6. INTEGRATION OF RENEWABLE ENERGY SOURCES IN THE EUROPEAN TRANSMISSION GRIDS

Problem statement

- *Analysis of the technical feasibility and economical profitability of integrating into transmission electricity grids:*
  - *wind generation combined with gas-fired combined cycles;*
  - *wind generation combined with storage facilities (hydro pumping storage and CAES);*
  - *solar energy.*
- *Integration of transport of biogas and hydrogen with gas pipelines.*

Methodology

- *Collection of data on the state-of-the-art of RES and conditions for their integration into transmission grids*
- *Numerical simulations to assess the economical profitability of combining RES with gas-fired combined cycles. Economical evaluations have been based adopting the same fuel price scenarios used in the analysis of mid-long term investment trends for the electricity and gas sectors.*

Major results

- *For the successful integration of massive RES in the transmission grids, the most feasible solution from the economical and technical point of view is the combination of wind generation with gas fired combined cycles;*
- *Solar energy and combination of wind generation with storage (pumping stations and CAES) are not economically feasible in the mid term;*
- *Transportation of biogas in dedicated networks or in natural gas pipelines is not economical feasible without any subsidies;*
- *Transport of hydrogen mixed with natural gas is not economically and technically feasible.*

6.1 Introduction

This part of the project aimed at performing a cost-benefit analysis relevant to the introduction of significant levels of new generation technologies into the transmission network of the EU 30.

Installation of RES is gathering great momentum in the last years, thanks to an increased concern about pollution, growing import dependence and rising prices of traditional fuel sources. RES generation, in particular: wind, biomass, hydrogen and solar energy, allows sparing fossil fuel consumption and reducing overall greenhouse gas emissions. Among these new technologies of generation, wind is particularly important because of the impact of wind power on HV networks and of the significant number of installations, both onshore and offshore, entered in operation in Europe during the last years. Then, special attention was paid to the integration of wind power in the power transmission grid (sect. 6.2.2). A further important issue is the potential of creating a good combination between wind and gas generation: conditions for an economically profitable wind-gas combination are presented in 6.3 together with a sensitivity analysis with respect to the main parameters (emission costs, wind plants load factor, emission cost contributions to capacity credits). Furthermore, wind generation can be combined with storage facilities, particularly pumping storage plants, to enhance its weak characteristics of firm and dispatchable generation. Combination of wind energy with storage systems is presented in sect. 6.4.

An overview of the available technologies to exploit solar energy and perspectives for possible export of solar power from North Africa to Europe are addressed in sect. 6.5, while sect. 6.6.1 gives an overview of the current technologies applied to the exploitation of biomass as well as the expected future development. Finally, sect. 6.6.2 gives an overview on hydrogen production, storage and its transportation through pipelines. Possibility of combining natural gas versus hydrogen transportation is discussed together with the expected future developments.

6.2 Cost-Benefit analysis of integrating wind power

6.2.1 Scope of the Task

The aim of the task is to perform a detailed cost-benefit analysis of integrating renewable generation sources (RES), in particular wind energy, into the European transmission network. The analysis will consider different scenarios forecasting the level of penetration of wind energy in the Member States in the Enlarged European Union plus all the neighboring countries considered in the present study for a time horizon of medium term (2013) and of long term (2023).

6.2.1.1 Foreword

Renewable energies are playing an important role in electric systems and in the future decades the integration of non-negligible amounts of RES into the transmission grids will become a hot issue. Most of the RES are location dependent (e.g.: availability of water, sun, wind, etc.) and that prompts an adaptation of the grid to evacuate the generated power in compliance with the reliability standards and the security margins set by the TSO's.

In some cases, further to location dependence, the developments cost have highly location dependence. For instance, while windmills or solar power capital costs are almost independent of the location, hydro power plants or tidal civil works costs are highly dependant of site topographic and geological characteristics.

Therefore, it is only possible to obtain general conclusions from RES with capital costs with low dependence of location. For that reason, and taking into account that wind generation is having the highest growth rate among RES, our analysis is mainly oriented to examine wind power.

We performed a cost benefit analysis in the classical way of incorporating those sources with the highest probability of intervening in the supply of energy. Among them, the wind energy plays a fundamental role; therefore, further to the above paragraph considerations, this specific source of energy was analyzed with special care.

Wind power has important advantages for EU countries:

- No contaminant power, particularly no CO_2 emissions;
- Potential to mitigate dependence on energy importations from sources that are non-reliable or sensitive to market power exercise
- Zones with appropriate wind potential spread across the whole EU

Presently, we are witnessing a huge increase in installation of wind farms: in the last ten years wind farms have grown at a rate of 30%. This trend is foreseen to continue in the mid-long term. To this purpose, EWEA (the European Wind Energy Association) envisages at worldwide level an overall investment of some 706.9 b€ up to the year 2020, out of which 131 b€ in Europe.

The related amount of generated power would warrant a reduction of C02 emissions in excess of 10 billion of tons. According to EWEA a reduction of wind production costs of 2,45 c€/kWh is estimated. Consequently, the focus of this task will be essentially addressed to the estimation of the impact on the transmission grid by wind farms.

Actually, due to the intermittent nature of wind energy, the integration of wind generators into the transmission network gives rise to extra costs that can, in principle, be grouped into three categories:

- Costs relating to additional back-up generation that must be installed to make the overall generation system (conventional + wind generation) equivalent from the point of view of the security of supply (capacity margin) to one featuring only conventional generation.

  An important concept is the one of capacity credit, defined as the amount of capacity of conventional generation that can be displaced by intermittent wind capacity whilst maintaining the same degree of system security. Capacity credits can be found in literature (see for instance project GreenNet[Z]) as a value defining a percentage of the total wind capacity that can be considered as "reliable" as if it pertained to thermal generators and, thus, doesn’t require back-up thermal generation. For the remaining part of the wind capacity, a back-up generator must be installed. This involves extra costs.

  The additional capacity costs depend on different factors
    - the level of penetration of wind energy,
    - the load factor of the considered thermal equivalents,
    - the environment where wind generators are located (onshore-offshore) and the considered season of the year, both factors influencing significantly the capacity credit values,
    - the rate of interest and the life cycle of the plants.
- Additional balancing costs: due to the intermittency of wind generation, extra costs for system balancing must be accounted for. In this field, there are no analyses available in literature, but, rather, empirical data that vary depending from the source (2-4 €/MWh for Denmark and UK, 7 €/MWh for Germany).

- Grid extension costs: connecting wind generators to the grid entails extra costs. These costs are usually socialized via transmission and distribution tariffs and evaluated by country-specific studies based on comprehensive load flow analyses. These costs are also affected by the adopted costs allocation methodology:
    - "shallow basis" - only for the costs related to the lines directly connected to the wind generators are accounted for;
    - "deep basis" - also other costs related to other network transmission lines are considered, in proportion to the benefits wind generators are going to draw from them, in practice proportionally to the usage of them.

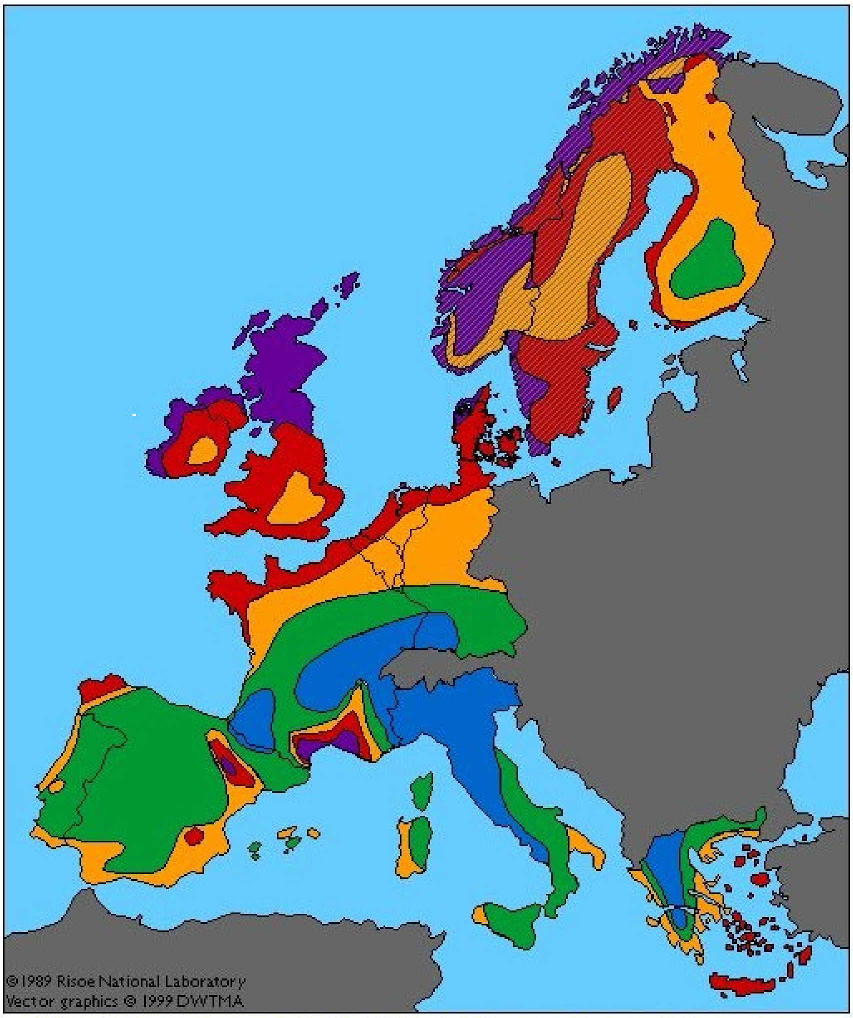
Basically, we identified three alternatives to overcome or minimize the impact of the above-mentioned extra costs:

- Developing of wind plants in zones with high load factors and transmit to the rest of Europe;
- Combination of wind plants with gas-fired combined cycles;
- Combination of wind plants with energy storage.

We analyze in the next sections the optimization of the use of wind power with these three alternatives

6.2.2 Transmission of wind power

The next picture shows the wind potential distribution across Western Europe.



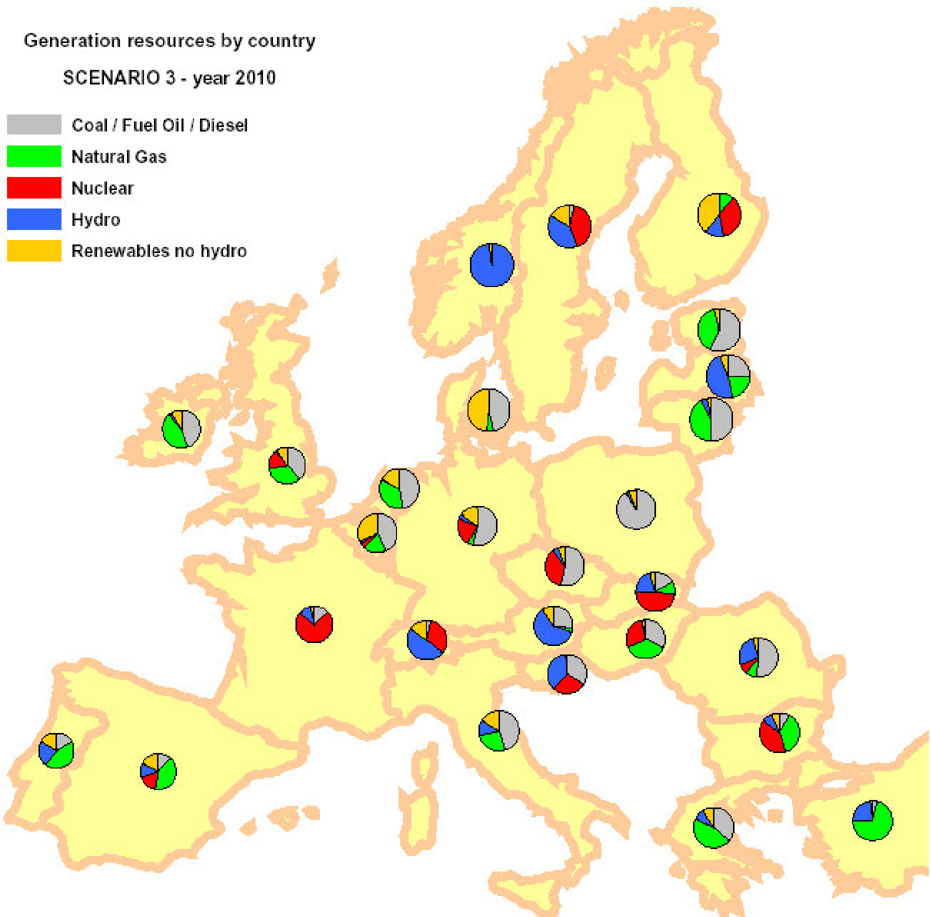
Wind Resources at 50 (45) m Above Ground Level

Colour	Sheltered terrain		Open plain		At a sea coast		Open sea		Hills and ridges	
	m/s	W/m²	m/s	W/m²	m/s	W/m²	m/s	W/m²	m/s	W/m²
	>6.0	>250	>7.5	>500	>8.5	>700	>9.0	>800	>11.5	>1800
	5.0-6.0	150-250	6.5-7.5	300-500	7.0-8.5	400-700	8.0-9.0	600-800	10.0-11.5	1200-1800
	4.5-5.0	100-150	5.5-6.5	200-300	6.0-7.0	250-400	7.0-8.0	400-600	8.5-10.0	700-1200
	3.5-4.5	50-100	4.5-5.5	100-200	5.0-6.0	150-250	5.5-7.0	200-400	7.0-8.5	400-700
	<3.5	<50	<4.5	<100	<5.0	<150	<5.5	<200	<7.0	<400
			>7.5							
			5.5-7.5							
			<5.5							

It is possible to verify that in zones with some particular terrain characteristics the power potential is substantially higher than in others. Open sea and hill ridges offers power potential 50% to 400% higher potential than sheltered or open plain terrains.

