This work focuses on the exergetic-based assessment of various flue gas recirculation options offered by oxy-combustion. In addition to enhancing the understanding of the system by locating the losses at unit operation level, this study allows the assessment of further process integration opportunities.

2. Methodology

A gross oxy-fired coal 1,100 MWe power plant operating at base-load and steady-state is modelled and simulated using Aspen Plus v7.2. Oxygen at 95 $\%_{mol}$ purity is provided by a conventional double column air separation unit (ASU) and an auto-refrigerated compression and purification unit (CPU) produces a 96 $\%_{mol}$ purity CO_2 flow at 110 bars in dense phase for further pipeline transportation. For the sake of consistency with other European studies on carbon capture technologies, the modelling hypotheses adopted in this study are based on the recommendations of the European Benchmarking Task Force (2011), unless otherwise stated. Low sulphur, international grade, Bituminous Douglas Premium coal with lower heating value (LHV) of 25.2 MJ/kg is considered and ISO standards for inland plant construction are adopted regarding the ambient conditions. Concerning the thermodynamic models, STEAM-NBS model is used for the steam cycle, RK-SOAVE for the boiler and flue gas depollution train and PR-BM for the cryogenic processes.

Using the material flow exergy content determination methodology described by Hinderink et al. (1996) and implemented by Jacobs Consultancy (2009), exergy analysis is carried out at unit operation level. The reference environment described by Szargut et al. (1988) is adopted and the reference state is 25 °C and 1.01325 bars. The coal exergy content has been assessed from its LHV using the method described by Szargut and Stryrylska (1964). The bituminous coal considered in this study has an exergy content of 26.7 MJ/kg.

3. Process Description

3.1 General description

Figure 1 presents a schematic representation of the reference oxy-fired power plant. A state-of-the-art supercritical power cycle with steam conditions of 300 bars / 600 °C / 620 °C is considered. The boiler feedwater (FW) is heated up to 315 °C by steam extractions in seven feedwater heaters (FWH) and a deaerator. Regarding heat rejection, natural draft cooling tower is used, leading to a condenser pressure of 48 mbars considering a cooling water temperature of 18°C.

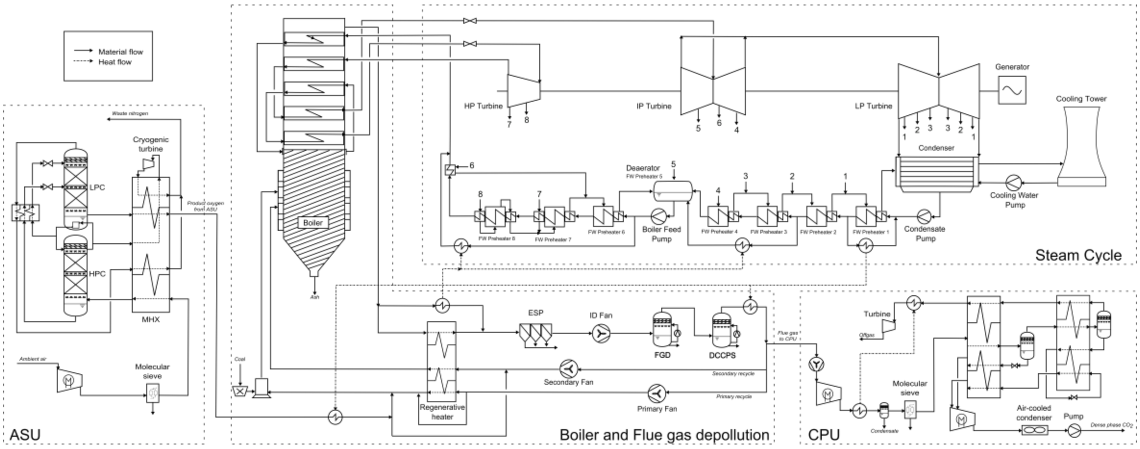

Figure 1: Simplified PFD of the reference oxy-combustion power plant

The boiler is modelled as a reactor calculating the chemical and phase equilibriums by minimization of the Gibbs free energy of the system at 1,250°C and the feedwater flows successively through an economizer, the water wall tubes and two superheaters. The reheat steam flows through two resuperheaters. After denitrification in a selective catalytic reduction (SCR) unit operating at high temperature, the flue gas heads to a Ljungstrom-type regenerative heater (RH). A flue gas bypass allows the integration of the surplus heat into the steam cycle. A portion of the primary recycle is also bypassed and remixed straight after the RH in order to cool down to 110 °C the flow heading to the coal handling system. Then, the flue gas passes successively through an electrostatic precipitator (ESP) for particles removal, a wet flue gas

In the reference case, the secondary recycle flows through particle removal in the ESP, desulfurization in the wet FGD and water removal in the DCCPS. The alternative secondary recycle options investigated in this study are the followings:

Case A - The secondary recycle is carried out before the regenerative heater in order to maximize the temperature. A high temperature particle removal device is used in order to avoid excessive ash concentration in the boiler and erosion of the secondary fan.

