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Reducing the Energy Penalty of CO_2 Capture and Storage Using Pinch Analysis

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Integration of CO_2 capture and storage (CCS) into coal fired power stations is seen as a way of significantly reducing the carbon emissions from stationary sources. A large proportion of the estimated cost of CCS is due to the additional energy expended to capture the CO_2 and compress it for transport and storage, reducing the energy efficiency of the power plant. This study uses heat integration to reduce the overall energy penalty and therefore the cost of implementing CCS. An existing pulverised brown coal power plant with a new CCS plant using solvent absorption is used as the basis for this study that shows the energy penalty reduces from 39% for a CCS plant with no heat integration to 24% for a plant with effective heat integration. The energy penalty can be further reduced by predrying the coal.

1. Introduction

Using an existing brown coal power station as a basis and adding on a new solvent based CCS plant with the option of adding lignite pre-drying, pinch analysis is used to examine the possibility for reducing the energy penalty associated with the addition of CCS. It is well known that pre-drying lignite increases the efficiency of conventional brown coal fired power plants (Li, 2004), however the impact of adding both CCS and pre-drying from an overall heat integration perspective has not to the authors knowledge previously been studied. Five cases have been reviewed,

Case 1: Base Case – This is the existing plant with no flue gas desulphurisation (FGD) or carbon capture plant.
Case 2: CCS – This case includes CCS and FGD with no heat integration.
Case 3: Integrated CCS – Includes CCS and FGD with maximum heat integration.
Case 4: CCS & Drying – Coal dewatering and CCS with maximum heat integration.
Case 5: CCS/Drying/Increased Steam – Utilises the additional heat content in the pre-dried coal to produce additional steam increasing the heat and power.

For each case the amount of raw coal fed to the plant is held constant and the amount and quality of steam produced from the boiler is held constant for all but case 5. All heat and power requirements for the additional equipment are assumed to be provided by the heat generated within the power plant.

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The existing power station is a 200MWe(nominal) / 220MWe(peaking) subcritical pulverised brown coal fired power plant that operates with a HP and LP turbine and no steam reheat. Steam is currently extracted from the exhaust of the high pressure turbine for deaeration and is also extracted from two points on the LP turbine for heating the boiler feedwater upstream of the deaerator. The raw brown coal has 60wt% moisture and is currently dried in the pulverising mills using flue gases extracted from the combustion chamber. A boiler feed water economiser and air preheater cool the flue gases down before exiting the stack at 260°C.

Solvent capture of CO_2 from pulverised coal power stations is considered to be the benchmark of the capture technologies and MEA is often used as the benchmark for comparison with other solvent systems. Therefore this study is based on a simple solvent system based on MEA.

A model of the base power plant has been developed in Aspen Plus® and validated against a Gatecycle® model of the same plant. The Aspen model includes the coal drying in the pulverizing mill, coal combustion, flue gas heat recovery and simulation of the steam cycle. For this study as the flue gas has greater than 200ppmv of SOx and less than 10ppm of NO_2 it is assumed that FGD will be required but there will be no additional equipment for NOx removal. The MEA capture plant and CO_2 compression were also modelled in Aspen Plus®, however the heating/cooling curves of the MEA system heat exchangers predicted by the model were prorated for a reboiler duty from 4.4GJ/tCO_2 to 3GJ/tCO_2, to provide results comparable to the leading solvent technologies that report reboiler duties of 2.7 – 3.3 GJ/tCO_2 (IPCC, 2005). The CO_2 is compressed to 100bar using a 4 stage compressor with intercooling and water removal between the second and third stages of compression. Where lignite pre-drying has been considered, the drying is assumed to occur between 100-185°C and the coal is dried to 45wt% moisture, which is the minimum that can be handled by the existing boiler plant.

2. Background

The addition of the CCS equipment creates an 'Energy Penalty' on the power plant as it requires heat to regenerate the solvent and power to operate the CO_2 compressors and auxiliary equipment, which all lead to reducing the electrical output from the power plant. For solvent capture plants the majority of the energy is used to regenerate the solvent. Generally it is proposed that this heat is supplied by extracting steam from the LP turbine, which reduces the electricity from the power plant and thus its net efficiency can be reduced by approximately 30 – 40% by the addition of CCS (IPCC, 2005).