Therefore, one of the alternatives to optimize the use of wind power is to concentrate wind plants in zones with high potential and to transmit to the rest of Europe. This alternative requires the development of important transmission facilities. Scenarios 3 and 4 of long run simulations (see chapter 3) already analyzed optimal transmission expansion required in case wind power generation will evolve according to the results from FORRES study (Policy scenario). Consequently, those simulations consider:

- Wind plants, as well other renewable technologies, developed as results from FORRES study (Policy scenario). The map below illustrates the participation of renewable resources in the generation dispatch of each country by 2010



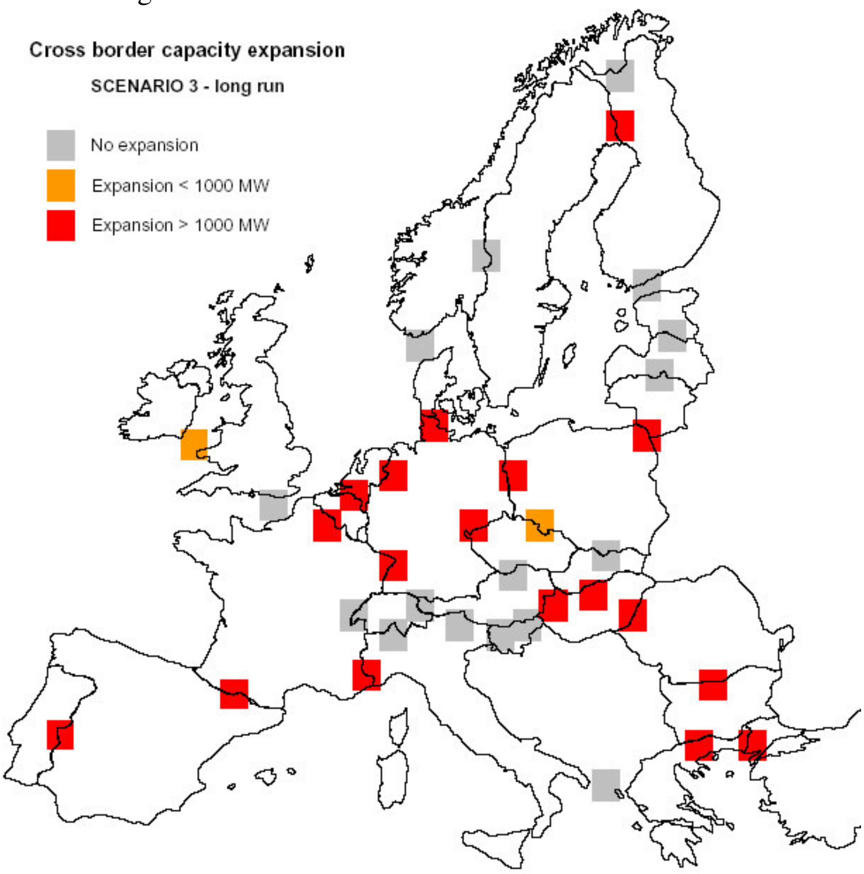
- Cross-border transmission capacity is optimized to maximize benefits from wind power

As shown in the table below, these scenarios imply significant investments on cross-border transmission, exceeding largely 1 b€ within the next ten years (2005-2015). Only scenarios where all generation expansion is simultaneously optimized with development of cross-border interconnectors (Scenarios 5 and 6) show higher level of required investments.

ACCUMULATED INVESTMENTS ON CROSS BORDER CAPACITY EXPANSIONS [million •]

Scenario	Key assumptions	2007	2010	2015
BASELINE		437.0	889.5	902.3
SCENARIO 1	*'Kyoto for ever'*	315.1	579.2	590.1
SCENARIO 2	*'Kyoto for ever' + Nuclear expansion*	356.1	680.6	715.7
SCENARIO 3	*High RES (Forres)*	432.6	1,021.7	1,495.6
SCENARIO 4	*'Kyoto for ever' + High RES (Forres)*	222.6	808.8	1,276.7
SCENARIO 5	*New generation optimized*	407.1	5,988.2	13,908.6
SCENARIO 6	*New generation optimized + High transm.cost*	25.6	3,113.7	9,377.9
SCENARIO 7	*High coal prices in NE Europe (PL)*	495.1	764.4	817.2
SCENARIO 8	*High efficiency in transmission (Primes)*	427.0	699.7	792.9
SCENARIO 9	*Combined High RES + Effic.transm.(Primes)*	401.0	666.4	962.7
SCENARIO 10	*Soaring oil and gas prices*	282.4	446.6	460.1
TSO questionnaire - UK sumbarine interconnectors inclusive		**211.2**	**2,043.6**	**2,172.2**
TSO questionnaire - Without UK sumbarine interconnectors		**211.2**	**1,050.8**	**1,179.4**

Cross border expansions required in the long run involve reinforcements in several international interconnections as shown in the figure below:



Finally, it is necessary to consider that, if wind plants are dispersed in several locations across Western Europe, it is possible that minimum simultaneous power be higher than zero because of diversity of wind regimes. In such case, in addition to replace fuels consumption in thermal plants, wind plants may provide some firm power.

6.3 Wind-Gas combination

6.3.1 Basic concept

The basic concept regarding wind-gas combination is to install windmills that would operate jointly with gas fired thermal plants. Since the expected wind plants load factors are in the range 25-35%, the best alternatives to complement are gas fired combined cycles (CC). Open cycle gas fired plants would be more convenient than CCs, if windmills load factor were above 80%. Therefore, we adopted for our analysis the use of CCs to complement windmills.

In this section we analyze the costs of energy production with the combination wind-gas against the cost of producing the same energy only with CCs.

The analysis is based on the following assumptions:

- The set windmills-CC is dispatched in such a way that total output is constant.
- The CCs are designed to follow inversely the production of windmills, in order to maintain constant output (i.e no further balancing costs).
- The following costs and financial parameters are used:

Parameters	Unit	Value
Discount Rate	%	8%
Life cycle facilities	years	20
CC Capital cost	€/kW	550
CC Fixed O&M	€/kW-year	6.5
CC variable cost (gas+variable O&M)	€/MWh	28.7
CC availability	%	90%
Windmill capital cost	€/kW	750
Fixed O&M	€/kW-year	10
Wind plant load factor	%	30%
Capacity credits	%	0%
CO_2 emission costs	€/t	20
CC emissions	t/MWh	0.34

Based on this information[1], the following energy prices were obtained:

- Energy cost with CC: 39.94 €/MWh
- Energy cost with wind-CC combination: 40.75 €/MWh

Although with the assumed data the wind-CC combination is more expensive than CC, the difference in costs is lower than reasonable estimation errors in the assumptions. The difference of 0.8 €/MWh arises from:

- Wind-CC fixed costs (capital + O&M) is 10.7 €/MWh more expensive than CCs alone.
- Wind-CC allows saving 7.8 €/MWh of gas costs
- Wind-CC allows saving 2.0 €/MWh on CO_2 emissions costs.

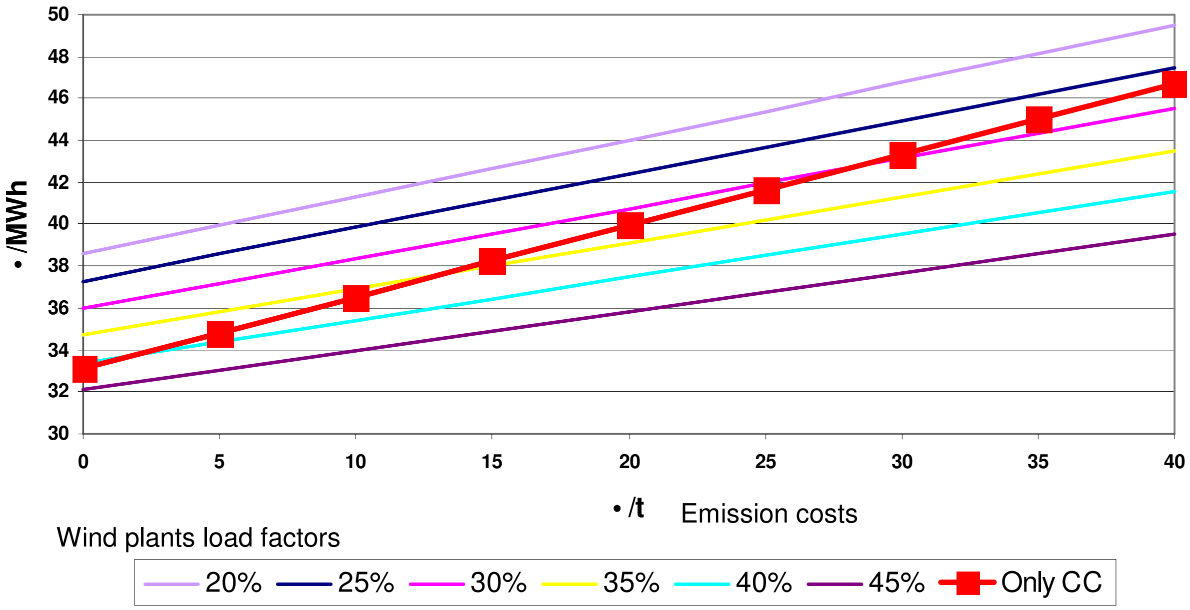
In the next paragraphs we analyze sensitivities to variables with higher level of uncertainty

[1] Contribution to peak means the power output that a wind plant could guarantee to the system with a level of probability compatible with system security. Typically, contribution to peak of windmills is zero. However, it might be greater than zero if simultaneous productions of windmills spread on very large extensions were considered.

6.3.2 Sensitivity to emission costs and plant factor

Next picture shows the sensitivity of energy cost produced by wind-CC combination (y-axis) to emission costs (x-axis) and wind plants load factor. Main conclusions on this picture are:

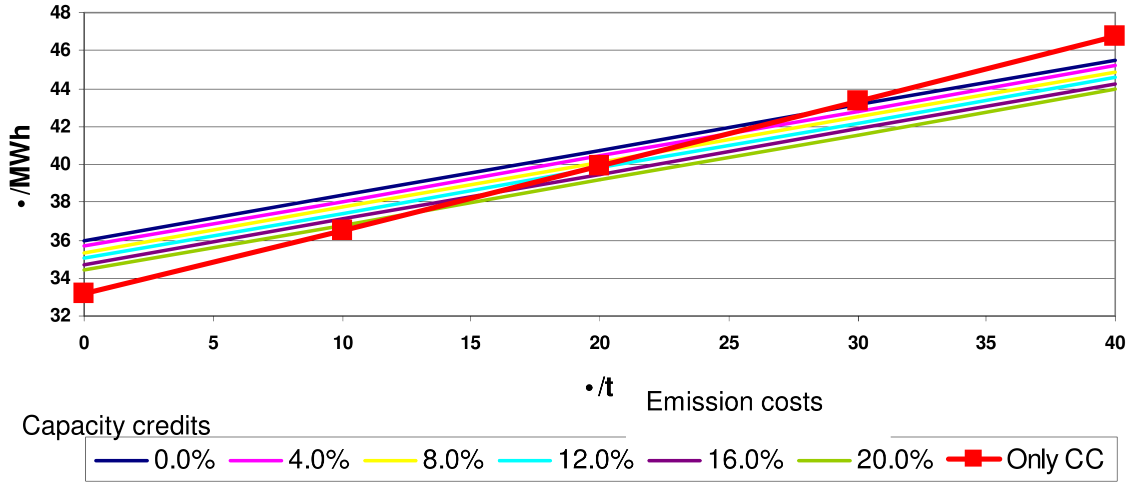
- For zero emissions costs, the break-even between CCs and wind-CC is plants load factor of 40%.
- With the assumptions of the base case (load factor 30%), the break-even is reached with emission costs of about 28 €/t



6.3.3 Sensitivity to emission costs contribution to capacity credits

For individual wind plants, or for those located in zones with the same wind regime, contribution to peak is zero. However, if the whole Western Europe is considered, probably this parameter might be greater than zero, although not very high. We analyze in this section the impact on energy price of non-zero contribution to capacity credits. In the next picture is shown the sensitivity of energy cost produced by wind-CC combination (y-axis) to emission costs (x-axis) and considering different wind plants contribution to capacity credits. Main conclusions on this picture are:

- For capacity credits varying from zero to 20%, the energy cost reduces 1.6 €/MWh.
- For capacity credits of 20%, and the assumptions of the base case, the break-even is reached with emission costs of about 18 €/t
- For capacity credits of 10%, and the assumptions of the base case, the break-even is reached with emission costs of about 23 €/t



6.3.4 *Other sensitivities*

The break even between energy cost with CC production and with wind-CC combination is reached when:

- The discount rate is 6.8%
- The life cycle of the plans is 26 years
- The capital costs of windmills is 680 €/KW
- The variable cost of CCs is 27.8 €/MWh

6.3.5 *Conclusions on wind-gas combination*

The wind-gas combination is a feasible alternative to mitigate drawbacks of windmills. Economic profitability is sensitive to cost of emissions, windmill load factor, discount rates, windmill capital costs and gas price.

