

Thermodynamic assessment of amine based CO₂ capture technologies in power plants based on European Benchmarking Task Force methodology

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H I G H L I G H T S

- European common methodology description for benchmark studies in carbon capture.
- Performance of PCC based on MEA and CESAR-1 (2-Amino-2-Methyl-Propanol and piperazine).
- CESAR-1 reduces power penalty by 25% for coal fired plant compared to standard MEA.
- CESAR-1 reduces power penalty by 12% for gas fired plant compared to standard MEA.

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A B S T R A C T

Post combustion CO₂ capture (PCC) with amine solvents is seen as one of the possible technologies which can be implemented in the near term to significantly reduce CO₂ emissions from fossil fuel power plants. One of the major concerns for its implementation at large scale in power plants is the high capital and operating costs of the technology. This paper examines the performance of advanced supercritical (ASC) pulverised coal and natural gas combined cycle (NGCC) power plants with two post-combustion CO₂ capture units. The capture units are based on chemical absorption with an advanced amine solvent, CESAR-1, which is an aqueous solution of 2-Amino-2-Methyl-Propanol (AMP) and piperazine (PZ), and the conventional Monoethanolamine (MEA) solvent. The comparison between the mentioned technologies is based on the technical assumptions and method provided by the European Benchmarking Task-force (EBTF) methodology, which is a first attempt for establishing a common European Standard for comparative studies. The resulting net electric efficiencies for the power plants without capture are 45.25% and 58.3% for the ASC PC and NGCC cases respectively. When CO₂ capture is applied, the net electrical efficiencies of the studied plants decreases. In the ASC power plant, the MEA capture unit decreases the efficiency by 11.7 percentage points, while the CESAR-1 capture unit decreases the efficiency by 9.4 percentage points. For the NGCC power plant, the reductions are 8.4 and 7.6 percentage points for the MEA and CESAR-1 capture units respectively. Therefore, the evaluation of CESAR-1 under the EBTF standards shows a reduction on power production penalty of 25% for the coal fired plant and 12% for the gas fired plant compared to conventional MEA.

1. Introduction

Carbon Capture and Storage (CCS) is seen as one of the promising technologies to abate CO₂ emissions from fossil fuelled power plants at a relatively high plant reliability and flexibility level [1,2]. One of the promising CCS strategies is post-combustion capture

(PCC) since it is more easily applicable to existing power plants. However, it must be outlined that oxy-fuel and pre-combustion routes can have other benefits such as reduced efficiency penalties [3,4].

Among the different technologies that can be applied to PCC, the chemical absorption concept is indicated as one of the best options for short term implementation [5], because it is partially proven at smaller scale and it has been used for different purposes in the process industry [6]. There are various PCC technological options commercialized or under development [7]. A large effort

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Nomenclature

AMP	2-Amino-2-Methyl-1-Propanol	LP	low pressure (bar)
ASC	advanced supercritical	MEA	monoethanol amine
CCR	CO ₂ capture ratio (–)	NGCC	natural gas combined cycle
COT	combustor outlet temperature (°C)	PCC	post combustion capture
<i>E</i>	emission rate (kg CO ₂ /kWh _e)	PZ	piperazine
EBTF	European Benchmarking Task Force	SCR	selective catalytic reduction
ESP	electrostatic precipitator	SPECCA	specific primary energy consumption for CO ₂ avoided (GJ/t CO ₂)
FGD	flue gas desulphurization	TIT	turbine inlet temperature (°C)
GECoS	group of energy conversion systems	ΔT_{\min}	minimum temperature approach in lean-rich heat exchanger (cold side) (°C)
GT	gas turbine		
HR	heat rate (kJ _{LHV} /kWh _e)		
HRSG	heat recovery steam generator		
IGCC	integrated gasification combined cycle		
IP	intermediate pressure (bar)		
LHV	low heat value of a specific fuel		

Greek symbols

η net electric efficiency of the power plant (% LHV)

is currently underway to improve the technology readiness of PCC and its integration with the power plants. Large scale demonstration projects are currently under development worldwide: the ROAD in The Netherlands [8], the NRG project within Clean Coal Power Initiative in the USA [9], and the NewGenCoal Project in Australia [10] just to mention few of them. Due to the research efforts, continuous improvements related to the efficiency of PCC technology are made. Therefore, the establishment and definition of baselines to assess the technical and economic potential of new solvents or processes is of importance. In this respect, baseline represents a realistic, reproducible and up-to-date performance of PCC technology that is used as a point of reference for other studies.

The baselines for PCC are constantly under review in order to provide an updated analysis on this technology. For specific technologies, baselines are provided by vendors [11]. There are studies that compare the impact of specific amine scrubbing technologies on different power plants' efficiency [12–15] and evaluate the potential improvements (either in solvent formulations or process design) of amine based systems [16]. More recent studies [17] have also provided an updated financial baseline for the implementation of CO₂ abatement technology in power plants.

Most studies focus on defining a baseline for a fixed percentage of CO₂ removal, which varies upon study. Also, alternative capture process schemes based on the Monoethanolamine (MEA) solvent are found in the literature and compared to the same baseline [18–20]. These process schemes focus on decreasing operating costs and, generally, increase the process complexity. This multi-variable system characteristic makes the assessment of amine technologies difficult, especially when it is desired to compare between different amine solvents. Other studies, such as Front End Engineering Designs or Conceptual Designs, give the design and overall investment costs of the capture plant as a quote given by the suppliers of the technology [21]. Consequently, this type of studies cannot be used to assess the influence of process parameters on the overall techno-economic performance. Some authors have overcome this issue by developing models for the analysis of capture processes with the MEA solvent [22–26]. Together with these studies, which provided a very good insight of advantages and drawbacks of PCC technologies, there is also a growing need for harmonizing methodology and assumptions taken for the technical and economic evaluations of capture technologies, in particular when different concepts are being compared. For this reason, the European Commission created a public project to unify the modelling methodologies of the European projects involved in carbon capture within the 7th framework R&D Programme [27–29].

This effort has been done within the European Benchmarking Task Force (EBTF) [30]. Models have been revised (e.g. in the CESAR project [28]) and the findings have been used to update the baselines.

This work compares the adoption of an innovative amine based solvent, named CESAR-1 (aqueous solution of 23% w/w AMP (2-Amino-2-Methyl-Propanol) and 12% w/w PZ (piperazine)) [31] to standard MEA solvent. The assessment is based on the EBTF methodology which allows a fast assessment of potential capture solvents. This work also can be used also as baseline for assessing other prospective solvent systems in the future. The two solvents and the methodology are applied to two different type of power plants: Advanced Supercritical Coal (ASC) and Natural Gas Combined Cycles (NGCC). The revised technical assumptions are consistent with the benchmarking work performed in other European projects.

