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Techno-economic assessment of novel vs. standard 5m piperazine CCS absorption processes for conventional and high-efficiency NGCC power plants

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Abstract

CO_2 capture and storage (CCS) can play a key role in the mitigation of greenhouse gas emissions, as it is generally applicable to many industrial sectors to limit the environmental impacts from fossil fuels usage. In this regard, natural gas-fired power plants are a suitable application for CCS technologies, although they produce flue gases with a much lower CO_2 concentration (i.e. ~4 %mol) than coal-fired power plant flue gases. Amine-based solvent absorption has been widely studied as a practical solution to decarbonize post-combustion flue gases from natural gas combined cycle power plants (NGCC).

This paper presents the methodology and the results of a techno-economic assessment of 5 molal (5m) piperazine (PZ) as a new potential baseline solvent for carbon capture from NGCC in three different case studies that have been considered relevant from a preliminary literature analysis. The three evaluated configurations are (i) conventional F-class NGCC coupled with the conventional absorber configuration with a direct contact cooler (DCC), (ii) conventional F-class NGCC coupled with an advanced absorber configuration (no DCC – flue gas cooling integrated within the absorber) and (iii) high efficiency, state-of-the-art H-class NGCC, coupled with the advanced absorber configuration. The present work is based on the most recent findings from University of Texas at Austin (UT) research activities, and it has been carried out by Laboratorio Energia e Ambiente Piacenza (LEAP) and Politecnico di Milano (POLIMI) researchers supported and sponsored by the CO_2 Capture Project (CCP).

Keywords: CCS; absorber configuration; piperazine; high efficiency combined cycle.

Nomenclature

CC	Combined Cycle
CCP	CO_2 Capture Project
CCS	CO_2 Capture and Storage
CCU	CO_2 Compression and dehydration Unit
DCC	Direct Contact Cooler
GHG	Green House Gases
GT	Gas Turbine
HRSG	Heat Recovery Steam Generator
IC	Intercooler
NGCC	Natural Gas Combined Cycle
PZ	Piperazine
ST	Steam Turbine

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1. Introduction

Greenhouse gases (GHG: CO_2, CH_4, N_2O and fluorinated gases) have been identified as the main causes of anthropogenic global warming associated with industrial activities. With specific reference to carbon dioxide, fossil fuel usage is considered the primary emission source of CO_2 [1]. Moreover, it has been estimated that energy-related emissions have grown by 1.4% in 2017 and reached 32.5 Gt_{CO2} [2] with the largest share from electricity and heat production [1]. Within this context, CO_2 capture and storage technologies (CCS) are expected to make a substantial contribution to reducing emissions from the global energy system as part of the effort to meet the goals of the Paris Agreement (2015), which seeks to limit the global average temperature increase below 2°C by the end of the century.

A mature technology that has been widely employed to treat post-combustion flue gases is chemical absorption with aqueous amine-based solvents. Considered effective for carbon dioxide separation from post-combustion gases, the CO_2 absorption is based on the principle of gas scrubbing, and specifically, MEA (usually 30 wt% monoethanolamine solution in water) has been used as a benchmark by many research initiatives (e.g. CaESAR[3] and CESAR[4] projects). Although MEA has a fast CO_2 reaction rate, which minimizes equipment size, this solvent has several drawbacks – including a high thermal energy requirement to strip CO_2 from the rich solvent (3,9 GJ/t_{CO2} [3]). Additionally, limitations in terms of maximum loading, expressed in mol_{CO2}/mol_{Alk} to avoid equipment corrosion and degradation of the solvent, as well as limits in allowable operating temperature, have spurred further research with the goal of identifying effective alternatives, either in the form of novel solvents or suitable process modifications. The present study has been sponsored by the CO_2 Capture Project (CCP [5]), a partnership involving several major energy companies working together to identify novel CCS technologies and accelerate their deployment at industrial scale for oil & gas related applications.

Among the potential alternatives to current amine-based solvents, Piperazine (PZ) has been identified as a promising second generation solvent for CO_2 capture based on extensive experimental activities at the University of Texas at Austin. PZ has some advantages over MEA - it has twice the absorption rate and has greater CO_2 capacity; it is also more oxidatively and thermally stable, which enables temperatures up to 150 °C in the scrubbing process without significant degradation [6]. The typical operating conditions of 5m PZ solution covers a temperature range from 40 to 150 °C. Temperatures lower than 40 °C are viable, however precautions must be taken to avoid solid formation that can occur depending on the solvent CO_2 loading. Solvent regeneration at higher pressures (6-8 bar) is possible because the solvent can be heated to 150 °C without significant degradation [7]. This significantly reduces the electric power required for the CO_2 Compression Unit (CCU).

Aqueous piperazine solutions have been tested at different concentrations and a 5m solution has been selected for the present investigation. The choice of solvent concentration is based on experimental data, showing that 5m PZ has higher viscosity-adjusted capacity for CO_2 absorption (i.e. mol CO_2 per kg of solvent) than 8m PZ [8] and it can operate at lower lean loading with better absorber performance than higher concentrations. The CO_2 absorption rate for 5m is approximately 30% higher than for 8m PZ, which reduces the size of the absorber. The 5m PZ solution is 50% less viscous than 8m PZ, which enhances heat and mass transfer, however L/G (lean solvent over flue gas flow-rate on a molar basis) must be higher in order to obtain the same capacity [7].

