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Coal Based Power Plants Using Oxy-Combustion for CO_2 Capture: Pressurized coal combustion to Reduce Capture Penalty

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The goal of this paper is to design and study a new variation of an oxy-combustion coal based power plant with CO_2 capture that employs a pressurized coal combustor. The concept is compared with an atmospheric pressure oxy-combustion power plant (baseline case). Such analyses would provide us with information regarding potential heat integration and improvement opportunities of oxy-combustion coal based power plants. The power cycle presented in this paper has a gross electric power output of 792 MW for the baseline case and 796 MW for the pressurized case. The auxiliary power consumption is reduced from 228.5 MW in the baseline case to 215.3 MW in the pressurized case. This results in a net LHV efficiency improvement of 1.7 percentage points over the baseline case. The improvements achieved in the pressurized case are due to reduced power consumption in the CO_2 compression and enhanced heat recovery in the acid condenser, despite additional oxygen compression power consumption. In both the cases, over 90% of the produced CO_2 is captured and compressed to 110 bar after removal of volatiles.

1. Introduction

Carbon Capture and Sequestration (CCS) is a technology that collects and concentrates the CO_2 emitted from large point sources, transports it to a suitable storage location and stores it away from the atmosphere for a sufficiently long time to avoid warming of the atmosphere. CCS is expected to play a pivotal role in stabilizing the atmospheric greenhouse gas levels within acceptable limits. It has been estimated that the average contribution of CCS in total emission reduction would range from 15% to 54% for stabilization targets of 750 ppmv to 450 ppmv CO_2 respectively (Morita et al., 2000). The deployment of CCS could help bring down the overall cost of mitigation of climate change in the longer run (Edmonds et al., 2000). One of the ways to capture CO_2 is referred to as the *oxy-combustion* method in which the fuel is burnt in an oxygen rich environment instead of air, thus resulting in a flue gas that contains mainly water and CO_2. This method is considered to have several advantages such as reduced environmental impact and competitive cost of electricity (Petrakopoulou et al., 2011 and Kanniche et al., 2010).
Oxy-combustion requires an upstream production of oxygen for combustion which is energy intensive and hence expensive. Downstream purification of the flue gas using a Compression and Purification Unit (CPU) is also required to remove the volatile components such as nitrogen, argon, oxygen, etc., after condensing the water, to achieve the required purity before compression and pipeline transport. A Cryogenic Air Separation Unit (ASU) is used for large scale production of oxygen. The ASU and the

CPU are responsible for an efficiency penalty of around 10 percentage points (Fu and Gundersen, 2010). There is a need to reduce this efficiency penalty in order to make oxy-combustion power plants attractive and ready for commercial deployment. One of the ways to reduce the capture penalty is to go for a pressurized coal combustion system which has several advantages over the atmospheric combustion system. Similar systems have been studied earlier (Fassbender, 2005) and pressurized coal combustion shows a reduction in capture penalty (Gazzino and Benelli, 2008).

In this study, a pressurized oxy-combustion coal based power plant with CO_2 capture is analysed and compared with an atmospheric counterpart. An acid condenser is required in both cases to recover the latent heat from the flue gases before it enters the CPU for purification.

2. Methodology

The simulation package Aspen Plus®[1] is used to model the steam cycle, atmospheric and pressurized boiler islands and the CO_2 Purification and Compression Unit. Also Thermoflow STEAM PRO®[1] is used to assist the simulation process by providing the parameters such as the pressure drops and other thermodynamic assumptions for the boiler and the steam cycle. IAPWS-95 physical properties method was used to estimate the steam/water parameters in the steam cycle. Peng Robinson cubic equation of state with the Boston-Mathias alpha function was used to simulate the boiler island while the same equation of state with k_{ij} binary interaction parameters was used to model the CPU. The ASU was not modelled, however, the energy required in producing and compressing the oxygen was taken into account.

Initially a steam cycle is modelled in Aspen Plus® assisted by STEAM PRO® which gives the gross power produced and the thermal energy requirements. Also the steam cycle provides the feedwater conditions and live steam parameters. Using this information, an oxy-combustion boiler can be designed that suits the steam cycle. A CPU is then designed for the boiler that removes the volatiles and compresses the flue gas to final pipeline specifications. Thermodynamic assumptions and simulation parameters, cycle description and performance results are provided in the subsequent sections. Various performance parameters such as the gross power produced, auxiliary power requirements and the net plant efficiency is calculated after combining the heat and mass balance models from Aspen Plus. Finally, the improvements brought by the pressurization are discussed along with the potential heat integration opportunities for the future.