2. Plant description

2.1. ASC pulverized coal case

The plant is based on an Advanced Super-Critical (ASC) Boiler and Turbine designed for a gross power output of about 819 MWe without any carbon capture. The general arrangement layout for the reference power plant is based on an inland site with natural draft cooling towers and delivery of the coal by rail. Fig. 1 shows the power plant scheme. The flue gas that exits the boiler goes through selective catalytic reduction (SCR) to control the polluting nitrogen oxides (NO_x), an electrostatic precipitator (ESP) for particulate removal, and flue gas desulfurization (FGD) to remove the pollutant sulphur dioxide (SO₂) before being released to the atmosphere through the stack. Emission limits for NO_x and SO_x are assumed equal to 120 mg/Nm³ and 85 mg/Nm³ (based on dry gas at 6% O₂), respectively [30]. These values represent the average of the emissions levels given by the analysis of best available technologies for coal power plants of the European commission [32]. The mass flow rates and conditions of the streams depicted in Fig. 1 are shown in Table 1.

2.2. NGCC case

The selected reference NGCC case for electricity production without carbon capture is based on two large-scale identical gas turbines (GT), "F class", each equipped with a heat recovery steam generator (HRSG), and a single steam turbine. The plant layout is shown in Fig. 2. This arrangement is commonly found among utilities, since it adds operational flexibility as required by a

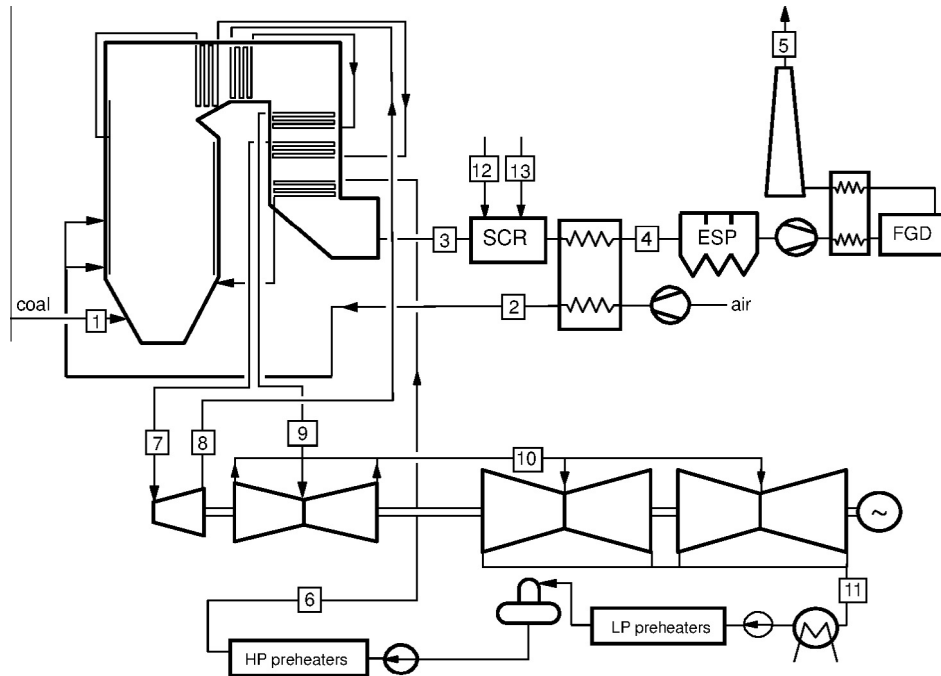


Fig. 1. Schematic layout of the ASC plant without carbon capture. SCR – selective catalytic reduction. ESP – electrostatic precipitator. FGD – flue gas desulphurization.

Table 1
Mass flow rate, pressure, temperature and composition of the main fluxes of the ASC reference plant (numbers refer to Fig. 1).

Point	Mass flow (kg/s)	T (°C)	P (Bar)	Composition (mol.%)					
				Ar	N ₂	O ₂	CO ₂	H ₂ O	SO ₂
1	66.6	15.0	–	See coal composition as in Appendix A					
2	686.6	15.0	1.0	See air composition as in Appendix A					
3	753.2	377.0	1.0	0.9	74.1	2.9	14.9	7.2	0.0
4	780.5	128.0	1.0	0.9	74.2	3.8	14.1	6.9	0.0
5	782.0	120.0	1.0	0.9	72.0	3.7	13.7	9.7	0.0
6	607.4	306.1	320.0					100.0	
7	607.4	600.0	270.0					100.0	
8	497.1	364.6	64.0					100.0	
9	497.1	620.0	60.0					100.0	
10	440.4	263.6	5.2					100.0	
11	360.1	32.2	4.8×10^{-2}					100.0	
12	0.1	9.0	–	Ammonia					
13	2.2	18.0	–	See air composition as in Appendix A					

Notes: Net power output 758.6 MW_e.
Net electric efficiency 45.25% LHV.

competitive electricity market [33]. The HRSG is a three pressure level and reheat type. Before feeding the gas turbine combustor, natural gas is preheated up to 160 °C by means of feed water extracted from the intermediate pressure (IP) drum, increasing the overall plant efficiency. The fuel flow rate to the gas turbine combustor is set to obtain an assumed turbine inlet temperature (TIT) of 1360 °C and air mass flow at compressor inlet is set at 650 kg/s. The characteristics of the main streams such as compositions and thermodynamic conditions are reported in Table 2.

3. Capture plant description and power plant integration

3.1. Capture technology selection

Most amine technologies are relatively comparable in terms of flow-sheet configurations. The thermal energy requirement for regeneration is one of the most important process parameters to consider when selecting a specific technology.

Thermal energy for regeneration in the Fluor Econamine pro-cess (based on MEA and flue gas from coal fired power plants)

has decreased from the early values of 4.2 GJ/t CO₂ [11] to 3.2–3.6 GJ/t CO₂ [12,34] thanks to improved solvent formulations, advanced process configurations and the introduction of heat integration. These figures can be further reduced with advanced stripper configurations [18–20]. The KS solvent family based on a hindered amine developed by Mitsubishi Heavy Industries.

Besides thermal energy for regeneration, other aspects to consider are the availability and maturity of the technology, solvent volatility, solvent toxicity, solvent degradation and cost. MEA is used at small scale in three existing power plants in the USA (Herzog, 1999). It has relatively low volatility and is less toxic than other solvents such as piperazine [35]. Moreover, properties of MEA solutions have been widely published in the literature. For these reasons, MEA is historically used as the standard solvent for PCC evaluation and it is a competitive baseline, despite other solvents have lower thermal regeneration energy (e.g. PZ has been reported to consume 2.6 GJ/t CO₂ [36]).