The present investigation has been carried out to evaluate the 5m PZ solution performance and costs for CO_2 capture from NGCC flue gas for several NGCC configurations. The work is a collaboration among CCP, LEAP-POLIMI and the group of Professor Gary Rochelle from the University of Texas at Austin. Experimental tests were conducted at the University of Texas at Austin to evaluate PZ absorption from flue gases at relevant conditions for NGCC (CO_2 concentration, temperature, loading, L/G, etc.). Details about the pilot tests and results are reported in [9]. The experimental data were used to validate a simulation model of the pilot unit previously developed by UT (Aspen Plus®), which is based on a thermodynamic model suitable for the description of PZ-water and PZ-water-CO_2 interactions [8], [10].

LEAP-POLIMI and CCP have moved from the pilot scale to the full scale simulation delivering three techno-economic assessments over the following case studies:

- Case 1: a “Conventional Configuration” featuring a standard PZ absorber column with in and out intercooling and a direct contact cooler (DCC). In this scheme, the NGCC is composed of 2 GT+1 ST featuring performance typical of established technologies (F-class GT), and flue gases from the HRSG are cooled down by means of a DCC upstream of the absorber.
- Case 2: an alternative scheme, referred to as “Advanced Configuration” with an advanced absorber column with pump-around intercooling, and no DCC included [11]. This case assesses the potential for capital and operating cost savings resulting from the DCC removal. Also, in this case, the combined cycle is composed of 2GT (F-class technology) +1ST.

- Case 3: a high efficiency (62.5%) combined cycle (NGCC, 1GT+1ST) coupled with the advanced absorber configuration (i.e. Case 2 absorber) to assess both the improved performance of the most recent H-class gas turbine (GE 9HA) and its impact on flue gases and the absorber unit.

2. Process Description

A schematic block flow diagram of the NGCC + CCS concept assessed in this work is shown in Figure 1. There are three major subsystems in the overall plant:

- The Combined Cycle (CC) power system is composed of gas turbines, steam turbines and a heat recovery steam generator (HRSG).
- The flue gases from the CC flow to the CO_2 capture island, which consists of absorption units for CO_2 capture with solvent, and stripping units where the CO_2-rich solution is regenerated and a CO_2 rich gas is released. The CCS island has a heat exchanger network (solvent coolers, reboiler and thermal-integrated recuperative heat exchangers).
- The low pressure CO_2 from the capture island is processed in the compression and dehydration unit (CCU) for pipeline export.

Depending on the case study, the CO_2 capture island may or may not have a direct contact cooler (DCC) upstream of the CO_2 absorber, which quenches the post-combustion NGCC flue gases down to an appropriate temperature to partially condense the water in the flue gas. The CO_2 absorption reaction in the absorber is exothermic, so cooling the flue gases enhances the absorption process. Additionally, the DCC reduces the gas volumetric flow rate, due to higher gas density and lower water content, and it may capture residual emissions (e.g. particulates and NOx), although this last effect has not been assessed in the CCS unit simulation.

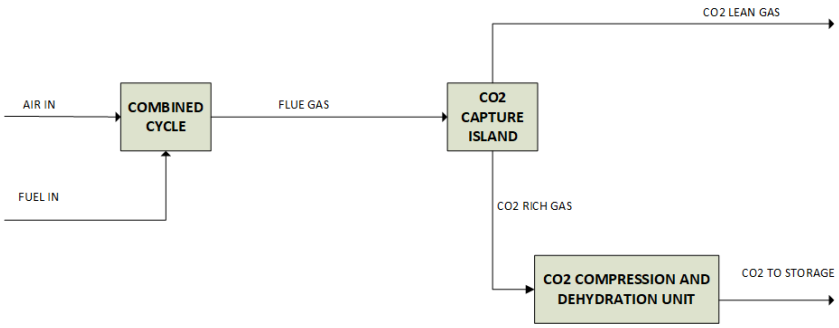

Figure 1: NGCC+CCS unit, overall plant composition (elementary block flow diagram with major equipment and streams).

The three case studies vary in equipment count and number of trains, depending on the plant size and flue gas flow rate to be processed (Case 1 and 2 have the same flue gas flow rate and composition ahead of the CCS island, whereas case 3 is different). Table 1 shows the number of units in the three case studies. In general, a single train has one gas turbine and one HRSG linked to one absorber and stripper with its associated heat-exchanger network. In all cases, there is a single steam turbine and a single CO_2 compression train.

For Case 1, which uses a DCC, each of the two absorption trains has a separate DCC. The process flow diagram for a single CCS train for Case 1 is shown in Figure 2, and for Cases 2 and 3 in Figure 3. As mentioned previously, Case 1 utilizes the conventional absorber configuration with a DCC similar to the one reported for 30 wt% MEA in an IEAGHG report [12]. The flow configuration for the absorber intercooler of Case 1 is different than that used for Cases 2 and 3. Case 1 utilizes an in-out intercooling mode, in which hot rich solvent is withdrawn at the bottom of a packed section, cooled and returned to the absorber at the top of the next lower section. This arrangement was demonstrated at the UT pilot plant. Cases 2 and 3 have a pump-around intercooling mode, in which the hot rich solvent is withdrawn from the bottom of a packed section, cooled and returned to the top of that same section. The latter mode has been studied by Zhang et al. [11] and identified as the optimal arrangement in cases with no DCC (i.e., Case 2 and 3). The choice of intercooling mode affects the packing selection, since the pump-around intercooling increases the net liquid flow through the packed sections where the system is implemented. The absorber column for all three cases uses three beds of structured packing for the absorption and a water wash section on the exiting flue gas to minimize solvent losses. In all cases, flue gas fans are used to overcome the pressure drop in the DCC, if present, the absorber packed section and the flue gas ducting.