6.4 Wind with energy storage

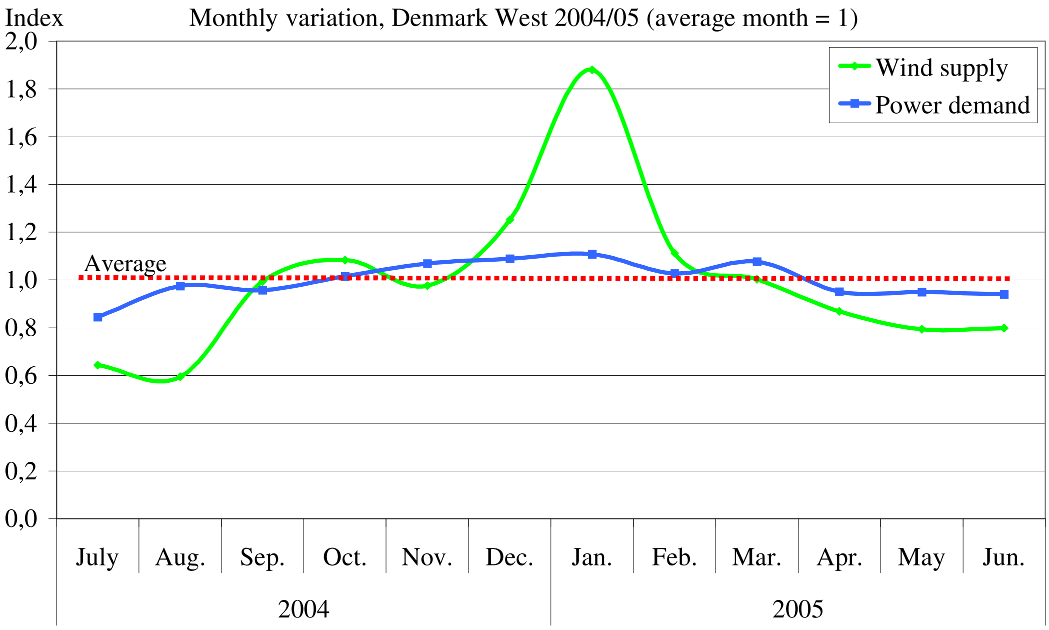
Storage of wind energy was evaluated through the additional cost of producing firm output from wind farms through implementation of auxiliary equipment for allowing that. In particular, the combination of wind generation with pumping power plants and CAES has been investigated. Other possibilities for using the surplus of wind power either through storage or adequate policy of consumptions (policies of Demand Side Management) are recalled in sect. 6.4.3.

Alternatives of wind energy storage in conventional hydro reservoirs was not analysed in this study for the following reasons:

- The coordinated operation of hydro and wind plants may be convenient to reduce balancing costs associated to intermittent generation of wind plants, but it does not increase the firm power of the set,
- Looking forward to generation expansion, most of the European hydro potential have already been developed, therefore this is not an alternative suited for meeting load growth.

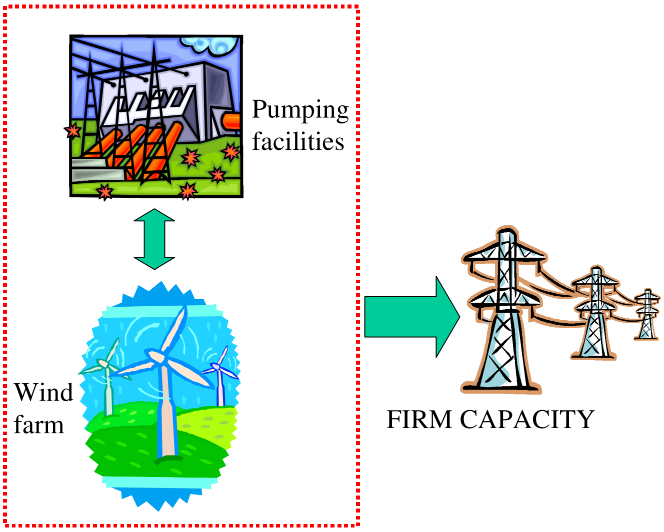
Nevertheless, in some particular existing hydro plants, which should be identified case-by-case, it may be convenient to expand their installed capacity if the firm energy of the hydro plant increases due to coordinated operation with wind farms.

Power demand varies over the year, but demand variations are limited when compared to the variations in the wind power supply, which fluctuates significantly over the year. The figure below shows the power demand and wind power supply in Denmark West with the average monthly output of 1 p.u. The wind power variations are large and have a peak in January at almost twice the yearly average wind power supply. The figures underlines that it will be difficult to deliver a constant power supply over a whole year. It will be simpler and less costly to deliver a constant power supply on a short time period such as on a weekly basis rather than on a yearly basis. It should be noted that the high wind power supply in Denmark west generally is occurring in the winter period when the power demand also is at its highest.



6.4.1 Storage through pumping power plants

The alternative of using pumping power plants associated to wind farms in order to produce firm output was analyzed. The figure below shows a basic scheme of this alternative:



Within this scheme, two options were analyzed:

- Baseload output
- Firm capacity on peak hours

Regarding costs, the main difference between the analysed base load and peak load cases are related to:

- Investments on required hydro generation capacity (not pumping), which should be equal to the total output capacity of the project (higher for peaking)
- Investments on required transmission for injecting output capacity into the grid: while the Peak load case needs 100 MW per each 100 MW of wind generation installed, the base-load case only requires 25 MW of transmission capacity between the facilities (wind generators and pumping station) and the power grid per each 100 MW of wind power capacity.

Calculations were based on real hourly wind speed records taken at different locations, numbered 1 to 4, with average load factors of wind generation between 20 and 33%.

Average load factors by location

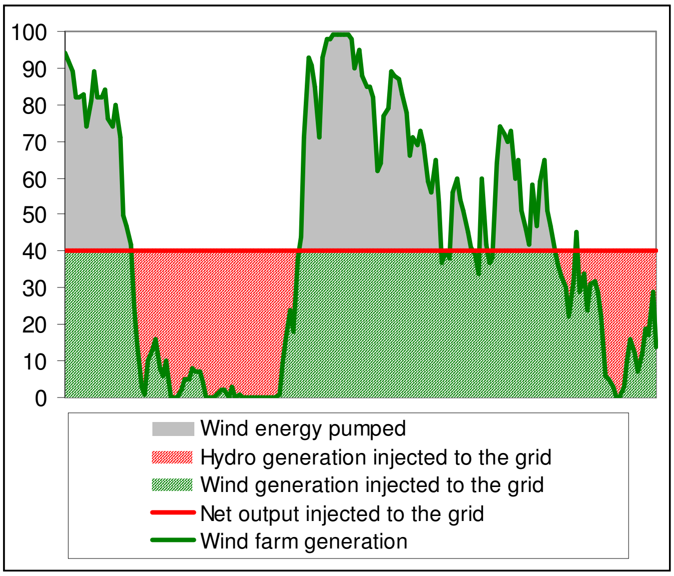
Location 1	32.1%
Location 2	24.4%
Location 3	19.2%
Location 4	18.5%

The following table shows the main hypothesis assumed. The main variable costs arise due to pumping losses, which are included implicitly through a discount in energy output.

MAIN PARAMETERS	
FACILITIES	
Installed wind power	100 MW
Required transmission	100 km
Pumping cycle losses	20%
Pumping head	400 m
INVESTMENT COSTS	
Wind power unit cost	750 •/kW
Transmission unit cost	0.50 •/kW/km
Pumping capacity	450.00 •/kW
Reservoirs	10.40 M•/Hm3 for 1 Hm3
	8.4 M•/Hm3 for 2 Hm3
Amortization period	20.00 years
Discount rate	8.0%

6.4.1.1 Baseload output

In this alternative, the aim of complementary pumping facilities is to transform the non-firm wind farm energy output into a baseload output as shown in the figure below:



The analysis was performed through a comparison between the energy price required for making the project profitable and the energy prices resulting from long run simulations as shown in the various scenarios.

Both transmission capacity (output capacity) and water storage capacity of the pumping facilities were optimized in order to reach a minimum load factor of 85% at minimum cost.

The tables below show the following results for different combinations of these parameters:

1. The resulting total cost expressed in €/firm-MW.
2. The associated load factor of the whole set (wind generation + associated pumping facilities).
3. The average energy priced required in order to make the project profitable under the assumptions adopted.

The figures show that:

- For a given level of storage capacity of the reservoir (row), unit cost results higher for lower output capacities (see first table) although firm output capacity and load factor increases (see second table). This is because total output capacity (expressed in MW) decreases and at the same required investments on pumping facilities increase.
- For a given output capacity (i.e. 25% of installed wind generation capacity) and from a certain level of water reservoir capacity (i.e. 2 Hm3 for output capacity 25%) the investment cost results higher. This is because bigger reservoirs are required for achieving higher load factors, and associated investment cost grows proportionally more than what load factor increases. However, the effect is the opposite for small reservoirs (i.e. less than 1.75 Hm3 for output capacity of 25%): in this case the unit cost results higher due to the fact that small reservoirs may produce spilling if wind generators are dispatched at full capacity during several hours in a row. This effect is shown for low output transmission capacities (less than 30%), since high capacities allow injection of most of the wind generation directly into the grid.

Location 1 – High wind potential

LOCATION #1 - TOTAL EQUIVALENT UNIT COST, EXPRESSED IN •/kW
AVERAGE WIND GENERATION: 32.1 % of installed capacity

<= WATER STORAGE CAPACITY [Hm3]	MAXIMUM OUTPUT CAPACITY AS A % OF WIND POWER CAPACITY =>					
	10%	20%	25%	30%	70%	100%
0.500	13,400	7,577	6,428	5,640	3,217	2,682
1.000	13,142	7,250	6,088	5,348	3,261	2,781
1.500	13,193	7,153	5,997	5,251	3,346	2,879
1.750	13,274	7,149	5,980	5,236	3,393	2,929
2.000	13,403	7,164	**5,980**	5,229	3,442	2,978
2.250	13,544	7,185	5,995	5,230	3,491	3,027
2.500	13,684	7,207	6,013	5,237	3,541	3,076

LOCATION #1 - OUTPUT LOAD FACTOR, EXPRESSED IN %
AVERAGE WIND GENERATION: 32.1 % of installed capacity

<= WATER STORAGE CAPACITY [Hm3]	MAXIMUM OUTPUT CAPACITY AS A % OF WIND POWER CAPACITY =>					
	10%	20%	25%	30%	70%	100%
0.500	92%	79%	73%	68%	44%	33%
1.000	96%	84%	79%	74%	45%	33%
1.500	98%	88%	82%	77%	45%	33%
1.750	99%	89%	84%	78%	45%	33%
2.000	99%	90%	**85%**	80%	45%	33%
2.250	99%	91%	86%	81%	45%	33%
2.500	99%	92%	86%	81%	45%	33%

LOCATION #1 - ENERGY PRICE REQUIRED, EXPRESSED IN •/MWh
AVERAGE WIND GENERATION: 32.1 % of installed capacity

<= WATER STORAGE CAPACITY [Hm3]	MAXIMUM OUTPUT CAPACITY AS A % OF WIND POWER CAPACITY =>					
	10%	20%	25%	30%	70%	100%
0.500	155.80	88.09	74.74	65.58	37.40	31.19
1.000	152.80	84.29	70.78	62.18	37.92	32.33
1.500	153.40	83.17	69.73	61.06	38.90	33.48
1.750	154.34	83.13	69.53	60.88	39.45	34.05
2.000	155.84	83.30	**69.52**	60.80	40.02	34.62
2.250	157.47	83.54	69.70	60.80	40.59	35.19
2.500	159.10	83.80	69.91	60.89	41.17	35.77

As shown in the tables below, required prices for making profitable similar projects located in other places with lower wind potential result higher; both optimal reservoir storage and output capacities result different as well.

Location 2 – Average wind potential

LOCATION #2 - OUTPUT LOAD FACTOR, EXPRESSED IN %
AVERAGE WIND GENERATION: 24.4 % of installed capacity

<= WATER STORAGE CAPACITY [Hm3]	MAXIMUM OUTPUT CAPACITY AS A % OF WIND POWER CAPACITY =>					
	10%	20%	25%	30%	70%	100%
0.500	88%	70%	64%	58%	34%	25%
1.000	94%	76%	69%	63%	35%	25%
1.500	97%	80%	72%	65%	35%	25%
1.750	98%	81%	73%	66%	35%	25%
2.000	98%	82%	74%	67%	35%	25%
2.250	98%	83%	75%	68%	35%	25%
2.500	99%	**84%**	76%	69%	35%	25%

LOCATION #2 - ENERGY PRICE REQUIRED, EXPRESSED IN •/MWh
AVERAGE WIND GENERATION: 24.4 % of installed capacity

<= WATER STORAGE CAPACITY [Hm3]	MAXIMUM OUTPUT CAPACITY AS A % OF WIND POWER CAPACITY =>					
	10%	20%	25%	30%	70%	100%
0.500	162.39	98.48	85.41	76.48	48.04	40.81
1.000	156.90	93.26	81.38	73.03	49.07	42.31
1.500	155.79	91.51	80.10	72.04	50.48	43.81
1.750	156.22	91.20	79.86	71.88	51.24	44.56
2.000	157.18	91.27	79.70	71.89	52.00	45.30
2.250	158.78	91.48	79.64	72.05	52.77	46.05
2.500	160.41	**91.89**	79.71	72.25	53.53	46.80

Location 3 – Low wind potential (1)

LOCATION #3 - OUTPUT LOAD FACTOR, EXPRESSED IN %
AVERAGE WIND GENERATION: 19.2 % of installed capacity

<= WATER STORAGE CAPACITY [Hm3]	MAXIMUM OUTPUT CAPACITY AS A % OF WIND POWER CAPACITY =>					
	10%	20%	25%	30%	70%	100%
0.500	92%	72%	63%	56%	29%	21%
1.000	96%	77%	68%	60%	29%	21%
1.500	99%	81%	70%	62%	29%	21%
1.750	99%	82%	71%	62%	29%	21%
2.000	99%	83%	72%	63%	29%	21%
2.250	100%	**84%**	73%	63%	29%	21%
2.500	100%	**84%**	73%	63%	29%	21%

LOCATION #3 - ENERGY PRICE REQUIRED, EXPRESSED IN •/MWh
AVERAGE WIND GENERATION: 19.2 % of installed capacity

<= WATER STORAGE CAPACITY [Hm3]	MAXIMUM OUTPUT CAPACITY AS A % OF WIND POWER CAPACITY =>					
	10%	20%	25%	30%	70%	100%
0.500	155.87	96.52	86.03	79.10	56.74	49.06
1.000	152.65	91.94	82.81	76.92	58.39	50.86
1.500	152.92	90.29	81.95	76.45	60.19	52.66
1.750	153.92	90.06	81.87	76.63	61.10	53.56
2.000	155.31	90.19	81.89	77.06	62.01	54.46
2.250	156.69	**90.56**	82.14	77.60	62.92	55.36
2.500	158.25	91.02	82.49	78.25	63.83	56.26