3. Process description

In order to maintain a consistency and to have a baseline for future studies, the simulation parameters are taken from published reports. Ambient conditions, fuel composition, steam cycle and cooling system parameters are obtained from an EBTF common framework document (Franco et al., 2009). The feedwater preheating system, auxiliary power consumption and some of the boiler parameters are obtained from STEAM PRO®. Other parameters such as the boiler pressure and pressure drop for the pressurized case are taken from Hong et al., 2010. The CPU simulation parameters are provided by Pipitone and Bolland, 2009 and Posch and Haider, 2011. Selected simulation parameters for the baseline case are provided in Table 1. Figure 1 shows the schematic of the boiler island and Figure 2 shows the steam cycle. The boiler island consists of a combustor (PC-boiler), the pressure of which depends on the case considered. It also has an ash removal and handling system (ESP), an induced draft fan (ID-fan), coal and oxygen feeds and an acid condenser. An air leakage stream is present only in the atmospheric case due to a negative gage pressure in the combustor. The ASU is not shown in the figure. A slip stream from the boiler after the ID-fan is passed through the acid condenser where additional heat is removed and supplied to the steam cycle. In Figure 2, the placement of the acid condenser in the steam cycle is shown. The acid condenser is placed after the main condenser and before the low pressure feedwater heaters.

[1]STEAM PRO® and Aspen Plus® are registered trademarks of Thermoflow LTD and Aspen Technology, Inc., respectively.

In a typical large steam power plant, as many as eight feedwater heaters are used to preheat the boiler feedwater by extracting steam from various extraction points in the steam turbines. When using the acid condenser, part of this heating is performed by the slip stream from the boiler exhaust and hence corresponding steam extraction can be used in the steam turbines to generate additional power. Most of the exhaust gases are recycled to the combustor (PC-Boiler) to maintain the combustion temperature. In case of the pressurized boiler, another recycle stream is used to reduce the gas temperature further before the heat recovery steam generator (HRSG).

Table 1: Selected simulation parameters for the cycle

Parameter	Value		Units
Steam Cycle	Baseline	Pressurized	
Main steam pressure	280	280	bar
Main steam temperature	600	600	^oC
Reheat temperature	610	610	^oC
Condenser pressure	0.048	0.048	bar
Feedwater heaters	7	6	
Feedwater final temperature	315	315	^oC
Deaerator pressure	18	18	bar
Boiler island			
Evaporator pressure drop	15	15	bar
Boiler minimum design pinch	20	20	^oC
Boiler operating pressure	1.0124	10	bar
Excess oxygen@ combustor outlet	3	3	% (dry)
Combustor exit temperature	1850	1550	^oC
Oxygen purity	95	95	%