Many authors have investigated how to minimise the energy penalty associated with CCS, however none appear to use pinch analysis. Aroonwilas and Veawab (2007) and Romeo et al (2008) state that the optimal location to extract power for a solvent system is from the LP turbine at the appropriate pressure to provide steam at lowest quality that satisfies the solvent system reboiler requirements. Bozzutto et al (2001) propose an auxiliary turbine with steam from the IP/LP crossover to provide the steam at the required quality for the solvent reboiler. Desederi and Paolucci (1999) suggest utilising some of the available heat from the CO_2 compressor intercoolers and stripper condenser to heat the boiler feed water. An IEA GHG report (2006) proposes the production of hot water for coal pre-drying using waste heat in the flue gas, the stripper condenser and the CO_2 compressor intercoolers.

Linhoff and Alanis (1989) used pinch analysis to improve the efficiency of a power plant reducing the fuel use by 2.8% by determining the optimum amount of steam extracted from the turbines for a given number of boiler feedwater heaters and utilising topping and intermediate desuperheaters to achieve the required heat transfer. With the addition of CCS to a power plant, there are additional hot and cold streams which may result in process flowsheets that vary from what is now considered optimal.

For this study, the heat required for the CCS plant is provided by the extraction steam. A number of unique issues occur when using the steam as a hot utility variable;

1. The composite curves vary depending on where the steam is returned to the steam cycle. Where steam is used in direct heaters or is returned to the steam cycle using drain pumps, the cold composite curves upstream of the returned steam/condensate have a smaller flowrate compared to the curves downstream of the injected steam/condensate.
2. The target temperature of the hot utility changes depending on how the steam is used. Injected steam has a different target compared to steam used in heat exchangers.
3. The hot utility / extracted steam may cross the process pinch point as it is cooled thereby adding heat below the pinch point.
4. The process pinch point can be moved by varying the steam extraction amounts as the energy in the steam is included with the hot composite curve.

The above issues makes the problem of determining the targets for steam extraction extremely multivariable, to enable consistency the following method is proposed;

1. The cold composite curves are considered to be constant and are based on a water flowrate equal to the amount of steam generated.
2. All extraction steam is cooled down to the condenser temperature and returned to the steam cycle at the surface condenser.

This procedure enables the targeting process to proceed with consistent cold composite curves and hot utility target temperatures. However, the extraction steam will invariably cross the process pinch, possibly move the process pinch and will have multiple solutions that achieve the required heating load. Linhoff and Alanis (1989) created a number of simultaneous equations to determine the amount of steam to be extracted by creating a pinch at every steam level. Commercial pinch analysis software will not perform this procedure and therefore for this initial study the amount of steam extracted at the next greatest temperature level above the process pinch was increased until a utility pinch was created then the next level was increased and so forth until the hot utility requirement was met.

This procedure even though it is representative of using surface heaters, does not preclude the use of direct contact heaters in a final design. As per Linnhoff and Alanis (1989) direct contact heaters can be considered thermodynamically equivalent to surface heaters, granted this only occurs when the temperature driving forces are zero, but surface heaters in power plants generally have very low temperature driving forces and therefore the difference between the design using surface heaters compared to direct contact heaters will be minor.

3. Results

Table 1 Power Plant Performance

Case		1	2	3	4	5
Moisture Content (Inlet to mill)	wt%	61	61	61	45	45
Steam Production	kg/s	208	208	208	208	248
Flue Gas Temperature (After Economiser)	°C	362	362	362	416	189
Steam Extraction						
HP Exhaust (177°C)	kg/s	11	112	54	42	53
LP Bleed 1 (110°C)	kg/s	11	11	0	7	7
LP Bleed 2 (84°C)	kg/s	9	9	0	0	0
Electricity Produced	MW	220	172	205	208	203
Plant Auxiliary Power	MW	14	22	22	22	23
CO_2 Compression Power	MW	-	25	24	25	2*
Net Electrical Power	MW	206	125	158	161	178
Net Cycle HHV Efficiency	%	23	14	18	18	20
Reduction in Net Cycle HHV Efficiency	% Points	-	9	5	5	3
Energy Penalty	%	-	39	24	22	14
CO_2 Emissions	kt/y	2641	263	263	216	216
CO_2 Emissions	t/MWh	1.46	0.24	0.19	0.15	0.14

** The compression power in this case is offset by the addition of an auxiliary turbine*

4. Discussion

The base case (Case 1) describes the existing plant, therefore the extraction steam is included in the hot composite curves (Figure 1) and the hot and cold curves for this case are balanced. The base case is a threshold problem with a threshold ΔT_{min} of 30°C, with the pinch point located at the condenser for this ΔT_{min}. If the cooling water ΔT_{min} can be considered less than the other streams, which in reality the condenser will operate with a temperature difference of less than 10°C, then the pinch point becomes located at the lowest extraction steam temperature. The temperature driving forces of the existing plant range from less than 3°C in the surface heaters to greater than 400°C in the firebox of the boiler.

