downstream gas turbine: up to 75%	800-1,000°C
DMFC: Direct Methanol Fuel Cell	Cell: 35 - 40 % (methanol/air)	~70°C

Table 1-38: Properties of different fuel cell types

The cold start up time of the SOFC and MCFC takes several hours. Therefore SOFC and MCFC are not suitable for providing back up power. Here the fuel cell power plants are considered as backup power for solar thermal power plants and photovoltaics. The MCFC cannot be fueled with pure hydrogen because CO<sub>2</sub> is required for the cathode of the cell. Therefore in this study hydrogen fueled PEMFC has been taken into account.

### **Combined cycle gas turbine (CCGT)**

A combined cycle gas turbine power plant (CCGT) consists of a gas turbine and a steam turbine. The heat of the exhaust gases from the gas turbine is used to generate steam for the steam turbine. With this combination an electric efficiency up to 58% can be achieved. Until 2010 an efficiency of about 60% is feasible [TAB 1999]. Large present state of the art CCGT plants achieve an efficiency of about 55% (see Table 1-39)

Source	[Tuma 1997]	[Siemens 1998]	[Siemens 1998]	[Siemens 1998]	[TAB 1999]	[TAB 1999]
Type		GUD 2.94.2	GUD 2.94.2A	GUD 1S.94.2A		

Source	[Tuma 1997]	[Siemens 1998]	[Siemens 1998]	[Siemens 1998]	[TAB 1999]	[TAB 1999]
Size [MW <sub>e</sub> ]	21	478 <sup>2)</sup>	558 <sup>2)</sup>	285	180	600
Efficiency	44%	52.3%	54.4%	56.3%	53% (58%) <sup>1)</sup>	55% (60%) <sup>1)</sup>
Investment [EUR8kW <sub>e</sub> ]	511				675	534

<sup>1)</sup> expected for the year 2010; <sup>2)</sup> Multi shaft plant

Table 1-39: Technical and economic data of natural gas fueled CCGT power plants

According to [TAB 1999] the plant efficiency decreases by about 1-2 percentage points (average efficiency) due to aging after a longer time of operation. CCGT power plants generally can be fueled with all liquid and gaseous fuels including hydrogen (after modification e.g. of the gas turbine).

### 1.3.3 Pumped hydro storage

Conventional pumped hydro uses two water reservoirs, separated vertically. During off peak hours water is pumped from the lower reservoir to the upper reservoir. When required, the water flow is reversed to generate electricity. Some high dam hydro plants have a storage capability and can be dispatched as a pumped hydro. Underground pumped storage, using flooded mine shafts or other cavities, are also technically possible. Open sea can also be used as the lower reservoir. A seawater pumped hydro plant was first built in Japan in 1999 (Yanbaru, 30 MW) [ESA 2003].

Pumped hydro was first used in Italy and Switzerland in the 1890's. By 1933 reversible pump-turbines with motor-generators were available. Adjustable speed machines are now being used to improve efficiency. Pumped hydro is available at almost any scale with discharge times ranging from several hours to a few days. Their efficiency is in the 70% to 85% range [ESA 2003].



Figure 1-10: Pumped hydro power plant Goldisthal (Walter Bau AG)

By nature, pumped hydro storage requires special topographical conditions. They are economically accounted like power stations. Usually they are not built to serve as an energy storage for a single source of power plant but as a mean to control grid-stability independent from the source of input electricity as well as independent from the cause of electricity demand. Table 1-40 shows 1,000 MW and larger pumped hydro installations in the EU.

Plant	Operational start	Hydraulic head [m]	Max. output [MW <sub>e</sub> ]	Storage capacity [h]	Investment [10 <sup>6</sup> EUR]
Grand Maison, France	1987	955	1,800		
Markersbach, Germany	1981	290	1,050	4	
Goldisthal, Germany	2003	300	1,060	8	620
Piastra Edolo, Italy	1982	1,260	1,020		

Plant	Operational start	Hydraulic head [m]	Max. output [MW <sub>e</sub> ]	Storage capacity [h]	Investment [10 <sup>6</sup> EUR]
Chiotas, Italy	1981	1,070	1,184		
Presenzano, Italy	1992		1,000		
Lago Delio, Italy	1971		1,040		
Vianden, Luxemburg	1964	287	1,096		
Dinorwig, Wales, UK	1984	545	1,890	5	310

Table 1-40: Large pumped hydro installations in Europe [BENNO 1999], [IWR 2/2003], [ESA 2003], [ProfisaX 2002]

Pumped hydro power already is used for load leveling since many years. A pumped hydro power plant generally consists of two water basins. In 1999 within the EU-15 the installed capacity of pumped hydro has been reached 32.1 MW which represents 5.5% of the electricity generation capacity. The energy produced by means of stored water in 1999 was 24.3 TWh which is approximately 1.0 % to the total electricity production (2,533 TWh) [Crampes et al 2003].

### 1.3.4 Compressed air storage

Air is pumped underground into natural or artificially produced caverns. If electricity is required, the pressurized air is applied to power a turbine. The turbine powers an electrical generator.

By nature, compressed air storage systems cannot be applied on a decentralized basis. They require special geological conditions. Closed natural gas fields may be applied.

Furthermore, compressed air storage systems are by nature built on a large-scale. They are economically accounted like power stations. Usually they are not built to serve as an energy storage for a single source of power plant but as a mean to control grid-stability independent from the source of input electricity as well as independent from the cause of electricity demand.

Energy and power density	Energy and power density not relevant for large geological structures; for compressed gas tanks approx. 1 m <sup>3</sup> is required per kWh; the energy to power ration is approx. 1 : 10 and covers a range which is not covered by other storage technologies.
Cost/economy of scale	Smallest unit with approx. 20 kW
Response time	Approximately 0.1 seconds
Lifetime	No limitations of no. of cycles, long overall life expectancy
Efficiency	75 %, with negligible standby losses

Table 1-41: Technology profile for compressed air storage systems [EC 2001]

The cost per MWh<sub>e</sub> supplied power is potentially low compared to other means of electricity storage, especially, when natural caverns are available in the local geological formation.

Compressed air storage is a promising electricity storage to ease supply and demand within an electricity system which consists of a larger share of volatile renewable energies, such as wind or solar.

In the course of this study, electrical storage by means of compressed air facilities are not further taken into account due to its dependence on certain geological conditions.

### 1.3.5 Flywheel

Electrical energy may be stored by means of a rotating mass.

Therefore, an electrical motor uses electrical energy to drive a mass of defined shape, weight and dimension. The former electrical energy is now stored as kinetic energy with little losses. If power is required, the flywheel drives a generator. By this, kinetic energy is re-converted into electricity and the flywheel's number of rounds per minute is decreased.

The cycle efficiency is very high with this mean of energy storage. Yet, standby losses due to the mechanical friction of the bearing are significant.

The target application of flywheel energy storage is to be seen where high power, low energy and fast system response times are required over short period of time (e.g. with recuperation and acceleration in automobiles).

Energy and power density	Energy density approx. 0.01kWh/kg; 1 - 10 kWh and 300 kW up to 2 MW; Power to energy ratio is in the range of 1: 100
Cost/economy of scale	Smallest unit with approx. 100 kW output
Lifetime	No limitations of number of cycles, simple monitoring and long overall life time
Efficiency	Above 95 % but standby losses are 100 % per day

Table 1-42: Technology profile for flywheel energy storage systems [EC 2001]

The technological feasibility of flywheel energy storage is proven. The technology is not yet mature regarding its technical and economical viability.

The flywheel is not further considered as a means of energy storage in the course of this study due to its short time energy storage characteristics.

### 1.3.6 Super / ultra capacitors

Electrical energy is stored in an electromagnetic field in a capacitor which is designed to provide very large capacities (therefore the prefix 'super' or 'ultra'). Charge and discharge response time is very fast. The number of charge / discharge cycles is practically unlimited with a very high cycle efficiency.

Energy and power density	Single module up to 0.5 kWh and 15 kW; Energy and power density for a module in the range of 1.5 Wh/kg and 1.2 kW/kg, for a single supercapacitor in the range of 2 Wh/kg and 2 kW/kg.
Cost/economy of scale	Still very high costs mainly due to low production quantity, no commercial applications yet
Lifetime	No practical limits of number of cycles, but calendar life limited to approx. 8 – 10 years
Monitoring and control	Simple monitoring but complex control electronics is still required for operation
Efficiency	In-out efficiency is above 95 %. The self discharge rate is significant – approx. 5 % per day

Table 1-43: Technology profile for super-capacitors as electrical energy storage [EC 2001]

Newer developments are reported from [Jeol 2003] who claimed to have achieved a storage performance of 50-75 Wh/kg with its so-called "nanogate capacitor".

The characteristic of this type of energy storage rather focus on small scale applications ( $\ll 1 \text{ MW}_e$ ) where energy storage is required only over a short period of time ( $\ll 1 \text{ day}$ ). Super/ultra capacitors are thus not further examined in the course of this study.

### 1.3.7 Super-conducting magnetic energy storage

Electrical energy is stored in the magnetic field of a coil. The coil consists of a super-conducting wire. Thus, there is practically no electrical resistance in the storage system. Yet, the cooling requirements are stern.

The target application of super-conducting magnetic energy storage is to be seen where high power, low energy and fast system response times are required.