With respect to the capture process configuration, a standard flow-sheet of a 30 wt% MEA process is used as baseline. The thermal energy consumption of this process is around 3.6–3.7 GJ/t

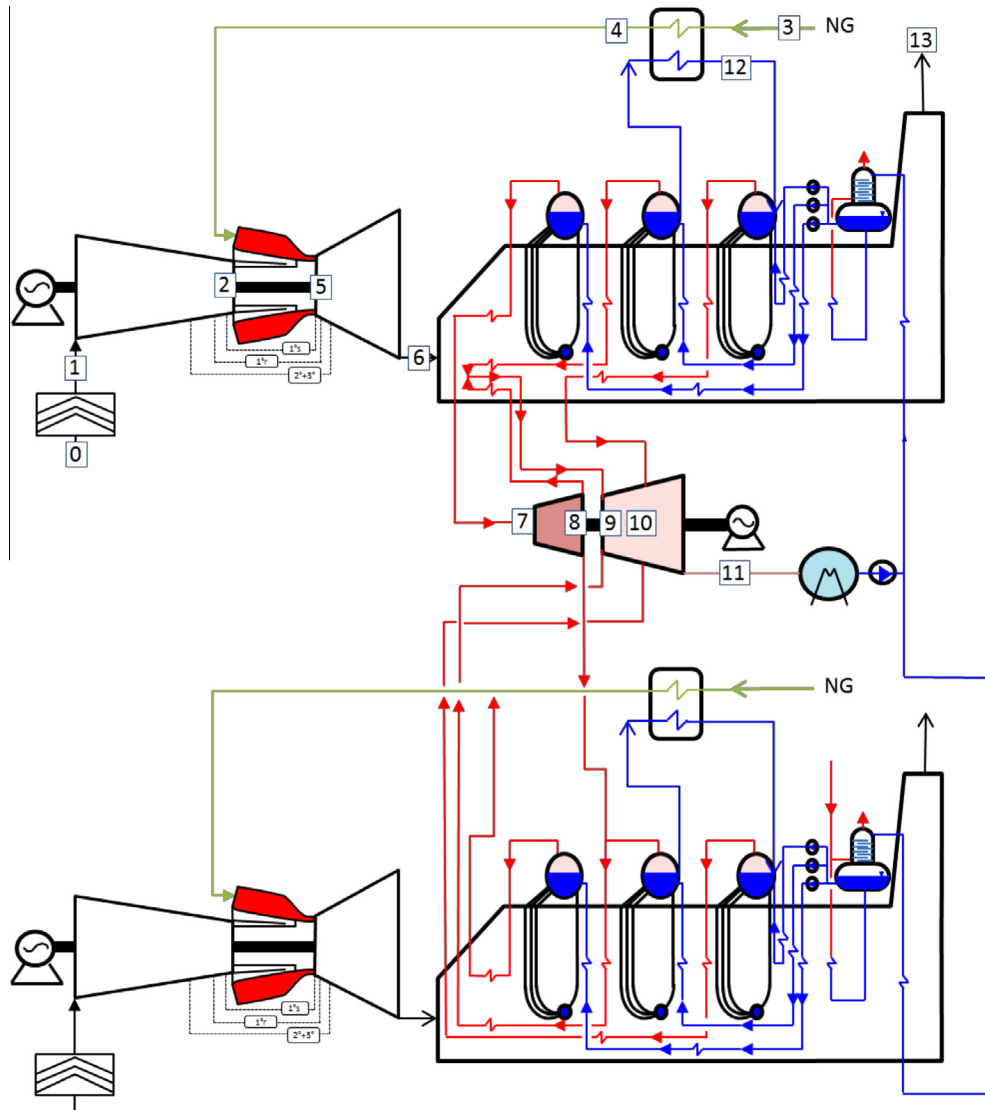


Fig. 2. Layout of the NGCC plant without carbon capture. NG – natural gas. HRSG – heat recovery steam generator.

CO₂ captured, based on the results of [31]. The energy consumption of the CESAR-1 solvent, for a standard flow-sheet of a 23 wt% AMP and 12 wt% PZ process is around 3.1 GJ/t CO₂ [31].

3.2. Capture plant description

The capture plant is designed to capture 90% of the CO₂ contained in the flue gas. Fig. 3 shows a generic scheme on how the standard capture process is designed for both solvents: MEA and CESAR-1. For the solid fuel case, the flue gas SO₂ content was assumed to be reduced to approximately 30 ppmv for the case without CO₂ capture. Further reduction to 10 ppmv is necessary for amine solvents and can be achieved by up-grading the FGD unit or by adding an SO₂ polishing step upstream the CO₂ absorber. For the present study case, FGD system modification was considered. As shown in Fig. 3, the flue gas is initially pre-treated in the direct contact cooler. At this unit the flue gas temperature is reduced to a suitable level for absorption. In the absorber, the flue gas is brought into contact with the solvent. The CO₂ is chemically bound to the amine solvent and leaves the column at the bottom. The clean flue gas exits the absorber and it is washed in the wash-in section to avoid solvent evaporation and balance water in the system. The loaded solvent is sent to the stripper via the lean-rich

heat exchanger. In the stripper, the solvent is thermally regenerated. The vapour leaving the stripper is condensed at 40 °C. The condensate is separated from the gas in a flash vessel (40 °C, 1.6 bar) and recycled back to the stripper at the top stage (water reflux). The CO₂ product gas, once separated from the condensate, is compressed, liquefied and pumped to 110 bar as set by storage requirements.

The process scheme is essentially the same for both solvents studied in this work. However, there are some differences regarding flue gas cooling and washing sections that depend on the flue gas type and the solvent used. Flue gas cooling depends on the initial conditions of the flue gas and the solvent volatility.

For the ASC case, flue gas at FGD outlet is water saturated. Flue gas cooling is achieved by direct contact with water where the excess of water is sent to water treatment system. The final temperature must be controlled in order to limit solvent emissions and close the water balance. Therefore, the temperature depends on the solvent used. The low volatility of MEA allows final temperatures of the exhaust gas of around 50 °C without major losses of solvent. These temperatures can be achieved without the gas cooling step. The water balance and exhaust gas temperature are maintained by a small water make-up in one washing section. When the AMP/PZ mixture is considered, the flue gas exit

Table 2
Mass flow rate, pressure, temperature and composition of the main fluxes of the NGCC reference plant (numbers refer to Fig. 2); for point 5 (maximum cycle temperature) the table indicates the three most commonly used definitions in the international literature.