Case B - In this recirculation option, the flue gas undergoes particle removal and is recycled, wet, at a temperature around 130 °C and is reheated against the flue gas up to 310°C in the RH.

Case C - In this last option, the secondary flow is sent recycled after sulphur removal but before the DCCPS.

Table 1: Flue gas acid dew point at the regenerative heater outlet calculated using Okkes correlation

	Reference	Case A	Case B	Case C
P_{SO3} (μbar)	3.4	6.8	6.9	3.2
P_{H2O} (bar)	0.09	0.17	0.17	0.22
$T_{dew\ point}$ (°C)	116	127	127	126

In oxy-fuel combustion, the higher water content in the flue gas generally leads to 20 – 40 K higher acid dew points compared to air-fired combustion (Kather and Kownatzki, 2011). Thus, the flue gas temperature has to be kept above the acid dew point associated to the flue gas sulphur trioxide and water content. The acid dew points assessed using the correlation described by Okkes and Badger (1987) are reported in Table 1. The temperature of the flue gas is kept above 130 °C as long as it has not been desulfurized in order to ensure that no acid condensation occurs.

4. Results

Figure 3 shows the exergy losses occurring in the boiler and flue gas depollution sections for the reference oxy-fired plant and the three alternative cases. The oxygen flow is preheated by feedwater according to the temperature of the flue gas recycle flow (Table 2). The temperature approach for these liquid/gas heat exchanges is assumed to be 10 °C. It has to be noted that the oxygen preheat temperature in Case A is limited by the feedwater maximum temperature (315 °C).

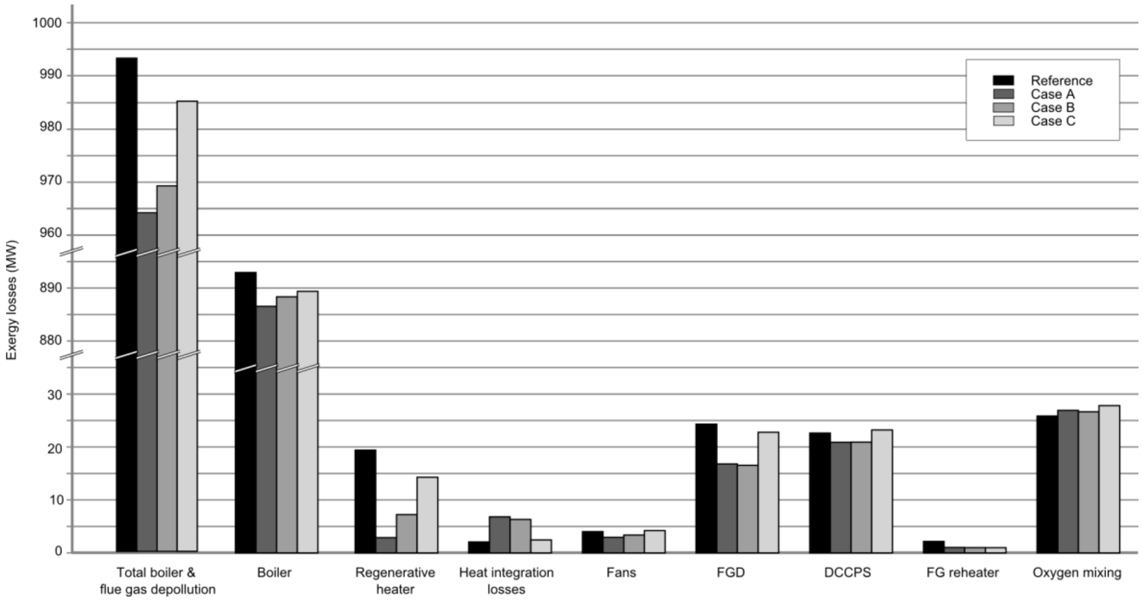

Figure 3: Exergy losses occurring in the boiler and flue gas depollution sections for the different cases

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