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ASSESSMENT OF MASS AND ENERGY INTEGRATION ASPECTS FOR IGCC POWER PLANTS WITH CARBON CAPTURE AND STORAGE (CCS)

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ABSTRACT. Integrated Gasification Combined Cycle (IGCC) is a power generation technology in which solid fuel is partially oxidized by oxygen and steam / water to produce a combustible gas called syngas. Syngas can then be used either for power generation or processed to various chemicals (hydrogen, ammonia, methanol etc.). Carbon Capture and Storage (CCS) represent a group of technologies aimed to capture CO_2 from energy-intensive processes and then stored for long period of time in suitable geological locations. This paper evaluates in details mass and energy integration aspects for an IGCC power plant fitted with pre- and post-combustion carbon capture configurations based on gas-liquid absorption processes (chemical and physical solvents).

Case studies analyzed in the paper are using coal to produce around 375 - 485 MW net electricity simultaneous with capturing about 90 % of the carbon contained in the feedstock. Two carbon dioxide capture options (post- and pre-combustion capture options) are compared with the situation of no carbon capture in term of mass and energy integration aspects as well as quantification of overall energy penalties. Plant options (no capture, pre-combustion and post-combustion capture) are modelled using ChemCAD and the simulation results used to asses integration aspects as well as overall plant performance indicators.

Keywords: *Gasification; Carbon Capture and Storage (CCS); Process integration*

INTRODUCTION

Energy issue is important and actual considering the need of security for energy supply, environmental protection and climate change prevention by reducing the greenhouse gas emissions. It is known that solid fossil fuels

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reserves (mainly coal and lignite) ensure a greater energy independence compared with liquid fossil fuels (oil) or gaseous fossil fuels (natural gas) [1], but coal utilization is looked with concern because of bigger greenhouse gas emissions (CO_2). For example, for production of one MWh electricity, the carbon dioxide emission in case of natural gas is about 350 – 400 kg and in case of coal about 800 – 900 kg [2-3]. The main aim of this paper is to evaluate the main mass and energy integration aspects of various carbon dioxide capture options (pre- and post-combustion capture both based on gas-liquid absorption processes) applicable to the energy conversion process by solid fuel gasification.

For climate change mitigation, a special attention is given to the reduction of CO_2 emissions by capture and storage techniques (CCS) [4]. From the point of view of carbon capture, there are several technological options, the most important are: post-combustion capture from flue gases, pre-combustion capture, oxy-combustion, chemical looping etc. [5-6]. After capturing, CO_2 must be stored safely for a long period of time, several practical options are under evaluation: storage in geological reservoirs, storage in exhausted oil and gas reservoirs, enhanced oil recovery (EOR) or injection in coal beds that cannot be mined due to the high depth (Enhanced Coal Bed Methane Recovery - ECBM) [6].

In this paper, the authors have analysed pre-combustion and post-combustion capture options of carbon dioxide using physical and chemical solvents [7-10]. The evaluated power generation technology is based on coal gasification (partial oxidation). These two carbon capture options are in the development and implementation stage to be applied within the power sector. The power plant concepts evaluated in this paper generate about 375 - 485 MW electricity using a Combined Cycle Gas Turbine (CCGT). Three plant configurations were analyzed in details by mathematical modelling and simulation:

Case 1: Conventional IGCC technology, no carbon capture;
Case 2.a: IGCC with pre-combustion capture using physical (Selexol®) solvent, 90% carbon capture rate;
Case 2.b: IGCC with pre-combustion capture using chemical (Methyl-DiEthanol-Amine - MDEA) solvent, 90% carbon capture rate;
Case 3: IGCC with post-combustion capture using chemical (Methyl-DiEthanol-Amine - MDEA) solvent, 90% carbon capture rate.