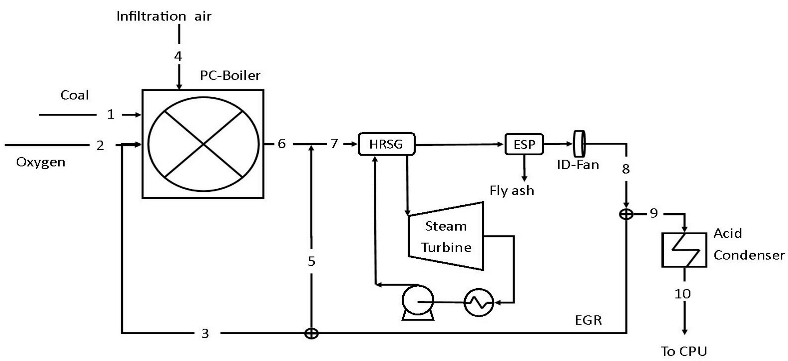

Figure 1: Boiler island

The emission control system is shown in two parts in Figures 3 and 4. It is noteworthy to mention that for coals with a sulphur content of less than 1%, there is no need to remove sulphur from the exhaust gas before recirculation (DOE/NETL, 2008). Although the concentration of sulphur compounds is amplified in the boiler due to flue gas recirculation, it will be well under the boiler design conditions for the coal considered in this study (0.52% sulphur). The emission control system is designed to remove sulphur dioxide as sulphuric acid in a water wash column at a pressure of 20 bar. Flue gas slip stream is cooled to 25 ^oC, any condensation is removed and then compressed to 20 bar. The flue gas is cooled again and water is added to remove sulphur as sulphuric acid (Stream 24) in the water wash column (FGD) in Figure 3. Traditional wet flue gas desulfurization is not required as it is easier to remove SO_x and NO_x together under high pressure in a water wash column (White et al., 2010). Then the flue gas is again compressed to 33 bar, cooled and any moisture present is removed by using adsorption to avoid ice formation in the downstream purification where it will be cooled below the dew point.

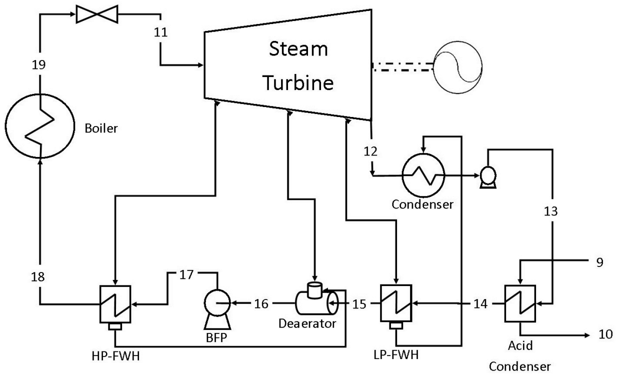

Figure 2: Steam cycle

Flue gas stripped completely of SO_x and moisture enters the double flash purification unit shown in Figure 4. The gas enters a cold box (E-1) where it is cooled to -30 ^oC (Stream 27) and separated in a flash drum (F3). Then again, the resulting vapour (Stream 28) is cooled to -54 ^oC and separated in a flash drum (F4). Cooling for the above process is provided by evaporating part of the liquid streams (Stream 29 and 34) after throttling them to a lower pressure. While the impure stream rich in volatiles are vented to the atmosphere as the only emissions from the power plant, the CO_2 rich stream is compressed, cooled and then pumped to the final pipeline pressure of 110 bar.

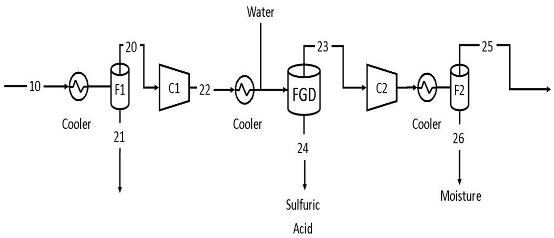

Figure 3: Flue gas desulphurization unit

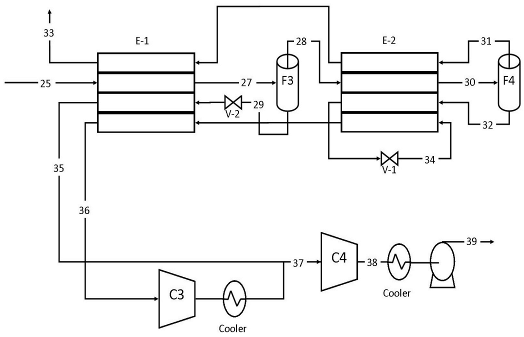

Figure 4: Compression and Purification Unit

4. Performance and results

Cycles for both the baseline case and the pressurized case are identical except for the operating pressure of the boiler island and the number of feedwater preheaters. In the pressurized case, as more latent heat can be extracted from the flue gases, only two low pressure feedwater heaters are present. The performance summary of both the cases is presented in Table 2. It is evident that the pressurized cycle has some clear advantages over the atmospheric case. Total auxiliaries are reduced by 13.2 MW, mainly due to the reduction in CO_2 compression work. Table 3 provides a summary of major streams in the cycle for both cases. The air leakage stream is absent in the pressurized case as the boiler is operating at a pressure higher than the atmospheric pressure. This results in some savings in energy in terms of downstream purification of the flue gas stream.