For case 2, where CCS is added without heat integration, the heat for the solvent regeneration is supplied from the next available turbine extraction point (177°C). More than half of the steam generated is required to meet this demand as well as the existing deaeration requirements. Where the CCS plant is added with heat integration (Case 3) using a ΔT_{min} of 3°C (Figure 2), the steam extraction requirements are reduced by more

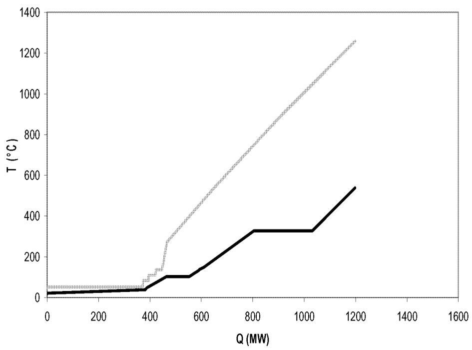

Figure 1 - Base plant

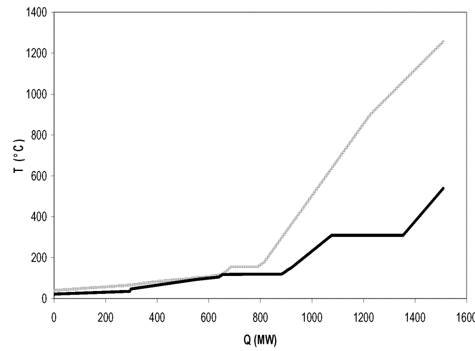

Figure 2 - Balanced curves - case 3

than 50%. The pinch point changes from the condenser for the base case to a hot stream temperature of 116.6°C. The integrated CCS plant has an energy penalty of 24%, which is a 15% point improvement on the non-integrated case.

4.1 Integrated CCS & Drying (Cases 4 & 5)

Adding pre-drying results in a 2% improvement in the energy penalty in comparison to the integrated CCS case without pre-drying. With coal pre-drying included the air preheat is removed entirely to reduce the maximum combustion temperature, however in this case the theoretical flue gas temperature still increases by just over 110°C. This increase may limit the level of pre-drying that is able to be achieved due to constraints of the existing boiler.

There are two pinch points in cases 4 & 5 at hot stream temperatures of 104°C and 120°C. The process pinch point is reduced to 104°C which can be attributed to the increased temperature of the flue gas and the removal of the air-preheat. The introduction of a second pinch point at 120°C is a result of some low pressure extraction steam being able to be used rather than requiring entirely HP exhaust steam.

From the results of Case 4 & 5 it appears that the value of preheating the air in a power plant may be reduced when CCS is added. Air-preheating on a conventional power plant increases the efficiency by reducing the stack losses, however as the flue gas exhaust temperature will need to be lowered for current solvent CO_2 capture technologies, the stack losses are lowered and the flue gas energy may be better utilized for other duties.

For case 5, it is assumed additional steam is produced and is utilised in a new auxiliary turbine. There is sufficient heat in the boiler flue gas to provide at least 20% additional steam, which can be used to provide enough energy in the auxiliary turbine to offset the CO_2 compression power and provide steam at the desired level for the solvent stripper. The energy penalty for this case reduces to 14%, however it is likely to have the highest capital costs of all the cases due to increasing the amount of steam produced in the boiler and introduction of a new turbine.

4.2 Effect of ΔTmin

The effect of altering the ΔT_{min} on the amount of extraction steam required and the amount of gross electricity that is produced is shown in table 2. For this study a very optimistic ΔT_{min} of 3°C is used for all cases. In reality the economic ΔT_{min} for each type of process will be different and variable minimum temperature driving forces for different processes will be used in future work.

Table 2 Effect of ΔT_{min} on the extraction steam flow and gross electricity production

ΔTmin(°C)	HP Steam (177°C)	LP Steam 1 (110°C)	LP Steam 2 (84°C)	Gross Electricity (MW)
3	54	0	0	205
10	53	7	0	203
20	81	0	0	192

5. Conclusion

Heat integration pinch analysis has been conducted for 4 CCS cases and targets for power production, net efficiency and the CCS penalty have been determined. The targets show some sensitivity to ΔTmin and further economic optimisation is required to determine the final penalty. However, the results indicate that with heat integration and coal pre-drying, a CCS retrofit may not incur the large penalties quoted in the literature.

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