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Pre-combustion, Post-combustion and Oxy-combustion
in thermal power plant for CO$_2$ capture

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Abstract

This paper presents a summary of technical-economic studies. It allows evaluating, in the French context, the production cost of electricity derived from coal and gas power plants with the capture of CO$_2$, and the cost per ton of CO$_2$ avoided. Three systems were studied: an Integrated Gasification Combined Cycle (IGCC), a conventional combustion of Pulverized Coal (PC) and a Natural Gas Combined Cycle (NGCC). Three main methods were envisaged for the capture of CO$_2$: pre-combustion, post-combustion and oxy-combustion.

For the IGCC, two gasification types have been studied: a current technology based on gasification of dry coal at 27 bars (Shell or GE/Texaco radiant type) integrated into a classical combined cycle providing 320 MWe, and a future technology (planned for about 2015-2020) based on gasification of a coal - water mixture (slurry) that can be compressed to 64 bars (GE/Texaco slurry type) integrated into an advanced combined cycle (type H with steam cooling of the combustion turbine blades) producing a gross power output of 1200 MWe.

Nomenclature

IGCC:	Integrated gasification combined cycle
IGCC-1200:	IGCC of quench type delivering 1200 MWe as gross power output
IGCC-300:	IGCC of radiant type delivering 300 MWe as gross power output
NGCC:	Natural Gas Combined Cycle
NGCC-480:	advanced NGCC delivering 480 MWe as gross power output
PC:	Pulverised coal power plant
PC-1200:	PC delivering 1200 MWe as gross power output
HHV:	High Heating Value (total calorific value of fuel)
LHV:	Low Heating Value (HHV less latent heat of the water of combustion)
ASU:	Air separation unit
MEA:	methylethanolamine
DEA:	diethanolamine
MDEA:	methyldiethanolamine
Selexol™:	process using dimethylether of polyethylene glycol (DMPEG)
Syngas:	synthetic gas produced by the gasification

1. Introduction

The industrial feasibility of separating the CO_2 contained in a gas mixture no longer needs to be demonstrated: for example, the ammonia industry uses many hydrogen production units derived from natural gas, in which the final step is CO_2/H_2 separation. Similarly, in the field of natural gas production, excess CO_2 contained in the gas in some deposits has to be extracted so that methane can be marketed efficiently.

In the case of exhaust gases from electrical power stations, other handicaps include firstly the presence of impurities, and secondly the dilution of CO_2 by nitrogen in the combustion air: in general, CO_2 represents only 5% (for the NGCC system) to 15% (for the PC system) of the volume of exhaust gases. If it is required to separate the CO_2 efficiently, it is obviously tempting to remove the nitrogen from the air in order to make the capture process easier. For the IGCC process, this option was necessary even before the emergence of the CO_2 / greenhouse effect problem, mainly for economic reasons related to the reduction in the volume of installations and therefore the resulting savings in materials, the savings being particularly important when the gasification pressure is increased. For other processes, the use of oxygen as an oxidant requires that exhaust gases should be recycled to maintain conventional temperature levels and thus avoid the need to completely change the sizes of all combustion systems (boilers for PC and combustion chambers for NGCCs). However, note that for NGCC the problem of the expansion turbine arises because it's not adapted to a working fluid composed mainly of CO_2 when it's designed for N_2 as mainly working fluid.

2. Different CO_2 capture processes

Our studies [1- 4], present more technical details as well as bulky bibliography concerning the three systems targeted by CO_2 capture operation: Integrated Gasification Combined Cycle (IGCC), Natural Gas Combined Cycle (NGCC), and combustion of Pulverized Coal (PC). For the IGCC, two gasification types have been studied: firstly an existing technology based on gasification of dry coal at 27 bars (Shell or Texaco radiant type) integrated into a conventional combined cycle producing an output of 320 MWe (referenced here as IGCC-300) and a future technology (planned for about 2015 - 2020) based on gasification of a coal-water mixture (slurry) that can be compressed up to 64 bars (GE / Texaco type) integrated into an advanced combined cycle (H type with

cooling of the combustion turbine blades by steam) with a gross power output of 1200 MWe (referenced here as IGCC-1200). The technology on which most experiments have been carried out at the moment is of the Radiant type, although it cannot yet be considered as being mature. Its efficiency is better than the slurry technology (by more than 2 percentage points), because there is less water to be evaporated in the gasification operation. However, it is limited to 30 bars by coal pressurization levels, and its cost is higher than the slurry technology for which the coal can be pressurized up to 64 bars. For PC, two types of power stations were studied: a sub-critical power station with a gross power output of 600 MWe (Q600 not presented in this paper) and a super-critical power station with a gross power output of 1200 MWe (referenced here as PC-1200). Two combined cycles were studied for NGCC: a combined cycle based on a 9H type combustion turbine line associated with an evaporation boiler line and a single shaft steam turbine line, the assembly providing a gross power of 480 MWe (referenced here as NGCC-480), and another combined cycle with twice the gross power, composed of two 9H type combustion turbine lines associated with two evaporation boiler lines and one steam turbine line (not presented here as the scale effect is not so interesting).

The results presented in this work are applicable to a small number of cases, namely: two IGCCs: the Radiant type IGCC (IGCC–300) and the Slurry type IGCC (IGCC–1200); the supercritical PC-1200 and the NGCC-480. It can be considered that these are the most representative systems of the installations that will be used to replace existing fleets: the radiant type IGCC remains the reference (technology similar to that proposed by Shell), but the Slurry type process is included because its production cost is lower than the radiant type, even if its efficiency is lower. The PC-1200 can be constructed at the present time and there is a significant benefit from the scale effect and

its efficiency is better than the Q-600 that is not presented herein. There are no advantages with the 920 MWe NGCC at the current price of natural gas, especially if it will be required to operate in semi-base or in peak, and therefore it was decided to present only the 480 MWe NGCC.

Three main methods can be envisaged for the capture of CO_2 with these three systems (see Figure 1):

1)   **pre-combustion capture**: to capture CO_2 in a synthesis gas after conversion of CO into CO_2;

2)   **post-combustion capture**: to capture CO_2 in the exhaust gases once the fuel has been fully burned with air;

3)   **capture in oxy-combustion**: consisting of combustion in oxygen with recycling of exhaust gases (therefore composed mainly of CO_2 and water) and purification of the CO_2 flow, to eliminate incondensable gases.

Various processes can be envisaged for separation of the CO_2 contained in a gas mixture. They are based on chemical, physical or hybrid absorption, adsorption, membranes separation or cryogenic separation [5,7-11]: Romeo et al. [5] pointed out the high energy penalty in post-combustion using absorption with typical amines solvent. They investigate some process integration variants in order to minimize both the energy penalty and the cost of avoided CO_2 in post-combustion for coal power plant. Peeters et al. [6] developed similar studies than the formers dedicated however to post-combustion in NGCC systems. van Loo et al. [7] evaluated activated MDEA as alternative solvent relatively to MEA (monoethanolamine) applied. Amelio et al. [11] investigated pre-combustion comparing classical CO2 adsorption removal and innovative technologies using membrane separation.