PLANT CONFIGURATIONS AND DESIGN ASSUMPTIONS

Conventional IGCC technology for power production is a thermo-chemical process in which the solid feedstock is partially oxidized with oxygen and steam to produce syngas (a mixture of H_2 and CO). Syngas is then desulphurised in an Acid Gas Removal (AGR) system in which H_2S is captured from the syngas and send to a Claus plant to be partially oxidised to sulphur. Syngas is then burned in a gas turbine (GT) to generate power (syngas-fuelled gas turbine). Hot flue gases from the GT are used to raise steam which is then expanded in a steam turbine (ST) to generate power.

Recently the gasification technology received renew interest due to promising reduced energy and cost penalty for carbon capture as well as the potential to be operated in multi-fuel multi-product scenario. This means that IGCC power plant are able to process lower grade fuels compared with combustion processes as well as the capability to poly-generate various total or partial decarbonised energy vectors (power, hydrogen, substitute natural gas, liquid fuels by Fischer - Tropsch synthesis).

Conceptual layout of a modified IGCC scheme for power generation with carbon dioxide capture using pre-combustion option is presented in Figure 1 [9,11].

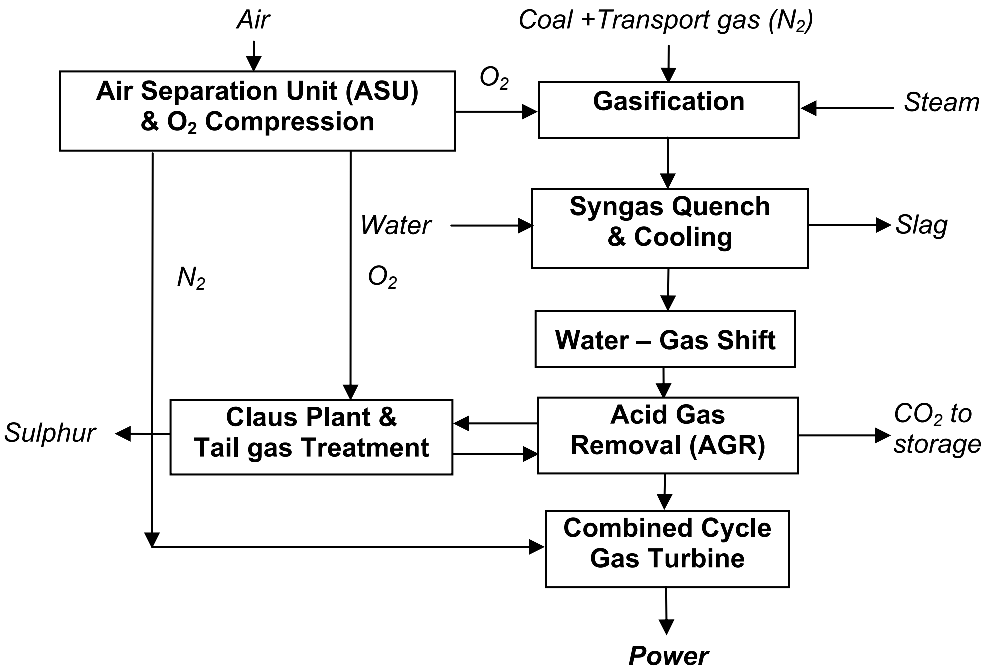


Figure 1. Layout of IGCC scheme for power production with CO_2 pre-combustion capture

The main differences of IGCC with pre-combustion CO_2 capture scheme compared with a conventional IGCC scheme without carbon capture is the presence of water gas shift (WGS) stage of carbon monoxide (having the role to concentrate the carbon species in the form of CO_2 that can be later captured) and a bigger Acid Gas Removal (AGR) system which captures, in addition of hydrogen sulphide as in the conventional technology, also carbon dioxide [11]. The decarbonised gas (hydrogen-rich gas) is then used in a combined cycle gas turbine to produces power (hydrogen-fuelled gas turbine).

The other IGCC-based carbon capture option evaluate in the paper is the post-combustion method in which the carbon dioxide is captured from the flue gases produced by syngas burning in the gas turbine. Basically, this option is similar with and IGCC power plant is which the gas turbine fuel gases are treated for CO_2 capture. The conceptual layout of an IGCC scheme for power generation with carbon capture using post-combustion option is presented in Figure 2 [12].