Energy and power density	Negligible energy content (up to 1 kWh) but very high power output (3 MVA). Data on energy or power density are meaningless for PQ applications
Cost/economy of scale	Smallest unit available has higher power output than any competing technology except pumped hydro and large compressed air storage. The cost of auxiliary equipment and the low numbers sold prevent cost competitiveness for smaller

	power levels.
Response time	A few milliseconds because of the control circuits and power electronics
Lifetime	No limitations of number of cycles, easy monitoring
Efficiency	99 % are guaranteed for PQ applications, mostly caused by standby losses
Operating constraints	Large self contained unit (trailer) which ensures that all constraints are met

Table 1-44: Technology profile for super-conducting magnetic energy storage systems [EC 2001]

The technological feasibility of super-conducting magnetic energy storage is proven. The technology is not yet mature regarding its technical and economical viability.

The super-conducting magnetic energy storage technology is not further considered in this study.

### 1.3.8 Thermal storage

The storage of thermal energy is only relevant for solar thermal power plants. Thermal energy storage is part of the solar thermal power system to extend its annual equivalent full load hours. The description and assessment of thermal energy storage is part of the technological description of solar thermal power plants in the main part of the Final Report.

In case of the solar thermal power plants the electricity storage are considered as additional storage to bridge more than 24 hours (e.g. a cloudy day) and to elevate the equivalent full load period from about 6,400 to about 8,760 hours per year for base load operation.

## A2 WP1 – TERRESTRIAL AND SPACE BACKGROUND DATA

### 2.1 Terrestrial scenario data

Basic scenario data is listed in this subchapter. Land area requirements for pumped hydro storage are not included in these figures and must be added separately. Land area requirements for hydrogen storage is negligible compared to land area requirements of power production units.

#### 2.1.1 Scenario 0.5 GW

##### a) Electricity storage via hydrogen

Total installed SOT capacity in 2030: ~1 GW<sub>e</sub>

Country	Number of plants	Electricity supply [GW <sub>e</sub> ]	Thereof via HVDC [GW <sub>e</sub> ]	Land area [km <sup>2</sup> ]
Greece	1	0.1	0.0	23
Italy	0	0.0	0.0	0
Portugal	0	0.0	0.0	0
Spain	2	0.2	0.0	45
Turkey	2	0.2	0.0	45
Malta	0	0.0	0.0	0
Cyprus	0	0.0	0.0	0
Total zone 1	5	0.5	0.0	113
Total zone 0	0	0.0	0.0	0
<b>Total</b>	<b>5</b>	<b>0.5</b>	<b>0.0</b>	<b>113</b>

Table 2-1: Installed SOT plants for 0.5 GW scenario (H<sub>2</sub> storage)

##### b) Electricity storage via pumped hydro

Total installed SOT capacity in 2030: ~0.7 GW<sub>e</sub>

Country	Number of plants	Electricity supply [GW <sub>e</sub> ]	Thereof via HVDC [GW <sub>e</sub> ]	Land area [km <sup>2</sup> ]
Greece	1	0.1	0.0	23
Italy	0	0.0	0.0	0
Portugal	0	0.0	0.0	0

Country	Number of plants	Electricity supply [GW <sub>e</sub> ]	Thereof via HVDC [GW <sub>e</sub> ]	Land area [km <sup>2</sup> ]
Spain	2	0.3	0.0	45
Turkey	1	0.1	0.0	23
Malta	0	0.0	0.0	0
Cyprus	0	0.0	0.0	0
Total zone 1	4	0.6	0.0	90
Total zone 0	0	0.0	0.0	0
<b>Total</b>	<b>4</b>	<b>0.6</b>	<b>0.0</b>	<b>90</b>

Table 2-2: Installed SOT plants for 0.5 GW scenario (pumped hydro)

## 2.1.2 Scenarios 5 GW

### a) Electricity storage via hydrogen:

Total installed SOT capacity in 2030: ~10 GW<sub>e</sub>

Country	Number of plants	Electricity supply [GW <sub>e</sub> ]	Thereof via HVDC [GW <sub>e</sub> ]	Land area [km <sup>2</sup> ]
Greece	4	0.4	0.0	90
Italy	6	0.6	0.0	135
Portugal	4	0.4	0.0	90
Spain	20	2.1	0.0	450
Turkey	14	1.5	0.0	315
Malta	0	0.0	0.0	0
Cyprus	0	0.0	0.0	0
Total zone 1	48	5.0	0.0	1,080
Total zone 0	0	0.0	0.0	0
<b>Total</b>	<b>48</b>	<b>5.0</b>	<b>0.0</b>	<b>1,080</b>

Table 2-3: Installed SOT plants for 5 GW scenario (hydrogen storage)

### b) Electricity storage via pumped hydro

Total installed SOT capacity in 2030: ~7.2 GW<sub>e</sub>

Country	Number of plants	Electricity supply [GW <sub>e</sub> ]	Thereof via HVDC [GW <sub>e</sub> ]	Land area [km <sup>2</sup> ]
Greece	4	0.6	0.0	90
Italy	6	0.9	0.0	135
Portugal	4	0.6	0.0	90
Spain	10	1.5	0.0	225
Turkey	10	1.5	0.0	225
Malta	0	0.0	0.0	0
Cyprus	0	0.0	0.0	0
Total zone 1	34	5.0	0.0	765
Total zone 0	0	0.0	0.0	0
<b>Total</b>	<b>34</b>	<b>5.0</b>	<b>0.0</b>	<b>765</b>

Table 2-4: Installed SOT plants for 5 GW scenario (pumped hydro storage)

### 2.1.3 Scenario 10 GW

#### a) Electricity storage via hydrogen:

Total installed SOT capacity in 2030: ~20 GW<sub>e</sub>

Country	Number of plants	Electricity supply [GW <sub>e</sub> ]	Thereof via HVDC [GW <sub>e</sub> ]	Land area [km <sup>2</sup> ]
Greece	4	0.4	0.0	90
Italy	8	0.8	0.0	180
Portugal	4	0.4	0.0	90
Spain	40	4.1	0.0	900
Turkey	40	4.1	0.0	900
Malta	0	0.0	0.0	0
Cyprus	0	0.0	0.0	0
Total zone 1	96	10.0	0.0	2,160
Total zone 0	0	0.0	0.0	0
<b>Total</b>	<b>96</b>	<b>10.0</b>	<b>0.0</b>	<b>2,160</b>

Table 2-5: Installed SOT plants for 10 GW scenario (H<sub>2</sub> storage)

#### b) Electricity storage via pumped hydro

Total installed SOT capacity in 2030: ~14.4 GW<sub>e</sub>

Country	Number of plants	Electricity supply [GW <sub>e</sub> ]	Thereof via HVDC [GW <sub>e</sub> ]	Land area [km <sup>2</sup> ]
Greece	4	0.6	0.0	90
Italy	8	1.2	0.0	180
Portugal	4	0.6	0.0	90
Spain	26	3.8	0.0	585
Turkey	26	3.8	0.0	585
Malta	0	0.0	0.0	0
Cyprus	0	0.0	0.0	0
Total zone 1	68	10.0	0.0	1,530
Total zone 0	0	0.0	0.0	0
<b>Total</b>	<b>68</b>	<b>10.0</b>	<b>0.0</b>	<b>1,530</b>

Table 2-6: Installed SOT plants for 10 GW scenario (pumped hydro)

## 2.1.4 Scenario 50 GW

### a) Electricity storage via hydrogen:

Total installed SOT capacity in 2030: ~100 GW<sub>e</sub>

Country	Number of plants	Electricity supply [GW <sub>e</sub> ]	Thereof via HVDC [GW <sub>e</sub> ]	Land area [km <sup>2</sup> ]
Greece	20	2.1	0.0	450
Italy	40	4.1	0.0	900
Portugal	12	1.2	0.0	270
Spain	110	11.4	0.0	2,475
Turkey	300	31.1	0.0	6,750
Malta	0	0.0	0.0	0
Cyprus	0	0.0	0.0	0
Total zone 1	482	50.0	0.0	10,845
Total zone 0	0	0.0	0.0	0
<b>Total</b>	<b>482</b>	<b>50.0</b>	<b>0.0</b>	<b>10,845</b>

Table 2-7: Installed SOT plants for 50 GW scenario (H<sub>2</sub> storage)

### b) Electricity storage via pumped hydro

Total installed SOT capacity in 2030: ~72 GW<sub>e</sub>

Country	Number of plants	Electricity supply [GW <sub>e</sub> ]	Thereof via HVDC [GW <sub>e</sub> ]	Land area [km <sup>2</sup> ]
Greece	20	2.9	0.0	450
Italy	35	5.1	0.0	788
Portugal	12	1.8	0.0	270
Spain	100	14.7	0.0	2,250
Turkey	174	25.6	0.0	3,915
Malta	0	0.0	0.0	0
Cyprus	0	0.0	0.0	0
Total zone 1	341	50.1	0.0	7,673
Total zone 0	0	0.0	0.0	0
<b>Total</b>	<b>341</b>	<b>50.1</b>	<b>0.0</b>	<b>7,673</b>

Table 2-8: Installed SOT plants for 50 GW scenario (pumped hydro storage)

### 2.1.5 Scenario 100 GW

#### a) Electricity storage via hydrogen:

Total installed SOT capacity in 2030: ~200 GW<sub>e</sub>

Country	Number of plants	Electricity supply [GW <sub>e</sub> ]	Thereof via HVDC [GW <sub>e</sub> ]	Land area [km <sup>2</sup> ]
Greece	80	8.3	0.0	1,800
Italy	120	12.4	0.0	2,700
Portugal	30	3.1	0.0	675
Spain	335	34.7	0.0	7,538
Turkey	400	41.5	0.0	9,000
Malta	0	0.0	0.0	0
Cyprus	0	0.0	0.0	0
Total zone 1	965	100.1	0.0	21,713
Total zone 0	0	0.0	0.0	0
<b>Total</b>	<b>965</b>	<b>100.1</b>	<b>0.0</b>	<b>21,713</b>