Point	Mass flow (kg/s)	T (°C)	P (Bar)	Composition (mol.%)					
				Ar	N ₂	O ₂	CO ₂	H ₂ O	NO _x
0	650.0	15	1.01						
1	650.0	15	1.00	Air composition, as in Appendix A					
2	523.4	417.5	18.16						
3	15.3	10	70	NG composition, as in Appendix A					
4	15.3	160	70						
5	538.7	COT 1443.3	17.6	0.88	73.71	10.47	4.87	10.07	1.4×10^{-3a}
	–	TIT 1360.0	–	–	–	–	–	–	–
	665.3	TIT _{iso} 1265.7	–	0.89	74.38	12.39	3.96	8.38	1.4×10^{-3}
6	665.3	608	1.04	0.89	74.38	12.39	3.96	8.38	1.4×10^{-3}
7 ^b	153.7	559.5	120.9	–	–	–	–	100	–
8 ^b	153.7	337.7	28	–	–	–	–	100	–
9 ^b	185.0	561	22.96	–	–	–	–	100	–
10 ^b	20.9	299	3.52	–	–	–	–	100	–
11 ^b	205.9	32.2	4.8×10^{-2}	–	–	–	–	100	–
12	6.8	230	28	–	–	–	–	100	–
13	665.3	86.8	1.01	0.89	74.38	12.39	3.96	8.38	1.4×10^{-3}

Net power output 829.9 MW_e.

Net electric efficiency 58.3% LHV.

COT – combustor outlet temperature.

TIT – turbine inlet temperature.

TIT_{iso} – turbine inlet temperature, ISO conditions.

^a Value equivalent to 15 ppmv.

^b Two gas turbines.

temperature must be reduced to 30 °C to avoid substantial evaporation of the solvent. In this case, the flue gas fed to the absorber column needs to be cooled to similar temperatures to avoid water accumulation in the system. After cooling, the flue gas is contacted in the absorber with the solvent mixture. Due to the high volatility of AMP, two washing sections are adopted to decrease the temperature of the flue gas leaving the absorber at 30 °C approximately. The final concentration of AMP in the off-gas is below 1 ppmv for this case.

For the NGCC case, flue gas is not saturated with water. Therefore, flue gas cooling could be achieved by direct contact with water (as in the previous case) or via humidification. Regarding MEA, flue gas temperature is reduced to 40 °C with direct contact with water,

resembling the coal case. With respect to the AMP/PZ mixture, the flue gas temperature is reduced to 40 °C by humidifying the gas. Two washing sections are used to reduce the temperature of the flue gas leaving the absorber to 40 °C approximately. The final concentration of AMP in the off-gas is below 3 ppmv for this case. Although this case has higher AMP emissions, it requires less cooling water for gas cooling and does not generate a blow down waste water stream. In the case that environmental regulators do not allow this option, the direct cooling system could be also used in this case to reach temperatures of 30 °C in the flue gas leaving the absorber and consequently reducing AMP emissions to 1 ppmv.

In the above-mentioned analysis, the entrainment of solvent droplets or in the form of aerosols has not been included. This

Table 3
Investigated advanced supercritical pulverised coal power plant cases with two different solvents for CO₂ capture: power plant with no capture (ASC no capture), power plant with MEA capture process (ASC with MEA) and power plant with CESAR-1 capture process (ASC with CESAR-1).

	ASC no capture	ASC with MEA	ASC with CESAR-1
<i>Power plant</i>			
Steam turbine (MW)	819.18	686.85	722.56
Feed water pump (MW)	–32.05	–32.05	–32.05
Forced fans (MW)	–3.50	–3.50	–3.50
Induced fans (MW)	–9.60	–9.60	–9.60
Condensate extra pump (MW)	–0.55	–0.28	–0.35
Auxiliaries for heat rejection (MW)	–6.32	–3.06	–3.95
Pulverised coal handling (MW)	–3.33	–3.33	–3.33
Ash handling (MW)	–1.89	–1.89	–1.89
FGD auxiliaries (MW) ^a	–3.32	–3.32	–3.32
<i>CO₂ capture plant</i>			
CO ₂ compression (MW)	–	–44.80	–44.80
Blower (MW)	–	–8.50	–8.50
Pump auxiliaries (MW)	–	–9.30	–4.10
Capture section heat rejection auxiliaries (MW)	–	–4.80	–5.40
<i>Performance summary</i>			
Net power output (MW)	758.62	562.42	601.77
Thermal power input (MW)	1676.55	1676.55	1676.55
Net electric efficiency (%)	45.25	33.55	35.89
CO ₂ emissions (kg _{CO₂} /MWh _{el})	771.90	104.30	97.51
CO ₂ avoided (%)	–	86.48	87.37
Solvent regeneration energy (GJ/t CO ₂)	–	3.70	2.71
SPECCA (GJ/t CO ₂) ^b	–	4.16	3.07

^a Flue gas desulphurization auxiliaries.

^b Specific primary energy consumption for CO₂ avoided.

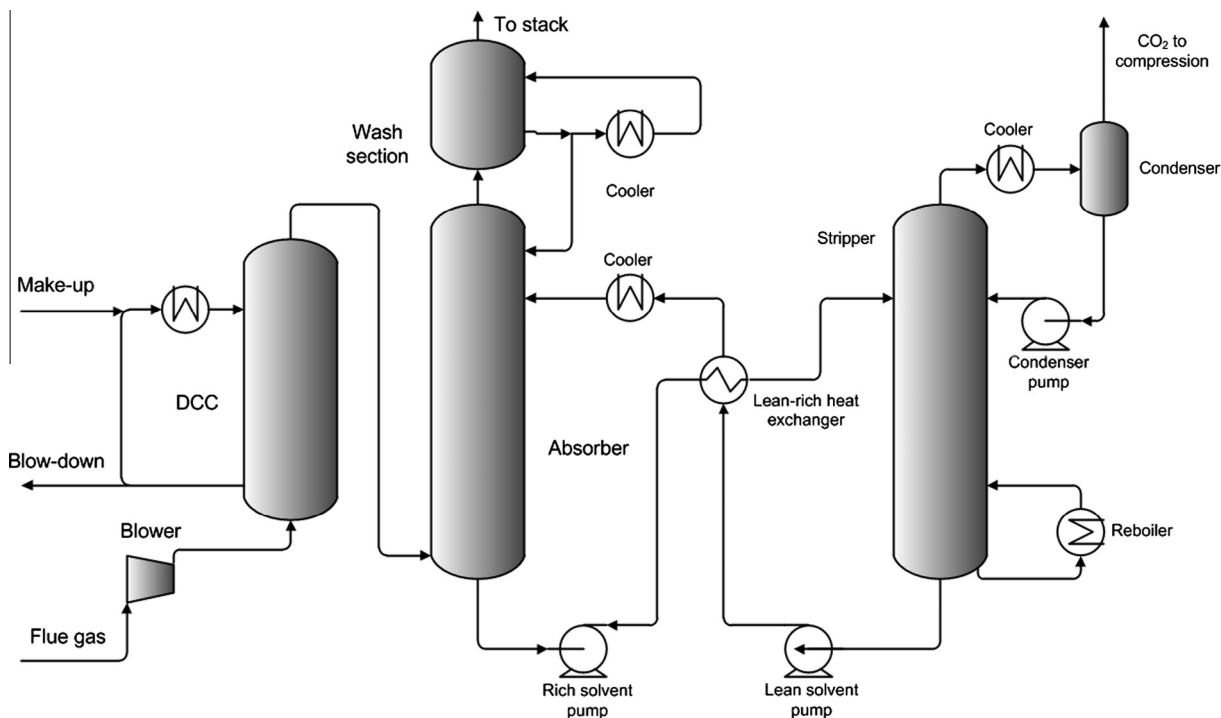


Fig. 3. CO₂ capture section. Generic flowsheet for the two solvents investigated: MEA and CESAR-1.

aspect is also important from environmental and operational aspects. Nevertheless, choosing appropriated demisters, reduces entrainment to a level that emissions can be predicted with the present models.