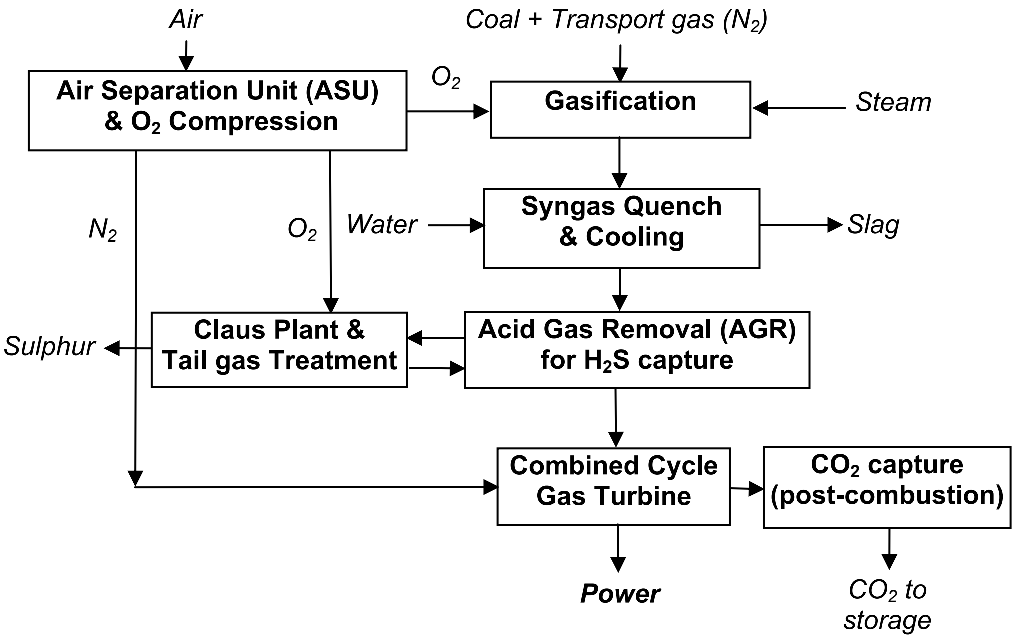


Figure 2. Layout of IGCC scheme for power production with CO_2 post-combustion capture

For the case studies analyzed in this paper, coal was considered as feedstock (fuel characteristics being presented in Table 1).

Table 1. Fuel (coal) characteristics

Parameter	Coal
Proximate analysis (% wt.)	
Moisture	8.10
Volatile matter	28.51
Ash	14.19
Ultimate analysis (% wt.)	
Carbon	72.04
Hydrogen	4.08
Nitrogen	1.67
Oxygen	7.36
Sulphur	0.65
Chlorine	0.01
Ash	14.19
Lower heating value - LHV (MJ/kg a.r.)	25.353

As gasification reactor, the option was in favour of entrained flow type operating at high temperature (slagging conditions) which give a high conversion of solid fuel (~99%). From different gasification technologies available on the market, Shell technology was chosen, the main factors for consideration were dry feed design of the gasifier and syngas quench which ensure the high energy efficiency [13].

Other main sub-systems of the plant and theirs design assumptions used in the modelling and simulation are presented in Table 2 [9,14].

Table 2. Main design assumptions

Unit	Parameters
Air Separation Unit (ASU)	Oxygen purity: 95% (vol.) Delivery pressure: 2.37 bar Power consumption: 225 kWh/ton O_2 No air integration with gas turbine
Gasification reactor (Shell)	Oxygen / solid fuel ratio (kg/kg): 0.84 Steam / solid fuel ratio (kg/kg): 0.12 Nitrogen / solid fuel ratio (kg/kg): 0.09 O_2 pressure to gasifier: 48 bar Pressure: 40 bar Temperature: >1400^{o}C Carbon conversion: 99.9 % Syngas quench
Shift conversion (Cases 2.a and 2.b)	Sulphur tolerant catalyst Two adiabatic beds Pressure drop: 1 bar / bed