Table 1: Summary of the different pieces of equipment at plant level (# unit refers to the pieces of equipment; # train refers to the plant sections).

	CASE 1	CASE 2	CASE 3
Combined cycle	NGCC	NGCC	High-efficiency NGCC
- GT	2 units	2 units	1 unit
- ST	1 unit	1 unit	1 unit
- HRSG	2 units	2 units	1 unit
- Total Electric Power w/o CCS Island	830 MWe	830 MWe	760 MWe
CCS island			
- DCC	2 units	-	-
- Absorber	2 units	2 units	1 unit
- Advanced Flash Stripper	2 units	2 units	1 unit
CCU	1 train	1 train	1 train

A surge tank is included in the solvent circulation loop. This provides residence time to smooth flow rate fluctuations from the stripper as well as providing a mixing volume for the addition of solvent make-up and composition tuning. The lean solvent is pumped to the top of the absorber column, where it flows downward and counter-current to the upward flow of flue gas. The rich solvent is pumped from the bottom of the absorber, and heated via heat exchangers prior to feeding into the advanced flash stripper (more details in Lin [6]), where it is regenerated in a pressurized stripping column. To regenerate the rich solvent under pressure requires higher solvent temperatures, which are achieved through a combination of rich solvent preheat via heat exchange and use of a reboiler. An advantage of the pressurised regeneration is the lower electric duty from the CO_2 compression unit, which is composed of four compression stages with inter-refrigeration.

More details on the process flow diagram for the CCS unit are reported in Table 2.

Table 2: Equipment description for a single train - Case1, 2, 3

	CASE 1	CASE 2	CASE 3
Flue gas Fan	Upstream of the DCC, Δp=100 mbar	Δp=50 mbar	Δp=50 mbar
Direct Contact Cooler	3 m packing Structured Mellapak 250 Y	-	-
Intercooling Mode	n.2 in/out IC	n.2 pump-around IC	n.2 pump-around IC
Absorber Packing			
- Top Bed	Sulzer Mellapak Standard 250Y	Sulzer Mellapak Standard 250X	Sulzer Mellapak Standard 250X
- Intermediate Bed	Sulzer Mellapak Standard 250Y	Sulzer Mellapak Standard 2X	Sulzer Mellapak Standard 2X
- Bottom Bed	Sulzer Mellapak Standard 250Y	Sulzer Mellapak Standard 2X	Sulzer Mellapak Standard 2X
Water-wash	3m, structured packing	3m, structured packing	3m, structured packing
Stripper	2 beds, Raschig Super Ring N. 0.5-Metal	2 beds, Raschig Super Ring N. 0.5-Metal	2 beds, Raschig Super Ring N. 0.5-Metal
CO_2 Compression Unit	1 train per plant, 4 compression stages	1 train per plant, 4 compression stages	1 train per plant, 4 compression stages