Location 4 – Low wind potential (2)

LOCATION #4 - OUTPUT LOAD FACTOR, EXPRESSED IN %
AVERAGE WIND GENERATION: 18.5 % of installed capacity

<= WATER STORAGE CAPACITY [Hm3]	MAXIMUM OUTPUT CAPACITY AS A % OF WIND POWER CAPACITY =>					
	10%	20%	25%	30%	70%	100%
0.500	79%	61%	54%	49%	28%	20%
1.000	**86%**	67%	59%	53%	28%	20%
1.500	90%	70%	62%	56%	28%	20%
1.750	91%	71%	63%	57%	28%	20%
2.000	92%	72%	64%	58%	28%	20%
2.250	92%	73%	65%	58%	28%	20%
2.500	93%	73%	66%	59%	28%	20%

LOCATION #4 - ENERGY PRICE REQUIRED, EXPRESSED IN •/MWh
AVERAGE WIND GENERATION: 18.5 % of installed capacity

<= WATER STORAGE CAPACITY [Hm3]	MAXIMUM OUTPUT CAPACITY AS A % OF WIND POWER CAPACITY =>					
	10%	20%	25%	30%	70%	100%
0.500	180.82	114.36	100.19	90.30	58.56	49.88
1.000	**169.96**	106.74	94.67	85.98	59.84	51.71
1.500	167.13	104.27	92.39	84.28	61.71	53.54
1.750	167.28	103.92	91.79	83.97	62.65	54.45
2.000	168.14	103.80	91.58	83.97	63.58	55.37
2.250	169.02	104.05	91.52	84.23	64.52	56.28
2.500	170.17	104.44	91.75	84.61	65.45	57.20

Next table summarizes the results achieved for each analysed location. It is worth to note that results are not directly linked to wind potential of each location, although less potential suggests higher required prices. This is because the particular wind speed profile of each case, which has significant influence in the water storage capacity required: i.e. two locations may have similar expected average wind speeds, but pumping facilities for reaching similar load factors as output will require a bigger reservoir in that location where periods with very low or zero wind generation are typically longer, consequently required investments may not be equal for similar targeted output load factors.

RESULTS SUMMARY - BASELOAD OUTPUT

Location number	Avg.wind generation [%]	Baseload Output [MW]	Reservoir capacity [Hm3]	Required price [•/MWh]	Load factor [%]
#1	32.1%	25	2.00	69.52	84.8%
#2	24.4%	20	2.50	91.89	83.5%
#3	19.2%	20	2.25	90.56	83.7%
#4	18.5%	10	1.50	167.13	90.2%

Consequently, the project should face electricity prices whose average over a time interval equal or higher to the resulting load factor should be at least equal to the values shown in the table above for each location of the wind farm. Next table summarizes the average marginal energy prices as resulted from the long run simulations:

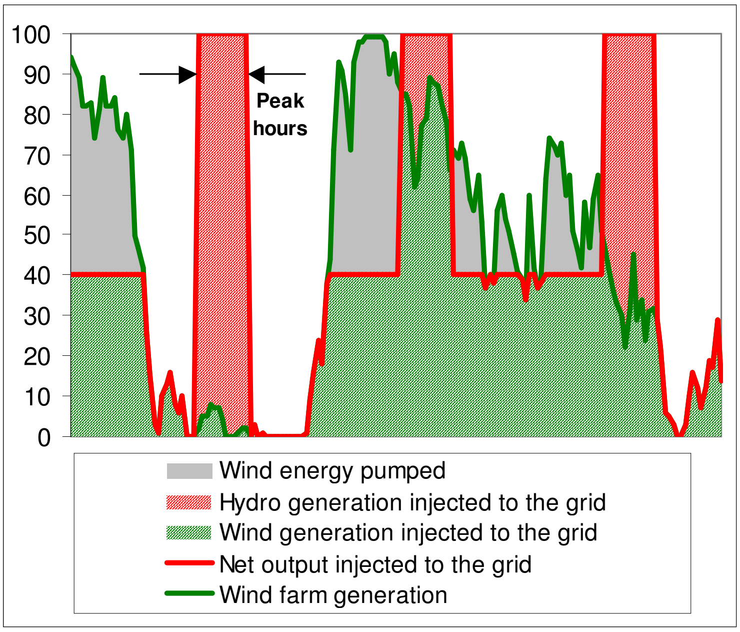
AVERAGE MARGINAL PRICE OF ELECTRICITY [• /MWh] EU-30

Scenario	Key assumptions	2007	2010	2015	2020	2025	2030
	BASELINE	39.34	28.12	29.33	30.51	32.82	35.50
S 1	*' Kyoto for ever'*	52.26	29.49	30.59	45.84	50.56	68.52
S 2	*' Kyoto for ever' + Nuclear expansion*	58.94	29.39	30.54	33.60	33.78	35.03
S 3	*High RES (Forres)*	39.12	26.50	26.82	27.50	23.43	18.34
S 4	*' Kyoto for ever' + High RES (Forres)*	40.85	28.43	29.24	30.91	31.30	31.67
S 5	*New generation optimized*	39.45	29.52	31.20	31.18	33.28	35.09
S 6	*New generation optimized + High transm.cost*	39.01	29.59	30.70	31.28	33.64	35.68
S 7	*High coal prices in NE Europe (PL)*	39.52	28.21	29.01	30.48	32.28	35.26
S 8	*High efficiency in transmission (Primes)*	39.22	27.14	28.41	28.95	31.75	35.89
S 9	*Combined High RES + Effic.transm.(Primes)*	39.22	27.23	28.13	28.05	30.58	35.03
S 10	*Soaring oil and gas prices*	45.26	57.64	59.79	61.98	66.35	71.01

Only scenarios S1 (Baseline + carbon emission constraints according Kyoto protocol during the whole simulated period) and S10 (soaring oil and gas prices) show prices compatible with that required for location 1 (high wind potential) at the end of horizon planning. Locations with lower wind potential require higher average energy prices than those that can be expected for long run according the simulated scenarios.

6.4.1.2 Firm capacity on peak hours

In this alternative, the aim of complementary pumping facilities is that wind farm energy is available as much as possible in peak hours, as shown in the figure below:



Analysis was performed through a comparison between total cost (investment + O&M) of necessary equipment to provide firm capacity at peak hours from a wind farm facility and the energy marginal prices at peak hours that resulted from long run simulations in each modelled country (EU-30).

In this case the storage capacity of the required water reservoir was taken from the optimal solution for Baseload problem solved above, since this capacity has proven to be enough for managing water between subsequent peaks of wind generation.

Significant differences with respect to the equipment required for Baseload are:

- The capacity of required transmission: while a capacity around 20% of wind generation capacity is required for baseload output, transmission capacity equal to installed wind capacity is required for providing firm capacity on peak.
- The hydro generation capacity, that now is required to be equal to the net output capacity (100 MW for 100 MW of installed wind capacity).

RESULTS SUMMARY – FIRM CAPACITY AT PEAK

Location number	Avg.wind generation [%]	Peak Output [MW]	Reservoir capacity [Hm3]	Required peak price [•/MWh]	Peak Load factor [%]
#1	32.1%	100	2.00	71.58	100.0%
#2	24.4%	100	2.50	94.67	100.0%
#3	19.2%	100	2.25	93.34	100.0%
#4	18.5%	100	1.50	172.94	100.0%

It should be noted that required prices for making wind+pumping set profitable are only for peak hours instead for almost 85% of time as required in Baseload output case.

Next figures show peak prices of electricity as resulted from long run simulations:

AVERAGE MARGINAL PRICE OF ELECTRICITY ON PEAK HOURS [• /MWh]   EU-30

Scenario	Key assumptions	2007	2010	2015	2020	2025	2030
BASELINE	*BASELINE*	41.82	29.94	31.42	32.98	35.78	38.05
S 1	*' Kyoto for ever'*	57.87	32.05	33.79	67.44	81.03	139.51
S 2	*' Kyoto for ever' + Nuclear expansion*	66.71	31.88	33.71	39.08	38.30	39.36
S 3	*High RES (Forres)*	41.63	28.56	29.65	30.88	33.72	34.07
S 4	*' Kyoto for ever' + High RES (Forres)*	43.34	30.63	31.74	34.51	38.74	43.24
S 5	*New generation optimized*	42.80	35.43	37.93	35.90	36.74	38.34
S 6	*New generation optimized + High transm.cost*	42.20	33.95	36.31	37.25	40.51	40.33
S 7	*High coal prices in NE Europe (PL)*	42.42	30.29	31.33	32.84	34.97	37.62
S 8	*High efficiency in transmission (Primes)*	42.48	29.59	31.01	31.63	35.20	40.52
S 9	*Combined High RES + Effic.transm.(Primes)*	42.45	29.79	30.67	31.10	34.45	39.92
S 10	*Soaring oil and gas prices*	48.29	59.15	61.86	64.51	69.35	73.44

Similarly to Baseload option, this alternative faces appropriate prices in scenarios S1 and S10 for high wind potential location. However, such prices are reached before than in Baseload. Particularly, S1 scenario shows suitable conditions for developing this alternative since almost year 2020, while S10 scenario (soaring oil & gas prices) shows them since 2025.

In addition, S1 scenario shows that also locations with lower wind potential could develop complementary pumping facilities towards the end of horizon planning (year 2030).

6.4.1.3 Conclusions on combination of wind with hydro pumping storage

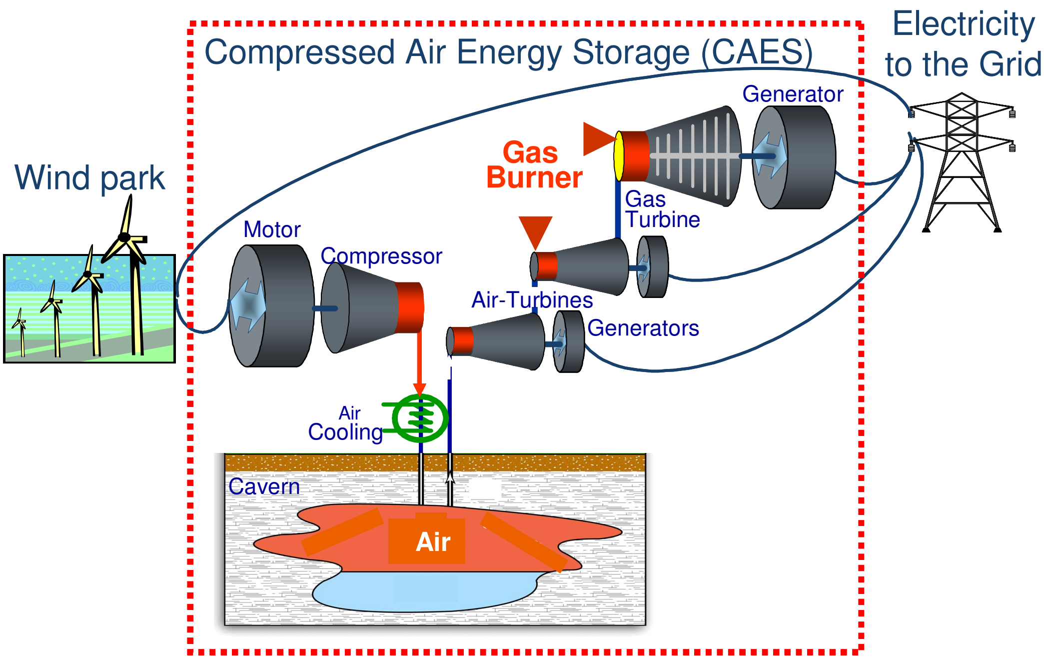
"Kyoto for ever" and "Soaring oil & gas prices" scenarios seem to provide the most suitable conditions for developing associated pumping facilities to wind farms in order to increase their reliability of supply, delivering firm generation capacity by this kind of wind farms.

According to the average marginal prices of electricity obtained by long run simulations, use of pumping facilities for providing firm capacity at peak hours (peaker function) seems to be a most appealing alternative than providing baseload output. This latter alternative makes the combination of wind-pumping storage plants equivalent to a baseload thermal plant (i.e. combined cycle).

However, market conditions for private investors develop this kind of facilities without any kind of special incentives seem to appear not before the year 2015.

6.4.2 Storage through air-compressed reservoirs

Compressed Air Energy Storage (CAES) has been analysed to evaluate the costs of supplying a stable power supply to the grid. The principles behind CAES are shown in the figure below.



In times of high wind power supply the energy can be stored as compressed air in an underground salt cavern. In periods with low or no wind power production, the cavern is discharged. The air stream is then used together with gas in the plant to generate power. In this way the wind power stored reduces the gas need and increases the efficiency of the gas power plant.