However, all these various processes are neither equivalent nor at the same stage of development. Cryogenic separation does not appear to be a contender, because it requires too much energy and is too expensive when the volume of CO_2 in the exhaust gases is too low and is at atmospheric pressure. However, in the case of a high pressure gas mixture with a high content of CO_2, it would be possible to liquefy it by cooling it without using too much energy, to separate it from other gases. Separation by membranes is attractive, particularly in the case in which membranes are associated with a chemical solvent for which they act as a selective contactor with CO_2 (combination of filtration and chemical absorption), but there are also many problems with the development of this technique: impact of dust, steam, physical degradation of membranes. Adsorption on a solid, used on clean gases at the present time to produce a very good quality of CO_2 for food industry, does not appear to be suitable for processing very high gas flows containing many impurities.

Finally, only physical and chemical (or hybrid) absorptions and oxy-combustion associated with purification of CO_2 (usually cryogenically) appear to be suitable at mid-term for use in high capacity power stations, but the choice of the "best" absorbent remains a very open question and oxy-combustion still has to be demonstrated on the industrial scale and several years of research and development will probably still be necessary (probably 15 to 20 years). For absorption, it has been demonstrated that physical solvents are more appropriate for CO_2 partial pressures greater than 8 bars, while chemical solvents are more appropriate for CO_2 partial pressures of less than 8 bars. Chemical processes based on primary amines such as MEA (monoethanolamine) are preferred when the partial pressure of CO_2 is genuinely very low (less than 1 bar), while chemical processes based on tertiary amines such as MDEA (methyldiethanolamine) are preferred when the partial pressure of CO_2 is slightly

higher; MDEA is actually easier to regenerate under these conditions and its lack of reactivity is compensated by the addition of a kinetic absorption activator such as piperazine or MEA. The absorption capacity of amines increases with the partial pressure of CO_2 and begins to saturate at a partial pressure of 8 bars; beyond this limit, the performance of physical absorption improves and increases linearly with the partial pressure of CO_2 (Henry's law) [12].

3. Application to the capture of CO_2 for different thermal power station systems

Not all systems are compatible with all capture methods: the IGCC system can only be envisaged with the pre-combustion capture method [8] (the high pressure is used to separate CO_2 by physical absorption), the PC system can be adapted to post-combustion capture and oxy-combustion, and the NGCC system can be adapted to the three capture methods, even though the pre-combustion capture option (reforming of methane and then capture of CO_2 on synthetic gas after conversion of CO into CO_2) is economically fairly expensive compared with the other two methods (this method should only be attractive in special cases, for example when hydrogen is necessary for a refinery).

Sensitivity and optimization studies were carried out for each of the options envisaged for the three systems. For post-combustion and pre-combustion capture, we considered the optimization of the CO_2 content in the solvent, the theoretical number of plates in absorption and regeneration columns, the solvent flow, the reflux ratio in the regeneration column, the regeneration heat and obviously the CO_2 capture ratio itself. For oxy-combustion, we considered optimization of the level of purity provided by the Air Separation Unit (ASU), the degree of purity of the CO_2 produced, the degree of leak tightness of the exhaust gas circuit (in the case of PC) and a study on the influence of these parameters on the CO_2 capture rate.

3.1. Basic assumptions

The results presented herein are all based on the same ISO ambient conditions (15°C, 1.013 bars and 60% relative humidity). This is particularly important for the energy performances of the studied processes. The pressure and the relative humidity have a significant impact on the performances of combustion turbines, and the ambient temperature imposes a vacuum at the condenser and therefore controls the performances of steam turbines. Concerning fuels, the coal used is a standard international quality steam coal (LHV ~ 26 MJ/kg, 7% humidity, 15% ash and 1% sulfur). The annual operating times used (operation in base) are 8000 hours for NGCC, 7800 hours for PC and 7500 hours for IGCC. Installations are amortized over 30 years for all systems. The maintenance item for NGCC was reinforced to justify this minimum operating duration. For availability, we assumed 92% for NGCC, 90% for PC and 85% for IGCC.

The economic estimates in our studies have been produced on consistent bases using exactly the same assumptions for each of the different systems and the different capture processes; they can thus be used to make fairly accurate comparisons between the different systems studied (except for uncertainties in the estimates that are far from being negligible); on the other hand, their absolute values may be quite inaccurate compared with 2008 prices[1]; It's why the absolute costs are not given in this paper, but only relative costs to Pulverized coal power plant without CO_2 capture (used as reference). All relative costs mentioned in this work exclude transport and storage costs of CO_2. For engineering and management of installations, we increased equipment costs by 8% for PC and NGCC, and by 10% for IGCC. We also allowed for contingencies equal to 5% for PC and NGCC, and 8% for IGCC. The results presented herein are based on a discount rate of 11%, considered to be the most probable in the medium and

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[1] for example, due to the fast increase in the price of metals or the price of fuel

long term and construction times were fixed at 2 years for NGCC, 4 years for PC and 5 years for IGCC. The discount rate and the construction period are of overriding importance for interest during construction. Any delay in construction will substantially increase this type of expense. We also assumed parity between the American Dollar (USD) and the Euro (EUR).

We used the following reference values for the purchase prices of coal and natural gas:

1) for coal: 60 EUR/tonne, equivalent to 2.26 EUR/GJ HHV. This price is composed of 46 EUR per tonne of coal CIF ARA (including Cost, Insurance and Freight to one of the ports of Amsterdam, Rotterdam or Antwerp), plus 14 EUR/tonne for transport from the port to the power station;

2) for natural gas: a price of 6.29 EUR/GJ HHV. This price originates from the price of natural gas delivered to the procurement point at the frontier of the country equal to 230 EUR/1000 Nm^3, equivalent to 22 EUR/MWh or 5.84 EUR/GJ HHV, plus 1.19 EUR/MWh for the TICGN tax (Taxe Intérieure de Consommation sur le Gas Naturel - Internal Tax on Consumption of Natural Gas) and 0.43 Euro/MWh for transport from the procurement point to the power station.

3.2. Results

3.2.1. Pre-combustion capture

Pre-combustion capture relates to the treatment of a synthetic gas composed principally of CO and hydrogen. Gasification of coal or reforming of natural gas with oxygen leads to a mixture composed principally of $CO + H_2$ (on dry), and then after conversion of CO with steam, to a mixture of $CO_2 + H_2$. CO_2 can then be separated using a physical absorbent (which is less expensive as an investment and less penalizing for the efficiency than if the exhaust gases are treated, because the gas is under pressure

and there is no nitrogen); CO_2 is sent to the compression unit while hydrogen is used as input to a combined cycle to produce electricity. The IGCC concept was no so far presented by the American DOE as being the "clean coal" power station of the future in a context in which something else other than electricity has to be produced from the coal (for example synthetic fuels). However, this system is still handicapped by low availability and high investment and production costs.

The optimum separation process will be chosen as a function of the partial pressure of CO_2 in the gas to be treated. In the case of pre-combustion capture, the partial pressure of CO_2 depends on the IGCC process chosen for coal, or the pressure of the reforming process chosen for natural gas. However, the increase in pressure is not a free operation, and it must be assured that the gain in capture due to the high pressure is not cancelled out by the additional energy that has to be supplied.

The first case that we studied was pre-combustion capture in a Puertollano radiant type IGCC operating at 27 bars (Figure 3). The partial pressure of CO_2 provided by this system is about 8 bars which, as mentioned earlier forms a ceiling (saturation) for the performances of chemical processes and which is the threshold beyond which physical processes become more attractive.

The quench type gasification (Figure 4), other alternative studied here, has gasifier operated at 64 bars, and is fed with a mixture of coal and water (slurry), the shift conversion is inserted immediately downstream the gasification system as the synthetic gas contains enough water to convert CO into CO_2.