Unit	Parameters
Acid Gas Removal - AGR (all cases)	Solvent: Selexol®; H_2S capture only Solvent regeneration: thermal (heat)
CO_2 pre-combustion capture (Cases 2.a and 2.b)	Solvent: Selexol®, MDEA Separate H_2S and CO_2 capture Selexol regeneration: pressure flash 4 levels: 12 bar / 5 bar / 2 bar and 1.05 bar MDEA regeneration: thermal (heat)
CO_2 post-combustion capture (Case 3)	Solvent: MDEA (Methyl-DiEthanol-Amine); Solvent regeneration: thermal (heat)
CO_2 compression and drying (Cases 2 and 3)	Delivery pressure: 100 bar Compressor efficiency: 85% Solvent used for drying: TEG
Claus plant & tail gas treatment	Oxygen-blown H_2S-rich gas composition: > 20% (vol.)
Gas turbine	Type: M701G2 Net power output: 334 MW Power efficiency: 39.5% Pressure ratio: 21 Turbine outlet temperature (TOT): 588°C
Heat Recovery Steam Generator (HRSG) and steam cycle (Rankine)	Three pressure levels: 118 / 34 / 3 bar MP steam reheat Steam turbine isoentropic efficiency: 85% Steam wetness ex. steam turbine: max. 10%
Heat exchangers	ΔTmin. = 10°C Pressure drop: 1 % of inlet pressure

Captured CO_2 stream has to comply with a quality specification considering the final use. Considering transport (pipeline) and storage option (EOR or aquifers), CO_2 stream has to have very low concentration of water (<500 ppm) and hydrogen sulphide (<100 ppm) as these components could give corrosion problems along the pipeline network [15].

MODELING AND SIMULATION OF PLANT CONCEPTS

The three IGCC-based energy conversion processes described above: Case 1 – Conventional IGCC without carbon capture; Case 2 – IGCC with pre-combustion capture and Case 3 – IGCC with post-combustion carbon capture were mathematical modelled and simulated using ChemCAD and Thermoflex software. As thermodynamic package used in simulations, Soave-Redlich-Kwong (SRK) model was chosen considering the chemical species present and process operating conditions (pressure, temperature etc.).

Simulation of plant configurations yields all necessary process data (mass and molar flows, composition, temperatures, pressures, power generated and consumed) that are needed to assess the mass and energy integration aspects as well as the overall performance of the processes.

The following key plant performance indicators were used:

- *Cold gas efficiency* (CGE) shows the overall efficiency of the gasification process (conversion of solid fuel into syngas) and it is calculated with the formula:

$$CGE = \frac{Syngas\ thermal\ energy\ [MW_{th}]}{Feedstock\ thermal\ energy\ [MW_{th}]} * 100 \tag{1}$$

- *Syngas treatment efficiency* (STE) indicates the energy losses through the syngas conditioning line (shift conversion) and acid gas removal (AGR) system. This indicator is calculated with the formula:

$$STE = \frac{Syngas\ thermal\ energy\ ex.\ AGR\ [MW_{th}]}{Syngas\ thermal\ energy\ ex.\ quench\ [MW_{th}]} * 100 \tag{2}$$

- *Gross and net electrical efficiency* (η_{gross} and η_{net}) shows the overall plant performance in term of overall energy conversion process. These indicators are calculated as follow:

$$\eta_{gross} = \frac{Gross\ power\ output\ [MW_e]}{Feedstock\ thermal\ energy\ [MW_{th}]} * 100 \tag{3}$$

$$\eta_{net} = \frac{Net\ power\ output\ [MW_e]}{Feedstock\ thermal\ energy\ [MW_{th}]} * 100 \tag{4}$$

- *Carbon capture rate* (CCR) is calculated considering the molar flow of captured carbon dioxide divided with carbon molar flow from the feedstock:

$$CCR = \frac{Captured\ CO_2\ molar\ flow\ [kmole/h]}{Feedstock\ carbon\ molar\ flow\ [kmole/h]} * 100 \tag{5}$$