For the CAES plant the main assumptions are shown in the following tables:

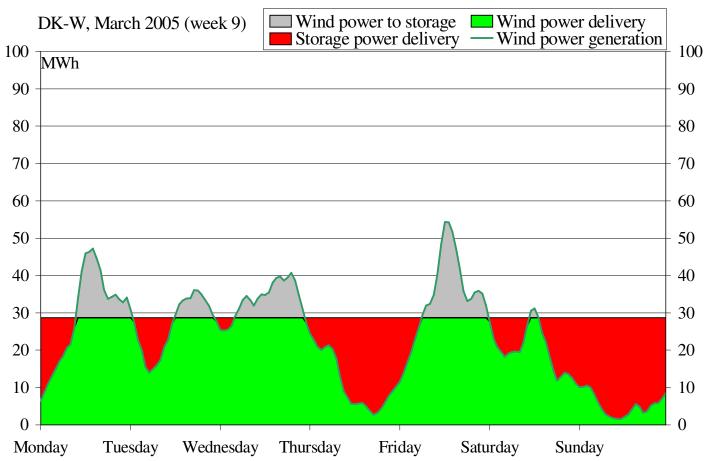
MAIN PARAMETERS FOR CAES		
FACILITIES FOR CAES		
Generation capacity	100	MW
Compression capacity	60	MW
Compression,generation and reservoirs	600	•/kW

CAES			
Energy input		122.000	MWh el
Energy output		186.000	MWh el
Energy Output increase:		52%	
Gas use	1,2 MWh per 1 MWh el	223.200	MWh gas
Gas cost	9,4 EUR/MWh	2.1	M EUR
Fixed and variable costs		2.2	M EUR

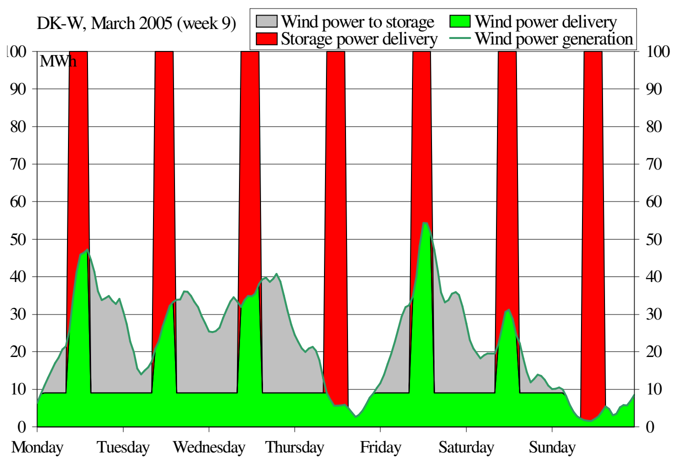
CAES operates differently from a pumped hydro storage. For every 1 MWh energy stored, an amount of 1.6 MWh of energy is produced. The reason for this is that the CAES used both gas and air to generate power. Every MWh taken from the CAES therefore also has a variable cost for the gas consumed (gas price is as given in the baseline scenario).

The idea behind supplying a stable power supply is illustrated in the figure below.

Base load



Peak load



The results from the pumped hydro storage showed that there was not a significant cost difference between the base load and the peak load cases. The CAES therefore only uses one setup, which can operate in both modes. The result shows, as expected, that the unit costs are highly dependent on the number of operating hours. When using the same storage size and power output as in the pumped hydro case the unit costs are 59 €/MWh. However, if the plant is operating for 3000 hours or 300 000 MWh the unit costs fall to 41 €/MWh, as can be seen in the table below.

Power output MWh	Full operating hours, h	Load factor	Unit cost EUR/MWh
186150	1862	0,21	58,6
200000	2000	0,23	55,4
300000	3000	0,34	40,9
400000	4000	0,46	33,7

Unit costs (excluding the cost of power for input)

These unit costs do not include the costs for the input power, which is the power that is stored. As is shown in the next section, power prices have a tendency to fall in areas with a high share of wind capacity at times with a high wind power generation. These are also the periods with a need to store power. The price of power, for the hours when it is stored, should therefore be expected to be significantly lower the average power price.

To compare the unit costs of CAES with those of pumped hydro the same cost for power should be used in both examples. When including a cost of 27 €/MWh the unit costs of CAES rise from 59 to 79 €/MWh[2].

The costs of a stable power supply from pumped hydro storage or CAES are reasonably similar considering they are general examples and not specific investment projects. Both the pumped hydro and the CAES are dependent on geological location. The pumped hydro storage has its strength in mountain areas while the CAES has its strength in areas, which are rich on salt, but other underground storages such as depleted mines can also be used for CAES.

6.4.3 Storage versus transmission investment or use of surplus power production for heat generation

In case of surplus of wind power generation there are at least four other technical solutions, in addition to pumped hydro and CAES that can be used for absorbing such production or conveying it to the consumers:

- Expanding the transmission system and widening of bottlenecks
- Use for heat production instead of fossil fuel as oil, gas or district heating
- Production of intermediate energy intensive products (hydrogen)
- Flexible energy consumption (cooling, manufacturing) adopting suitable tariff policy shifting the consumption to the hours with highest wind generation and lower prices

Most focus has been on the expansion of the transmission system, probably because such expansion is not paid by the owners of wind generators. However, when the most obvious de-bottlenecking has taken place this will be a relative expensive solution.

In Denmark the solution has been a combination of strengthening of the transmission systems to Norway and Sweden and the use of variable hydropower in those countries.

Large scale "power storage" can also be made, as previously mentioned, in the form of compressed air energy storage (CAES) by use of large caverns or other spaces like depleted mines. In Europe, the only

[2] Less than 1 MWh of energy is used for air compression to produce 1 MWh of energy output from CAES, therefore the power price is not fully reflected in the increased unit costs.

operating CAES storage is the Hunsdorf energy storage in Germany, which was originally built as back up for a nuclear power plant.

6.5 Integrating solar energy into the European power network

Europe is recently experiencing an impressive growth of wind farm installations, though in a quite unbalanced way, because of different national legislations. Beyond wind generation, another appealing RES that can play an important role in the next two decades is represented by solar energy. Energy can be generated by photovoltaic (PV) installations or by Concentrating Solar Power (CSP). PV generation is extremely expensive, as for the capital costs, and, consequently, its generation costs are far in excess to the normal range of production costs. On the contrary, CSP requires lower investments and its production cost may become competitive with the expected consumer power prices. CSP technology can be exploited through three different systems: parabolic troughs, power towers and parabolic dishes (or dish/engine systems).

6.5.1 Overview of solar thermal technologies

Parabolic trough systems use parabolic trough-shaped mirrors to focus sunlight on thermally efficient receiver tubes that contain a heat transfer fluid (Fig. 6.1). This fluid is heated to 390 °C and pumped through a series of heat exchangers to produce superheated steam, which powers a conventional turbine generator to produce electricity. Large fields of parabolic trough collectors supply the thermal energy used to produce steam for a Rankine steam cycle.

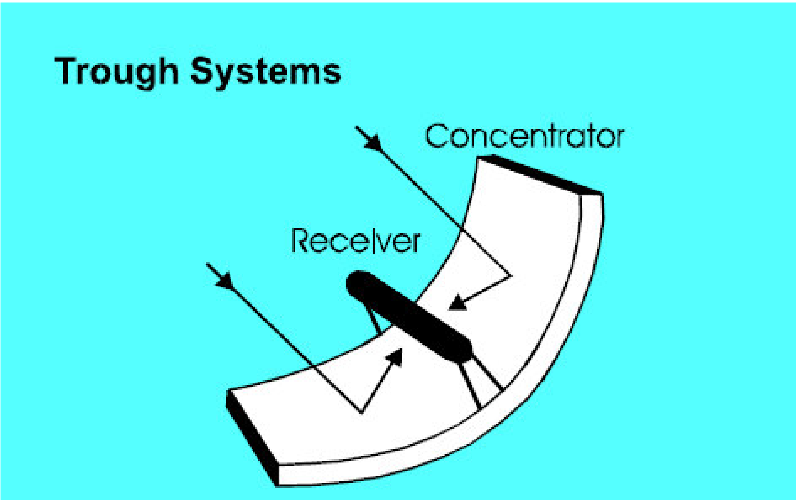


Fig. 6.1 Solar parabolic trough (source [1])

Power tower systems use a circular field array of heliostats (large individually-tracking mirrors) to focus sunlight onto a central receiver mounted on top of a tower (Fig. 6.2). The first power tower, Solar One, which was built in Southern California and operated in the mid-1980' s, used a water/steam system to generate 10 MW of power.The addition of the thermal storage capability makes power towers unique among solar technologies by promising dispatchable power at load factors of up to 65%. In this system, molten-salt is pumped from a "cold" tank at 288 °C and cycled through the receiver where it is heated to 565 °C and returned to a "hot" tank. The hot salt can then be used to generate electricity when needed. Current designs allow storage ranging from 3 to 13 hours.

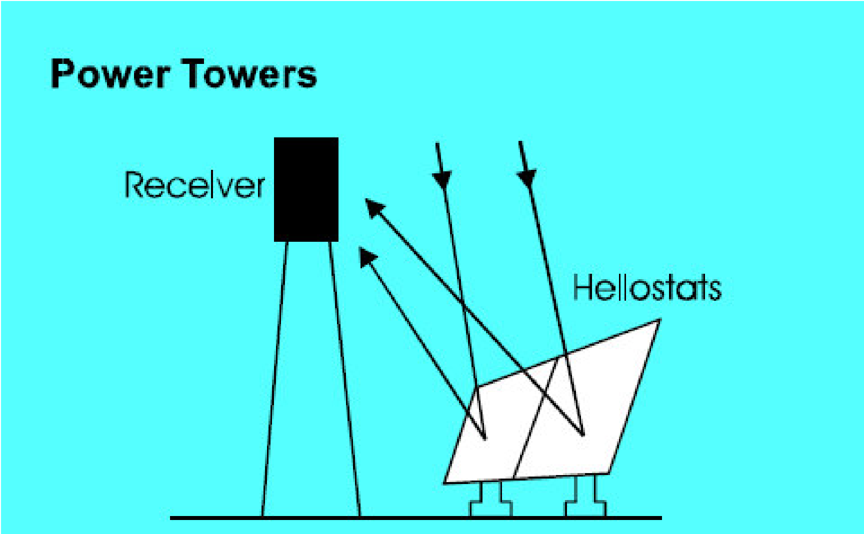


Fig. 6.2 Solar power tower (source [1])

Dish/Engine systems use an array of parabolic dish-shaped mirrors (stretched membrane or flat glass facets) to focus solar energy onto a receiver located at the focal point of the dish (Fig. 6.3). Fluid in the receiver is heated to 750 °C and used to generate electricity in a small engine attached to the receiver. Engines currently under consideration include Stirling and Brayton cycle engines. Several prototype dish/engine systems, ranging in size from 7 to 25 kW have been deployed in various locations worldwide. High optical efficiency and low startup losses make dish/engine systems the most efficient (29.4% record solar to electricity conversion) of all solar technologies. In addition, the modular design of dish/engine systems make them a good match for both remote power needs in the kilowatt range as well as hybrid end-of-the-line grid-connected utility applications in the megawatt range.

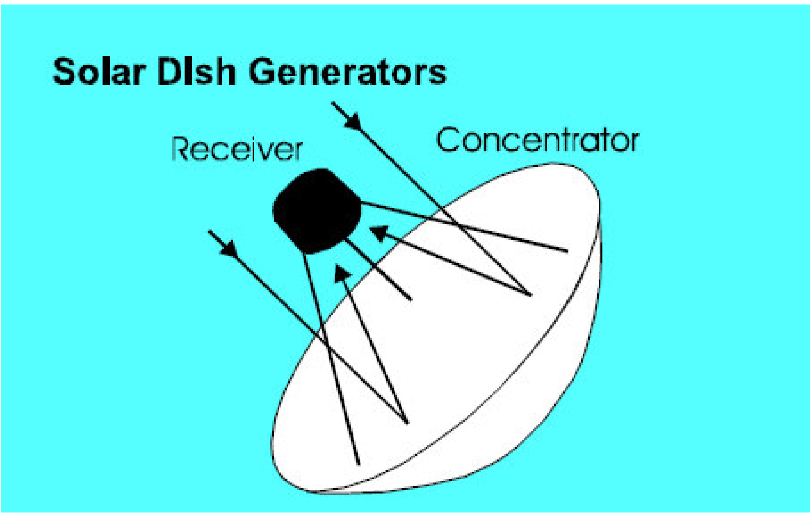


Fig. 6.3 Solar dish/engine system (source [1])

6.5.2 *Integrated Solar-Combined Cycle Systems*

Because the above technologies involve a thermal intermediary, as already mentioned, they can be readily hybridised with fossil fuel and in some cases adapted to utilize thermal storage. The primary advantage of hybridisation and thermal storage is that the technologies can provide dispatchable power and operate during periods when solar energy is not available. Hybridisation and thermal storage can enhance the economic value of electricity produced and reduce its average cost. CSP' s relatively low cost and ability to deliver power during periods of peak demand—*when and where we need it*—mean that CSP can be a major contributor to the future needs for distributed sources of energy.

The possibility of integrating a CSP with a gas turbine combined-cycle is an innovative solution recently proposed. The new design concept of "Integrated Solar Combined-Cycle" system (ISCCS) makes use of a parabolic trough plant combined with gas turbine combined cycle [4], [5]. The ISCCS has generated much interest because it offers an innovative way to reduce cost and improve the overall solar-to-electric efficiency. A process flow diagram for an ISCCS is shown in *Fig. 6.4*. The ISCCS uses solar heat to supplement the waste heat from the gas turbine in order to increase power generation in the steam Rankine bottom cycle. In this design, solar energy is generally used to generate additional steam and the gas turbine waste heat is used for preheat and steam superheating. Most designs have looked at increasing the steam turbine size by as much as 100%. The ISCCS design will likely be preferred over the solar Rankine plant in regions where combined cycle plants are already being built.