After a first selection, three processes were finally selected and studied in detail: a physical absorption process using methanol, another physical absorption process (the

Selexol process) for which the solvent is based on dimethylether of polyethylene glycol (DPEG) and a process using an active amine-based chemical solvent, MDEA.

In addition to the equipment necessary for CO_2 capture (absorption and desorption columns, pumps, heat exchangers, expansion tanks, etc.), we included the following in the process:

- a catalytic reactor, used to convert CO into CO_2 before the separation ("shift conversion");

- a cooling system for the process with methanol in order to maintain an optimum temperature of -30°C in the absorption column;

- a downstream methanol vapor recovery system to limit losses of absorbent;

- a device for lowering the water content in CO_2 produced to less than 20 ppm (by mass) to prevent acid corrosion in the transport network;

- a CO_2 150 bar compression station associated with a gas cooling system (final temperature < 40°C) to satisfy the specifications for the CO_2 transport network.

Furthermore, after optimization, the CO_2 capture ratio was chosen to be equal to 85% for the three separation processes. This ratio results from combining the CO to CO_2 conversion ratio (90%) and the efficiency of the CO_2 separation itself (about 95%).

Finally, the methanol- based process was found to have the best performances in terms of the energy penalty [13] (reduction in the electrical efficiency of the power station), the production cost per kWh and the cost per tonne of CO_2 avoided, even if in the case of Puertollano type IGCC, the difference observed with the other two capture processes is not very high. This methanol process was also selected for the Texaco IGCC-slurry (see Figures 3 and 4) and for reforming of natural gas, both operating at

high pressure, equal to 64 bars for the IGCC and more than 70 bars for reforming of natural gas.

Under these conditions, the modeling results show (Figure 7) that the global efficiency of the power station drops to 32.5% net on the LHV basis with a methanol-based capture process for IGCC-slurry, and to 33.5% for the Puertollano radiant type IGCC. This efficiency is about 9 percentage points less than the efficiency of the reference power station without capture for the IGCC-slurry, and more than 10 points lower for the radiant type IGCC, which therefore represents a relative reduction in the efficiency of 22%. The main items responsible for this loss of efficiency are the capture station with its refrigeration system (methanol and exhaust gases), and the CO_2 compression station, the consumption of the two being approximately equal. However, note that the auxiliary with the highest consumption for both reference and capture plants is still the ASU, accounting for 44%.

In the case of the NGCC with reforming of natural gas, the relative penalty on efficiency is of the same order of magnitude as in the case of the IGCC: the efficiency drops from about 60% without capture to less than 46% with pre-combustion capture, which represents a relative drop of 23%.

As can be seen in Figure 7, capturing CO_2 costs a great deal of energy, which causes a large drop in the global efficiency of the power station. Therefore, more fuel has to be consumed to produce the same amount of electricity. In other words as shown in Figure 2 below, a power station with capture produces actually more CO_2 per kWh than a power station without capture, but more than 85% of the CO_2 is captured. Therefore the quantity of CO_2 actually "avoided" in the atmosphere is not the amount that is captured, but is the difference between the quantity that the reference power station would have emitted without capture, and the quantity emitted by the power

station with capture. The quantity of "CO_2 avoided" is obviously less than the quantity of "captured CO_2" due to the reduction in the net production efficiency. This is why it is important to make a clear distinction between "CO_2 captured" and "CO_2 avoided".

3.2.2. Post-combustion capture

Post-combustion capture consists of treating exhaust gases on the output side of the PC or NGCC (see Figure 5 for the case of PC). As mentioned earlier, technologies based on chemical absorption appear to be best adapted to this separation. Other technologies, adsorption, membranes and cryogeny, are even less suitable for post-combustion capture than for pre-combustion capture, mainly for the following two reasons:

- a much lower partial pressure of CO_2 in post-combustion exhaust gases than in synthetic gas originating from a gasifier or a reformer: about 50 mbars in NGCC exhaust gases and 100 mbars in PC exhaust gases compared with 8 bars (for the Puertollano type IGCC) to more than 16 bars (for the Texaco IGCC-slurry and NGCC before reforming) in synthetic gas;

- the presence of larger quantities of dust, impurities such as SO_x and NO_x and incondensable gases, particularly oxygen (which do not exist or exist only in very small quantities in synthetic gas).

The choice of the absorbent is guided by the partial pressure of CO_2 in the gas to be treated. As mentioned above, the very low levels of CO_2 partial pressures in exhaust gases impose chemical absorption.

Chemical absorption (processes with amines, Benfield process with potassium carbonate) is an industrial technology and has been used for decades, but in the past it has only been used to treat very clean gas mixtures containing no or few impurities such as dust, SO_x, NO_x, oxygen (ammonia industry and fertilizer industry, separation of CO_2

from natural gas), or containing only very small quantities of them. Therefore, chemical absorption will have to satisfy two challenges before it can be applied to the capture of CO_2 in exhaust gases from coal power stations, firstly related to its strong energy demand for the regeneration of the absorbent (increasing with decreasing of CO_2 partial pressure), and secondly degradation of the absorbent by impurities contained in the exhaust gases to be treated. Degradation of chemical solvents will be treated subsequently in the chapter concerning technical limitations.

3.2.3. Oxy-combustion

In the previous sections, we described the importance of the partial pressure of CO_2 in the gas to be treated, for separation processes. The principal advantage of oxy-combustion is that it increases very significantly the partial pressure of CO_2 in the exhaust gases from combustion, because it avoids the dilution of exhaust gases with nitrogen in air. Obviously, an air separation unit is necessary to provide almost pure oxygen to the boiler. A PC oxy-combustion diagram is shown in Figure 6. Combustion is made using pure oxygen (up to 97% purity), but in which a small amount of nitrogen and argon remains. A big part of the exhaust gases are recycled in the boiler to maintain the usual temperature levels of PC without capture. This avoids full resizing of the boiler and its associated exchangers. The flow of uncycled CO_2 still contains water vapor, impurities (particularly some NO_x and SO_x amounts that remain in the exhaust gas of scrubbing systems) and incondensable gases such as oxygen, nitrogen and argon. These latter are originating from the ASU and parasite air entries due to the lack of seal of the PC cycle (combustion chamber, deduster, gas - gas heater, etc.). The content of CO_2 in these exhaust gases is of the order of 75% on wet gas. The next step is to condense the water and purify the CO_2 until 99% pure so that it can be transported in the supercritical state. The presence of incondensable gases in the CO_2 flow transported by pipeline in the supercritical state can cause vibrations and shock loads in the pipe,

which can cause mechanical damage. However, no known study has attempted to specify critical concentrations of these incondensable gases. All that is agreed upon unanimously is the concentration of water and most works published on this subject agree upon a fixed limit of 20 ppm by mass (50 ppm by volume). Thus in our study, a dehydration system using triethylene glycol (TEG) followed by a cryogenic impurity separation device are integrated into the CO_2 compression / liquefaction step.