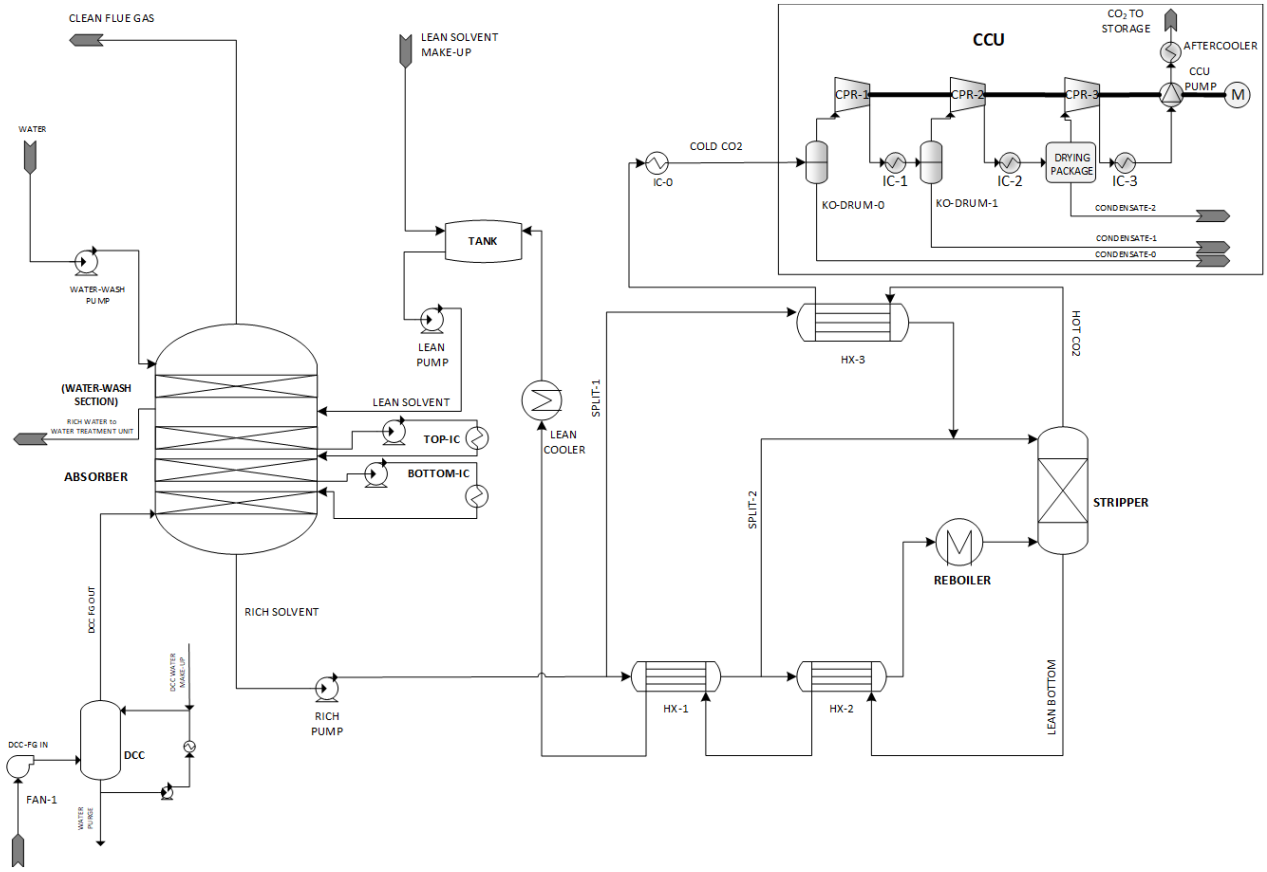

Figure 2: Process flow diagram representing a single train from Case 1.

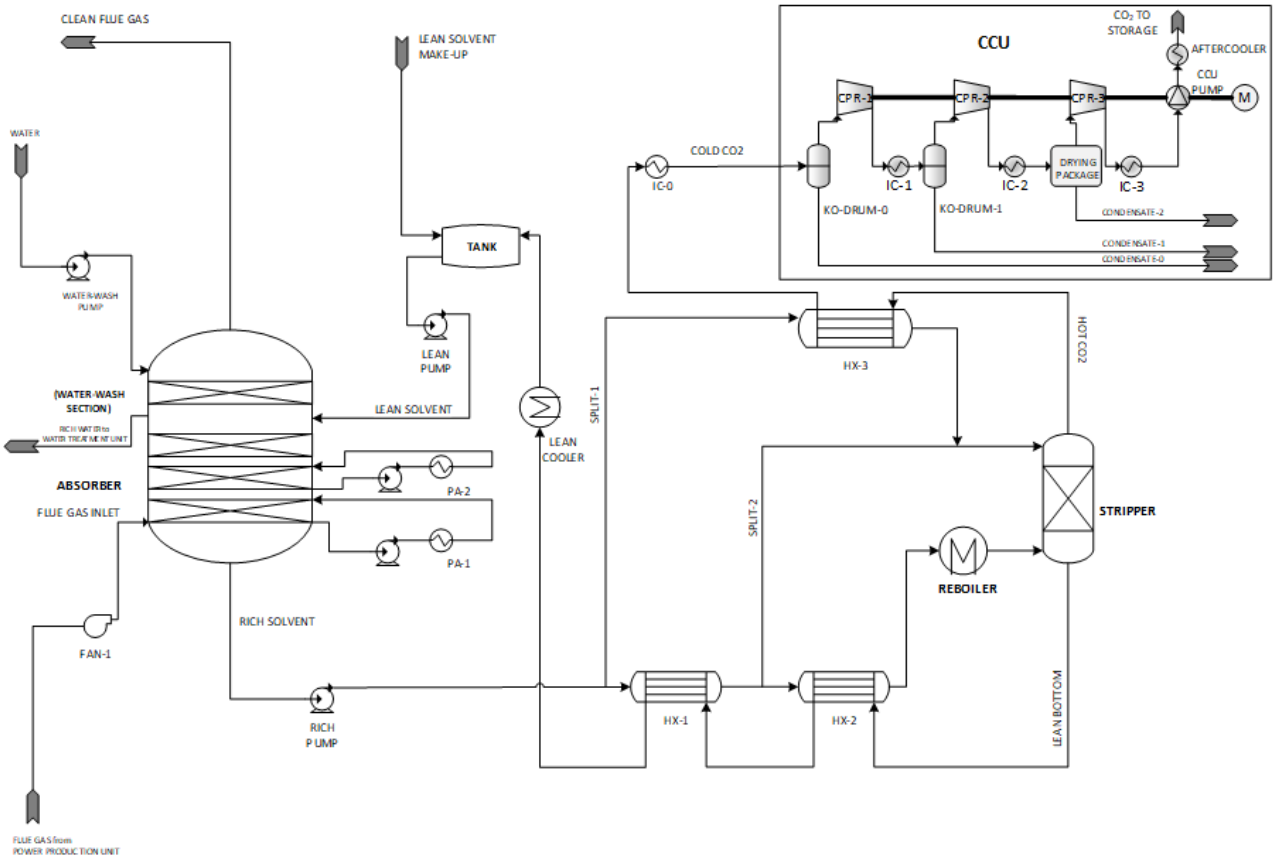

Figure 3: Process flow diagram representing a single train from Case 2 and 3.

3. Technical and Economic Framework

In this section, the modelling approach for the analysis of the standalone NGCC units and the integrated NGCC-CCS plant is described. The primary tools for this work were Aspen Plus® v.9 and Thermoflex® v. 27.