3.3. Power plant integration

The integration of PCC technology in the power plant will result in plant power output and efficiency reduction, regardless the solvent system. In this work the capture plant has been integrated in the power plant cycle with the same degree of heat integration for all the solvents evaluated. Therefore, this evaluation shows the effect of the different solvent systems in plant performance.

The reboiler requires a steam pressure of 3 bar. The steam necessary to supply the reboiler is extracted from the steam turbine IP/LP crossover in both NGCC and ASC plants in order to limit steam turbine modification with respect to the reference case. The resulting steam pressure is at 5.2 bara in the ASC case and 4.0 bara for the NGCC case. The steam is then suitably conditioned (through pressure reduction and attemperation) for reboiler use. Steam conditions at the reboiler entrance are 134 °C and 3.05 bar. The condensate is returned into the boiler feed water train in the ASC case and to the HRSG feed water train in the NGCC case. No advanced heat integration is included in the design.

The investigated cases, assumed a new build power station with carbon capture; it is therefore considered that they would be designed simultaneously and the steam turbines would be optimized for steam extraction at nominal conditions. As the power plant is considered a base load power plant, the effect of the turbine re-design and steam extraction on the efficiency at part load has not been considered.

4. Methodology

The modelling procedures for the simulation of the power cycles and the capture processes are consistent with EBTF common framework document [30]. A summary of modelling parameters,

including fuel and air compositions, boiler, turbine and pump efficiencies can be found in Appendix A.

The mass and energy balances of the power cycles were carried out using a proprietary computer code (GS) developed by the GECOS group at the Department of Energy of the Politecnico di Milano to assess the performance of gas/steam cycles [37–40]. The code has been calibrated and is capable of generating very accurate estimations of combined cycles performance. Calibration and accuracy have been described in previous publications [41,42]. In the coal power plant case, ultrasupercritical live steam parameters (300 bar, 600/620 °C) are selected according to today state-of-the-art large plants. The steam turbine plant consists of HP turbine, IP turbine and LP turbine with extraction points for regenerative heating of feed water and condensate. There are nine feed water heaters that produce boiler feed-water at 315 °C. For the gas power plant, the typology of gas turbine considered is large-scale “F class” 50 Hz. There is a triple pressure heat recovery steam generator (HRSG) with single reheat.

The capture process technical data and performance are determined by simulation using Aspen Plus[®] commercial software. The E-NRTL thermodynamic package was selected to predict CO₂ solubility in the MEA solvent. MEA model parameters were retrieved from MEA data package released in 2008. The absorption process is modelled with three unit operations: direct contact cooler (simulated as a flash unit), absorber and water wash section (simulated with the ASPEN RadFrac[®] model). The RadFrac[®] model assumes a sequence of equilibrium stages. Stage efficiencies are considered during sizing of the equipment. The lean-rich heat exchanger is designed on the basis of a fixed overall heat transfer coefficient and a temperature approach of 5 °C (cold in-hot out approach). The stripper is simulated again with the ASPEN RadFrac[®] model. The top two stages serve as a washing section. Moreover, the stripper is designed at a constant molar recovery ratio. This value is used to control the lean loading at which the process operates and its value was selected to adjust the specific heat consumption to the experimental optimum. The experimental values for specific heat consumption from [31] were used to fine-tune the models.

Table 4

Investigated natural gas combined cycle power plant cases with two different solvents for CO₂ capture: power plant with no capture (NGCC no capture), power plant with MEA capture process (NGCC with MEA) and power plant with CESAR-1 capture process (NGCC with CESAR-1).

	NGCC no capture	NGCC with MEA	NGCC with CESAR-1
<i>Power plant</i>			
Gas turbine (MW)	2 × 272.12	2 × 272.12	2 × 272.12
Heat recovery steam cycle (MW)	292.78	215.67	226.5
HRSC auxiliaries (MW)	3.42	3.41	3.41
<i>CO₂ capture plant</i>			
CO ₂ compression (MW)	–	22.60	22.60
Blower (MW)	–	14.96	14.96
Pump auxiliaries (MW)	–	4.65	2.89
Heat rejection auxiliaries (MW)	3.74	4.37	4.27
<i>Performance summary</i>			
Net power output (MW)	829.86	709.92	722.61
Thermal power input (MW)	1422.57	1422.57	1423.57
Net electric efficiency (%)	58.34	49.90	50.76
CO ₂ emissions (kg _{CO₂} /MWh _{el})	351.67	41.10	40.40
CO ₂ avoided (%)	–	88.31	88.52
Solvent regeneration energy (GJ/tCO ₂)	–	3.95	3.39
SPECCA (GJ/tCO ₂) ^a	–	3.36	2.94

^a Specific primary energy consumption for CO₂ avoided.

The CO₂ compressor consists of four inter-cooled stages with a fixed isentropic efficiency for each stage equal to 85%. The Peng Robinson equation of state was selected to predict CO₂ properties during compression.

The results of the thermodynamic simulations are expressed in terms of the (net electrical LHV) efficiency, the CO₂ capture ratio (CCR) and the CO₂ avoided, given respectively by:

$$\eta = \frac{\text{Net Power}}{\text{Thermal Power Input (LHV}_{\text{NG}})} \quad (1)$$

$$\text{CCR} = \frac{\text{CO}_2 \text{ captured}}{\text{CO}_2 \text{ at capture system inlet}} \quad (2)$$

$$\text{CO}_2 \text{ avoided} = \frac{E_{\text{REF}} - E_{\text{CC}}}{E_{\text{REF}}} \quad (3)$$

Finally, a measure of the energy consumption related to CO₂ capture is given by the specific primary energy consumption for CO₂ avoided (SPECCA, GJ/t CO₂), which is defined as:

$$\text{SPECCA} = \frac{\text{HR}_{\text{CC}} - \text{HR}_{\text{REF}}}{E_{\text{REF}} - E_{\text{CC}}} = \frac{3600 \cdot \left(\frac{1}{\eta_{\text{CC}}} - \frac{1}{\eta_{\text{REF}}} \right)}{E_{\text{REF}} - E_{\text{CC}}} \quad (4)$$

where HR is the heat rate of the plants (kJ_{LHV}/kWh_e), E is the CO₂ emission rate (kg_{CO₂}/kWh_e), η is the net electric efficiency of the power plant and the subindexes REF and CC refer to the reference case for electricity production without carbon capture and the case with integrated carbon capture respectively (for the ASC PC and NGCC cases defined in Section 2).