3.2.4. Comparison between different capture processes

The calculations (see Figure 7) show that the highest efficiency with capture is obtained for NGCC with post-combustion capture, with an efficiency of 50% compared with 60% without capture. The next highest is the oxy-combustion in PC, with an efficiency of almost 35% compared with 45% without capture, and then IGCC-Puertollano[2] with pre-combustion capture with an efficiency of the order of 33.5% compared with 44% without capture. The lowest efficiency is obtained with post-combustion capture in PC, equal to 30% which is 15 points less than PC without capture (if MEA is used). Therefore, from a purely energetic point of view without considering economic Figures, it would be recommended to only consider pre-combustion capture in IGCC, post-combustion in NGCC and oxy-combustion in PC. Nevertheless, post-combustion capture in PC, although its efficiency seems to be lower than oxy-combustion PC, is now seen inevitable if it is required to be able to retrofit coal-fired power stations that will be built between now and 2020 (which accounts for more than 1000 GW). For NGCC, oxy-combustion is not a possibility for all current combustion turbines, their compression and expansion systems are not suitable for CO_2 as main working fluid; oxy-combustion of natural gas could only become technically viable if

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[2] In our study, the efficiency of the Puertollano IGCC has been calculated using a conventional combined cycle. The efficiency could be better in the case of an advanced cycle (H cycle).

innovative cycles such as the Graz cycle are adopted, and provided that they can be brought into an industrialization phase in order to reduce the cost.

Concerning investment (see Figure 8), the least expensive technology comparatively to PC investment cost which is given 100 as reference, remains NGCC with or without capture, 40% of the PC for NGCC without capture and 83% for NGCC with post-combustion capture. PC and IGCC-slurry (GE / Texaco) are in second position at 169% for PC with oxy-combustion, 101% for IGCC-slurry without capture but only 164% for the IGCC-slurry with pre-combustion capture. The radiant type IGCC is more expensive than IGCC-slurry and PC, at 122% for the Puertollano type IGCC without capture and 185% for the pre-combustion option. However, it will be noted that the additional investment costs induced by capture are much higher for NGCC (110% greater than NGCC cost without capture) than for radiant type IGCC (52% greater than IGCC-300 cost without capture), IGCC-slurry (62% greater than IGCC-1200 cost without capture) or oxy-combustion in PC (69% greater than PC-1200 cost without capture).

The lowest production costs (see Figure 9) are obtained with oxy-combustion PC (148% of PC without capture) and IGCC-slurry with pre-combustion capture (154%). The production cost of radiant type IGCC with capture in pre-combustion is of the same order of magnitude as NGCC with post-combustion capture (162%).

On the other hand, the lowests costs per tonne of CO_2 avoided are obtained with pre-combustion capture in IGCC-slurry (65% of the cost of CO_2 avoided in PC with post-combustion capture), oxy-combustion in PC (71%) and the radiant type IGCC with capture in pre-combustion (73%) (see Figure 10). The highest cost per tonne of CO_2 (234%) is obtained using pre-combustion capture in NGCC.

4. Limitations of the different capture processes

As mentioned above, in carrying out our studies, we obviously assumed that the processes and equipment used work as we would like them to do, although this remains to be demonstrated experimentally and on the industrial scale. In this chapter, without attempting to be exhaustive, we will summarize the assumptions that form limitations to the conclusions of our evaluations, limitations concerning technical and economic aspects.

4.1. Technical limitations

We have assumed that the specific problems that will be encountered in coal power stations with capture have been solved, although this is obviously not the case at the moment: problems remain with oxy-coal combustion boilers, hydrogen turbine for IGCC with CO_2 capture, degradation of amines, separation of incondensable gases in oxy-combustion (what about impurities in a cryogenic system?), etc. These main limitations are indicated in the table 1.

4.2. Economic limitations

The economic estimates presented in this balance are relevant for a comparison between the different systems, but their absolute values may vary significantly as a function of the cost of metals, the price of fuels, tension on the equipment market (availability of construction and supervision teams), etc. For example, prices of metals have increased continuously since 2002 - 2003, to double by 2007 - 2008, which obviously has a large impact on the final investment and production cost, but should not modify relative costs between different systems.

Similarly, if the discount rate changes, it will have a significant impact on all economic estimates: the investment cost, the production cost and the cost per tonne of CO_2 avoided. As we have seen, the fuel cost also has an important impact on the

production cost and on the cost per tonne of CO_2 avoided, particularly for NGCC for which it represents more than 70% of the production cost. In some cases, our estimates are very similar to estimates made by our American and Canadian colleagues, although the structure (breakdown) is significantly different. Fuel, equipment and installation prices are usually lower in North America, but discount rates may be higher than in Europe [14-16].

Concerning IGCC, it is clear in our studies that dry pressurization of coal is one of the key elements that can significantly improve the technical and economic performances of this technology. Progress on dry coal pressurization pumps is necessary, to avoid firstly the complex lock systems in the case of a Puertollano type IGCC, and the mixture of coal with water in the case of the IGCC-slurry; the recent announcement about development of such a pump capable of achieving a pressure of 40 bars suggests a potential improvement for this type of technology.

Finally, the question about operation at low loads, at semi-base or at peak-load should be considered. In theory, all systems could operate at a minimum load of 50% and for a number of hours corresponding to operation in semi-base or in peak-load. However, efficiencies at low load are seriously degraded and production costs, that are already high for CO_2 capture operations, increase significantly if the power station does not operate at base load. Thus, for an annual operation of only 3750 hours instead of 7500 hours, the cost of an IGCC-slurry with capture increases by almost 60%, which is more than double the cost of the IGCC-slurry without CO_2 capture. The same calculation for PC gives a production cost with oxy-combustion capture increased by 63% for 3900 hours of operation per year, compared with the cost of production for 7800 hours of operation per year. The impact on the production cost of operation in semi-base for NGCC is lower than for IGCC and PC because the proportion of the

investment in the production cost is lower, and the cost increases by 24% in NGCC with post-combustion capture when operating for 4000 hours per year instead of 8000 hours per year.

5. Conclusions

The technical and economic estimates presented in this work are not the only parameters in determining the choice of a system for the capture of CO_2. Constraints related to resources such as fuel and water may also influence this choice. Therefore, it appears difficult to make a once-and-for-all decision about the "best CO_2 capture process"; however, the results of our studies suggest that pre-combustion capture by physical absorption (methanol) should be used for IGCC, oxy-combustion should be used for PC and post-combustion capture (amines) should be used for NGCC.

However, these recommendations are based on a number of assumptions that may be more or less "dependable" depending on the process. For example, capture processes are supposed to operate reliably, which remains to be demonstrated on an industrial scale, at least for post-combustion and oxy-combustion capture. On the other hand, pre-combustion capture on synthetic gas is industrially mature, but the IGCC system into which it must be integrated still has availability problems. The studies that we have carried out assume that the specific problems that we will encounter for coal-fired power stations with capture have been solved, which is not the case at the present time: coal combustion boiler with oxygen, hydrogen turbine for IGCC with CO_2 capture, degradation of amines, separation of incondensable gases in oxy-combustion (and what about impurities in a cryogenic system?), etc. Finally, it is quite clear that the evaluation studies that we have carried out are no more than a first phase and must be continued with other more detailed pre-feasibility studies, particularly in engineering, to enable a

more accurate evaluation of the industrial feasibility of the different processes for capturing CO_2.