Table 2-9: Installed SOT plants for 100 GW scenario (H<sub>2</sub> storage)

#### b) Electricity storage via pumped hydro

Total installed SOT capacity in 2030: ~144 GW<sub>e</sub>

Country	Number of plants	Electricity supply [GW <sub>e</sub> ]	Thereof via HVDC [GW <sub>e</sub> ]	Land area [km <sup>2</sup> ]
Greece	42	6.2	0.0	945
Italy	62	9.1	0.0	1,395
Portugal	27	4.0	0.0	608
Spain	150	22.0	0.0	3,375
Turkey	400	58.8	0.0	9,000
Malta	0	0.0	0.0	0
Cyprus	0	0.0	0.0	0
Total zone 1	681	100.0	0.0	15,323
Total zone 0	0	0.0	0.0	0
<b>Total</b>	<b>681</b>	<b>100.0</b>	<b>0.0</b>	<b>15,323</b>

Table 2-10: Installed SOT plants for 100 GW scenario (pumped hydro)

## 2.1.6 Scenario 500 GW

### a) Electricity storage via hydrogen:

Total installed SOT capacity in 2030: ~1,000 GW<sub>e</sub>

Country	Number of plants	Electricity supply [GW <sub>e</sub> ]	Thereof via HVDC [GW <sub>e</sub> ]	Land area [km <sup>2</sup> ]
Greece	109	11.2	1.6	2,453
Italy	174	18.0	0.0	3,915
Portugal	43	4.5	0.0	968
Spain	522	52.9	17.6	11,745
Turkey	1960	193.2	143.2	44,100
Malta	0	0.0	0.0	0
Cyprus	0	0.0	0.0	0
Total zone 1	2,808	279.8	162.4	63,180
Egypt	200	18.2	18.2	4,500
Algeria	500	45.6	45.6	11,250
Libya	500	45.6	45.6	11,250
Morocco	914	83.4	83.4	20,565

Country	Number of plants	Electricity supply [GW <sub>e</sub> ]	Thereof via HVDC [GW <sub>e</sub> ]	Land area [km <sup>2</sup> ]
Tunisia	300	27.4	27.4	6,750
Total zone 0	2,414	220.2	220.2	54,315
<b>Total</b>	<b>5,222</b>	<b>500.0</b>	<b>382.6</b>	<b>117,495</b>

Table 2-11: Installed SOT plants for 500 GW scenario (H<sub>2</sub> storage)

## b) Electricity storage via pumped hydro

Total installed SOT capacity in 2030: ~719 GW<sub>e</sub>

Country	Number of plants	Electricity supply [GW <sub>e</sub> ]	Thereof via HVDC [GW <sub>e</sub> ]	Land area [km <sup>2</sup> ]
Greece	109	15.6	6.3	2,453
Italy	174	25.6	0.0	3,915
Portugal	43	6.3	0.0	968
Spain	522	73.9	40.1	11,745
Turkey	1960	271.9	227.9	44,100
Malta	0	0.0	0.0	0
Cyprus	0	0.0	0.0	0
Total zone 1	2,808	393.2	274.4	63,180
Egypt	146	18.9	18.9	2,029
Algeria	170	22.0	22.0	2,363
Libya	170	22.0	22.0	2,363
Morocco	170	22.0	22.0	2,363
Tunisia	170	22.0	22.0	2,363
Total zone 0	826	106.8	106.8	11,481
<b>Total</b>	<b>3,634</b>	<b>500.0</b>	<b>381.2</b>	<b>74,661</b>

Table 2-12: Installed SOT plants for 500 GW scenario (pumped hydro)

## 2.2 Space reference systems

### 2.2.1 Selection of 'Sun Tower' concept for 0.5 GW scenario

Quite logically, one can provide this power level by way of a single, 500-MW station continuously beaming to a single rectenna, in which case the station is in GEO, or through a number of power stations passing over one or more rectennae in sequence. The reference source does not hold a 500-MW point, that has accordingly been interpolated, through

the examination of the trends associated with the nominal power plant level for specific quantities: mass and cost related to power for the collection and transmission subsystems, cost per unit mass for the supporting subsystems (AOCS, structure, C&DH etc.), and percentile fraction of the overall quantity for the mass of the supporting subsystems and for the cost of the system AIT&E effort. Quite a number of the resulting parameters appear rather little influenced by the variation in the station's power – fact which seems a reasonable consequence of the modular definition of the Sun Tower system. The major anomalies are extreme values showing up in the cost of the AOCS (twice as high as for the other power levels), and for the structure/ C&DH subsystem (similarly lower): these variations even out at the unit-cost level, which marches well within the expected uncertainty. For the integration effort, the percentile related to the overall cost was used, as that parameter is very stable.

Finally, we assumed four times the delivered power as the total installed power capacity (i.e. 2000 MW vs 500 MW), to cover the cycling of the power stations over the ground sites. The resulting assessment is summarized in Table 2-13. Surprisingly, the systems cost appears to increase with the size of the power station, as does the total mass injected into orbit. Examination of the values collected in Table 2-14 shows that, while the development (non-recurring) specific costs do indeed decrease with growing system's power, both the mass- and cost-related parameters for the power collection and transmission subsystem slightly grow with the nominal power level of the satellite station. This trend seems to make the estimates for larger Sun Towers more robust: accordingly, we selected the architecture consisting of eight 250-MW stations as reference for the present scenario. Such an approach eliminates any need for storage during satellites' eclipses.

## ANNEX: WP1 – Terrestrial and space background data

Final Report

<b>Nominal station power</b>	<b>MW</b>	<b>50</b>	<b>250</b>	<b>500</b>	<b>1000</b>
<b>No of stations</b>		<b>40</b>	<b>8</b>	<b>4</b>	<b>1</b>
<b>Total non-recurring costs</b>	<b>M\$</b>	<b>1774</b>	<b>2030</b>	<b>2159</b>	<b>2265</b>
<b>Total recurring costs</b>	<b>M\$</b>	<b>6720</b>	<b>8349</b>	<b>11654</b>	<b>7148</b>
<b>Total SPS cost</b>	<b>M\$</b>	<b>8494</b>	<b>10379</b>	<b>13814</b>	<b>9413</b>
<b>Mass of all units</b>	<b>t</b>	<b>21160</b>	<b>28274</b>	<b>39690</b>	<b>38397</b>
Mass of an SPS unit	t	529	3534	9922	38397
Power transmission	t	230	1384	3353	9468.5
Solar collection	t	264	1592	3864	10893
AOCS	t	11	163	772	962
Structure, C&DH, ...	t	24	395	1933	17074
Propellant mass (max)	t	9	140	600	750
<b>Non-recurring Costs</b>					
Power transmission costs	M\$	773	773	750	765.5
Power collection costs	M\$	423	430	450	428.5
AOCS	M\$	63	262	618	199
Structure, C&DHS, ...	M\$	211	212	97	396
System AIT&E	M\$	304	353	245	477
<b>Unit costs</b>					
Power transmission	M\$	63	347	830	2326
Solar collection	M\$	55	330.5	830	2307
AOCS	M\$	4	132	579	343
Structure, C&DH, ...	M\$	8	24	101	682
System AIT&E	M\$	38	210.6	574	1490

Table 2-13: Summary of cost data for different power-level Sun Tower stations

<b>Nominal station power</b>	<b>MW</b>	<b>50</b>	<b>250</b>	<b>500</b>	<b>1000</b>
<b>Specific values</b>					
Power transmission subsystem	kg/W	0.0046	0.0055	0.0067	0.0095
Solar collection subsystem	kg/W	0.0053	0.0064	0.0077	0.0109
AOCS	%	2.08%	4.61%	7.78%	2.50%
Structure, C&DH, ... subsystems	%	4.54%	11.18%	19.48%	44.47%
<b>NR</b>					
Power transmission	\$/W	15.46	3.09	1.50	0.77
Solar collection	\$/W	8.46	1.72	0.90	0.43
AOCS	\$/kg	5727.27	1607	800	207
Structure, C&DH, ...	\$/kg	8791.67	537	50	23
System AIT&E	\$/kg	574.67	100	30	12
	%	17.14%	17.39%	17.37%	17.35%
<b>Recurring</b>					
Power transmission	\$/W	1.26	1.39	1.66	2.33
Solar collection	\$/W	1.1	1.32	1.66	2.31
AOCS	\$/kg	363.64	809.8	750.0	356.6
Structure, C&DH, ...	\$/kg	333.33	59.5	52.0	40.0
System AIT&E	\$/kg	71.83	59.6	50.0	38.8
	%	22.62%	20.18%	19.70%	19.04%

Table 2-14: Sun Tower specific parameters' values.