- *Specific CO_2 emissions* (SE_{CO_2}) are calculated considering emitted CO_2 mass flow for each MW power generated:

$$SE_{CO_2} = \frac{Emitted\ CO_2\ mass\ flow\ [kg/h]}{Net\ power\ generated\ [MW_e]} * 100 \tag{6}$$

In term of ancillary energy consumptions (power, heat and cooling water) for CCS cases, the following indicators was used:

- *Specific power consumption* (SPC) are calculated considering the power consumption for captured CO_2 mass flow:

$$SPC = \frac{Ancillary\ power\ consumption\,[MW_e]}{Captured\ CO_2\ mass\ flow\,[kg/h]} * 100 \tag{7}$$

- *Specific heating consumption* (SHC) are calculated considering the heating consumption for captured CO_2 mass flow:

$$SHC = \frac{Ancillary\ heating\ consumption\,[MW_{th}]}{Captured\ CO_2\ mass\ flow\,[kg/h]} * 100 \tag{8}$$

- *Specific cooling consumption* (SCC) are calculated considering the cooling consumption for captured CO_2 mass flow:

$$SCC = \frac{Ancillary\ cooling\ consumption\,[MW_{th}]}{Captured\ CO_2\ mass\ flow\,[kg/h]} * 100 \tag{9}$$

MASS AND ENERGY INTEGRATION ASPECTS

The simulation results of all investigated case studies were used to assess mass and energy integration aspects. The most important in term of evaluating overall energy conversion process are the heat and power integration analysis of the gasification island and syngas conditioning line (first system) and the power block (Combined Cycle Gas Turbine - CCGT) as the second system. For optimisation of energy efficiency the steam raised in the gasification island was used to cover the ancillary heating consumptions (e.g. solvent regeneration), the rest was integrated in the Rankine cycle of the power block. On the other hand, cold condensate from the steam turbine was pre-heated in the syngas conditioning line and then returned back to Heat Recovery Steam Generator (HRSG).

As illustrative example, Table 3 presents the steam cycle parameters for Case 2.a (Shell-based IGCC with pre-combustion capture using Selexol).

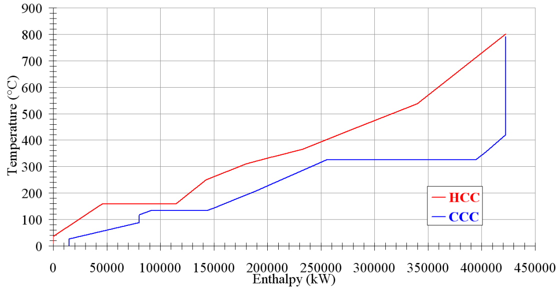
The simulation results were used to perform energy integration analysis (pinch analysis) for optimisation of overall energy efficiency. Hot and cold composite curves (HCC and CCC) as well as grand composite curves of gasifier island & syngas conditioning line and power block were constructed. As minimum approach temperature, a conservative value of 10^oC was chosen [16-17]. Considering Case 2.a as illustrative example, Figure 3 presents composite curves and grand composite curves for gasification island and syngas conditioning line (including WGS reactors) and Figure 4 presents the same curves for power block (CCGT).