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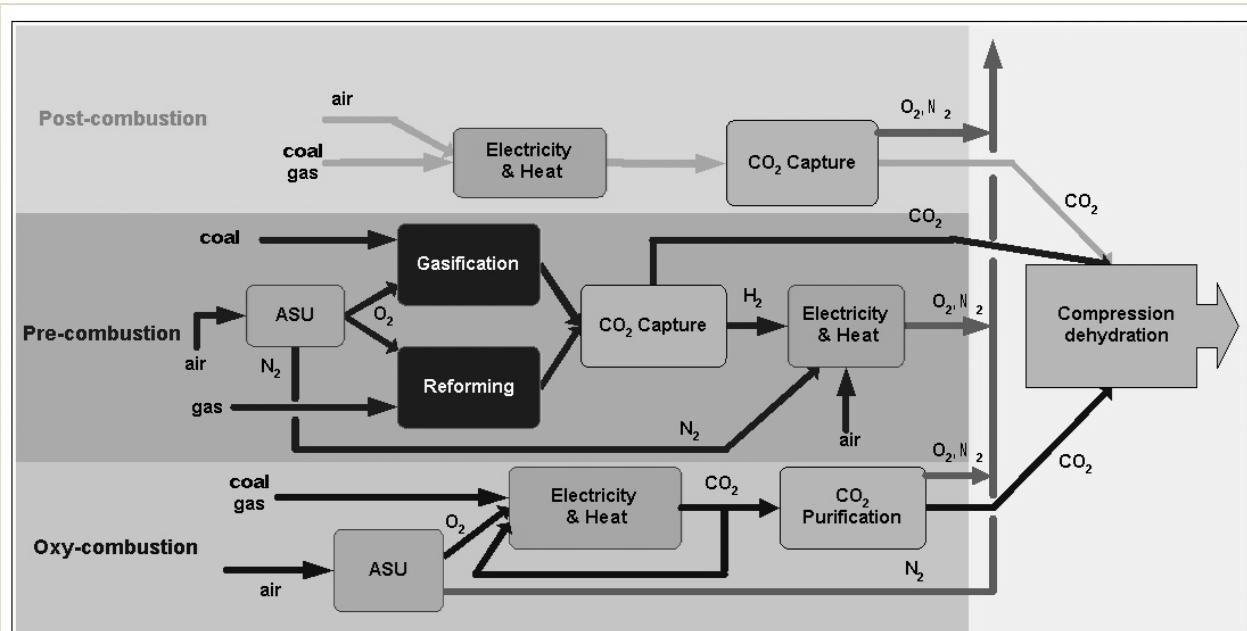
Figure 1: the three CO₂ capture processes
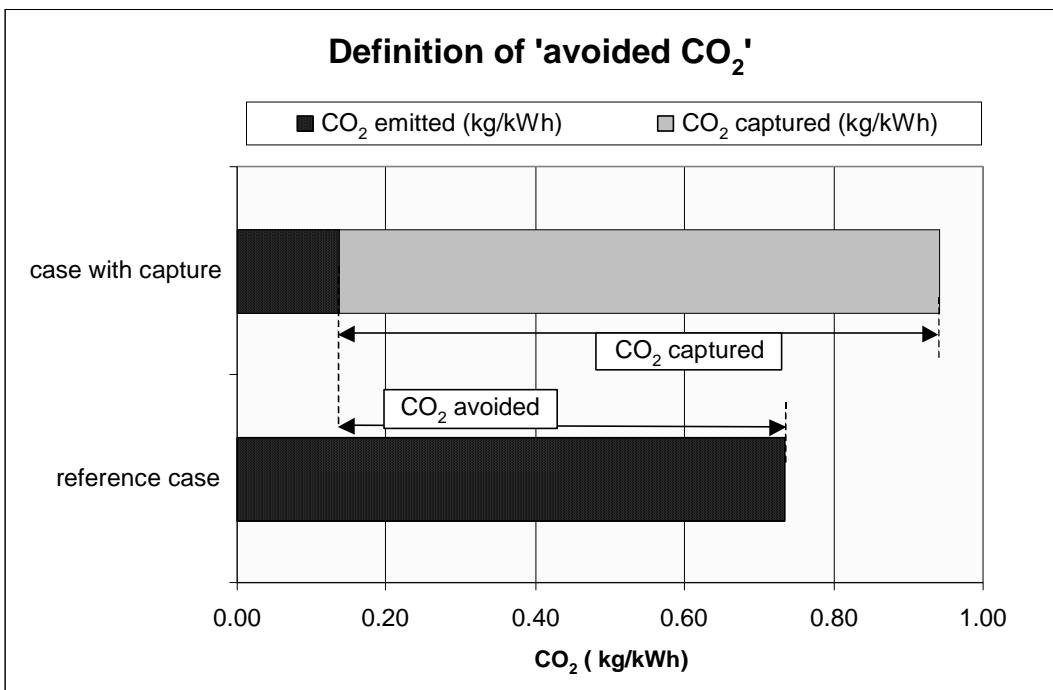
Figure 2: "Captured CO$_2$" and "CO$_2$ avoided" per kWh produced
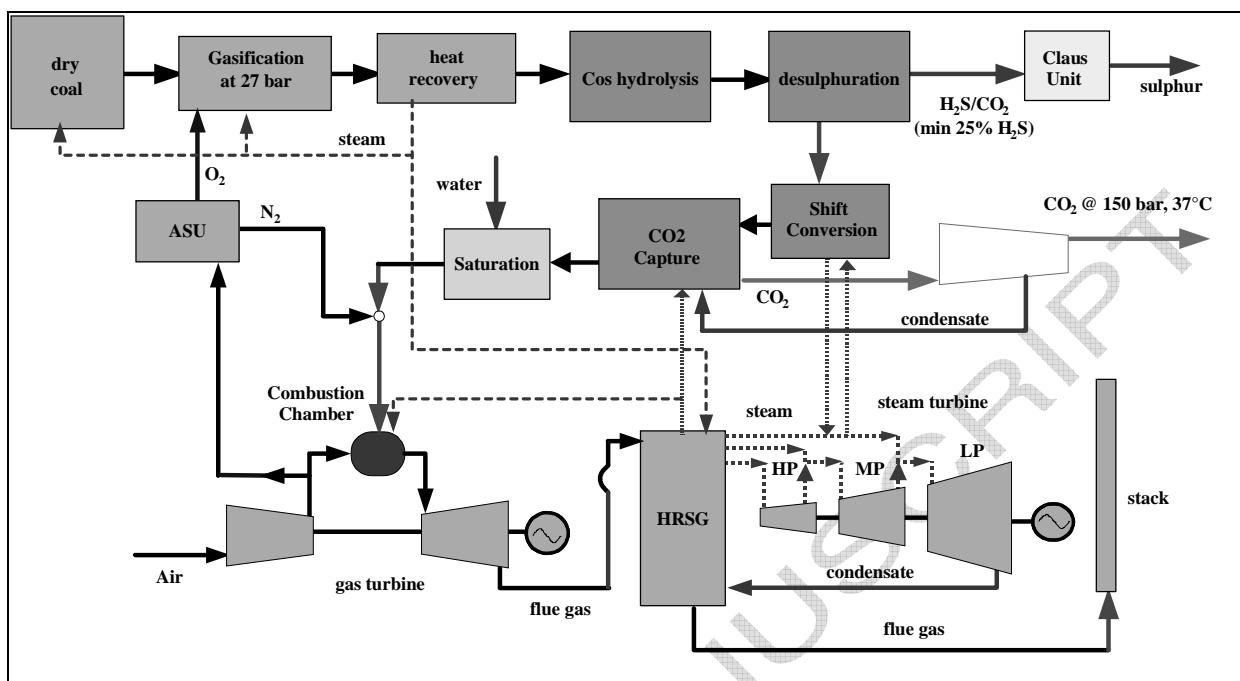
