Power plant CO_2 capture heat integration

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Preface

This report has been produced by IEA Clean Coal Centre and is based on a survey and analysis of published literature, and on information gathered in discussions with interested organisations and individuals. Their assistance is gratefully acknowledged. It should be understood that the views expressed in this report are our own, and are not necessarily shared by those who supplied the information, nor by our member countries.

IEA Clean Coal Centre is an organisation set up under the auspices of the International Energy Agency (IEA) which was itself founded in 1974 by member countries of the Organisation for Economic Co-operation and Development (OECD). The purpose of the IEA is to explore means by which countries interested in minimising their dependence on imported oil can co-operate. In the field of Research, Development and Demonstration over fifty individual projects have been established in partnership between member countries of the IEA.

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Abstract

The output and efficiency of a coal-fired power station unit fitted with CO_2 capture equipment will be significantly lower than that of a similar plant without capture because some of the energy produced by burning the fuel will be needed to operate the added systems. Incorporating an aqueous amine-based CO_2 scrubbing system in a simple arrangement could decrease the efficiency by as much as 30% of value. However, work at various research institutes and universities shows that the decrease in performance could be reduced by improved heat integration and other techniques. The present report reviews these studies.

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Acronyms and abbreviations

AHP	absorption heat pump
AHP	absorption heat transformer
A-USC	advanced ultra-supercritical
CCU	CO_2 compression unit
CHP	combined heat and power
CCS	carbon (dioxide) capture and storage
CO_2	carbon dioxide
DCOE	differential cost of electricity
EUF	energy utilisation factor (a measure of efficiency of CHP)
FEED	front end engineering and design
FGD	flue gas desulphurisation
GW	gigawatts
HE	heat exchanger
HENS	heat exchanger network synthesis
HP	high pressure
IEA	International Energy Agency
IEA CCC	IEA Clean Coal Centre
IEAGHG	IEA Greenhouse Gas R&D Programme
IP	intermediate pressure
kJ	kilojoule
kPa	kilopascal
kW	kilowatt
kWh	kilowatt hours
LHV	lower heating value
LIGA	Lithographie, Galvanik und Abformung (German acronym for lithography, electroplating and moulding)
LP	low pressure
MEA	monoethanolamine
MJe	megajoules electrical
MOO	multi-objective optimisation
MPa	megapascals
MW	megawatts
MWe	megawatts electrical
MWth	megawatts thermal
PC	pulverised coal
PCC	pulverised coal combustion
PMV	pressure maintaining (control) valve
USC	ultra-supercritical
US DOE	US Department of Energy

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1 Introduction

Incorporation of carbon dioxide (CO_2) capture systems will be required on coal-fired power plants to address concerns over climate change. The maximum net electrical output from a coal-based power plant employing currently available CO_2 capture and compression technologies will be significantly lower than that of a similar plant firing the same quantity of coal without capture. This is because some of the energy – thermal and electrical – produced at the plant will be needed to operate the CO_2 capture and compression processes. One of the most tested systems for capture of the CO_2 from pulverised coal combustion plants is chemical absorption of the gas from the flue gases using a solvent, and the commonest suggested reagent for this purpose is an aqueous solution of monoethanolamine (MEA). The solvent will have to be regenerated to release the CO_2 as a concentrated stream for storage as well as for recycling of the solvent. The energy required for this will be provided by a major extraction of steam from the power plant, reducing generation, while the additional auxiliary power demand will directly reduce the net electrical output.

While good chemical engineering practice means that, after giving up its heat, the condensed steam would ultimately be returned to the main feedwater flow, closer examination of the changed energy flows in a CO_2 capture plant has pointed to ways to further reduce the energy penalty of incorporating CO_2 capture: some heat that would otherwise be rejected by the capture plant could be re-used. However, a constraining factor is the low-grade nature of much of the heat that is available. Economics must play a part in selecting the optimum solutions, but there is definite scope for some worthwhile utilisation. The additional approaches to energy utilisation by the CO_2 capture plant, and recovery of energy from it, form the subject of the present report.

There are other potential means to reduce the energy penalties of CO_2 capture, for example, employing improved solvents and using totally different capture technologies, such as membranes. However, reconsidering the scope for better integration can be relevant to these also.

Recently, heat exchanger network synthesis (HENS) has become a tool for optimising heat exchange between multiple streams of plants, and its application to CO_2 capture is reported. There are also a number of breakthrough technologies, including heat exchangers with micro-channels and those using novel materials, such as ceramic matrix composites, that might be considered for some components. In the course of this review, such systems were investigated, but there appear to be limited possibilities of taking advantage of these technologies in this sphere. Other approaches to saving energy include using a new type of CO_2 compressor, and this is also discussed.

Although not within the scope of this review, it is also possible to supply the energy required for solvent regeneration by other means entirely, for example, using a separate coal- or gas-fired boiler, which could itself be fitted with a CO_2 capture system. Another way could be to use a gas turbine in a windbox system, where the gas turbine's partially oxygen depleted flue gases are used as combustion air in the coal-fired plant (Sanchez del Rio and others, 2013). This could maintain, or even increase, the site power output.

The gas turbine could be integrated with the existing coal plant in various ways to supply the heat and the power required for the capture systems. The post-combustion capture plant on the final flue gases would capture the CO_2 from both processes in a single system. Such repowering, without CO_2 capture, has been applied in Germany to increase efficiency, but not yet combined with CO_2 capture.

This report is structured in the following way. In Chapter 2, an introduction is given to post-combustion CO_2 capture systems by solvent scrubbing. Chapter 3 contains descriptions of work on heat integration. Chapter 4 reviews some developments in novel heat exchangers, novel CO_2 compression systems and other areas. The overall summary and conclusions are in Chapter 5.