## 2.2.2 Selection of 'Solar Disk' concepts for 5 GW, 10 GW, 50 GW, 100 GW, 150 GW and 500 GW scenarios

<b>Nominal station power</b>	<b>MW</b>	<b>50</b>	<b>250</b>	<b>500</b>	<b>1000</b>
<b>No of stations</b>		<b>400</b>	<b>80</b>	<b>40</b>	<b>20</b>
<b>Delivered power</b>	<b>MW</b>	<b>5000</b>	<b>5000</b>	<b>5000</b>	<b>5000</b>
<b>Total non-recurring costs</b>	<b>M\$</b>	<b>1774</b>	<b>2030</b>	<b>2159</b>	<b>2265</b>
<b>Total recurring costs</b>	<b>M\$</b>	<b>67200</b>	<b>83490</b>	<b>116525</b>	<b>142966</b>
<b>Total SPS cost</b>	<b>M\$</b>	<b>68974</b>	<b>85520</b>	<b>118684</b>	<b>145231</b>
<b>Mass of all units</b>					
<b>Mass of an SPS unit</b>	<b>t</b>	<b>529</b>	<b>3534</b>	<b>9919</b>	<b>38397</b>
Power transmission	t	230	1384	3355	9469
Solar collection	t	264	1592	3860	10893
AOCS	t	11	163	772	962
Structure, C&DH, ...	t	24	395	1932	17074

Table 2-15: Summary of cost data for 5-GW architectures based on Sun Tower stations

<b>Nominal power</b>	<b>MW</b>	<b>250</b>	<b>500</b>	<b>1000</b>	<b>5000</b>
<b>No of stations</b>		<b>20</b>	<b>10</b>	<b>5</b>	<b>1</b>
<b>Power delivered</b>	<b>MW</b>	<b>5000</b>	<b>5000</b>	<b>5000</b>	<b>5000</b>
<b>Total non-recurring costs</b>	<b>M\$</b>	<b>2467</b>	<b>2469</b>	<b>2467</b>	<b>2467</b>
<b>Total recurring costs</b>	<b>M\$</b>	<b>12560</b>	<b>12130</b>	<b>11660</b>	<b>11515</b>
<b>Total SPS cost</b>	<b>M\$</b>	<b>15027</b>	<b>14599</b>	<b>14127</b>	<b>13982</b>
<b>Mass of all units</b>	<b>t</b>	<b>59700</b>	<b>60384</b>	<b>61010</b>	<b>64453</b>
Mass of a unit	t	2985	6038	12202	64453
Power transmission	t	2097	4200	8387	41858
Solar collection	t	578	1150	2314	11544
AOCS	t	174	356	733	4461
Structure, C&DH, ...	t	136	332	768	6590

Table 2-16: Summary of cost data for 5-GW architectures based on Solar Disk stations

<b>Nominal power</b>	<b>MW</b>	<b>1000</b>	<b>5000</b>	<b>10000</b>
<b>No of stations</b>		<b>500</b>	<b>100</b>	<b>50</b>
<b>Power delivered</b>	<b>MW</b>	<b>500000</b>	<b>500000</b>	<b>500000</b>
<b>Total non-recurring costs</b>	<b>M\$</b>	<b>2467</b>	<b>2467</b>	<b>2498</b>
<b>Total recurring costs</b>	<b>M\$</b>	<b>1166000</b>	<b>1151500</b>	<b>1238507</b>
<b>Total SPS cost</b>	<b>M\$</b>	<b>1168467</b>	<b>1153967</b>	<b>1241006</b>
<b>Total mass in orbit</b>	<b>t</b>	<b>6101000</b>	<b>6445300</b>	<b>6650311</b>
Mass of a unit	t	12202	64453	133006
Power transmission	t	8387	41858	83716
Solar collection	t	2314	11544	23088
AOCS	t	733	4461	10774
Structure, C&DH, ...	t	768	6590	15429

Table 2-17: Summary of cost data for 500-GW architectures based on Solar Disk stations

### **2.2.3 Costs split of SPS systems**

Costs in million US\$<sub>1997</sub>

	0.5 GW				5 GW				10 GW				50 GW				100 GW				150 GW				500 GW			
	non-recurring costs <sup>1)</sup>	system costs <sup>2)</sup>	deployment costs	cost share in %	non-recurring costs <sup>1)</sup>	system costs <sup>2)</sup>	deployment costs	cost share in %	non-recurring costs <sup>1)</sup>	system costs <sup>2)</sup>	deployment costs	cost share in %	non-recurring costs <sup>1)</sup>	system costs <sup>2)</sup>	deployment costs	cost share in %	non-recurring costs <sup>1)</sup>	system costs <sup>2)</sup>	deployment costs	cost share in %	non-recurring costs <sup>1)</sup>	system costs <sup>2)</sup>	deployment costs	cost share in %	non-recurring costs <sup>1)</sup>	system costs <sup>2)</sup>	deployment costs	cost share in %
A: SSP system manufacturing capability	2.640	0	0	17,4%	1.680	0	0	7,6%	8.050	0	0	17,3%	8.050	0	0	4,7%	8.050	0	0	2,4%	8.050	0	0	1,8%	8.050	0	0	0,5%
B: Ground launch Infrastructure	0	0	0	0,0%	0	0	0	0,0%	0	0	0	0,0%	0	0	0	0,0%	0	0	0	0,0%	0	0	0	0,0%	0	0	0	0,0%
C: Earth-to-orbit (ETO) system	0	0	0	0,0%	0	0	0	0,0%	0	0	0	0,0%	0	0	0	0,0%	0	0	0	0,0%	0	0	0	0,0%	0	0	0	0,0%
D: In space transportation	0	0	0	0,0%	0	0	0	0,0%	0	0	0	0,0%	0	0	0	0,0%	0	0	0	0,0%	0	0	0	0,0%	0	0	0	0,0%
E: In space infrastructure	50	1.056	0	7,3%	50	1.909	0	8,8%	50	3.819	0	8,3%	50	11.842	0	6,9%	50	23.684	0	7,2%	50	35.527	0	7,8%	50	95.450	0	5,7%
T: Relay space segment	0	0	0	0,0%	0	0	0	0,0%	0	0	0	0,0%	0	0	0	0,0%	0	0	0	0,0%	0	0	0	0,0%	0	0	0	0,0%
F: SSP: Space segment	2.030	8.352	0	68,4%	2.467	11.660	0	63,5%	2.467	23.030	0	54,7%	2.467	115.150	0	68,4%	2.467	230.300	0	70,5%	2.467	345.450	0	76,1%	2.499	1.238.500	0	74,6%
G: SSP: Ground segment	670	298	0	6,4%	1.340	2.394	0	16,8%	3.000	4.674	0	16,5%	3.000	23.900	0	15,6%	3.000	47.800	0	15,4%	3.000	47.800	0	11,1%	4.243	240.739	0	14,7%
H: Commercial power utilities systems	0	75	0	0,5%	0	750	0	3,4%	0	1.500	0	3,2%	0	7.502	0	4,4%	0	15.003	0	4,5%	0	15.003	0	3,3%	0	75.015	0	4,5%
<b>TOTAL</b>	15.171 100,0%				22.251 100,0%				46.590 100,0%				171.961 100,0%				330.354 100,0%				457.346 100,0%				1.664.546 100,0%			

Table 2-18: Cost split of SPS systems without costs for SPS launching and deployment. Cost split categories base on structure defined in [NASA 1997].

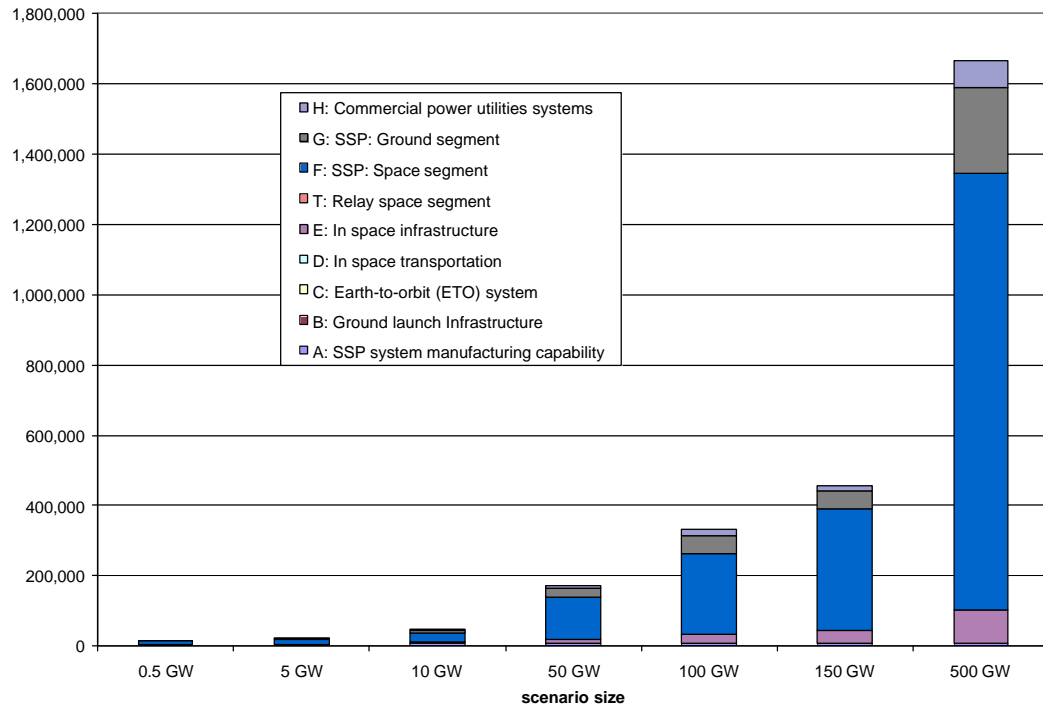


Figure 2-1: Cost split of SPS systems for different scenario sizes in million US\$<sub>1997</sub> based on [NASA 1997]

## A3 LAUNCH – FUEL COSTS

### 3.1 Hydrogen

The NASA-Freshlook study calculates with fuel prices of about \$0.3/kg fuel (liquid hydrogen + Oxygen). Subtracting oxygen cost of \$0.08/kg this implies specific hydrogen cost of  $(9 \times \$0.3/\text{kg} - 8 \times \$0.08/\text{kg}) = \$2.06/\text{kg}$  or 6.2 cts/kWh. For the following calculations, the conversion ratio 1 US\$=1EUR is chosen. In face of the general uncertainties this implies no "degradation" of the results.