Table 3. Steam cycle parameters - Case 2.a

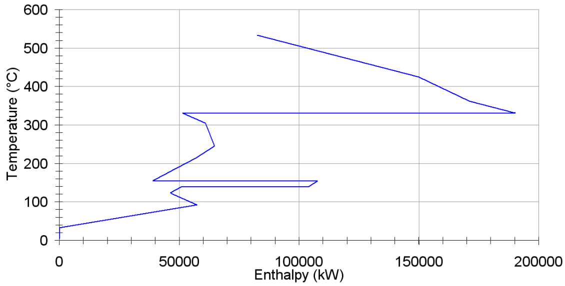
Stream	Flowrate (t/h)	Temperature (°C)	Pressure (bar)
HP steam from WGS reactors	188.00	326.94	120.00
HP steam from gasifier	243.85	420.00	120.00
HP steam to HP Steam Turbine	689.85	576.10	118.00
MP steam to MP reheater	384.35	392.24	34.00
MP steam to process units	305.50	417.55	41.00
LP steam from process units	89.50	208.69	3.00
LP steam to LP Steam Turbine	596.85	172.93	3.00
LP steam (6.5 bar) to process units	29.00	229.81	6.50
LP Steam Turbine exhaust	596.85	31.32	0.046
Cooling water to steam condenser	30500.00	15.00	2.00
Cooling water from steam condenser	30500.00	25.00	1.80
Hot condensate returned to HRSG	931.77	115.00	2.80
BFW to HP BFW pumps	683.00	115.00	2.80
BFW to MP BFW pumps	70.00	115.00	2.80
BFW to LP BFW pumps	171.50	115.00	2.80
Flue gas at stack	2813.64	99.98	1.02

As can be observed from Figures 3 and 4, significant heat recovery is done in form of HP steam from gasifier island (syngas boiler) and syngas conditioning line (WGS reactors) [18-19]. The first aspect is a specific feature of syngas quench gasifiers (e.g. Shell, E-Gas) and it confers a higher energy efficiency compared with water quench gasifiers (e.g. GE-Texaco, Siemens). The second mentioned aspect (WGS reactors) are common to all IGCC-based CCS configurations with pre-combustion capture. Shift reaction is exothermic and it gives the capability of HP steam raising but also it reduce the overall thermal energy send to the combined cycle [20]. This important aspect can be noticed by comparing syngas-fuelled and hydrogen-fuelled CCGTs.

Table 4 presents the specific power, heating and cooling consumptions of all investigated CCS cases, in addition another physical solvent - Rectisol® was evaluated. As can be noticed Selexol® process has the lower penalty in terms of energy consumption. Comparing the two physical solvents (Selexol® and Rectisol®), for Rectisol® the overall net efficiency is about 0.5 % lower than in case of Selexol for the same carbon capture rate. However, Rectisol has also some merits for instance the deeper syngas cleaning of undesirable components (e.g. H_2S). This is of particular importance in chemical applications (e.g. ammonia synthesis) where lower H_2S concentrations (<10 ppm) in the syngas are desirable.

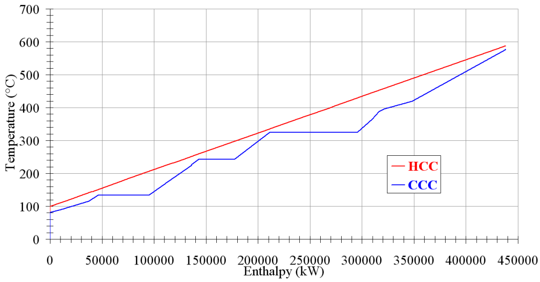


3.a. Hot and cold composite curves

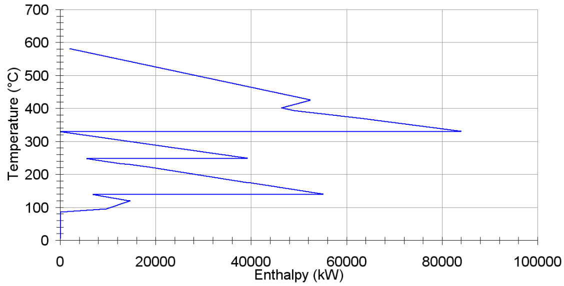


3.b. Grand composite curve

Figure 3. Energy integration analysis for gasification island and syngas conditioning line (Case 2.a)



4.a. Hot and cold composite curves



4.b. Grand composite curve

Figure 4. *Energy integration analysis for the power block (CCGT) (Case 2.a)*

Table 4. Energy consumptions pre- and post-combustion capture cases

Ancillary duty	Units	Pre-comb. Case 2.a Selexol®	Rectisol®	Case 2.b MDEA	Post-comb. Case 3 MDEA
SPC	kWh/kg CO_2	0.1078	0.1185	0.0949	1.35
SHC	MJ/kg CO_2	0.2236	0.3739	0.7016	2.80
SCC	MJ/kg CO_2	0.5591	0.6154	3.3143	3.72

Table 4 reveals the main causes of significant energy penalty for post-combustion cases (not only for gasification but also for combustion power plants) namely high power and heat (steam) consumption [21].