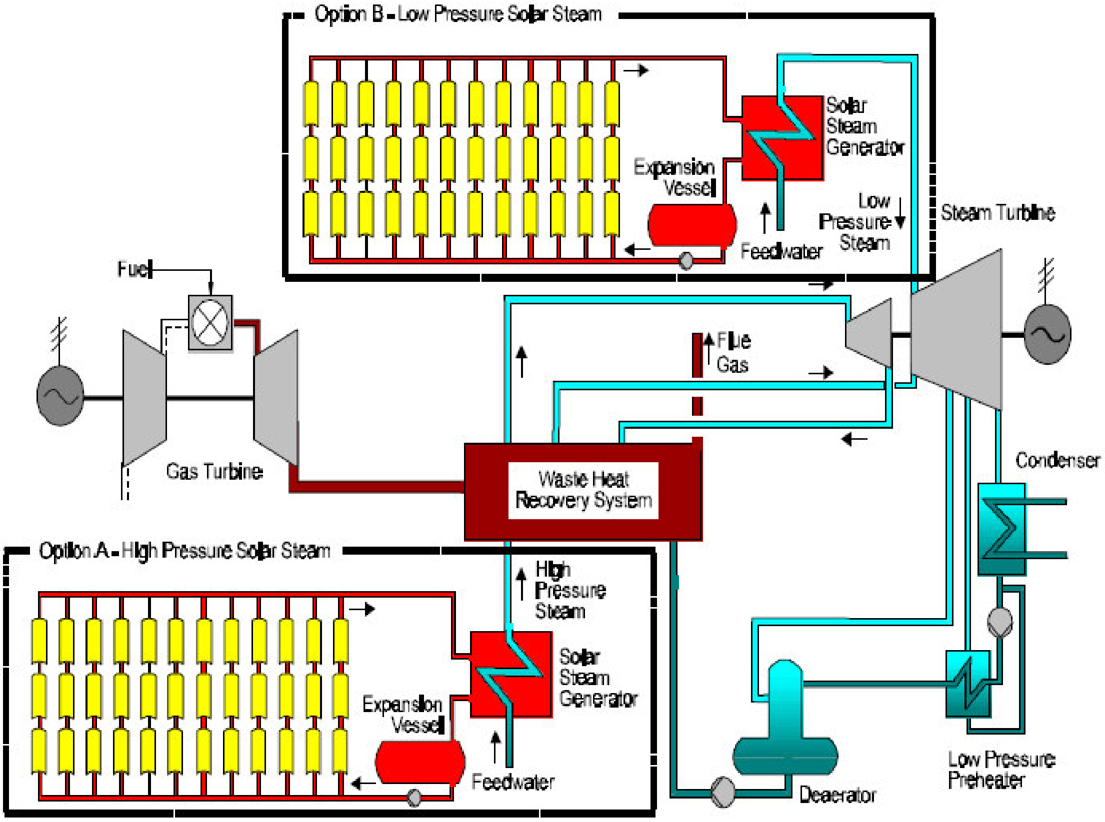


Fig. 6.4 Integrated solar / Combined-cycle system (source [1])

6.5.3 Technology comparison and costs for solar thermal technologies

Tab. 6.1 below highlights the key features of the three solar technologies. Towers and troughs are best suited for large, grid-connected power projects in the 30-200 MW size, whereas, dish/engine systems are modular and can be used in single dish applications or grouped in dish farms to create larger multi-megawatt projects. Parabolic trough plants are the most mature solar power technology available today and the technology most likely to be used for near-term deployments. Power towers, with low cost and efficient thermal storage, promise to offer dispatchable, high capacity factor, solar-only power plants in the near future. The modular nature of dishes will allow them to be used in smaller, high-value applications.

	Parabolic trough	**Power Tower**	**Dish/Engine System**
Size	30-320 MW*	10-200 MW	5-25 kW*
Operating Temperature (°C)	390	565	750
Annual capacity factor	23-50%*	20-77%*	25%
Peak efficiency	20% (d)	23%(p)	29.4% (d)
Net annual efficiency	11 (d)-16%*	7%(d)-20%*	12-25%*(p)
Commercial status	Commercially available	Scale-up demonstration	Prototype Demonstration
Technology Development Risk	Low	Medium	High
Storage available	Limited	Yes	Battery
Hybrid Designs	Yes	Yes	Yes

** Values indicate evolution in the period 2000-2030*

(p) predicted; (d): demonstrated

Tab. 6.1 – Comparison of the technical characteristics of solar thermal technologies

Towers and dishes offer the opportunity to achieve higher solar-to-electric efficiencies and lower cost than parabolic trough plants, but uncertainty remains as to whether these technologies can achieve the necessary capital cost reductions and availability improvements. Parabolic troughs are currently a proven technology primarily waiting for an opportunity to be developed. Power towers require the operability and maintainability of the "molten-salt technology" to be demonstrated and the development of low cost heliostats. Dish/engine systems require the development of at least one commercial engine and the development of a low cost concentrator.

Tab. 6.2 shows the actual and predicted costs for the three type of CSP technologies. Future costs are assuming to be decreasing by applying "learning curves". Learning curves are an empirical measure of the rate at which the costs of industrially manufactured products decrease over time. Because renewable technologies are in general less mature than fossil fuel technologies, costs are expected to decline faster than conventional production technologies. As it can be seen, the production cost related to parabolic troughs is the lowest among the three CSP technologies, even though in the future power towers can become competitive.

	Parabolic trough			Power Tower			Dish/engine system		
	2005	2010	2020	2005	2010	2020	2005	2010	2020
Levelised electricity (• /kWh)	0.12	0.09	0.08	0.13	0.08	0.05	0.17	0.12	0.07
Capital costs (• /W)	3.02	2.55	1.63	3.25	2.44	1.28	5.81	3.72	1.39
O&M costs (• /kWh)	0.12	0.06	0.05	0.14	0.05	0.03	0.46	0.17	0.10
Surface costs (• /m2)	730	365	320	550	308	232	3500	1740	370

Tab. 6.2 – Actual and predicted costs for solar thermal technologies (source [3])

Through the use of thermal storage and hybridization, solar thermal electric technologies can provide a firm and dispatchable source of power. Firmness implies that the power source has a high reliability and will be able to produce power when the utility needs it. Dispatchability implies that power production can be shifted to the period when it is needed. As a result, firm dispatchable power is of value to a utility because it offsets the utility's need to build and operate new power plants. This means that even though a solar thermal plant might cost more, it can have a higher value.

6.5.4 Solar energy exploitation in North-Africa and possibility of export to Europe

Since CSP plants can only focus direct solar radiation and cannot concentrate diffused sky radiation, they only perform well in very sunny locations. Therefore, CSP technology is limited to specific areas of southern Europe, North and southern Africa, the Middle East, western India, western Australia, the Andean Plateau, north-eastern Brazil, northern Mexico and the south-western USA.

Particularly interesting for Europe is the possibility of taking advantage from the large and still unspoilt solar resources in North Africa (e.g.: the potential of solar energy in Algeria is estimated in excess of 160 TWh/yr). Solar energy potentials in North Africa and the Middle East are superior to the European sites in terms of quality (intensity by factor up to 3) and of quantity (size and availability of sites), as visible in Fig. 6.5. Analysing the map it is possible to get an idea of the electricity generation potential per km2 (GWh/km2/yr) by multiplying the colour code numbers with 8760 hours. The theoretical potential of the good (green) areas in the Sahara exceeds the EU power demand. Moreover, CSP can be combined with fossil fuel generation, widely available in the region, as well as with wind generations, considering the very good wind conditions in many areas of Sahara, especially along the Atlantic coastline and in Egypt along the Gulf of Suez.

Exploitation of the RES potential in North Africa can be achieved provided that a series of requirements are fulfilled. These are pertinent to geopolitical, economic and technical issues. On the political level, the EU recognised the need for enhancing the collaboration with the southern and eastern Mediterranean countries and in November 1995 the Council of the EU adopted the "Barcelona Declaration" [7].More recently, an agreement protocol between the EU and the countries of the Maghreb was signed in December 2003 regarding progressive integration of the electricity supply markets of Morocco, Algeria and Tunisia with those of the European Internal Energy Market (IEM) with the following aims [8]:

- To favour the creation of an electricity market in the Maghreb from 2006 onwards by the gradual adoption of a national policy in the energy sector aimed at promoting standard regulations in the whole Maghreb area;
- To gradually integrate the Maghreb electric market with that of the EU.

In parallel to the above initiatives the ‘Trans-Mediterranean Renewable Energy Co-operation” was launched with the aim of fostering the renewable energy optimization by long-distance power interconnection between EU and North Africa up to the Middle East.

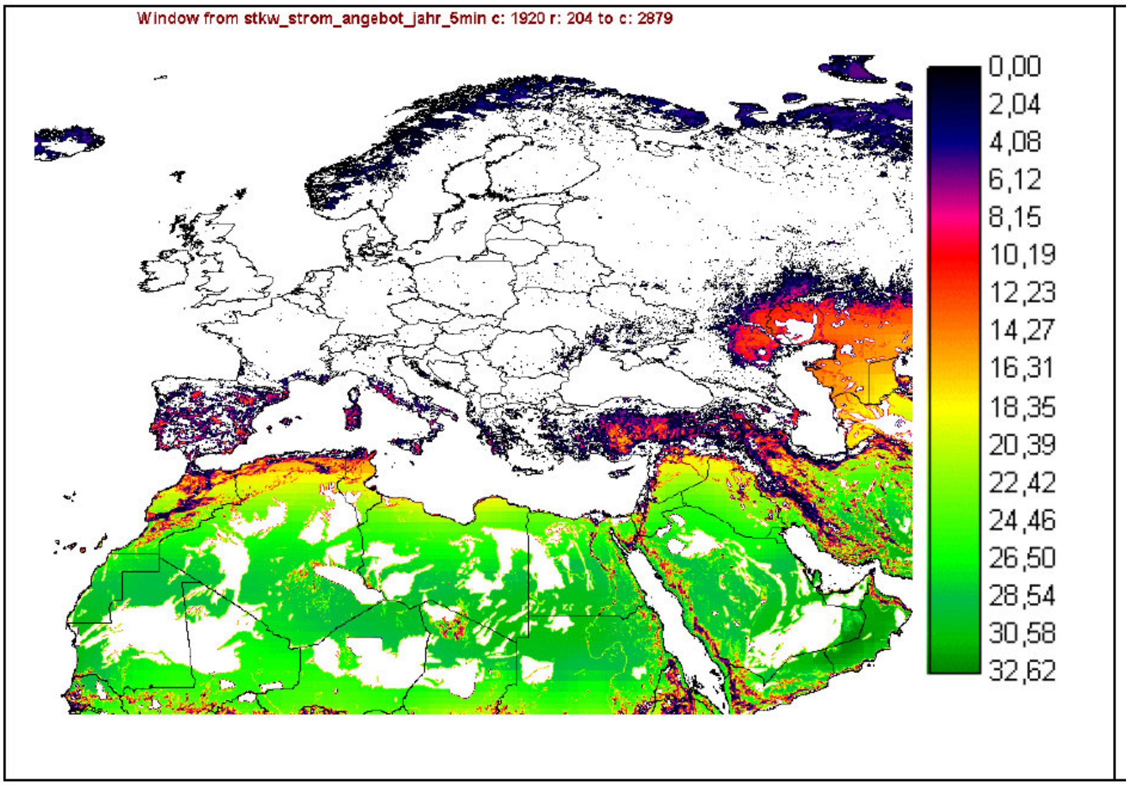


Fig. 6.5 Annual average electricity generation potential of CSP in MW/km2, averaged over an area of 5x5 km2 (source [6])

From the technical point of view, the most attractive solution looks to be the exploitation of direct North-Africa / South Europe (Italy and Spain) links through HVDC submarine cables. To this purpose, a series of projects has already been investigated and some of these can be commissioned by the year 2010. *Fig. 6.6* shows the HVDC submarine links between North Africa and Europe, the feasibility of which has been recently analysed or is going to be investigated. More in detail the situation is the following:

1 (Algeria – Spain and SAPEI: Sardinia-Italy): feasibility studies completed in 2003

2 (Algeria – Italy): feasibility study completed in 2004

3 (Tunisia – Italy): ongoing feasibility study (to be completed in December 2005)

4 (Libya – Italy): feasibility study to be started in 2006.

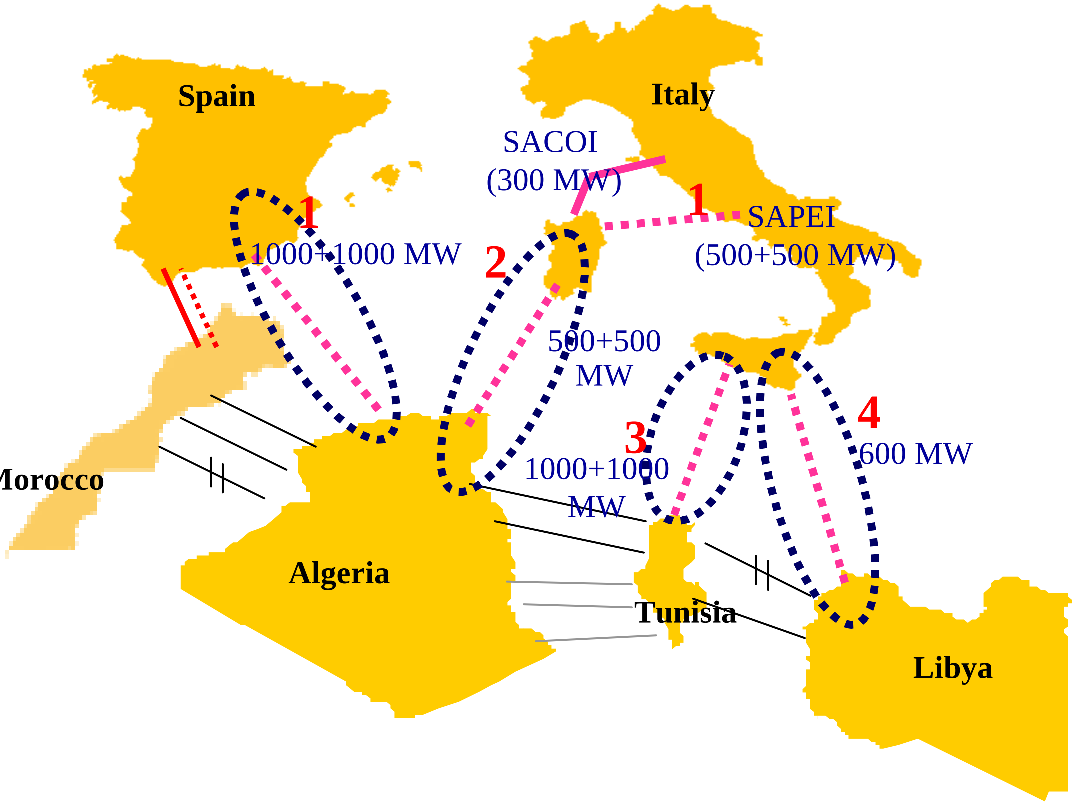


Fig. 6.6. Possible HVDC interconnections in the Mediterranean (source [9]).