5. Results and discussion

5.1. Coal fired power plant case

The ASC case was simulated according to the procedures described in Section 4. The performance attributes of the power plant with and without carbon dioxide capture using the two solvent systems evaluated in this work are summarized in Table 5. Both solvent systems have been modelled to capture 90% of the CO₂ in exhaust gases and have been integrated in the power plant cycle with the same degree of heat integration (see Section 3.3).

The power plant has a steam turbine output of 819 MW, with about 60 MW of auxiliaries of which 50% is due to the feed-water pump. The resulting net electric efficiency is 45.25% with specific emissions of 772 kg_{CO₂}/MWh_e which are consistent with the state of the art of pulverised coal plants (advanced supercritical and ultra-supercritical plants) [43,44]. When CO₂ capture is applied, the steam turbine gross power output decreases, because of steam bleeding for solvent regeneration. Boiler and other components are not affected by CO₂ capture.

Regarding the MEA solvent, the steam turbine power output reduces approximately 130 MW (–15%), while auxiliaries consumption remains constant except for heat rejection and extra condensate pump. CO₂ capture consumptions account for 67.4 MW of which 44.8 MW are due to CO₂ compressor work. The solvent recirculation pump requires 9.3 MW because of the high solvent flow rate and absorber height. Resulting efficiency penalty is 11.7% with 86.6% of CO₂ avoided. The resulting avoidance is lower than the capture rate, because it is calculated as a function of specific emissions, at the same time dependent on the overall plant efficiency, which decreases compared to the reference case.

The innovative solvent named CESAR-1 requires less reboiler heat duty than MEA with benefits for steam turbine gross power output (+35.7 MW than MEA case). Another advantage is the higher capacity, thus reducing solvent flow rates and recirculation pump consumption. The resulting net electric efficiency is 35.9%(+2.4% higher than in the MEA case) with slightly higher CO₂ avoided. Focusing on SPECCA, CESAR-1 has a primary energy consumption of 3.1 GJ/tCO₂, which is 25% lower than MEA.

It is of importance to mention that the heat of regeneration obtained for MEA is consistent with the experimental value found by Knudsen (2011). However, the thermal energy for regeneration obtained for CESAR-1 is lower than the experimental value obtained by this author (Section 3.1). One possible explanation for this discrepancy is that the absorption column used by [31] is designed for MEA, and, having CESAR-1 slower reaction kinetics than MEA, the approximation to equilibrium obtained in operation does not correspond to the real capacity of this solvent, resulting in higher heat of regeneration. The results presented in Table 3 are obtained by simulation. Regarding the CESAR-1 solvent, the specific heat of regeneration is reduced by 27% compared to MEA.

5.2. Natural gas fired power plant case (NGCC)

The performances of the NGCC case without capture and the investigated case with CO₂ capture are presented in Table 4. The NGCC power plant without capture shows a net electric efficiency of 58.3% which is a value in the range of modern NGCC large power plants [33]. The predicted net electric efficiency penalty for MEA is 8.4 percentage points, predominantly due to lower steam turbine power output (65% of the impact), but also additional auxiliaries. Compared to the ASC case, the efficiency penalty is lower because of the lower specific emissions of natural gas as well as the fact that the steam turbine power share is about 35%, so penalization for steam extraction is lower. Adoption of CESAR-1 as solvent reduces the efficiency penalty for CO₂ capture because of lower reboiler heat duty and reduced recirculating pump consumption.

The calculated SPECCA for MEA is 3.36 MJ/kg_{CO₂} which reduces to 2.94 MJ/kg_{CO₂} for CESAR-1 (12% reduction). Compared to the ASC case, the advantages of CESAR-1 over MEA are reduced. The main factors affecting this reduction can be found by analysing the different contributions to the overall energy consumption of the CO₂ capture plant:

- Reboiler duty: related to the thermal requirements to regenerate the solvent.

Table 5
Comparison of the ASC and NGCC results to other studies. Solvent is MEA 30 wt%.

	Units	This work	Le Moullec [19] ASC	NETL [12] SC PC	Rao et al. [22] ASC	Abu-Zhara et al. [25,26] ASC	This work	Amrollahi et al. [18] NGCC	NETL [12] NGCC
<i>Reference power plant</i>									
Gross power output	MW	819.18	1200	580.4	650	–	837.02	391.3	564.7
Net power output	MW	758.62	–	549.99	–	575	829.86	384.3	555.08
Gross efficiency	LHV %	48.86	–	42.99	–	–	58.84	57.4	56.64
Net efficiency	LHV %	45.25	–	40.74	–	45	58.34	56.4	55.7
<i>Base case capture</i>									
Reboiler duty ^a	GJ/t CO ₂	3.7	3.6	3.24	4.2	3.9	3.95	–	–
Abs pressure drop	mbar	100	–	–	140	100	100	50	–
Stripper pressure	bar	1.8	–	1.6	–	1.8	–	–	–
Steam turbine power loss ^b	GJ _e /t CO ₂	0.9	0.95	0.72	0.62	–	1.06	0.9	1.07
CO ₂ compression	GJ _e /t CO ₂	0.31	0.36	0.29	0.55	–	0.31	0.33	0.30
Pumps and blower	GJ _e /t CO ₂	0.15	0.1	0.44	–	–	0.27	0.15	0.44
Total	GJ _e /t CO ₂	1.36	1.41	1.44	1.17	–	1.64	1.39	1.82
<i>Reference power plant + capture plant</i>									
Gross power output	MW	819.18	1200	662.8	–	–	759.91	357.8	511
Net power output	MW	562.42	–	549.97	460	399	709.92	335	473.57
Gross efficiency	LHV %	40.97	–	35.48	–	–	53.42	52.5	51.3
Net efficiency	LHV %	33.55	–	29.44	–	31	49.9	49.2	47.5
Efficiency loss	% Points	11.7	11.94	11.3	–	14	8.44	7.2	8.20

^a Other sources not reported in the table estimate reboiler duty at 3.54–3.6 GJ/t CO₂ [24].

^b Other sources not reported in the table estimate steam turbine power loss at 0.94 GJ_e/t CO₂ and 0.93 GJ_e/t CO₂ [20,24].

Table 6
Sensitivity analysis for the ASC case with MEA solvent and CESAR-1 solvent. Parameters varied are reboiler duty, pump efficiency, blower and compressor efficiencies.