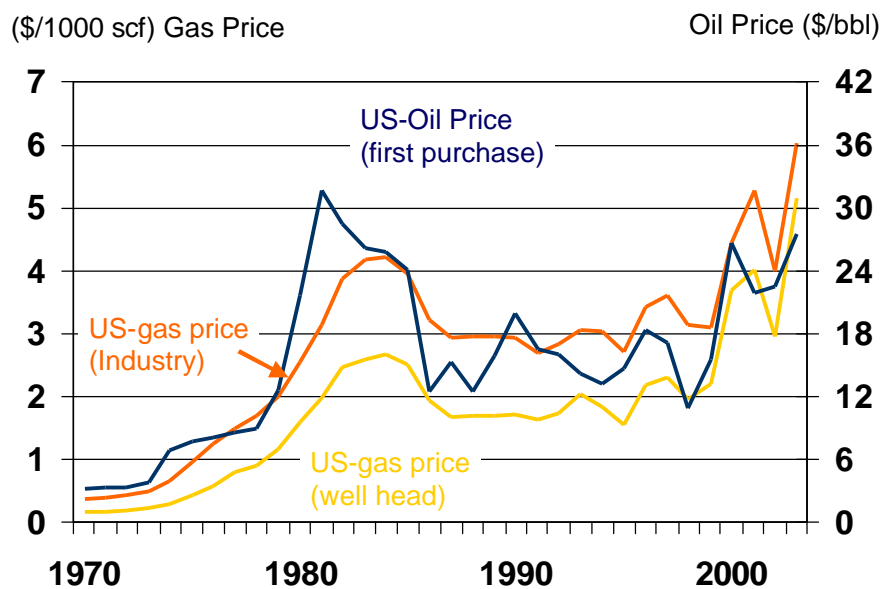
According to the Encyclopedia Astronautica liquid hydrogen cost at NASA in 80ies were at \$3.6 /kg and liquid oxygen cost at \$0.08/kg. The theoretically required hydrogen to oxygen ratio is 1:8 per weight. This sums up to specific fuel cost of 0.47 EUR/kg fuel. [Astronautica 2004] or, if the ratio 1:6 is chosen, to 0.58 EUR/kg fuel.

Today and in the past, the cheapest way to produce hydrogen is via steam reforming of natural gas, despite electrolysis from large hydropower in remote areas and for local consumption. The conversion efficiency of natural gas steam reforming into liquid hydrogen is about 50%. Therefore this 6.2 cts/kWh liquid hydrogen cost correspond to 1 cts/kWh natural gas price, at highest, if we take care for reformer and liquefaction plant with about 2 cts/kWh<sub>H<sub>2</sub></sub> and O&M cost (other than energy) and earning margins with another 2 cts/kWh<sub>H<sub>2</sub></sub>  $[(6.2 \text{ cts/kWh} - 2 \text{ cts/kWh} - 2 \text{ cts}) \times 0.5 = 1.1 \text{ cts/kWh}_{\text{natgas}}]$ .

From gas price analysis it can be understood that such low energy prices were common in the 70ies in the US. (1 cts/kWh = \$ 2.7/1000scf). However, in the meantime the situation has changed substantially. To put more realistic figures on fuel cost, the following graph sketches the cost development of natural gas (being the fuel of choice for hydrogen production), and crude oil in the US since 1970 until today.

The graph in Figure 3-1 exhibits the dramatic gas price increases in the US. In 1970 oil was roughly three times as expensive as gas, always according to the same energy content. This factor reduced to a factor of two around 1980. Today gas is even more expensive than oil – a relative price increase of more than a factor of three in 30 years!

Different from Europe, in the US the gas price is not automatically coupled to the oil price, but based on its own logic. The strong increases over the last years reflect increasing production costs – mainly due to deep sea exploration and smaller reservoirs which are faster exhausted – and shrinking supplies since about 2000. Analysts expect gas prices to hike even higher over the next years [Simmons 2002].



Source: US-DoE, 2004

Figure 3-1: Annual oil and gas prices in the USA according to DoE Statistics (nominal prices). The crude oil price corresponds to the gas well head price. A gas price of \$1/1000 scf roughly corresponds to 6 barrel oil or according to its energy content and is equivalent to 0.37 cts/kWh

Before 1973 natural gas prices below 1 \$/1000 scf were usual. These figures have changed dramatically. In 2003 well head gas prices were above 5 \$/1000 scf with industry prices exceeding the 6 \$-limit. During winter time, monthly industry average prices for the whole US already exceeded the \$8/1000scf barrier. For the year 2030 gas prices might be expected even higher. For commercial launches, industry gas prices are to be chosen. To set a lower limit on fuel prices, a 8 \$/1000 scf gas price translates in liquid hydrogen cost of at least \$ 3 /kg.

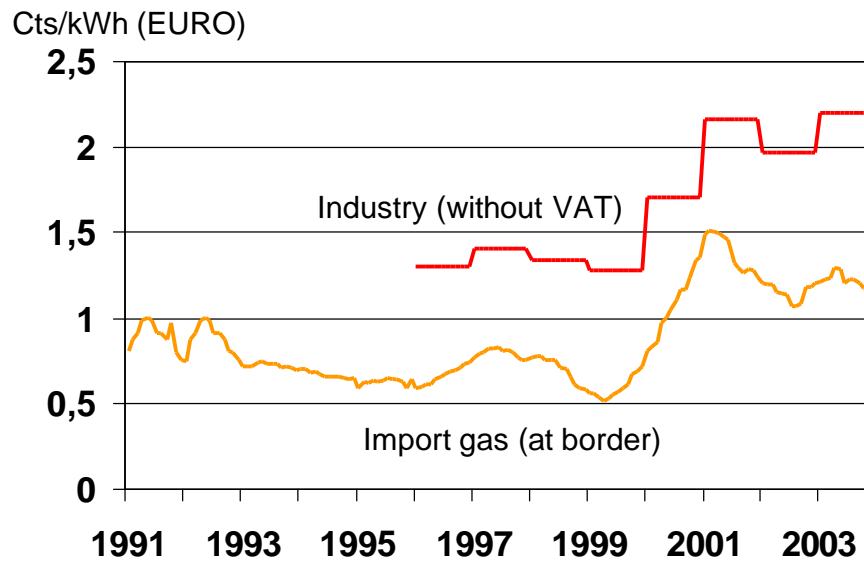
Specific gas price per Energy unit:  $\$8/1000\text{scf} * (1000\text{scf}/270 \text{ kWh}) = 3 \text{ cts/kWh}$

Specific hydrogen price per energy unit including Plant cost and earning margins:

$2 \text{ cts/kWh} + (3 \text{ cts/kWh} / 0.5) + 1 \text{ cts/kWh} = 9 \text{ cts/kWh} = \$ 3/\text{kg liquid hydrogen}$

This is still below the price of \$ 3.6/kg which is reported as being paid by NASA during the 80ies.

Adapting the results to a European perspective reveals that here gas prices are generally higher by a factor 3 – 4. Figure 3-2 shows the monthly development of gas import prices at the German border and the German industry prices without VAT.



Source: Import prices: <http://www.bmwi.de/Navigation/Technologie-und-Energie/energiepolitik,did=7880.html>  
 Industry prices: <http://www.bmwi.de/Redaktion/Inhalte/Downloads/egasjahr-september-2003.property=pdf.pdf>  
 2003 LBST estimate

Figure 3-2: Monthly natural gas price at German border and annual German industry gas prices

Actually a gas price of at least 2 cts/kWh seems realistic. This would result in LH<sub>2</sub> costs of at least:

$$(2 \text{ cts/kWh} + (2 \text{ cts/kWh} / 0.5) + 1 \text{ cts/kWh}) * 33 \text{ kWh/kg} = \$ 2.31/\text{kg}_{\text{LH}_2}$$

A doubling of gas prices would result in about \$3.6/kg liquid hydrogen.

### 3.2 Oxygen

Oxygen in large quantities is produced via liquefaction of air or in recent years via air separation by advanced membranes. Main cost factors are investment cost for plant, O&M cost and electricity cost. In estimating future cost increases, the critical variable are electricity cost. Typically, electricity consumption is 0.5 kWh/Nm<sup>3</sup>. However, state-of-the-art plants consume only 0.3 kWh/Nm<sup>3</sup> [Praxair 2003].

Today's electricity cost for large consumers are in the order of 5 - 6 cts/kWh<sub>el</sub>. This transforms in a cost share of 1 cts/kg oxygen.

A state-of the art oxygen production plant costs about 20 Mio Euro for a capacity of 165 t/day [Praxair 1999]. Assuming 15 year operation and 6 percent depreciation results in an annuity factor a=0.103; This translates in specific investment cost of 3.3 cts/kg.