To have a clearer picture about the impact of CCS technology in IGCC power plants, Table 5 presents normalised mass and energy balances for generation of 1 MWh net power using Shell gasifier (Case 1a vs. Case 1b). As can be noticed from Table 5, the introduction of carbon capture implies a significant increase of all normalised mass and energy flows for instance 25% for coal, 24% for oxygen, 22% for cooling water etc.

Table 5. Normalised mass and energy balances for Case 1 vs. Case 2.a

Input	Units	Value		Output	Units	Value
Case 1						
Coal	kg	304.62		Net power	MWh_e	1.00
Nitrogen	kg	468.74		Captured CO_2	kg	0.00
Oxygen	kg	257.10		Flue gases	kg	5922.52
Air	kg	5025.10		Sulphur	kg	1.83
Cooling water	kg	73148.66		Ash (dry)	kg	39.61
Fresh water	kg	41.22		Process water	kg	134.05
Energy (coal)	MWh_{th}	2.15		Cooling water	kg	73148.66
				Thermal energy (CW)	MWh_{th}	0.92
Case 2.a						
Coal	kg	382.53		Net power	MWh_e	1.00
Nitrogen	kg	489.71		Captured CO_2	kg	847.17
Oxygen	kg	320.11		Flue gases	kg	6495.31
Air	kg	5861.57		Sulphur	kg	2.26
Cooling water	kg	89018.98		Ash (dry)	kg	49.75
Fresh water	kg	670.44		Process water	kg	327.10
Energy (coal)	MWh_{th}	2.69		Cooling water	kg	89018.98
				Thermal energy (CW)	MWh_{th}	1.03

RESULTS AND DISSCUSSIONS

After performing mass and energy integration analysis, the results were used for quantification of overall key performance indicators of evaluated power plants concepts. Tables 6 and 7 presents overall plant performance indicators of analysed case studies in comparison with the plant concept without CCS. Table 6 is presenting the evaluation of pre-combustion capture (Case 2.a: Shell-based IGCC power plant with Selexol-based pre-combustion capture and Case 2.b: Shell-based IGCC power plant with MDEA-based pre-combustion capture) and Table 7 for post-combustion capture (Case 3: Shell-based IGCC power plant with MDEA-based post-combustion capture).

Table 6. Overall plant performance indicators - pre-combustion capture

Main Plant Data	Units	Case 1	Case 2.a	Case 2.b
Coal flowrate (a.r.)	t/h	147.80	165.70	165.70
Coal LHV (a.r.)	MJ/kg	25.353		
Coal thermal energy (A)	MW_{th}	1040.88	1166.98	1166.98
Raw syngas energy (B)	MW_{th}	839.05	934.76	934.76
Cold gas efficiency (B/A * 100)	%	80.61	80.10	80.10
Syngas exit AGR energy (C)	MW_{th}	835.41	831.92	831.92
Treatment efficiency (C/B *100)	%	99.56	88.99	88.99
Gas turbine output (M701G2)	MW_e	334.00	334.00	334.00
Steam turbine output	MW_e	224.01	210.84	200.72
Expander power output	MW_e	0.68	0.78	1.18
Gross electric power output (D)	MW_e	558.69	545.62	535.90
ASU consumption	MW_e	39.91	44.73	44.72
Gasification island consumption	MW_e	8.38	9.12	10.05
AGR consumption	MW_e	6.12	39.81	36.35
Power island consumption	MW_e	19.09	18.78	18.70
Ancillary consumption (F)	MW_e	73.50	112.44	109.82
Net power output (G = D - F)	MW_e	485.19	433.18	426.08
Gross efficiency (D/A * 100)	%	53.67	46.75	45.92
Net efficiency (G/A * 100)	%	46.61	37.11	36.51
Carbon capture rate	%	0.00	90.79	91.24
CO_2 specific emissions	kg/MWh_e	741.50	86.92	85.51