Case 1 and 2 are based on a NGCC designed to generate 830 MWel of net electric power at full load without capture, with a net electric efficiency of 58,30% on a LHV basis (more details on the combined cycle are reported in the CaESAR project [3]). The NGCC with capture has been simulated to account for extraction of steam from the steam turbine cycle for solvent regeneration (CCS island reboiler). Two different absorber configurations are analysed in Cases 1 and 2, with most effective one applied to Case 3, which utilizes a high efficiency, H class gas turbine. Although not reported as a separate case study, the high efficiency turbine-based NGCC was analysed without capture to provide base line performance metrics for Case 3.

Case 3 illustrates a high-performance, low-emitting plant which combines the most recent state-of-the-art combined cycle together with an advanced absorption CCS process.

The design of the Direct Contact Cooler (Case 1) is based on a recent IEAGHG study [12]. The flue gas fan is placed upstream of the DCC to avoid sub-atmospheric operation of the DCC.

The same design specifications have been used for the three cases to provide comparability, as was done in studies by Frailie et al. [10], Sachde and Rochelle [13]. As previously noted, a simulation based on the thermodynamic model developed at UT was calibrated against experimental results from the UT pilot [9] and used as a starting point to predict the performance of a full scale column. The absorber height has been varied with the goal of identifying the minimum solvent flow rate to achieve 90% of CO_2 capture. The liquid solvent flow rate (L) as a function of packing height shows an asymptotic approach to the minimum rate of solvent (Lmin) as the number of separation stages increases, corresponding to infinite absorber height. The operating solvent rate was set at 120% of the minimum on a molar basis [11]. This solvent rate sets the absorber height in accordance to the relationship (L vs packing height) determined by the simulations. The criterion to define the absorber diameter refers to the distance from flooding (30% distance).

The lean piperazine solvent entering the absorber can be varied by changing process conditions in the solvent stripper. The optimum value of lean loading has been established as 0,226 mol_{CO2}/mol_{Alk} based on results from the UT experimental campaign [9]. This lean loading minimizes the equivalent work (Weq) of the capture operation. Weq is the performance index which represents the overall equivalent electricity expenditure due to CO_2 capture and compression. The equivalent work consists of the summation of fan work (W_{fan}), pump work (W_{pump}), compression work (W_{comp}) and equivalent work from the reboiler duty (W_{heat}) [6][14].

The 5m PZ solvent lean loading specified for the absorption process is therefore 0,226 mol_{CO2}/mol_{Alk}. The stripper pressure and reboiler temperature which attain the minimum Weq, while obtaining the previously mentioned lean loading, are 5,8 bar and 150 °C. The stripper diameter was set to achieve 80% of flooding. The packing height has been set to 7 m, a value representing a good compromise between packing utilization efficiency (i.e. packing costs) and Weq reduction, as reported by UT previous work of Lin [15].

The CO_2-rich gas leaving the stripper is sent to the CCU, which utilizes a 4 stage inter-cooled compressor. The compression ratio over each stage is set to attain equal outlet temperatures. The target pressure for the CO_2 rich gas to storage (stream "CO_2 to storage" in Figure 2, Figure 3) is 110 bar.

Together with the Weq, the SPECCA index [16] has been adopted as metrics to assess and compare the three cases in a way that focuses on the primary energy consumed for capturing CO_2. SPECCA stands for Specific Primary Energy Consumption for CO_2 Avoided, and it is generally accepted as a performance indicator of CCS-equipped power plants, since it fairly measures the primary energy penalty of a power plant with CO_2 capture against a reference power plant without CCS.

$$SPECCA = \frac{3600 \times \left(\frac{1}{\eta_{el,CCS}} - \frac{1}{\eta_{el,ref}}\right)}{e_{CO2,el,ref} - e_{CO2,el,CCS}} \quad (1)$$

Where:

- $\eta_{el,CCS}$: power plant net electric efficiency with amine capture
- $\eta_{el,ref}$: power plant net electric efficiency without CCS, i.e. for Case 1,2 ηel, NGCC=58,3%, for Case 3 ηel, NGCC=62,5%
- eCO2,el,CCS: power plant net specific emission rate with amine capture
- eCO2,el,ref: power plant net specific emission rate without CCS, i.e. for Case 1,2 eCO2,el,ref= 351,8 kgCO2/MWhel , Case 3 eCO2,el,ref= 330 kg_{CO2}/MWh_{el}

In Case 1 and 2 the reference power plant is the same as in the CaESAR study, while for Case 3, the high efficiency combined cycle w/o capture (cfr. Section 4. "Performance Results") has been used to calculate the reference values of power plant electric efficiency and specific emission.

The technical evaluation included a detailed sizing of equipment, which provides the input for capital cost

estimation. Based on sizing information, the total equipment cost (TEC) of the power plant with capture is calculated by adopting a bottom-up approach, where a single piece of equipment is priced according to the following power-law relationship (Eq. 2):

$$TEC[M\$] = C_0 \left(\frac{S}{S_0}\right)^f \quad (2)$$

Where TEC is the actual cost of the equipment item, S is the actual size, f is the scale factor. S_0 and C_0 are respectively dimension and cost of a reference component.