Adding O&M cost of similar size, at worst, results in total oxygen cost of about 8 cts/kg. Energy cost are included with about 12.5 percent share. Even a tripling of electricity cost would shift total oxygen cost to only 10 cts/kg.

### 3.3 Total fuel cost

It seems justified, to assume oxygen cost not increasing above \$0.1/kg. If we put a range of today's natural gas cost and a tripling over the next 30 years, this adds to a range of total fuel cost of between.

Today's cost:  $1/9 * \$ 3/\text{kg}_{\text{H}_2} + 8/9 * \$ 0.08/\text{kgO}_2 = \mathbf{\$0.4/\text{kg}_{\text{fuel}}}$

Upper limit (tripling of gas price):  $1/9 * \$ 7/\text{kg}_{\text{H}_2} + 8/9 * \$ 0.1/\text{kgO}_2 = \mathbf{\$0.9/\text{kg}_{\text{fuel}}}$

These figures might set an acceptable range for the fuel cost.

The influence of the development of natural gas prices as discussed here is only considering the fuel costs for launch and not for any other assessment of space or terrestrial systems.

## A4 WP3 – COMBINATION

### 4.1 Substitution of terrestrial storage

The following table shows the results for SOT and SPS systems (with and without launch costs).

Scenarios	0.5	5	10	50	100	500	GW
SPS 2,300 hr/yr without launch costs	0.934	0.137	0.143	0.106	0.102	0.102	EUR/kWhe
SPS 2,300 hr/yr 1,000 EUR/kgpayload	1.733	0.309	0.325	0.288	0.284	0.290	EUR/kWhe
SPS 2,300 hr/yr 600 EUR/kgpayload	1.413	0.240	0.253	0.215	0.211	0.215	EUR/kWhe
SPS 2,300 hr/yr 200 EUR/kgpayload	1.094	0.171	0.180	0.142	0.138	0.140	EUR/kWhe
SOT 6,400 h/yr without storage	0.041	0.036	0.035	0.032	0.031	0.029	EUR/kWhe
SOT base load with hydrogen storage	0.090	0.082	0.080	0.076	0.075	0.076	EUR/kWhe
SOT base load with pumped hydro storage	0.058	0.053	0.051	0.049	0.047	0.050	EUR/kWhe
SPS base load without launch	0.280	0.041	0.043	0.032	0.030	0.031	EUR/kWhe
SPS base load 1,000 EUR/kgpayload	0.519	0.093	0.097	0.086	0.085	0.087	EUR/kWhe
SPS base load 600 EUR/kgpayload	0.423	0.072	0.076	0.064	0.063	0.064	EUR/kWhe
SPS base load 200 EUR/kgpayload	0.327	0.051	0.054	0.043	0.041	0.042	EUR/kWhe

Table 4-1: Levelized costs for SPS and SOT systems.

For further discussion of the levelized costs of space systems following launch parameter are assumed and calculated:

- Average launch cost target of 1,000 EUR/kg<sub>payload</sub>
- Average launch cost target of 600 EUR/kg<sub>payload</sub>
- Average launch cost target of 200 EUR/kg<sub>payload</sub>

Table 4-1 shows LEC calculated for SPS systems operated for 2,360 full load hours per year. These systems are optimized to substitute the amount of required terrestrial storage for SOT base load systems only to avoid the production of surplus electricity. SOT plants generate power for 6,400 full load hours per year. For comparison cost results are given in the table above for SOT systems with hydrogen and pumped hydro storage respectively. The lowest LEC of SPS systems are given for base load operation.

## A5 WP4 – ENERGY PAYBACK TIMES

The definition of basic materials concerning their specific primary energy effort is given in the course of this chapter.

For the supply of steel the German steel mix is assumed. According to [GEMIS 2002] the German steel mix consists of 80% oxygen steel and 20% electric steel. In oxygen steel plants mainly pig iron is used as feedstock for the production of steel (only about 180 kg scrap per t of steel). For the production of steel via electric steel plants mainly scrap is used.

	Concrete [kWh/kg]	Cement [kWh/kg]	Steel [kWh/kg]
Biomass	0.001	0.004	0.000
Brown coal	0.073	0.412	- 0.116
Hard coal	0.094	0.532	4.323
Hydro power	0.001	0.005	0.034
Crude oil	0.068	0.215	0.806
NG	0.009	0.039	- 0.183
Nuclear	0.024	0.113	- 0.125
Waste	0.006	0.028	0.811
Wind power	0.000	0.001	- 0.002
Total	0.275	1.350	5.548

Table 5-1: Energy requirements for the supply of concrete, cement and steel [GEMIS 2002]

Stainless steel is an alloy consisting of chrome, Nickel and conventional steel. For the calculation of the energy requirement for the supply of stainless steel a typical composition as indicated in [ESU 1996] has been assumed.

	Input	Output
Chrome [kg/kg]	0.16	-
Nickel [kg/kg]	0.13	-
Steel [kg/kg]	0.71	-
Electricity [kWh/kg]	0.26	-
Stainless steel [kg]	-	1.00

Table 5-2: Input and output data for the supply of stainless steel [ESU 1996]

The primary energy requirement for the supply of chrome is 32.3 kWh per kg of chrome and the primary energy requirement for the supply of nickel is 43.4 kWh per kg of nickel [GABIE 2002].

For copper a mixture of secondary and primary copper has been assumed. The share of secondary copper has been assumed to be 85%. In Europe aluminum enjoys high recycling rates, ranging from 41% in beverage cans to 85% in building and construction and 95% in transportation. Meanwhile comprehensive systems for the recovery of used aluminum exist in all major European countries [Azom 2002]. Consequently for aluminum also a share of 85% secondary aluminum has been assumed.

The supply of copper is rather electricity intensive. Since the electricity mix is changing in the future (higher share of renewable electricity sources) the supply of copper (and also aluminum) has to be calculated.

	Input	Output
Copper scrap [kg/kg]	1.040	-
Coke [kWh/kg]	2.556	-
Electricity [kWh/kg]	1.056	-
Copper [kg]	-	1.000

Table 5-3: Input and output data for the supply of secondary copper [GEMIS 2002]

	Input	Output
Copper scrap [kg/kg]	0.57	-
Copper ore [kg/kg]	1.87	-
H <sub>2</sub> SO <sub>4</sub> [kg/kg]	1.88	-

	Input	Output
Electricity [kWh/kg]	1.222	-
Natural gas [kWh/kg]	1.750	-
Copper [kg]	-	1.000

Table 5-4: Input and output data for the supply of primary copper [GEMIS 2002]

Sulfuric acid ( $H_2SO_4$ ) is formed as by-product in many industrial processes. Therefore no energy requirement is taken into account for the supply of  $H_2SO_4$ .

	Input	Output
Copper ore from source [kg/kg]	1.000	-
Electricity [kWh/kWh]	0.983	-
Lime [kg/kg]	0.080	-
Mechanical work [kWh/kg]	0.750	-
Steel [kg/kg]	0.014	-
Water [kg/kg]	0.022	-
Copper ore [kg]	-	1.000

Table 5-5: Input and output data for the mining of copper ore [GEMIS 2002]

The mechanical work is supplied by a diesel engine with an efficiency of 30%. Today the electricity used in the copper mines is derived from coal. Therefore a coal power station with an efficiency of approximately 40% has been assumed for the electricity supply of the copper mine.

	Input	Output
Aluminum scrap [kg/kg]	1.164	-
Chlorine [kg/kg]	0.002	-
Electricity [kWh/kg]	0.411	-
Heat [kWh/kg]	2.009	-
KCl [kg/kg]	0.021	-
Aluminum [kg]		1.000

Table 5-6: Input and output data for the supply of secondary aluminum [GEMIS 2002]

	Input	Output
Al <sub>2</sub> O <sub>3</sub> [kg/kg]	1.900	-
AlF <sub>3</sub> [kg/kg]	0.018	-
Anode C [kg/kg]	0.430	-
Electricity [kWh/kg]	13.4	-
Heat [kWh/kg]	1.063	
Aluminum [kg]		1.000

Table 5-7: Input and output data for the supply of primary aluminum [GEMIS 2002]

	Input	Output
Bauxite [kg/kg]	2.000	-
CaO [kg/kg]	0.040	-
NaOH [kg/kg]	0.122	-
Electricity [kWh/kg]	0.258	-
Heat [kWh/kg]	2.222	
Al <sub>2</sub> O <sub>3</sub> [kg]	-	1.000

Table 5-8: Input and output data for the supply of Al<sub>2</sub>O<sub>3</sub> [GEMIS 2002]

	Input	Output
Bauxite [kg/kg]	1.528	-
CaO [kg/kg]	0.028	-
NaOH [kg/kg]	0.133	-

	Input	Output
Heat [kWh/kg]	3.017	-
AlF <sub>3</sub> [kg]	-	1.000

Table 5-9: Input and output data for the supply of AlF<sub>3</sub> [GEMIS 2002]

	Input	Output
Bauxite source [kg/kg]	1.471	-
Electricity [kWh/kg]	0.002	-
Mechanical work [kWh/kg]	0.044	-
Bauxite [kg]		1.000

Table 5-10: Input and output data for the mining of bauxite [GEMIS 2002]

Glass fiber reinforced plastics contains 50 to 80% glass fiber. The rest is epoxy resin. For the calculation a glass fiber content of 80% has been assumed. Table 5-11 shows the input and output data for the production of glass fiber and Table 5-12 shows the input and output data for the production of epoxy resin.