	ASC no capture	BASE case	Reboiler duty sensitivity	Pump efficiency sensitivity	Blower efficiency sensitivity	CO ₂ compressor efficiency sensitivity
<i>ASC case with MEA</i>						
Reboiler duty (GJ/t CO ₂)	–	3.7	3.3	4.1	3.7	3.7
Pump efficiency (%) ^a	–	80	80	80	75	85
CO ₂ compressor efficiency (%) ^b	–	85	85	85	85	85
Blower efficiency (%) ^b	–	85	85	85	85	80
Net efficiency (% LHV)	45.2	33.5	34.4	32.7	33.5	33.6
<i>ASC case with CESAR-1</i>						
Reboiler duty (GJ/t CO ₂)	–	2.7	2.4	3.0	2.7	2.7
Pump efficiency (%)	–	80	80	80	75	85
CO ₂ compressor efficiency (%)	–	85	85	85	85	85
Blower efficiency (%)	–	85	85	85	85	80
Net efficiency (% LHV)	45.2	35.9	36.5	35.3	35.9	35.9

^a Refers to hydraulic efficiency.

^b Refers to isentropic efficiency.

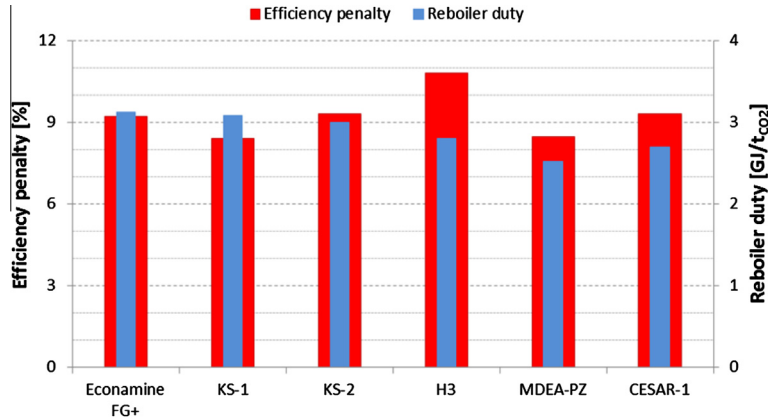


Fig. 4. Comparison of the ASC results to other studies for several solvents based on Refs. [16,46–48].

- Auxiliary consumption of pumps and blower: pump work is related to the solvent capacity. Lower capacities require higher solvent circulation and will lead to higher pump work. Blower work is related to absorber's pressure drop, which has been fixed in the common frame work.
- Compression work: it is equal for both solvent systems per unit CO₂ captured, since the operating pressure of the regenerator is the same.

Tables 3 and 4 show the thermal requirements to regenerate the MEA and the CESAR-1 solvents for the ASC Power plant and NGCC power plant respectively. As shown in these tables, the predicted MEA specific heat of regeneration is higher for the NGCC case than for the ASC case. The reason behind this difference is the lower content of CO₂ present in the NGCC flue gas (ca 4 vol%), which requires more energy for separation per unit of CO₂ captured due to the lower driving force.

Regarding the CESAR-1 solvent, the specific heat of regeneration is reduced by 27% for the ASC case and only 15% for the NGCC case. This reduction difference is explained by the different options used in the flue gas cooling unit. The NGCC case with CESAR-1 solvent uses a humidifier that reduces the temperature to only 47 °C. This option reduces the cooling costs but the absorber operates at a slightly higher temperature at the bottom of the absorption column than that of the MEA case. At higher temperature, the capacity of the CESAR-1 solvent is lower, resulting in a lower reduction of the regeneration energy compared to the ASC case, where both solvents use the same flue gas cooling option.

5.3. Comparison with other studies

This section compares the results of this work data available in the literature for the MEA solvent and other relevant solvents such as the KS family. The review is not exhaustive (since that is not the focus of this paper). Instead, the most recent studies on this topic have been selected for comparison. Table 5 compares the main results of this study for the ASC and NGCC cases to other evaluations. Based on the comparison shown in this table, the estimated total power loss per unit of CO₂ captured is comparable to the results of Le Moulec [19] in the ASC case. The small differences in steam turbine power loss (i.e. the turbine power loss due to the steam bleed necessary for the reboiler) arise from integration aspects, such as, pressure of the steam stream, conditioning of this steam stream and return of steam condensate in the boiler feed water line. Nevertheless, the estimated reboiler duty is similar. There are also differences in blower and pump consumption. These differences are mainly related to the assumed absorber pressure

drop. The EBTF assumption (taken in this work) is conservative (100 mbar) [30]. The small difference in compression work might be related to different operating pressure in the stripper. Table 5 also compares the main results of this study for the NGCC case to the evaluation of Amrollahi et al. [18]. In this case, the steam turbine power loss estimated in this work is about 15% higher than that found in the mention study. Different integration with the power plant could be one reason for this difference. However, differences in the estimated reboiler duties might also play a role. Although the reboiler duty is not explicitly mention in Amrollahi et al., this work has used Aspen Plus for simulation while Amrollahi and co-workers have used Unisim (Honeywell). Differences in the prediction of MEA properties might lead to different reboiler duties, as explained in Darde et al. [45], which will explain the different results.

Fig. 4 extends the comparison to other solvent families on the basis of CO₂ capture from coal combustion flue gas based on various sources [16,46–48]. The figure shows that the capture technologies based on hindered amines (KS-1 and KS-2) and activated tertiary amines (MDEA-PZ) have a lower reboiler duty compared to MEA and are more in the line of the performance of CESAR-1 reported in this work.

5.4. Sensitivity analysis

As shown in the previous section, the selection of different design parameters of the equipment involved in the process, software type and thermodynamic package might influence the results. For this reason, a parametric sensitive analysis was conducted with the models developed for this study. This sensitivity shows how plant efficiency varies to variations on reboiler duty, pump and blower efficiency and compressor efficiency.

The sensitivity analysis was done by varying one single parameter at a time. The following variations were taken:

- Reboiler duty: –10% to +10% of the nominal result.
- Pump efficiency: 75–85%.
- Blower and compressor efficiency: 80–90%.
- Results are summarized in Tables 6 and 7 for the ASC and the

NGCC cases respectively. As it is appreciable from the tables, the parameter that mostly affects the results is the reboiler duty. For the MEA solvent, variations of 10% in the reboiler duty will change the net plant efficiency of the ASC and NGCC cases by 2.4% and 1.10% respectively. For the CESAR-1 solvent, the influence is lower, 1.7% and 1.20% respectively. This is important since different software types or amine property data packages might lead to different specific reboiler duty, as also discussed in Darde et al. [45].

Table 7
Sensitivity analysis for the NGCC case with MEA solvent and CESAR-1 solvent. Parameters varied are reboiler duty, pump efficiency, blower and compressor efficiencies.