Table 2: Performance summary

Item	Baseline	Pressurized	Units
Fuel energy input, LHV	1647.5	1618.7	MWth
Condenser duty	880	904	MWth
ST shaft power	806.8	810.9	MW
ST-Gen losses	15.3	15.4	MW
Gross electric power	791.6	795.5	MWe
Steam cycle aux.	6.8	6.8	MWe
ASU power req.	121.7	150.5	MWe
Boiler island aux.	15.8	24.1	MWe
CPU power req.	84.2	33.9	MWe
Total auxiliaries	228.5	215.3	MW
Net electric power	563.1	580.3	MW
Net plant efficiency, LHV	*34.2*	35.9	%
Net plant heat rate, LHV	10533	10043	kJ/kWh
CO_2 emissions	51	21	g/kWh

Although more compression work is required to compress the oxygen rich stream before the combustor, savings achieved in the CPU compression work more than compensates for it. ASU power requirement is increased by 28.8 MW, while the CPU energy requirement is reduced by 50.3 MW resulting in a net savings of 21.5 MW. The recycle ratio in the pressurized case is different from that of the baseline case because the combustor is considered adiabatic and no heat transfer to the water/steam takes place in the high pressure combustor. All the heat transfer takes place in a steam generator located after the combustor and hence the flue gas needs to be cooled before the steam generator to avoid hot corrosion. This leads to more flue gas being circulated for temperature control. Also due to the change in pressure drop, the fan power requirement in the pressurized case is increased by 8 MW.

Table 3: Stream parameters of select streams (a- baseline case; b- pressurized case)

	Temperature C		Pressure bar		Total Flow kg/sec	
Stream	a	b	a	b	a	b
2	15.0	132.3	1.60	10.50	141.7	141.9
3	345.2	347.5	1.04	10.00	507.0	730.6
4	15.0	n/a	1.01	n/a	11.0	n/a
5	n/a	347.5	n/a	10.00	n/a	411.1
7	1884.7	1206.6	1.01	10.00	715.9	1338.8
9	345.2	347.5	1.04	10.00	208.9	197.1
10	57.4	57.4	1.04	10.00	208.9	197.1
11	600.0	600.0	280.00	280.00	605.0	605.0
12	32.1	32.1	0.05	0.05	355.8	366.4
13	32.4	32.4	22.00	22.00	459.9	459.9
14	83.7	98.3	22.00	22.00	459.9	459.9
15	172.0	172.0	22.00	22.00	459.9	459.9
16	207.1	207.1	18.00	18.00	605.0	605.0
18	310.0	310.0	324.81	324.81	605.0	605.0
25	25.0	25.0	33.00	33.00	180.6	169.4
28	-30.0	-30.0	32.00	32.00	46.0	21.0
29	-30.0	-30.0	32.00	32.00	134.7	148.5
32	-54.0	-54.0	31.00	31.00	20.7	9.2
33	15.0	15.0	31.00	31.00	25.3	11.8
39	33.5	33.6	110.00	110.00	155.4	157.6

Due to a higher pressure in the flue gases, the dew point of the water vapour is raised and hence more of the latent heat available in the flue gas slip stream can now be recovered in the acid condenser. This takes the feedwater temperature prior to the low pressure feedwater heater to 98.3 degrees compared to the 83.7 degrees of the baseline case. As a result, only six feedwater heaters, including the deaerator, are required in the steam cycle. This saves both capital cost as well as some extraction steam from the turbines. An additional power of 4 MW is produced in the steam turbines as a result of this. The overall savings account to 17.2 MW of net electric power.

5. Conclusion

The simulation results show that a pressurized oxy-combustion power plant is more efficient than its atmospheric counterpart. By compressing a smaller amount of gas (Oxygen) before the combustor, considerable savings can be achieved in the compression work of the exhaust gases after the combustor, leading to a net savings in the overall auxiliary power consumption. Efficiency improvement achieved is in the order of 1.7 percentage points. The LHV efficiency of the pressurized case is 35.9% which is in line with another similar study by Hong et al., 2009. In addition, the CO_2 recovery factor is improved by 2.8 percentage points to 97.8%. Further heat integration within the cycle such as utilization of compression heat from the CPU in the steam cycle and better usage of the impurity stream from the CPU could result in additional energy savings and will be investigated in the future.

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