Figure 3: Radiant-IGCC with capture of CO_2
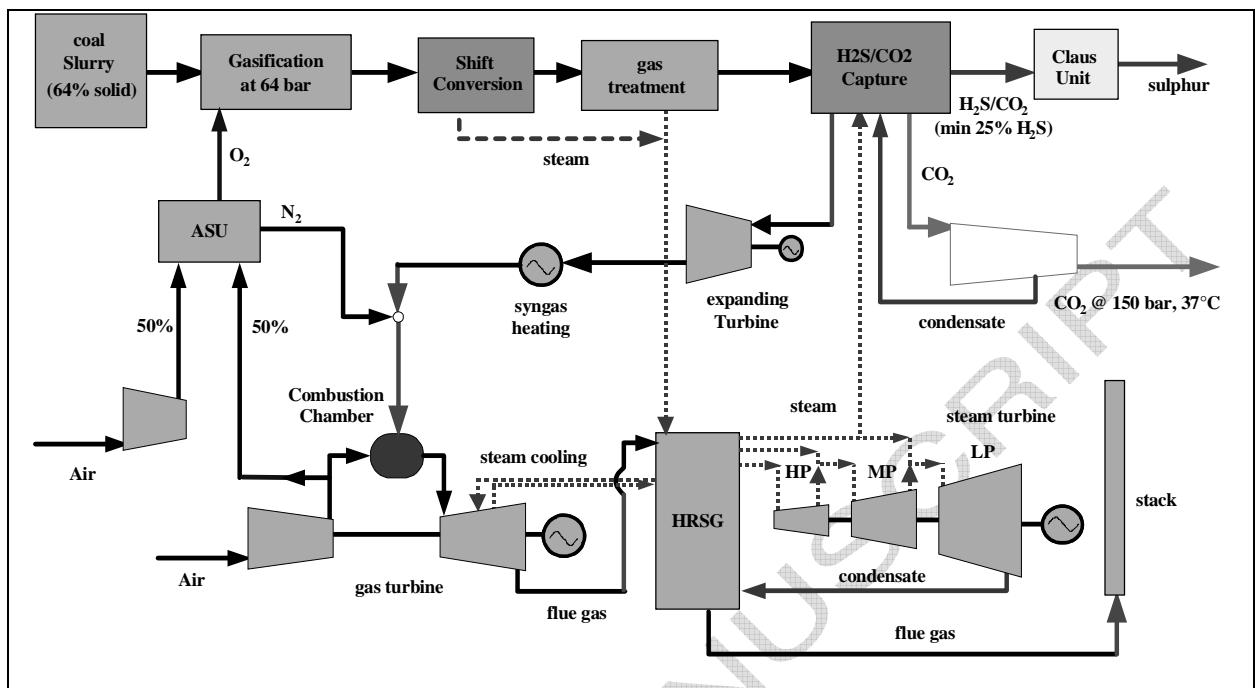
Figure 4: Quench-IGCC-slurry with capture of CO$_2$
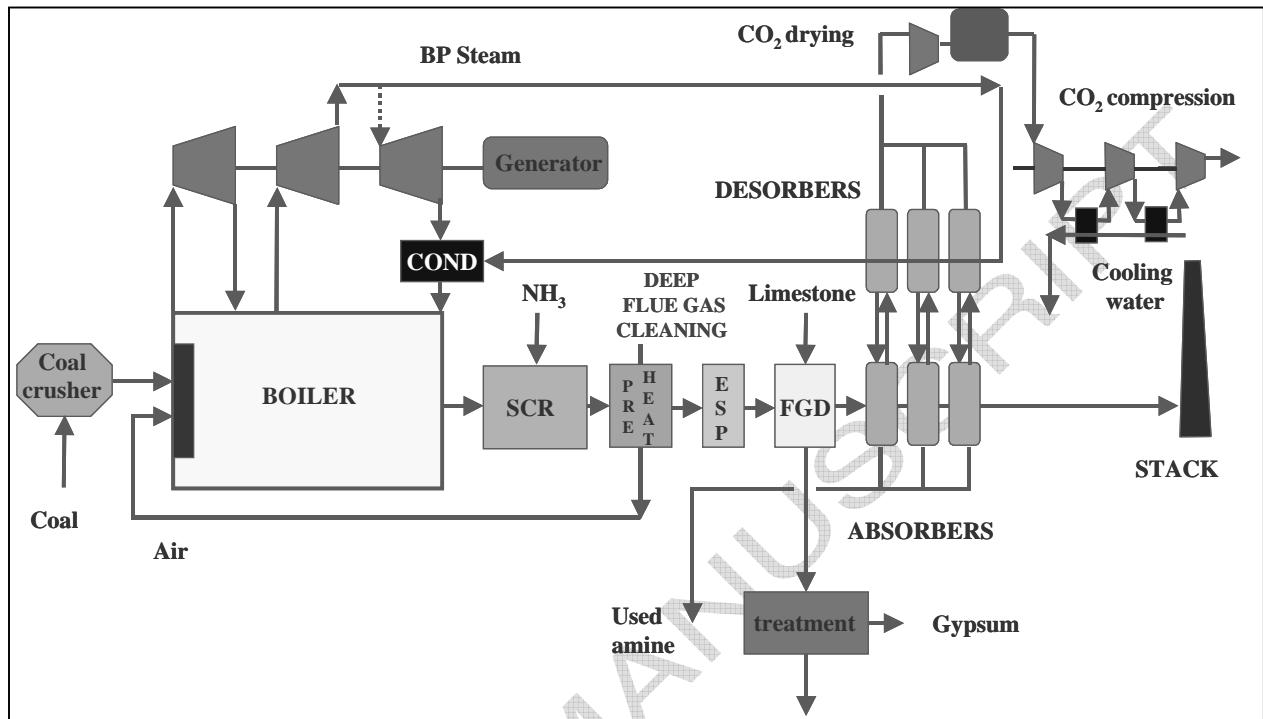
Figure 5: Post-combustion capture on PC
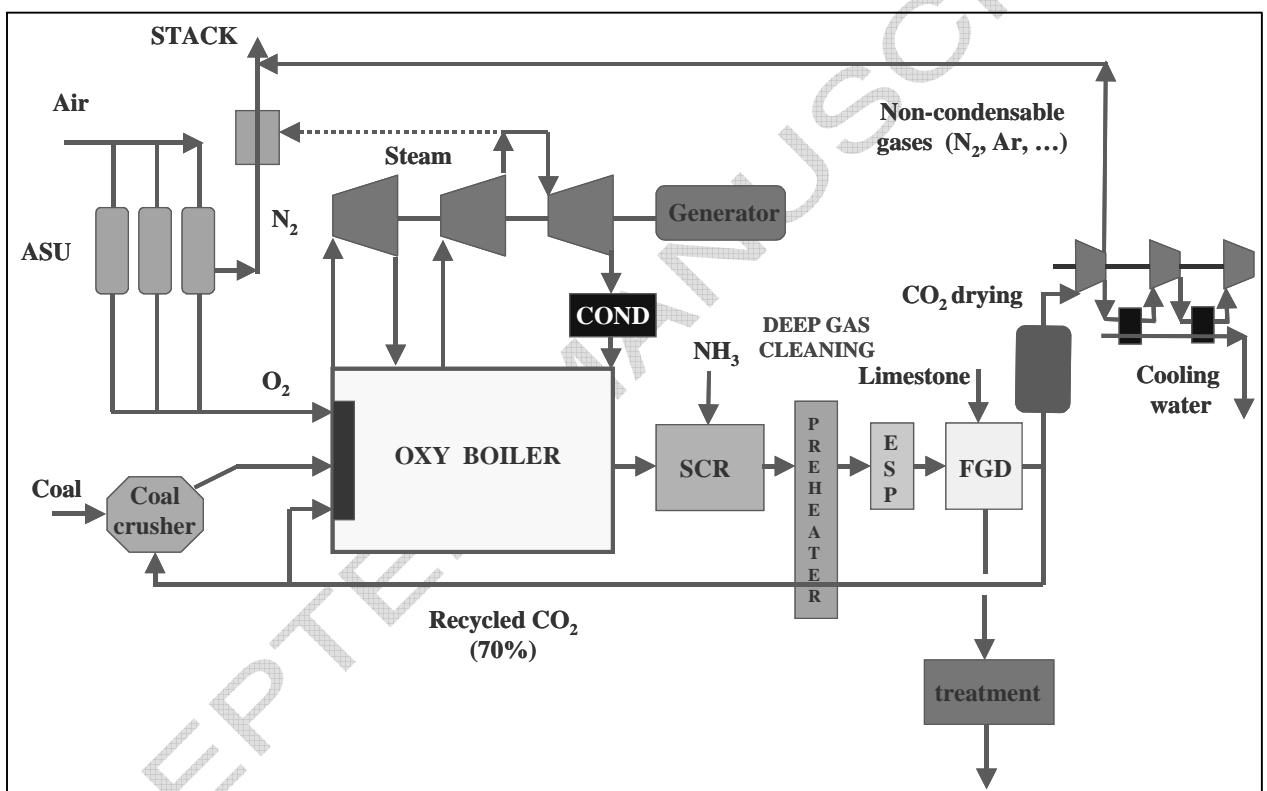
**Figure 6: Oxy-combustion capture on PC**