	Input	Output
Material source [kg/kg]	1.000	-
Natural gas [kWh/kg]	5.49	-
Electricity [kWh/kg]	1.32	-
Glass fiber [kg]	-	1.000

Table 5-11: Input and output data for the production of glass fiber [Stiller 1999]

	Input	Output
Benzene [kg/kg]	0.230	-
Ca(OH) <sub>2</sub> [kg/kg]	0.356	-
Chlorine [kg/kg]	0.738	-
NaOH [kg/kg]	0.304	-
Propylene [kg/kg]	0.792	-

	Input	Output
Electricity [kWh/kg]	0.150	-
Epoxy resin [kg]	-	1.000

Table 5-12: Input and output data for the production of epoxy resin [Stiller 1999]

Chlorine is produced via electrolysis of NaCl employing a membrane electrolysis plant. In [GEMIS 2002] the requirement of energy and materials is allocated by the molar ratio between NaOH and chlorine (Cl).

For every t of Cl<sub>2</sub> about 1.128 t NaOH and 0.028 t H<sub>2</sub> are produced and about 1.710 t of NaCl is required. As the energy and material requirement is allocated by the molar ratio between NaOH and Cl about 0.855 kg NaCl are required for the production of 1 kg Cl<sub>2</sub> and about 0.014 kg H<sub>2</sub> are produced. Na<sub>2</sub>CO<sub>3</sub> is required as precipitant to remove contamination from the electrodes.

	Input	Output
Electricity [kWh/kg]	1.353	-
Heat [kWh/kg]	0.075	-
Na <sub>2</sub> CO <sub>3</sub> [kg/kg]	0.022	-
NaCl [kg/kg]	0.855	-
Water [kg/kg]	0.254	-
Chlorine [kg/kg]	-	1.000
H <sub>2</sub> [kWh/kg]	-	0.467

Table 5-13: Input and output data for the supply of chlorine [GEMIS 2002]

NaOH is produced via electrolysis of NaCl employing a membrane electrolysis plant. In [GEMIS 2002] the requirement of energy and materials is allocated by the molar ratio between NaOH and chlorine (Cl).

For every t of NaOH about 0.887 t Cl<sub>2</sub> and 0.0248 t H<sub>2</sub> are produced and about 1.516 t of NaCl is required. As the energy and material requirement is allocated by the molar ratio between NaOH and Cl about 0.758 kg NaCl are required for the production of 1 kg NaOH and about 0.0124 kg H<sub>2</sub> are produced.

	Input	Output
Electricity [kWh/kg]	1.200	-
Heat [kWh/kg]	0.067	-
Na <sub>2</sub> CO <sub>3</sub> [kg/kg]	0.020	-
NaCl [kg/kg]	0.758	-
Water [kg/kg]	0.225	-
NaOH [kg]	-	1.000
H <sub>2</sub> [kWh/kg]	-	0.413

Table 5-14: Input and output data for the supply of NaOH [GEMIS 2002]

Table 5-15 shows the input and output data for the supply of NaCl. Sodium chloride (NaCl) is extracted via mining. The data indicated in [GEMIS 2002] are derived from German companies.

	Input	Output
Electricity [kWh/kg]	0.0160	-
Heat [kWh/kg]	0.0009	-
Mechanical work [kWh/kg]	0.0038	
NaCl [kg]	1.005	1.000

Table 5-15: Input and output data for the supply of NaCl [GEMIS 2002]

	Input	Output
Biomass [kWh/kg]	0.001	-
Brown coal [kWh/kg]	0.022	-
Hard coal [kWh/kg]	0.028	-
Hydro power [kWh/kg]	0.002	-
Crude oil [kWh/kg]	0.059	-
NG [kWh/kg]	1.141	-
Nuclear [kWh/kg]	0.027	-
Waste [kWh/kg]	0.007	-
Minerals [kg/kg]	1.76	
CaO [kg]	-	1.00

	Input	Output
CO <sub>2</sub> [g/kg]	-	1015
CH <sub>4</sub> [g/kg]	-	0.658
N <sub>2</sub> O [g/kg]	-	0.008

Table 5-16: Input and output data for the supply of CaO [GEMIS 2002]

Liquid oxygen (LO<sub>2</sub>) and liquid nitrogen (LN<sub>2</sub>) is generated via air separation and liquefaction. Both LO<sub>2</sub> and LN<sub>2</sub> are useful products. In [GEMIS 2002] the electricity consumption is allocated by mass to the two products LO<sub>2</sub> and LN<sub>2</sub>. Therefore the electricity consumption both for the production of LO<sub>2</sub> and for LN<sub>2</sub> is equivalent (0.56 kWh/kg).

	Input	Output
Electricity [kWh/kg]	0.56	-
Air [kg/kg]	1.00	
LO <sub>2</sub> [kg]	-	1.00

Table 5-17: Input and output data for the air separation with liquefaction for the production of LO<sub>2</sub> [GEMIS 2002]

	Input	Output
Electricity [kWh/kg]	0.56	-
Air [kg/kg]	1.00	
LN <sub>2</sub> [kg]	-	1.00

Table 5-18: Input and output data for the air separation with liquefaction for the production of LN<sub>2</sub> [GEMIS 2002]

LH<sub>2</sub> is used together with LO<sub>2</sub> as propellant for the launch vehicle for the space solar concept. LH<sub>2</sub> is generated via electrolysis with downstream hydrogen liquefaction. For the production of hydrogen the electricity consumption for electrolysis as for the H<sub>2</sub> storage for the solar thermal power plant has been used (1.538 kWh per kWh of H<sub>2</sub>).

	Input	Output
Electricity [kWh/kWh <sub>LH2</sub> ]	0.300	-
GH <sub>2</sub> [kWh/kWh <sub>LH2</sub> ]	1.000	-
LH <sub>2</sub> [kWh]	-	1.000

Table 5-19: Input and output data for hydrogen liquefaction

The lower heating value of hydrogen is 33.33 kWh/kg. Then the electricity consumption per kg of LH<sub>2</sub> is 10 kWh per kg of LH<sub>2</sub>.

For the thermal storage of the solar thermal power station with central receiver so-called "solar salt", a mixture of NaNO<sub>3</sub> and KNO<sub>3</sub> is used. NaNO<sub>3</sub> is made from nitric acid (HNO<sub>3</sub>) and sodium carbonate (Na<sub>2</sub>CO<sub>3</sub>).

	Input	Output
HNO <sub>3</sub> [kg/kg]	0.741	-
Na <sub>2</sub> CO <sub>3</sub> [kg/kg]	0.624	-
Water [kg/kg]	-	0.106
CO <sub>2</sub> [kg/kg]	-	0.259
NaNO <sub>3</sub> [kg]	-	1.000

Table 5-20: Input and output data for NaNO<sub>3</sub>

	Input	Output
NH <sub>3</sub> [kg/kg]	0.282	0.001
O <sub>2</sub> from Air [kg/kg]	1.016	-
Water [kg/kg]	-	0.287
N <sub>2</sub> O [kg/kg]	-	0.006
NO <sub>x</sub> [kg/kg]	-	0.004
Heat [kWh/kg]	-	0.778
HNO <sub>3</sub> [kg]	-	1.000

Table 5-21: Input and output data for the production of HNO<sub>3</sub> [GEMIS 2002]

The energy requirement for the supply of ammonia (NH<sub>3</sub>) is indicated with some 11 kWh per kg of NH<sub>3</sub> [NREL 1999]. The production of sodium carbonate (Na<sub>2</sub>CO<sub>3</sub>) is carried out

via the Solvay process. Table 5-22 shows the net input and output data for the production of  $\text{Na}_2\text{CO}_3$  via Solvay process.

	Input	Output
$\text{CaCO}_3$ [kg/kg]	1.130	-
NaCl [kg/kg]	1.550	-
Hard coal [kWh/kg]	2.205	-
Water [kg/kg]	62.5	-
Coke [kWh/kg]	0.618	-
Natural gas [kWh/kg]	0.304	-
$\text{Na}_2\text{CO}_3$ [kg]	-	1.000

Table 5-22: Input and output data for the production of  $\text{Na}_2\text{CO}_3$  [GEMIS 2002]

The residue contains  $\text{CaCl}_2$ .

For the energy requirement which are associated with the use of plastics, high density polyethylene (HDPE) generally has been assumed. In some cases the use of low density polyethylene (LDPE) has been indicated. Table 5-23 shows the input and output data of the supply of high density polyethylene (HDPE).

	Input	Output
Oil (mass) [kg/kg]	0.870	
Natural gas (mass) [kg/kg]	0.306	
Biomass [kWh/kg]	0.008	
Brown coal [kW/kg]	0.025	
Hard coal [kW/kg]	0.661	
Hydro power [kW/kg]	0.222	
Oil [kWh/kg]	3.364	
Natural gas [kWh/kg]	2.178	
Nuclear [kWh/kg]	0.867	
HDPE [kg]	-	1.000

Table 5-23: Input and output data for the production of high density polyethylene (HDPE) [GEMIS 2002]

It has to be noted that in [GEMIS 2002] the oil and natural gas input which is converted to the final product (including losses) is taken into account as material input and not as energy input. Only the energy use for heat and electricity generation is taken into account as energy. Other literature sources consider all combustible inputs as energy. If the oil and natural gas which is converted to the plastics is considered as energy input the energy use for the supply of high density polyethylene (HDPE) would be some 22 kWh per kg of HDPE instead of some 7 kWh per kg of HDPE. Therefore there are large differences in the literature concerning the energy requirement for the supply of plastics although the emissions of CO<sub>2</sub> are approximately equivalent.