The overall capital expenditure required to build the plant on a green-field basis is the Total Plant Cost (TPC), accounting for TEC, installation costs, indirect costs, escalation and contingencies. Moreover, the operating costs are computed with the purpose of estimating the First Year Cost of Electricity (COE) and the Cost of CO_2 avoided (CCA). A summary of the assumptions related to the economic evaluation are reported in Table 3. The economic framework will be described more in detail in a future work from the same authors.

Table 3: Financial assumptions.

Assumption	Value
Cost and financial	
Plant type	Green-field
Cost year basis	2014
Base currency used, $	US Dollars
Average exchange rate (2014), $/€	1,329
Investment lifetime, years	25
Inflation rate,%	2
Discount rate, %	10
First year capital charge factor, %	9,43
Fuel cost, $/GJ (2014)	4,5
Number of equivalent hours, hours equivalent at full load / year	7880

4. Performance Results

The main results of process simulations carried out via Thermoflex® to define the performance of a high efficiency combined cycle (Case 3- NGCC without capture) are reported in Table 4. The reference NGCC w/o capture for Case 1 and 2 have been taken from CaESAR 2011 [3].

Table 4: High Efficiency NGCC w/o capture.

Process section	Quantity	Units	Total Value
High Efficiency Combined Cycle (1GT + 1 ST)	Fuel input	MW_{LHV}	1215,8
	Gas turbine model	-	GE 9HA.02 (GTPRO)
	Configuration	-	1GT + 1ST
	Gas Turbine Net Power Output	MW_e	528,5
	Steam Cycle Gross Power Output	MW_e	190,4
	Steam Cycle pumps, auxiliaries, cooling tower	MW_e	8,3
	Steam Cycle Net Power Output	MW_e	182,1
	Plant Net Power Output	MW_e	710,6
	Flue gases mass flow rate at HRSG exhaust	kg/s	983,9
	$\%_{mol}$ CO_2 in HRSG flue gases	$\%_{mol}$	4,56%

An overview of the absorber simulation results for the three cases, as well as process assumptions and set-up conditions are reported in Table 5 (when more than one train is envisaged by the absorption island, information are related to a single train only).

Table 5: Assumption and main absorber simulation results per train. In Case 1 solid formation has been excluded after appropriate check of the thermodynamic operating window (temperature vs. loading).

	CASE 1	CASE 2	CASE 3

Flue gas inlet temperature at absorber inlet	[°C]	35	100	114
Flue gas pressure at absorber inlet	[bar]	1,06	1,06	1,06
Flue gas flow-rate	[kmol/s]	22,75	23,51	34,84
Flue gas inlet composition	[%mol]			
- H_2O		5,3	8,38	9,48
- CO_2		4,08	3,96	4,56
- N_2		77,87	75,27	74,84
- O_2		12,75	12,39	11,13
Lean solvent temperature	[°C]	40	40	40
Lean loading	mol_{CO2}/mol_{Alk}	0,226	0,226	0,226
Rich loading	mol_{CO2}/mol_{Alk}	0,359	0,348	0,354
L/G=1,2*Lmin/G	mol/mol	1,67	1,76	1,94
L/G_{CO2}	$mol_{solvent}/mol_{CO2}$	40,85	44,53	42,55
Packing height	[m]	13	11	11

Table 6 shows the performance summary for the three cases. Case 1 utilizes a DCC, unlike Cases 2, so a larger pressure increase across the flue gas fan is required to overcome packing and piping pressure drop relative to Case 2. This results in nearly double the power consumption for the flue gas fan of Case 1 compared to Case 2.

It is interesting to note that Case 1 achieves a lower specific thermal consumption for solvent regeneration compared to Case 2, even though Case 2 has a lower SPECCA. Rather than to the amount of circulating solvent, this is due to a higher quantity of CO_2 per unit of solvent (i.e. the inverse of L/G_{CO2} ($mol_{solvent}/mol_{CO2}$)), which is also related to a greater rich loading attained at the absorber outlet. Comparing the three cases, the specific reboiler thermal duty has a trend which is consistent with the L/G_{CO2} at the absorber, hence it shows an opposite trend with respect to the rich loading.

The power required for the compression and dehydration (CCU) is similar for Case 1 and 2 due to the equal amount of CO_2 to be compressed and stored. Case 3 is a smaller plant size, so the overall captured CO_2 flow-rate is lower, requiring less compression power.

The overall plant performance of Case 3, as summarized by the SPECCA index, is superior to the other plant configurations. More specifically, SPECCA from Case 1 is 28% higher than $SPECCA_{Case\ 3}$ and SPECCA from Case 2 is 24% higher than $SPECCA_{Case\ 3}$.

Table 6: Performance Summary of the three case study.