Efficiency without and with CO$_2$ capture
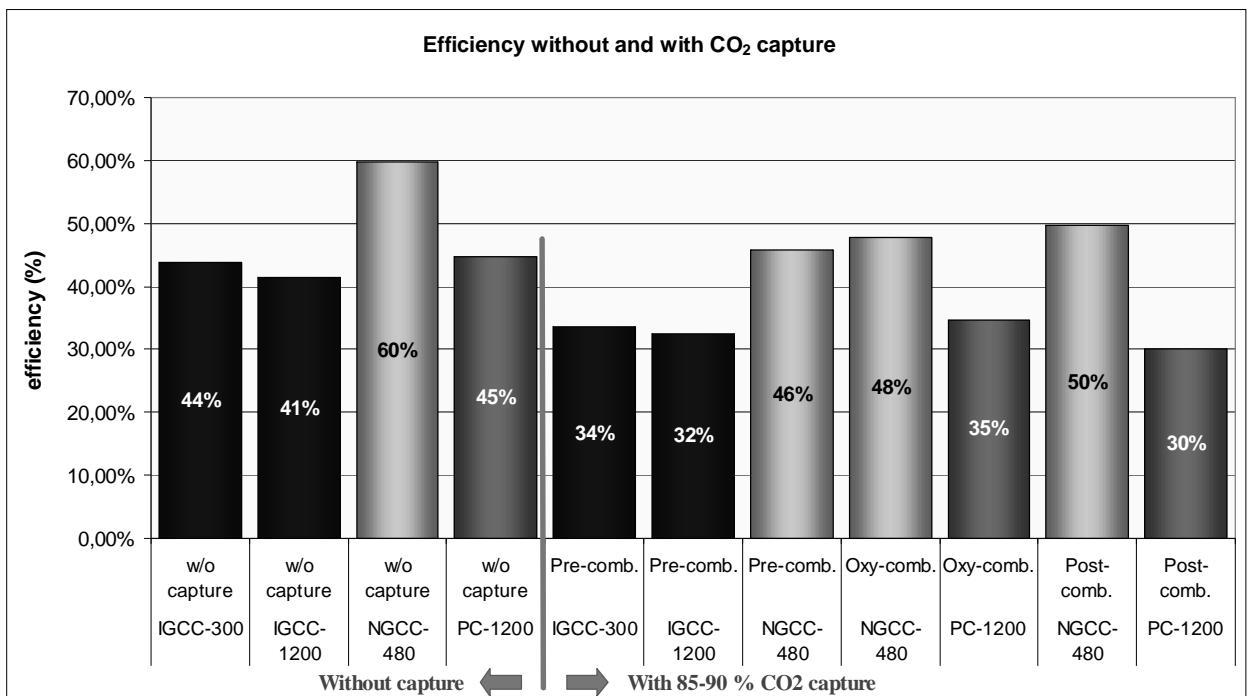
**Figure 7: Efficiency of the different systems with and without CO$_2$ capture**
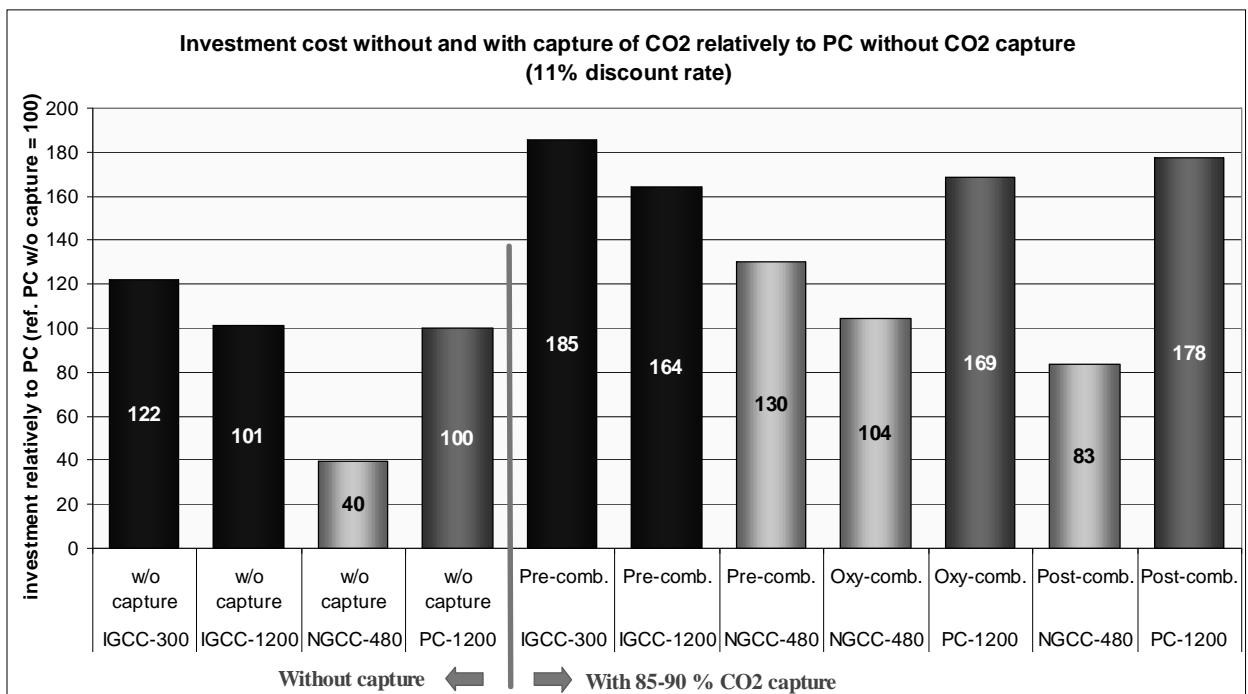
**Figure 8: Investment cost of the different systems with and without CO$_2$ capture**
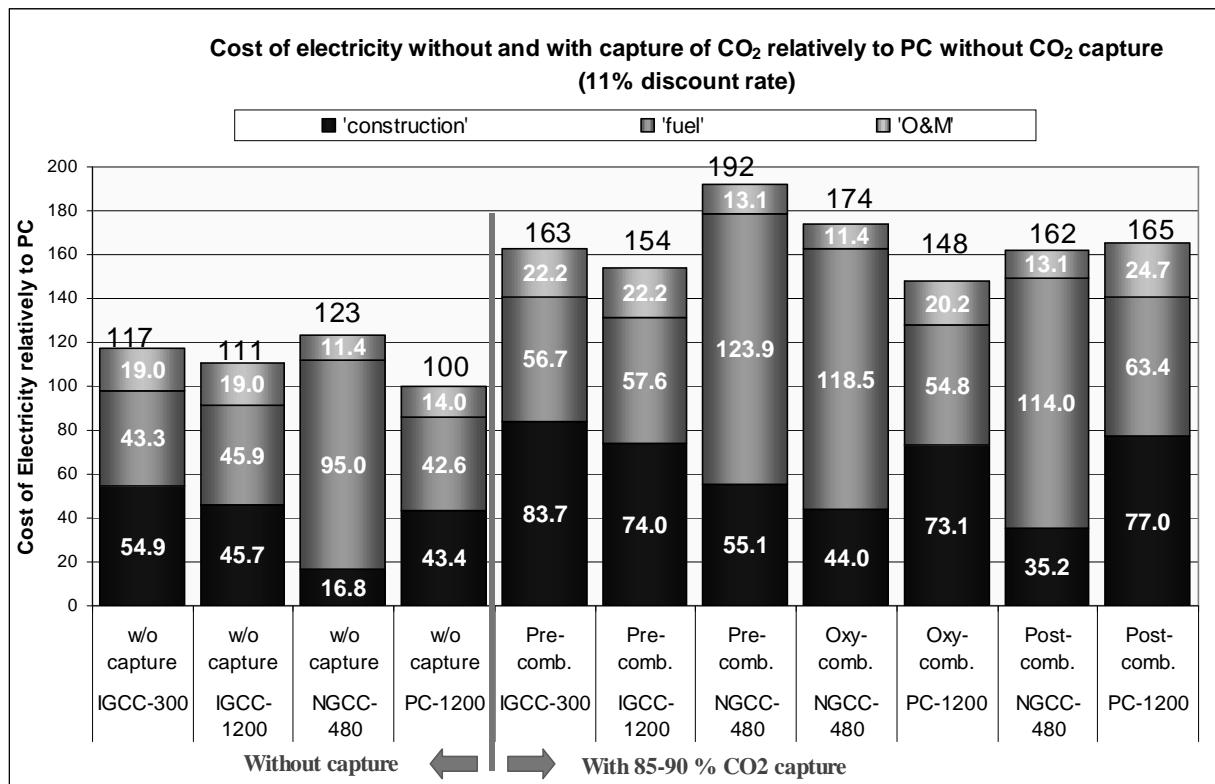
**Figure 9: Production cost of the different systems with and without CO₂ capture**
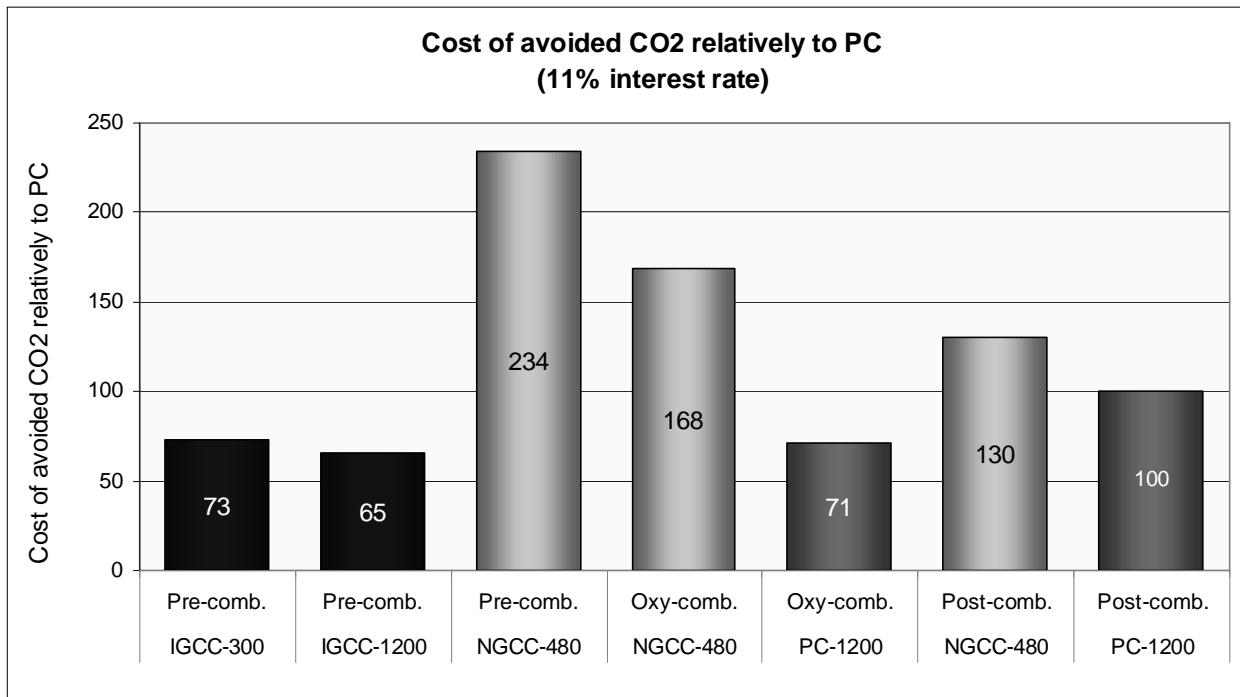
Figure 10: Cost per tonne of CO_2 avoided for the different CO_2 capture processes