Table 5-24 shows the input and output data for the supply of low density polyethylene (LDPE).

	Input	Output
Oil (mass) [kg/kg]	0.548	-
NG (mass) [kg/kg]	0.660	-
Biomass [kWh/kg]	0.019	-
Brown coal [kW/kg]	0.042	-
Hard coal [kW/kg]	0.753	-
Hydro power [kW/kg]	0.292	-
Oil [kWh/kg]	2.183	-
NG [kWh/kg]	2.417	-
Nuclear [kWh/kg]	0.964	-
Heat [kWh/kg]	-	0.417
HDPE [kg]	-	1.000

Table 5-24: Input and output data for the production of low density polyethylene (LDPE) [GEMIS 2002]

Combination of the different processes with upstream processes and additional data from literature sources lead to the energy requirement for the supply of the different materials as shown in Table 5-25.

	Electricity mix 1999 [kWh/kg]	Electricity mix 2020 [kWh/kg]	Source
Aluminum secondary	3.63	3.42	GEMIS, 2002
Aluminum primary	48.09	39.5	GEMIS, 2002
Argon	8.89	8.89	Herendeen et al, 1979
Chromium	32.32	32.32	GABIE, 2002
Concrete	0.28	0.28	GEMIS, 2002
Copper secondary	7.13	6.52	GEMIS, 2002
Copper primary	14.75	14.05	GEMIS, 2002
Fiberglass	9.50	8.74	GEMIS, 2002, Stiller 1999
Glass fiber reinforced plastics (GRP)	8.92	8.14	GEMIS, 2002, Stiller 1999
Carbon fiber reinforced plastics	153.00	153.00	Achternbosch et al, 2003
Liquid hydrogen (LH <sub>2</sub> ) from EU electricity mix	180.93	144.18	GHW 2001; Linde 1994; Air Liquide 2002
Liquid hydrogen (LH <sub>2</sub> ) from EU electricity mix	171.60	136.74	GHW 2001; Air Liquide 2002
LH <sub>2</sub> from NG	64.30	64.30	Linde 1992; Air Liquide 2002
Insulation (PU foam)	26.12	26.12	GABIE, 2002
Insulation (rock wool)	4.06	4.06	GEMIS, 2002
Lead (sekundary)	0.37	0.35	GEMIS, 2002
Lead (primary)	7.45	6.94	GEMIS, 2002
Lithium	194.44	194.44	ESU, 2003
Manganese	28.32	22.63	ESU, 1996
Nickel	43.4	43.4	GABIE, 2002
Liquid oxygen (LO <sub>2</sub> )	1.57	1.25	GEMIS, 2002
Liquid nitrogen (LN <sub>2</sub> )	1.57	1.25	GEMIS, 2002
Iron	6.53	6.53	Meier, 2002
Plastics (HDPE)	7.33	7.33	GEMIS, 2002
Plastics (LDPE)	6.18	6.18	GEMIS, 2002
Metallurgic silicon	39.16	31.23	KFA 1992; GEMIS, 2002
Electron grade silicon	191.8	124.23	KFA 1992; GEMIS, 2002

	Electricity mix 1999 [kWh/kg]	Electricity mix 2020 [kWh/kg]	Source
Solar grade silicon	85.85	75.59	KFA 1992; GEMIS, 2002; ESU 2000
Steel	5.55	5.55	GEMIS, 2002
Stainless steel	15.48	15.33	GEMIS, 2002; ESU 1996; GABIE 2002
Titanium	255.56	255.56	Smil, 1999
Vanadium	1030.89	1030.89	Meier, 2002
Glass	3.38	3.36	GEMIS, 2002
NaOH	2.99	2.29	GEMIS, 2002; Linde 1992
Chlorine	4.00	2.58	GEMIS, 2002; Linde 1992

Table 5-25: Summary energy intensity of selected materials

## A6 POSSIBLE ENVIRONMENTAL IMPACTS OF EFFECTS FROM SPACE TRANSPORTATION

[OTA 1981, p 12] states some potential impacts of effluents from space transportation, such as the depletion of ionosphere, enhance of airglow in ionosphere, possible formation of noctilucent clouds in stratosphere and mesosphere to give some example issues which would have to be further investigated. Water vapor and  $\text{NO}_x$  emissions at high altitudes and their possible impacts are discussed in more detail in the following.

The natural water vapor content of the atmospheric layers above the troposphere (tropopause, stratosphere, stratopause, etc.) is lower than that of the troposphere. Further the retention period of water vapor is longer than in the troposphere (one year instead of 8 to 9 days).

In [Zittel 1996] the influence of the emissions of water vapor on the atmosphere from a global hydrogen energy economy has been investigated. Further the influence of high flying aircraft on the stratospheric water vapor budget has been considered especially when the aircraft is converted to hydrogen as fuel. Today's lower stratosphere contains approximately 1,300 million t  $\text{H}_2\text{O}$  with an annual average life time of one year. Annual vapor sources are as following:

- Diffusion from troposphere to stratosphere: ~220 million t  $\text{H}_2\text{O}$  per year
- Diffusion jets during storms: ~880 million t  $\text{H}_2\text{O}$  per year
- Methane and  $\text{C}_n\text{H}_m$  destruction in the stratosphere: ~110 million t  $\text{H}_2\text{O}$  per year
- Today's high flying aircraft: ~40 million t  $\text{H}_2\text{O}$  per year

According to [Graßl 1992] a ten percent increase of water vapor in the 10 to 15 km layer would increase the net radiation flux density by  $0.75 \text{ W/m}^2$ , where, for comparison, a doubling of  $\text{CO}_2$  would lead to a net flux enhancement of  $4 \text{ W/m}^2$ . This effect may even be enhanced by the formation of condensation trails (contrails) where observations indicate that the present 20 g  $\text{H}_2\text{O}$  emissions per flight-meter trigger the contrail formation of under-cooled stratospheric water vapor of up to 10 km in width and 2 km in height [Schumann 1991].

Therefore it has to be evaluated how operation of spacecraft changes the composition of the upper atmospheric layers such as the stratosphere. E.g. the conversion of all conventional aircraft to hydrogen fueled aircraft while not changing the cruising altitude would increase the  $\text{H}_2\text{O}$  mixing ratio of the lower stratosphere by about 20% with the above de-

scribed consequences. Therefore in [Zittel 1996] it has been concluded that hydrogen fueled aircraft have to reduce their cruising altitude below the tropopause. The location of the tropopause varies between 8 and 16 km depending on the season and the latitude. Therefore in the following also the amount of water released from the launch vehicle above 8 km is taken into account.

The engines of the launch vehicles are operated with excess hydrogen. The  $\text{LO}_2/\text{LH}_2$  ratio is indicated with 6:1 instead of 8:1. For the calculation it has been assumed that the excess hydrogen leaving the outlet of the engine reacts to hydrogen with the ambient oxygen nearby the jet. To estimate the amount of water vapor ( $\text{H}_2\text{O}$ ) formed at a height above 8 km the amount of fuel used below 8 km has been calculated.

Propellant per mission	4,965 t	
Number of space shuttle main engines (SSME)	40	[Koelle 2002]
Mass flow single engine	474 kg/s/SSME	[Koelle 2002]
Time until 8 km height is reached	70 s	[Koelle 2002]
Propellant released < 8 km	1,327	
Propellant released > 8 km	3,638	
$\text{LO}_2/\text{LH}_2$ mass ratio	6/1	
$\text{LH}_2$	520 t	
$\text{H}_2\text{O}$ formation	4,677	
Number of launches 500 GW scenario	19,001	
Deployment time	25 yr	
Annual $\text{H}_2\text{O}$ formation	3.55 million t	

Table 6-1: Amount of water formation from launch activities

In case of the largest (500 GW) scenario every year some 3.6 million t  $\text{H}_2\text{O}$  would be released into the tropopause, the stratosphere and in the atmospheric layers above. This has to be compared with the natural flow of water vapor from the troposphere (~1,210 million t per year) and with the water vapor release of today's aviation (~40 million t per year). As a result the launch activities for the 500 GW would add some 0.3% to the existing natural  $\text{H}_2\text{O}$  flow into the stratosphere and some 8.9% to the existing water vapor release of today's aviation. This might be acceptable if the world-wide installed SPS capacity remained at 500 GW.

Another point is the question whether there is formation of  $\text{NO}_x$ . Although  $\text{NO}_x$  cannot be formed in the combustion chamber of the engine because pure oxygen is the oxidant, some  $\text{NO}_x$  might be formed in the hot jet due to the reaction of ambient nitrogen molecules with ambient oxygen. The presence of  $\text{NO}_x$  in the stratosphere above 20 km enhances ozone depletion and as a result leads to a depletion of the ozone layer [Schumann 1990].

In [Schumann 1990] the influence of the operation of 500 hypersonic at an altitude of 22 km has been evaluated. If the 1988 subsonic commercial aircraft engines were used (40 g NO per kg of fuel) the global ozone reduction in the stratosphere would be about 19%. If the  $\text{NO}_x$  emissions were reduced down to approximately 5 g NO per kg of fuel (probably kerosene) then the global ozone reduction in the stratosphere would be some 2.8%.

There are still a number of open questions. Therefore, additional research is required to assess the environmental effects from space transportation, e.g. determining the maximum tolerable traffic rate and the potential benefit of using non-terrestrial materials.