	ASC no capture	BASE case	Reboiler duty sensitivity	Pump efficiency sensitivity	Blower efficiency sensitivity	CO ₂ compressor efficiency sensitivity
<i>NGCC case with MEA</i>						
Reboiler duty (GJ/t CO ₂)	-	4.0	3.6	4.4	4.0	4.0
Pump efficiency (%) ^a	-	80	80	80	75	80
CO ₂ compressor efficiency (%) ^b	-	85	85	85	85	85
Blower efficiency (%) ^b	-	85	85	85	85	85
Net efficiency (% LHV)	58.3	49.9	50.4	49.3	49.9	49.8
<i>NGCC case with CESAR-1</i>						
Reboiler duty (GJ/t CO ₂)	-	3.4	3.0	3.8	3.4	3.4
Pump efficiency (%)	-	80	80	80	75	80
CO ₂ compressor efficiency (%)	-	85	85	85	85	80
Blower efficiency (%)	-	85	85	85	85	85
Net efficiency (% LHV)	58.3	50.8	51.3	50.2	50.8	50.7

^a Refers to hydraulic efficiency.

^b Refers to isentropic efficiency.

6. Conclusions

This work has provided an updated reference for post-combustion capture (PCC) from fossil fuel power plants based on standard MEA solvent. The underlying assumptions and methods were taken from the benchmarking effort of the European Benchmark Task Force (EBTF), which is a first attempt for establishing a common European Standard for benchmarking and comparison studies. Regarding the benchmark, the paper has evaluated the performance of two different types of power plants (Advanced Supercritical Pulverized Coal and Natural Gas Combined Cycle) with and without carbon dioxide capture unit. The results of energy balances are similar to the results obtained in other studies available in the literature. However, larger deviations have been encountered for the NGCC power plant.

This work also shows the application of this method to a more advanced amine solvent, CESAR-1, (mixture of AMP 23 wt% and PZ 12 wt%). Evaluation of this solvent under the EBTF standards shows a reduction on energy penalty of 25% for the ASC reference plant and 12% for the NGCC reference plant compared to the MEA baseline. On the basis of these results, the better performance of CESAR-1 solvent has been established. Nevertheless, the net efficiency of power plants with capture can be improved by better heat integration between capture and power plant. This later aspect has not been addressed in this evaluation.

There are a number of important issues to consider when benchmarking new scrubbing technologies for post-combustion capture. The two main focus areas are the degree of heat integration and the characteristics of the solvent. With regard to the former, it is important to highlight that higher degrees of heat integration will further reduce the values for power penalty presented here. However, when one is concerned with comparing solvent scrubbing performance special care needs to be taken so all solvents are benchmarked under equal conditions. The standard adopted by EBTF considers a low degree of heat integration. Based on the performance here reported, a separate optimization could be undertaken to investigate the effects of heat integration for every solvent.

The characteristics of the solvent are the other focus area. The design of the capture unit depends on the solvent characteristics such as solvent volatility and toxicity and on flue gas conditions and composition. These aspects need to be carefully considered per case so a plausible design is implemented. In this study, several modifications to the baseline process were included in the capture model for the CESAR-1 solvent due to its higher volatility. These modifications are intended to avoid substantial evaporative losses of this solvent.

Finally, also process economics are important for the selection of the preferred technology. A separate study should be dedicated to estimate the economic viability of the described cases.

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Appendix A

The EBTF (European Benchmarking Task Force) report is the result of a joint effort of a team of members of the CAESAR, CESAR and DECARBit FP7 projects. It presents a compilation of assumptions and parameters for carbon capture projects evaluation, including material related to the costs and economics of carbon

capture. The document also provides three technical study cases of power plants without and with CO₂ capture. The evaluation of power plants with integrated post-combustion capture presented in this work is based on two of the power plant cases described in this document and the assumptions compiled in the common framework document. The following sections provide a summary of the most relevant technical assumptions and parameters.

A.1. Air

Temperature (ISO) (°C)	15
Pressure (ISO) (kPa)	101.325
<i>Composition, dry molar fraction (%)</i>	
N ₂	78.08
CO ₂	0.04
Ar	0.93
O ₂	20.95
ϕ	60%

A.2. Natural gas

Temperature (°C)	10
Pressure (bar)	70
Molar mass (kg/kmol)	18.0
<i>Composition, molar fraction (%)</i>	
CH ₄	89.00
C ₂ H ₆	7.00
C ₃ H ₈	1.00
C _{4-i}	0.05
C _{4-n}	0.05
C _{5-i}	0.005
C _{5-n}	0.004
CO ₂	2.00
N ₂	0.89
S	<5 ppm
High heat value (MJ/kg)	51.473
Low heat value (LHV) (MJ/kg)	46.502

A.3. Coal, douglas premium

<i>Proximate analysis (%)</i>	
Moisture	8%
Ash	14.15%
Volatiles	22.9%
Fixed carbon	54.9%
<i>Ultimate analysis (%)</i>	
Carbon	66.52%
Nitrogen	1.56%
Hydrogen	3.78%
Sulphur	0.52%
Chlorine	0.009%
Oxygen	5.46%
High heat value (HHV) (MJ/kg)	26.23
Low heat value (LHV) (MJ/kg)	25.17

A.4. Technical parameters for power plants (ASC PC and NGCC)

<i>Boiler</i>	
Pressure at boiler exit (bar)	300
Temperature at boiler exit (°C)	600
Single reheat pressure (bar)	60
Single reheat temperature (°C)	620
Boiler efficiency (% LHV)	94.5
Temperature losses from boiler to turbine (°C)	2
<i>Gas turbine</i>	
Pressure ratio	18.1
Air flow rate (kg/s)	650
TIT (°C)	1360
<i>Heat recovery steam generator</i>	
Steam evaporation pressures (bar)	130, 28, 4
SH and RH temperature (°C)	565
Condensation pressure (bar)	0.048
Pinch point ΔT (°C)	10
Sub cooling ΔT (°C)	5
Minimum approach ΔT in SH and RH (°C)	25
<i>Steam turbine</i>	
HP steam turbine efficiency (%)	92
IP steam turbine efficiency (%)	94
LP steam turbine efficiency (%)	88
Electrical and auxiliaries	
Generator efficiency (%)	98.5
Mechanical efficiency (%)	99.6
Electric consumption for heat rejection (%) of rejected thermal power 0.8*	

A.5. Technical parameters for capture plants

<i>CO₂ capture plant</i>	
Booster fan pressure ratio	1.1
Booster fan isentropic efficiency (%)	85
Booster fan driver efficiency (%)	95
Lean-Rich Heat exchanger ΔT_{\min} (°C)	5
Absorption column pressure (bar)	1.1
Absorption column number of stages	3
Absorption column pressure drop (mbar)	50
Stripper column pressure (bottom) (bar)	1.8
Stripper column pressure drop (mbar)	300
Stripper column number of stages	8
Steam pressure for solvent regeneration (bar)	3.2
Pumps head (bar)	10
Pumps hydraulic efficiency (%)	75
Pumps driver efficiency (%)	95
<i>CO₂ compression</i>	
Final delivery pressure (bar)	110
Intercooled stages	5
Compressor isentropic efficiency (%)	85
Temperature for CO ₂ liquefaction (°C)	25
Pump efficiency (%)	75

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