As can be noticed from the Table 6, comparing with a Shell-based IGCC scheme without carbon capture (Case 1), the pre-combustion capture using either physical and chemical solvents implies an energy penalty of about 9.5 net electrical efficiency percentage points for Selexol and 10.1 for

MDEA. The difference between the evaluated physical and chemical solvents are due to the higher regeneration heat needed for the chemical solvent (MDEA). When analysing also the post-combustion capture, one can noticed that this scheme implies a higher energy penalty compared with pre-combustion capture (1.1 net percentage points compared with Selexol and 0.5 compared with the same solvent - MDEA). Basically, this can be explained by the fact that carbon dioxide concentration in the syngas (about 40% vol.) and syngas pressure (about 30 bar) are much higher compared with post-combustion case when CO_2 concentration in the flue gases is about 8 – 10% vol. and the pressure is close to the atmospheric pressure [21-22].

Table 7. Overall plant performance indicators - post-combustion capture

Main Plant Data	Units	Case 1	Case 3
Coal flowrate (a.r.)	t/h	147.80	148.18
Coal LHV (a.r.)	MJ/kg	25.353	
Coal thermal energy (A)	MW_{th}	1040.88	1043.56
Raw syngas energy (B)	MW_{th}	839.05	835.37
Cold gas efficiency (B/A * 100)	%	80.61	80.05
Syngas exit AGR energy (C)	MW_{th}	835.41	831.95
Treatment efficiency (C/B *100)	%	99.56	99.59
Gas turbine output (M701G2)	MW_e	334.00	334.00
Steam turbine output	MW_e	224.01	135.67
Expander power output	MW_e	0.68	1.45
Gross electric power output (D)	MW_e	558.69	471.12
ASU consumption	MW_e	39.91	39.98
Gasification island consumption	MW_e	8.38	8.21
AGR consumption (incl. CO_2 compression)	MW_e	6.12	27.76
Power island consumption	MW_e	19.09	19.12
Ancillary consumption (F)	MW_e	73.50	95.07
Net power output (G = D - F)	MW_e	485.19	376.05
Gross efficiency (D/A * 100)	%	53.67	45.14
Net efficiency (G/A * 100)	%	46.61	36.03
Carbon capture rate	%	0.00	90.36
CO_2 specific emissions	kg/MWh_e	741.50	90.11

From the point of view of greenhouse gas emission, the implementation of carbon capture technology for an IGCC scheme is resulting in a substantial reduction of the specific carbon dioxide emission (85-90 CO_2/MWh for pre- and post-combustion capture vs. 826.05 kg CO_2/MWh for the case without capture). IGCC technology has also other important benefits from environmental point of view [13,23-24]: very low SO_x and NO_x emissions, possibility to process lower grade coal and lignite or other solid fuels (biomass of almost every sort, solid waste having energetic value) which are difficult to handle by conventional energy conversion process (e.g. steam plant).

CONCLUSIONS

This paper analyze from technical point of view, using modelling and simulation techniques and mass and energy integration analysis, the possibility of applying to IGCC power generation technology various carbon capture methods. One most commercially and technologically mature carbon capture method was evaluated namely gas-liquid absorption operated in pre- and post-combustion configurations. The main differences in term of energy efficiency and heat and power integration between a conventional IGCC scheme without carbon capture compared with a scheme with pre-combustion capture or a scheme with post-combustion capture were analysed in details.

As main conclusion, pre-combustion carbon dioxide capture method is more suitable for gasification process than post-combustion (0.5 - 1.1 net electricity percentage points lower energy penalty). The simulation results of the analysed plant concepts were also used for evaluation of environmental impact of gasification-based energy conversion processes with carbon capture and storage (quantification of specific CO_2 emissions, fuel decarbonisation rate).

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