All the above projects have been proposed for export of power from Maghreb to Europe generating power in gas fired combined-cycles located on the southern Mediterranean shores. However, they can be fruitfully exploited to convey also solar power, considering that the perspective of installed CSP in North Africa up to the year 2020 is a total amount of less than 1000 MW, essentially concentrated in Algeria and Egypt.

The average investment costs for the above South-North HVDC submarine links are in the range 350-450 M€ for links rated 1000 MW and around 730 MW for a link rated 2000 MW. These costs are obviously "location dependent" and cannot be generalised. Moreover, to the above costs related directly to the submarine cables and the AC/DC converter stations, further investment costs shall be considered concerning the reinforcement of the 400 kV from the converter stations to the load centres. These additional costs cannot be seen as parametric with respect to the size of the HVDC links, but they are related to the probability of occurrence of bottlenecks created by the new HVDC links. E.g.: exporting 500 MW from Algeria to the Italian mainland through Sardinia doesn't require any reinforcement of the south-north transmission backbone in Sardinia. Increasing the HVDC size to 1000 MW requires the doubling of the south-north 400 kV corridors with additional costs in the range of 70-100 M€.

Finally, it is worth recalling that the above south-north HVDC links are part of the EL 9 priority axes defined by the E.C.

6.5.5 Concluding remarks on integration of solar energy into electricity transmission grids

Combining RES, namely wing and solar energy widely available in North Africa, with conventional fossil fuel resources in the EU offers a series of benefits on the regional and continental scale:

- Strengthening of the political relations between European and Arab countries;
- Availability of an inexhaustible and sustainable product from North Africa for the large EU power market;
- Support for development in North-Africa by co-operative projects with Europe, as for engineering and production capacities in North-African countries
- Use of renewable energies will create qualified job opportunities and this may help to reduce emigration from North-Africa;
- Access to large-scale desalination opportunities in North-Africa to cope with their growing water demand;
- Cost-effective and rapid compliance of Europe with greenhouse gas reduction commitments.

The above benefits can be attained provided that a series of requirements are fulfilled, first of all a stable political environment in the North African countries that are still seen as risky countries by many investors. Measures to facilitate attraction of investments for both generation facilities and power transmission infrastructures shall be put in place (e.g.: loans and other aid instruments warranted by international institutions or banks). From the technical point of view, HVDC links look to be the most attractive solution. The average investment cost for a HVDC submarine link rated 1000 MW is in the range of 350-450 M€. To this cost, those related to the reinforcements of the terrestrial grids on the North Africa and South-Europe side shall be added: these latter are case dependent.

Possibility of import to the EU of large amount of solar and wind energy from North Africa shall be considered as a long-term perspective considering that at the moment the North-Africa countries are essentially addressing their energy policy to gas fuelled combined cycle units. Moreover, the difficulty of attracting investments combined with the high growth rate of the internal demand (in the range of 5-8% in the next 20 years) make it quite unlikely will have excess of electric energy to be exported to the EU.

6.6 Other renewable sources

Other RES that can be fruitfully exploited in the mid-long term are biogas and hydrogen. The main reason for mixing biogas or hydrogen into the natural gas grid is to reduce the use of fossil fuels in a feasible manner. Most European countries have a well-developed infrastructure for distribution of natural gas, which can be used.

As for biogas, considering its costs of transportation combined with the costs of transporting biomass to the plant, it turns out that the nowadays it is not economically convenient the transportation to mid-long distances through dedicated pipelines. Presently, biogas is normally only produced for local consumption in e.g. decentralised district heating or CHP plants. Hydrogen is currently not normally produced for energy purposes, but rather for industrial uses, which is also due to costs of producing hydrogen and of utilising it efficiently.

A solution to the cost of transport and the availability of a market can be that the biogas or hydrogen producers can distribute the gas to different consumers via the natural gas grid.

Gas quality

The gas qualities of natural gas, biogas, hydrogen and town gas are considerably different as illustrated in the table below. Biogas can be upgraded to natural gas standards, whereas gas from gasification processes, which is similar to town gas, cannot. Gas from gasification and pure hydrogen can better be distributed in town gas grids, as the gases are more similar to town gas. Town gas grids have, however, been cancelled for a period of many years and few are remaining. Other possibilities are to distribute the gases in new designated grids rather than mixing into the existing grids.

Parameter	Unit	Natural Gas	Biogas	Hydrogen	Town Gas
Calorific value (lower)	MJ/m3	36.14	21.48	10.8	16.1
Density	kg/m3	0.82	1.21	0.09	0.51
Wobbe index (lower)	MJ/m3	39.9	19.5	40.9	22.5
Max. ignition velocity	m/s	0.39	0.25	3.46	0.70
Theor. air requirement	m^3air/m^3gas	9.53	5.71	2.5	3.83
Max. CO_2-conc. in stack gas	Vol %	11.9	17.8	n.a.	13.1
Dew point	°C	59	60-160	n.a.	60

Tab. 6.3 Gas quality of different gases

6.6.1 Biomass

This section addresses distribution of biogas. Biogas plants are traditionally built in the immediate vicinity of a biogas consumer, such as a CHP plant or a district heating plant, which reduces the demand for a gas transportation grid. The biogas plants will typically have biogas storage facilities, enabling them to store the gas for a few hours, so it can be used during peak load. The storage facilities do not cover seasonal variations in gas demand. Access to a larger grid and thereby to more consumers, could make it possible to utilise the biogas plant facilities more optimally with a larger production.

There are a number of possibilities of distributing biogas:

- Biogas upgraded to natural gas standards and distributed in the natural gas grid
- Biogas distributed in local distribution grids, where the gas quality is less significant, e.g. because it is used for district heating
- Biogas distributed in designated grids

6.6.1.1 Description of current technologies

Biogas production

Biogas can be produced in:

- Biogas plants utilising e.g. manure, organic wastes and energy crops
- Waste water treatment plants
- Landfill sites (also called landfill gas)

The gas contents from the various plants vary as illustrated in the table below.

Component	Biogas plant	Waste water treatment plant	Landfill
Methane [%]	60-70	55-65	45-55
Carbon dioxide [%]	30-40	balance	30-40
Nitrogen [%]	<1	<1	5-15
Hydrogen Sulphide [ppm]	10-2000	10-40	50-300

Tab. 6.4 Typical raw (untreated) biogas compositions at different plants[3]

[3] New Gas qualities in the grid, Jan K. Jensen, DGC 2004

Existing biogas pipeline systems

Only few biogas plants exist, which distribute the biogas via the existing natural gas grid or a separate grid. Three unique plants exist in Sweden:4

Gothenburg

In Gothenburg a town gas grid exists which distributes a mixture of natural gas and air. With a distribution of 53% air and 47% natural gas the mixture is similar to the former town gas, which was produced by reforming of butan. In Gothenburg biogas is produced through fermentation of waste water. The biogas is mainly used for CHP production, but a part is compressed and mixed into the town gas grid. Before entering the grid, the Wobbe index and the heating value of the biogas is adjusted to the values of the natural gas – air mixture.

Stockholm

Hammarby sjöstad is a newly built area in the south of Stockholm. The area boasts modern architecture in combination with new technology and low use of energy together with high environmental standards. To reduce the use of energy the electric cookers in more than 1000 apartments have been changed to gas cookers. The gas used is biogas produced by fermentation of the waste water of the area and is distributed through a gas grid adapted to the standards for natural gas. The gas for the cookers is upgraded to a methane content of >97%, which makes it possible to build a station where the gas can be sold for transport purposes.

Laholm

Sydkraft Ab has built a demonstration plant in Laholm for upgrading of biogas to the natural gas grid. The biogas is produced from manure and organic waste. The upgrading takes place in three steps. The first step is separation of sulphur. The biogas has 65-70% methane before upgrading and through CO2 separation, the contents are increased to 97%. At the end the Wobbe number is adjusted by adding propane. The upgraded biogas enters the natural gas distribution grid, where the gas consists of 10-15% biogas. Injecting the biogas into the natural gas grid makes it possible to utilise all the available biogas, while the natural gas provides security of supply. The plant is expected to distribute up to 500 m³ upgraded biogas per hour.

6.6.1.2 Description of current cost level

Biogas

Biogas production costs are not easily calculated as prices vary a lot and are highly dependent on the specific plant, the biomass available etc. Biogas is normally sold at a price comparable to natural gas, taking the difference in heating value into account. This means that it is sold to around 60% of the natural gas price. Due to the effects of the Kyoto protocol, marginally higher prices can be expected as biogas is a CO2 neutral fuel.

Purification and upgrading

The major problem with mixing biogas into the natural gas grid is the high costs of purifying and upgrading to natural gas quality. In 2001 Danish Gas Centre estimated the price of purification and upgrading to 15 Eur ct/ Nm³. The Swedish Biogas Association reports of costs between 17-50 Eur ct/Nm³·[5].

Sydkraft in Sweden calculates with costs of purifying and upgrading being around 6-12 Eur ct/ Nm³.

[4] Swedish Gas Centre, April 2004

[5] Swedish Gas Centre, April 2004

The cost of cleaning the biogas of H2S is marginal in this connection - only around 0.15 Eur ct/ Nm³ assuming sizes of around 300m³/h up to 400m³/h and 20 years of operation according to the Danish biogas company, Xergi.

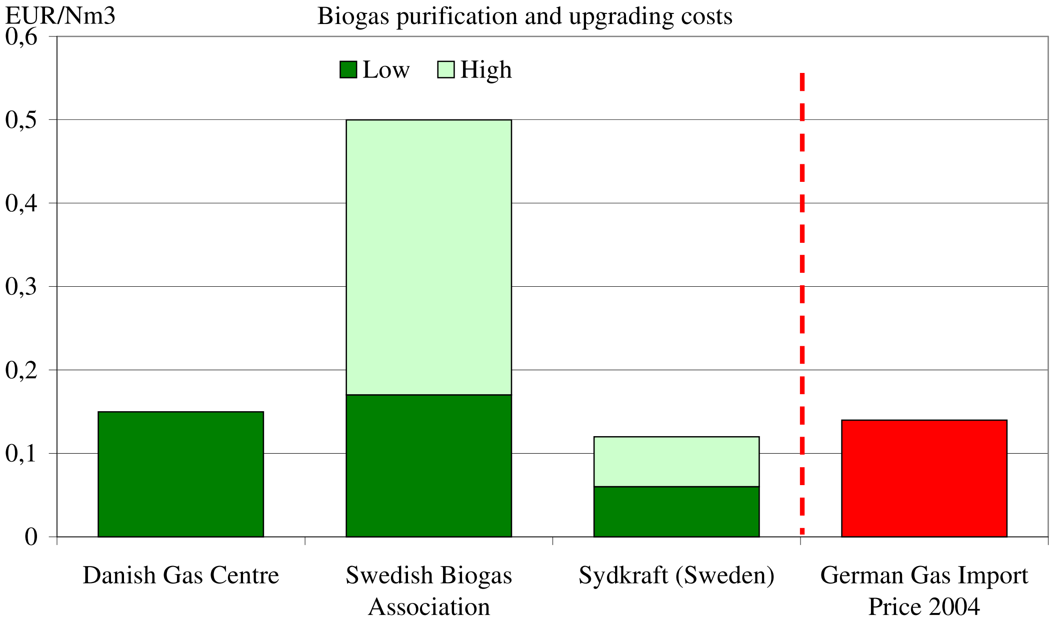


Fig. 6.7 Comparing biogas purification and upgrading costs with gas price

The cost of purification and upgrading of biogas to natural gas standards is in the same cost range as that of the German Gas import price in 2004. In addition to this comes the cost of the biogas itself.

Distribution

If biogas is not upgraded to natural gas quality, the volume of biogas, which needs to be transported to receive the same amount of energy is 1.7 times as high as when transporting natural gas. As the density of biogas is furthermore 0.5 times higher than natural gas, the effect needed to transport non-upgraded biogas in grids is around 2.5 times as high as the effect needed to transport natural gas.

6.6.1.3 Main challenges with biogas

A number of problems are common for hydrogen and biogas with regards to introduction into the natural gas grid[6]:

- Possible mixing relations
- Combustion characteristics
- Corrosion
- Toxicity (e.g. CO)
- Purity (dew points, dust, tar, trace elements, quality control)
- Odour demands for injected gas to the distribution grid
- Demands to documentation, measurement of flow and registration, so the consumers' bills are correct

[6] New Gas qualities in the grid, Jan K. Jensen, DGC 2004

Operational problems can be of technical or economical/legal nature:

- Measurement of gas consumption
- Gas appliances
- Adding odour
- Damage of pipes, valves and measuring units
- Grid capacity
- Payment (amount/energy)
- Gas supplier (who?)

Other problems with biogas can be lack of stable quality of the biogas and an insecure supply. Clear rules and guidelines are needed for all organisations involved. To ensure a good biogas quality, high investment costs are necessary.[7]

6.6.1.4 Expected future development

Biogas production can be a solution to both global and local environmental problems as well as enhance the security of supply of energy. However, the future of biogas production depends heavily on the legal framework in which it takes place. Currently, technologies are available which make it possible to utilise the fibre fraction of the degassed biomass for energy purposes, but legal framework and taxes currently prevent this. If it is made possible, a huge energy potential and a new biomass resource can be utilised, making it feasible to build biogas plants in more places.

Similarly there may be more focus in the future on utilising biogas plants for organic waste treatment mainly from industries, than simply for degassing and purifying manure. One example could be the possibility of treating dead animals and similar types of waste, which was formerly used as animal fodder, but this has recently been prohibited at EU level due to BSE ("mad cow" disease).

6.6.2 Natural gas vs. hydrogen transportation

One of the arguments in favour of producing hydrogen is the possibility to store energy. This can be an advantage in connection e.g. with windmills, where a surplus of electricity during some periods can be converted to hydrogen through electrolysis.