			CASE 1	CASE 2	CASE 3
Process Section	**Quantity**	**Units**	**Total Value**	**Total Value**	**Total Value**
Natural Gas Combined Cycle	**Fuel input**	**MW_{LHV}**	1422,6	1422,6	1215,8
	Gas Turbine Power Output (2 units)	MWe	544,2	544,2	528,5
	Steam Cycle Net Power Output w/o CCS	MWe	285,7	285,7	231,6
	Net Power Output w/o CCS	MWe	829,9	829,9	760,2
	Steam Cycle Net Power Output with PZ	MWe	225,9	221,5	184,6
	Gross Power Output with PZ	**MWe**	**770,1**	**765,7**	**713,1**
5m PZ Absorption Process	Power consumption DCC (water pumping + heat rejection)	MWe	3,6	0,0	0,0
	Power consumption solvent pumping	MWe	2,8	3,5	2,7
	Power consumption flue gases compression	MWe	17,0	8,6	6,2
	Power consumption for heat rejection	MWe	2,4	6,3	5,0
	Power consumption water wash	MWe	0,6	0,6	0,4
	Total Power CO_2 Capture Auxiliaries	**MWe**	**26,4**	**18,9**	**14,4**
	Captured CO_2	**kg/s**	**73,3**	**73,3**	**63,4**
	Reboiler Thermal duty	**MWth**	**186,9**	**200,5**	**166,9**
	Specific thermal consumption for solvent regeneration	**MJth/kgCO2**	**2,55**	**2,74**	**2,63**
CO_2 Compression and dehydration Unit (CCU)	**Total Power CO2 Compression**	**MWe**	**17,5**	**17,4**	**15,1**
Overall Plant Performance	**Net Power Output with CCS**	**MWe**	726,2	729,3	683,5
	Power Plant Net Electric Efficiency with CCS	**%**	51,0%	51,3%	56,2%
	CO_2 specific emissions w/o CCS	**kgCO2/MWh**	351,8	351,8	330,0
	CO_2 emissions with PZ	**kgCO2/s**	8,4	8,4	6,9
	CO_2 specific emissions with PZ	**kgCO2/MWh**	41,4	41,3	36,3
	Plant Net Electric Efficiency w/o CCS	**%**	58,3%	58,3%	62,5%
	SPECCA PZ Absorption	**GJ_{LHV}/t_{CO2}**	**2,83**	**2,73**	**2,20**

5. Techno-Economic Analysis

A comparison between the performance results calculated for Case 1 and 2 does not highlight any significant advantage of the advanced set-up versus the conventional one: the SPECCA index is not substantially different, and the net electric efficiency is virtually the same (51,0 % for Case 1 vs 51,3% for Case 2). Since the same amount of CO_2 is captured (73,3 kg/s) in each case, the total compression work at the CCU is the same (around 17 MWe in both cases). On the other hand, the reboiler thermal duty is lower in Case 1 because of a lower amount of circulating solvent, due to a higher rich loading. The lower reboiler duty leaves room for a slightly higher gross power output from the steam cycle (lower steam flow rate extracted from the ST). However, this is more than offset by the total power needed by the capture auxiliaries, which is larger for Case 1 compared to Case 2, due mainly to higher power demand for the flue gas fan 100 mbar instead of 50 mbar to overcome DCC and absorber pressure losses.

Case 3 shows the best performance among the three for the following reasons: (i) the higher efficiency of the starting NGCC power block, and (ii) the higher CO_2 concentration in the flue gas which enables a lower specific solvent flow rate, L/G_{CO2}, compared to Case 2. Case 1 also utilizes a lower L/G_{CO2} than Case 2, but has a considerably power demand for capture auxiliaries.

Although Case 1 and 2 do not show significant differences in terms of performance metrics, the introduction of an additional column (DCC), together with a bigger flue gas fan, does have an impact on the economic evaluation and cost of CO_2 avoided. A representative break-down of the total equipment cost is reported in Table 7.

Table 7: TEC summary for power and CCS sections (including items break-down for the capture island)

		CASE 1	CASE 2	CASE 3
Power section	M$2014	258,5	258,3	245,0
Capture section	M$2014	160,2	133,2	98,5
DCC		10%	-	-
ABSORBER		49%	54%	47%
STRIPPER		2%	3%	2%
FAN AND PUMPS		7%	4%	5%
HEAT EXCHANGERS		15%	19%	21%
CCU		15%	18%	22%
SOLVENT RECLAIMER, TANK		2%	3%	3%

In comparing the advanced versus conventional absorber case (Case 1 vs Case 2), the power section capital cost is almost identical. On the other hand, the CCS island is less expensive in the advanced configuration scenario (Case 2, 20% saving in TEC). The difference in capital cost drives the Cost of CO_2 avoided for the conventional case to be about 14% higher for Case 1 compared to Case 2. (cfr. Table 8, Case 1: 77,8 $/t$CO_2$ versus Case 2: 68,3 $/t$CO_2$).

Case 3, achieves the lowest SPECCA among the cases studied, mainly due to economies of scale from using a single train in both the power and CCS sections, leading to lower specific costs of the major CCS equipment units. Case 3 uses a larger GT (compared to the two in Cases 1 and 2), and a smaller and technologically more advanced (i.e. more expensive materials) steam cycle. This leads to the high-efficiency NGCC without capture having a higher specific cost than the conventional one (1105 $/kW versus 1059 $/kW), although the cost of generated electricity is lower due to higher net electric efficiency.

Finally, the most promising scenario from the economic point of view is Case 3, with a CCA of 59,0 $/t$CO_2$ (Table 9), which is roughly 31% higher for Case 1 and 15% higher in Case 2 (Table 8).