Table 1: The main limitations for studied systems

	Technical problems that still have to be solved effectively (R&D necessary) but which we have assumed to have been solved for the purposes of our studies	Technical weak points in the system	Financial hard points (what is most expensive when capture is added)
IGCC-slurry	Hydrogen turbine Acid gas conversion shift	Increased complexity for a process for which there are still problems with reliability without capture. Not well adapted to some coals (lignite, high ash and sulfur contents, etc.)	The conversion shift
Dry coal IGCC	Hydrogen turbine Acid gas conversion shift Badly adapted to high pressures	Increased complexity for a system for which there are still problems with reliability without capture.	The conversion shift
Pre-combustion capture NGCC	Hydrogen turbine	Carbon deposit on the reformer	Reformer
Post-combustion capture NGCC	Chemical regeneration of the degraded absorbent. Elimination of the degraded absorbent	Consumption of LP steam for regeneration	
Oxy-combustion NGCC	Oxy-combustion chamber. Compression level of the compression turbine Expansion turbine for CO_2	Separation of incondensable gases. Electrical consumption of auxiliaries	ASU Separation of incondensable gases

	Purification of CO_2		
Post-combustion capture PC	Chemical regeneration of the degraded absorbent. Elimination of the degraded absorbent	Degradation of the absorbent Consumption of LP steam for regeneration	
Oxy-combustion PC	Boiler and oxy burners. Parasite air entries. Purification of CO_2	Purification of CO_2 Electrical consumption of auxiliaries	ASU Purification of CO_2