This section focuses on centralised production of hydrogen from surplus wind energy through electrolysis and on distribution in both natural gas grids and dedicated hydrogen grids.

Due to the gas qualities of hydrogen and biogas, respectively, it is not equally interesting to mix the gases with natural gas and distribute it in the existing grid. Biogas can be upgraded, added to the natural gas grid and used in natural gas applications. It is as such a gas of lesser quality than natural gas. Hydrogen also has a lower energy content per m^3, but holds the advantage of being a clean gas, which can be used in fuel cells with a high demand for purity.

Therefore, in the long term it is less interesting to mix hydrogen with natural gas – thereby reducing the energy value of the natural gas as well as reducing the purity of the hydrogen. In the short term the technology can, however, be applied in a transition period.

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[7] Swedish Gas Centre, April 2004

Extensive knowledge exists in the field of transmission of hydrogen in dedicated steel pipes at high pressure, because several grids of this type exist around the world. In comparison little is known about the applicability of the natural gas distribution grid for distribution of pure hydrogen or of hydrogen/natural gas mixtures. Only few tests have been carried out. An American laboratory test in 1979 and a German test around 1980. Danish Gas Centre has in cooperation with the Danish gas companies carried out a literature study, which concludes that distribution of hydrogen in natural gas will cause problems, since some user groups, such as some gas engines can accept less than 1-2% hydrogen. Other user groups, such as boilers, will probably without adjustments be able to use up to 10-15% hydrogen without any problems. For components in the distribution grid problems are indicated for some lubricants and sealing agents.[8]

6.6.2.1 Description of current technologies

Hydrogen production and storage

Hydrogen can be produced in a number of ways, such as from:

- Natural gas, through reforming. This is by far the most common way today, and it is also the cheapest. It is, however, not a CO_2 neutral solution.
- Water and electricity, through electrolysis
- Gasification of coal or biomass
- Alcohols (ethanol or methanol), through reforming

Production of hydrogen through electrolysis can take place in two manners:

- Centrally. If electrolysis takes place centrally, the hydrogen can be stored and distributed by road/sea or in a pipeline network.
- Decentralised. Alternatively, the electricity can be transported in the electricity grid to decentralised electrolysers and storage facilities.

Hydrogen can be stored as compressed or liquefied in tanks or absorbed e.g. in metal hydrides, in a pipeline network mixed with natural gas or as pure hydrogen, or as methanol.

Existing hydrogen pipeline systems

In Germany two larger grids (around 50 km) and several smaller pipeline networks exist for transport and distribution of compressed hydrogen. There is also a pipeline network for hydrogen stretching for 1100 km into France, Belgium and The Netherlands. Here hydrogen is distributed at a pressure of 100 bar. Both of the hydrogen networks are owned by the French company Air Liquide.

In the USA smaller pipeline systems exist for liquid hydrogen, but the costs are high both for investment and operation and it is not likely that this will be the future transport and distribution system for hydrogen.

Some studies have looked into the technical feasibility of transporting hydrogen in existing natural gas grids. A Danish investigation carried out by the Danish Gas Centre shows that technical problems due to material only arise when more than 10% hydrogen is added to the natural gas in the grid. This is valid for transport pipes of CMn steel with a pressure of 170-190 bar. In Norway the Gas Technology Committee has

[8] Usability of the natural gas grid to pure hydrogen distribution, Danish Gas Technology Centre, March 2004

established that hydrogen distributed in mixtures with natural gas can be handled as natural gas in mixtures with up to 10-15% hydrogen.[9]

Hydrogen use

Pure hydrogen produced with electrolysis can be used in e.g. PEM fuel cells, which are used in cars. If hydrogen is mixed with natural gas, it limits the usability. Mixed with natural gas it can be used in some gas engines and in boilers as well as in high temperature fuel cells, such as SOFCs or in PEM fuel cells after reforming. Hydrogen mixed with natural gas is also often referred to as hythane or HCNG (Hydrogen Compressed Natural Gas).

Use of mixtures of hydrogen and natural gas:[10]

- 2% H_2: Operational problems for gas engines
- 25% H_2: Wobbe number below demands from the National Gas Regulations
- Up to 25 %: H_2 is not expected to give safety problems for new appliances, while some older gas appliances may only be used with up to 12% H_2 in the natural gas.

6.6.2.2 Description of current cost level

Hydrogen production

Today only 4% of the hydrogen is produced using electrolysis. The rest is produced from fossil fuels. The total production is around 500 billion Nm³/year, of which 20 billion Nm³/year is produced by electrolysis.

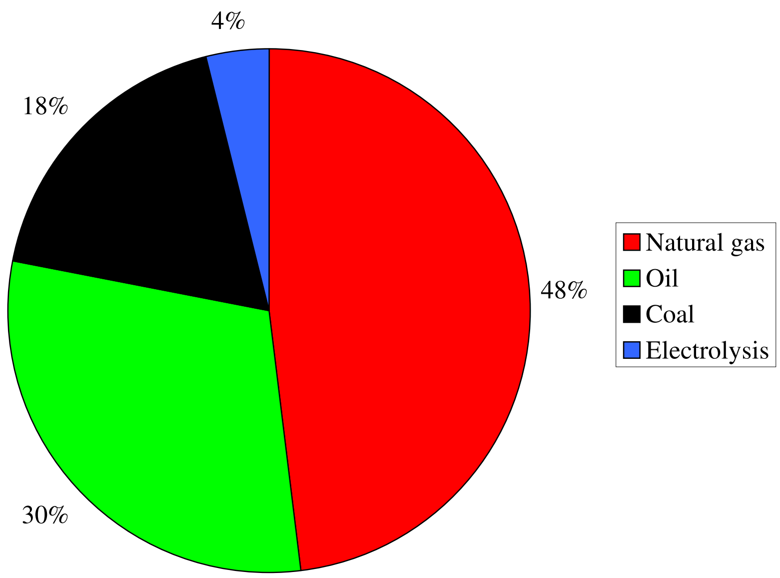

Fig. 6.8 - Worldwide production of hydrogen[11]

[9] Hydrogen as the energy carrier of the future, Special annex no. 1 to Public Report of Norway (NOU) 2004: 11
[10] New Gas qualities in the grid, Jan K. Jensen DGC 2004
[11] U.S. Department of Energy, 2004 (www.eere.energy.gov)

The table below illustrates estimates of costs of producing hydrogen through reforming of natural gas or through electrolysis.

Production method	Cost (EUR/Nm³)
Central reforming of natural gas	App.(*) 0.1
Decentralised reforming of natural gas	App. 0.8
Electrolysis (off peak)	App. 0.9
Electrolysis (peak)	App. 2.5

(*) App.: Approximately

Tab. 6.5- Prices of hydrogen production[12]. Note: cost level not confirmed

The cost of electrolysis varies greatly with the cost of the electricity used for the purpose. The examples of reforming of natural gas are shown, because it is the cheapest and most common way of producing hydrogen today. It will, however, not be relevant to reform natural gas into hydrogen just to mix it with natural gas subsequently.

Distribution

An example of a natural gas grid, which will be used for hydrogen transport estimates a reduction in capacity of 20-25% and an increase in the necessary compressor work of 3-4 times.[13]

The three paragraphs below are taken from the report 'Socio-economic Aspects of the Hydrogen Economy Development" by the Institute for Prospective Technological Studies, Joint Research Centre, EC, March 2003.

"*In the future the transport and distribution of hydrogen can be envisaged as part of a system of energy carriers networks, including electricity and natural gas. The gaseous hydrogen transport and distribution system might be similar to the current natural gas pipelines with significant technological innovations: new materials for the pipes able to avoid hydrogen leakage and different working pressures and flows to overcome the low energy density of gaseous hydrogen.*

The construction costs of a hydrogen pipeline currently range between 0.6-2 M€/km and the cost of transportation increases with the distance from source to destination and decreases with the quantity delivered. For small quantities of hydrogen, road transport by truck is more convenient. In this case the cost is heavily dependent from the distance: 1-3 €/GJ for liquefied and 4-40 for compressed hydrogen for a distance ranging from 20 to 800 km."

Capital costs of the infrastructures for transport applications, from production to the station, have been estimated between 400 and 800 €/car. The final cost of hydrogen could then reach 12-40 €/GJ. This would be lower than tax-free gasoline, which currently costs 10 €/GJ (one GJ is the energy content of 33 litres of petrol). In addition, we have to take into account that the fuel cells with hydrogen have a 2 times higher efficiency than combustion engines with petrol or Diesel."

In 2004 Norway estimated the costs of transporting Hydrogen Compressed Natural Gas (HCNG) in pipes as illustrated in the table below.

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[12] Natural gas and hydrogen – future possibilities, Bjarne Spiegelhauer, DGC, March 2004

[13] Hydrogen as the energy carrier of the future, Special annex no. 1 to Public Report of Norway (NOU) 2004: 11

Fuel	**H_2**		**HCNG, (10% H_2)**	
Pipe lines	Transmission	Distribution	Transmission	Distribution
Pressure [bar]	170-190	4	170-190	4
Diameter [mm]	500	110	500	110
Availability	low	high	high	high
Cost 2003 [kEur/km]**	766	328	600	600*
Cost 2010 (target) [kEur/km]**	328	191	120-180	120-180*

** Limited cost reduction potential, ** Yearly operation costs are approximately 0.5 % of investment*

Tab. 6.6 Fuel[14]

In the report 'Scenarios for joint usage of hydrogen as energy carrier in the future energy system of Denmark" from Roskilde University Centre April 2001 investment costs for new hydrogen pipelines (10-30 bar) are assumed to be 33.5 €/km per TJ/year. Investment costs are not assumed to decrease in the future.

In 2001 Hydro looked at the possibilities for H2 export via HCNG from Norway to the European continent and assessed that 'hydrogen production in Norway for export is technically feasible, but not economically viable. Hydrogen produced from Norwegian hydropower is still not competitive as fuel. In Germany such hydrogen would cost 1.4 times as much as liquid hydrogen produced in Germany with fossil fuel. Hydrogen would cost 1.6 to 3.3 times as much as petrol or diesel." Harmonising power prices in Europe will make the calculation even worse. This is noteworthy, as hydropower is one of the cheapest sources of electricity, except if surplus power from windmills can be used for free.

6.6.2.3 Main challenges with hydrogen

From the report 'Usability of the natural gas grid to pure hydrogen distribution" March 2004 by Danish Gas Technology Centre the overall conclusion is that test results indicate possibilities for hydrogen transport via the 19 bar steel distribution grid as well as via the 4 bar plastic distribution grid. The plastic grid requires additional investigations of the tendency towards changes in melting index and reduced resistance against oxidation after hydrogen exposure. Also, the tendency towards increased rigidity of PEM plastic and reduced rigidity for PE100 plastic needs to be investigated further. The project showed that all joints, components and fixtures of the gas grid should be checked for leakages at regular intervals. Certain components should be modified in order to be hydrogen tight.

HCNG can potentially be exported through existing pipeline networks. The main challenge in commercialising HCNG export is the need of change in the gas sales specifications and possible changes in the end user technology. Varying quality in the pipeline network can also increase the risk of leakage through diffusion, cracks etc.

As mentioned earlier, a number of problems are common for hydrogen and biogas with regards to introduction into the natural gas grid:

- Possible mixing relations
- Combustion characteristics

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[14] Hydrogen as the energy carrier of the future, Special annex no. 1 to Public Report of Norway (NOU) 2004: 11

- Corrosion
- Toxicity (e.g. CO)
- Purity (dew points, dust, tar, trace elements, quality control)
- Odour demands for injected gas to the distribution grid
- Demands to documentation, measurement of flow and registration, so the consumers' bills are correct

Operational problems can be of technical or economical/legal nature:[15]

- Measurement of gas consumption
- Gas appliances
- Adding odour
- Damage of pipes, valves and measuring units
- Grid capacity
- Payment (amount/energy)
- Gas supplier (who?)

6.6.2.4 Expected future development

U.S. Department of Energy lines up some expected future development in the field in the Small Business Innovation Research Program 2005, where the department expresses a need for:

"*a better fundamental understanding of hydrogen embitterment and diffusion to enable the development of lower cost metal alloys, plastics, or composites for hydrogen pipelines; improved metal welding or other joining techniques to reduce the material and labor costs associated with pipeline construction and repair; and improved seals to reduce hydrogen leakage in fittings and other components. It has also been suggested that interior or exterior coatings could be retrofitted on existing or new pipelines to achieve compatibility with hydrogen service. Grant applications are sought to develop advanced and novel approaches to significantly reduce the cost of new hydrogen pipelines (by as much as 50%) and/or technology to retrofit existing natural gas or petroleum pipelines for pure hydrogen transmission and distribution.*"

6.6.3 Conclusions on transport of biogas and hydrogen

It is possible to transport both hydrogen and biogas in pipeline networks with the technologies existing today. It is, however, more expensive than transporting natural gas due to the lower calorific values of biogas and hydrogen.

For biogas it is possible to upgrade the gas to natural gas standards and distribute it in existing natural gas networks, this is, however, a costly process. Similarly, it is possible to distribute the gas in town gas networks, which is less costly, as the gas can contain more CO2, however few such networks exist and are fully operational today. It is also possible to distribute the biogas in dedicated biogas networks, which makes it possible to avoid upgrading and thereby the expensive process of filtering out CO2. However, the investment of the dedicated grid may be prohibitive, and the gas may be used in less appliances.

It is less interesting to mix hydrogen with natural gas – thereby reducing the energy value of the natural gas as well as reducing the purity of the hydrogen. Studies also show that technical problems due to material arise when more than 10% hydrogen is added to the natural gas in some grids. Also distribution of hydrogen in

[15] New Gas qualities in the grid, Jan K. Jensen, DGC 2004

natural gas can cause problems, since some user groups can accept less than 1-2% hydrogen. For hydrogen it may be more relevant in the long run to distribute the gas in dedicated networks, as is already happening, since the purity of the gas is maintained and it can thus be used in more appliances such as low temperature fuel cells.

6.7 References

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