Table 8: Economic Assessment, Case 1 vs. Case 2

				CASE 1							CASE 2						
		EBTF w/o capture		EBTF with capture							EBTF with capture						
		Power section		Power section		CO2 removal section			Total		Power section		CO2 removal section			Total	
		[M$2014]	$2014/kW	[M$2014]	$2014/kW	[M$2014]	$2014/kW	$2014/tCO2capt	[M$2014]	[$2014/kW]	[M$2014]	[$2014/kW]	[M$2014]	[$2014/kW]	$2014/tCO2capt	[M$2014]	[$2014/kW]
	TEC	264,18	318,33	258,50	355,97	160,21	220,61	77,07	418,71	576,57	258,28	354,13	133,24	182,68	64,08	391,52	536,81
	TPC	879,14	1059,33	860,23	1184,56	789,81	1087,60	379,94	1650,04	2272,16	859,50	1178,46	656,85	900,61	315,93	1516,35	2079,08
Parameter	**U. of M.**																
Net Power	[MW]	829,9				**726,20**						**729,34**					
Electricity production	[MWh/y]	6539612				5722435						5747199					
Efficiency LHV	[%]	58,3%				51,05%						51,27%					
Fuel consumption	[GJ/h]	5125				**5121**						**5121**					
Fuel consumption	[GJ]	40381824				40356317						40356317					
Fuel cost	**[M$]**	**181,72**				**181,60**						**181,60**					
Fixed O&M	**[M$]**	**17,58**		**17,20**		**15,80**			**33,00**		**17,19**		**13,14**			**30,33**	
Variable O&M	**[M$]**	**12,10**		**10,59**		**14,88**			**25,46**		**10,63**		**14,94**			**25,58**	
Capital	**[M$]**	**82,88**				**155,56**						**142,95**					
First year capital charge	**[M$]**	**294,28**				**395,63**						**380,46**					
COE	**[$/MWh]**	**45,00**				**69,14**						**66,20**					
Specific CO2 emissions	[kg/MWh]	351,80				**41,44**						**41,26**					
Specific CO2 avoidance	**[kg/MWh]**	-				310,36						310,54					
Cost of CO2 avoided	**[$/t]**	**-**				**77,77**						**68,27**					

Table 9: Economic Assessment, Case 3

		CASE 3								
		62.5%NGCC w/o capture		62.5%NGCC with Adv PZ						
		Power section		Power section		CO2 removal section			Total	
		[M$2014]	[$2014/kW]	[M$2014]	[$2014/kW]	[M$2014]	[$2014/kW]	2014/tCO2cap	[M$2014]	[$2014/kW]
	TEC	252,38	332,01	244,99	360,00	98,51	144,76	54,76	343,50	504,76
	TPC	839,85	1104,85	815,27	1197,99	485,66	713,65	269,99	1300,93	1911,64
Parameter	**U. of M.**									
Net Power	[MW]	760,15				**680,53**				
Electricity production	[MWh/y]	5989986				5362577				
Efficiency LHV	[%]	62,52%				55,97%				
Fuel consumption	[GJ/h]	4377				**4377**				
Fuel consumption	[GJ]	34490779				34490779				
Fuel cost	**[M$]**	**155,21**				**155,21**				
Fixed O&M	**[M$]**	**16,80**		**16,31**			**9,71**		**26,02**	
Variable O&M	**[M$]**	**11,08**		**9,92**			**13,94**		**23,86**	
Capital	**[M$]**	**79,18**				**122,65**				
First year capital charge	**[M$]**	**262,26**				**327,74**				
COE	**[$/MWh]**	**43,78**				**61,12**				
Specific CO2 emissions	[kg/MWh]	330,00				**36,44**				
Specific CO2 avoidance	**[kg/MWh]**	-				293,56				
Cost of CO2 avoided	**[$/t]**	-				**59,04**				

6. Conclusions

The present study has aimed at comparing the energy and cost performance of two alternative absorber configurations adopting 5m piperazine solution for CO_2 capture from flue gases produced by a conventional F-class NGCC power plant. In addition, the most cost effective absorber design from the initial comparison has been paired with the new H-class NGCC technology.

The overall assessment has involved both experimental and modelling activities. An experimental pilot plant campaign commissioned by CCP has been performed by UT at Austin. The experimental outcome has been used to validate a piperazine absorption simulation, which incorporates a PZ-specific thermodynamic model (UT proprietary). LEAP-POLIMI, together with CCP, have moved forward from the pilot to the scaled-up process and assessed three main configurations: (i) conventional absorber with DCC, (ii) advanced absorber configuration (no DCC), (iii) advanced absorber configuration coupled with a high efficiency (H-class) combined cycle. The process simulations for the CO_2 absorption island have been built in Aspen Plus® (v. 9.0) and the high-efficiency power section has been simulated using Thermoflex® v. 27.

Following an initial comparison between Case 1 and Case 2, the "advanced absorber configuration" has been selected as the most convenient due to its lower cost of CO_2 avoided (68,27 $\$_{2014}$/t vs. 77,77 $\$_{2014}$/t) compared to the conventional absorber. Based on this result, Case 3 was designed to assess the impacts of a high-efficiency combined cycle coupled with the advanced absorber set-up defined in Case 2.

The techno-economic evaluation has identified Case 3 as the best performing scenario: it achieves a SPECCA index of 2,20 GJ_{LHV}/tCO_2, which is significantly lower than Case 1 (2,83 GJ_{LHV}/t_{CO2}) and Case 2 (2,74 GJ_{LHV}/tCO2).

Case 3 is estimated to attain a promising net electric efficiency, even with CCS (56,2%$_{LHV\ basis}$), hence a limited energy penalty due to capture (1,26 $MJ_{ele}/kg_{CO2\ captured}$). The superior energy efficiency and lower capital cost of Case 3 lead to the minimum cost of CO_2 avoided of 59 $\$_{2014}/t_{CO2}$ among the examined cases.

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