2 Post-combustion CO_2 capture systems

In this chapter, a summary is provided of the configuration of post-combustion capture using solvent scrubbing without advanced heat integration. For more details, the reader is referred to other IEA Clean Coal Centre reports (*see, for example*, Davidson, 2007, 2009, 2012). There is also an introduction to the issues concerning heat integration with the host plant.

2.1 General configuration of post-combustion capture systems using scrubbing

Figure 1 shows an outline of generic post-combustion CO_2 capture on a coal-fired plant using solvent scrubbing. The key feature is that the CO_2 is scrubbed from the flue gases after they emerge from the essentially conventional gas cleaning systems. Although the coal-fired power unit appears to be unchanged, there are important modifications that have to be made to produce a workable system. In particular, the CO_2 capture system requires substantial inputs of energy to operate.

In solvent scrubbing systems, a solvent consisting of an aqueous alkanolamine (generally referred to in this context, simply, as an amine) solution is contacted at about 40°C with the cooled flue gas in an absorber, where the CO_2 reacts with the amine and is thereby chemically captured. The CO_2-rich solvent is then passed to a stripping column (desorber), where the absorbed CO_2 is released as a concentrated stream by adding heat to reverse the chemical reaction of capture. Substantial quantities of steam have to be taken from the main plant to provide heat for the stripper reboiler, because major flow rates of reagent are needed for absorbing the quantities of CO_2 produced in combustion, plus the fact that the specific energy of regeneration is high. The stripping column typically operates at around 120°C and 0.15 MPa, and the steam extracted from the power plant, which needs to be at adequate temperature and pressure, is taken from the IP/LP crossover pipe. The CO_2-lean solvent is recirculated to the absorber after cooling, by heat exchange with the CO_2-rich solvent as well as through further cooling, to about 40°C. In addition, additional electrical power is drawn, to drive fans and pumps and to compress the CO_2 typically to over 10 MPa for transport as a supercritical fluid to geological storage. The cooling duty of the site can be significantly increased as a result of adding CO_2 capture systems.

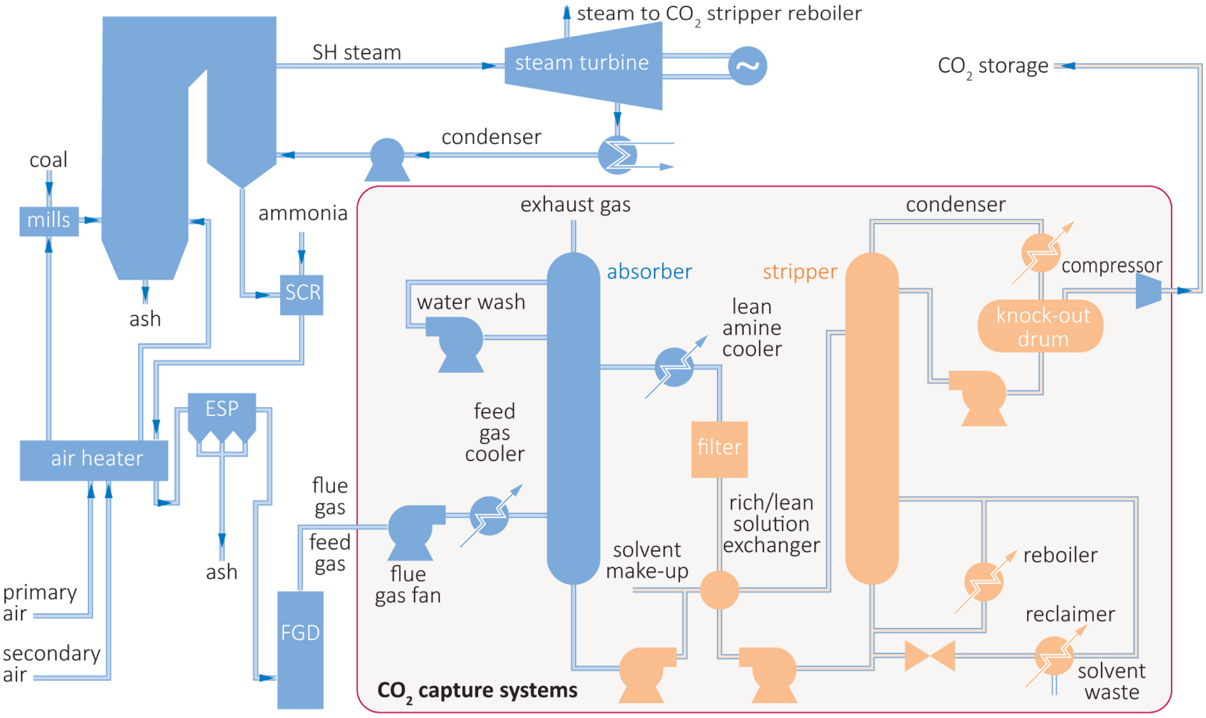

Figure 1 Simplified diagram showing post-combustion CO_2 capture on a coal-fired plant using solvent scrubbing (capture systems section based on Davidson, 2007)

2.2 Effect of adding CO_2 capture systems on efficiency

The energy usages and losses associated with the CO_2 capture systems will impact on plant output and efficiency in a major way, with up to 30% loss of efficiency in the absence of full heat integration. This can be equivalent to a percentage points decrease in efficiency of 12–13%. The steam extraction has the greatest effect, in the form of lost output, as extraction of up to 50% of the steam that would normally enter the LP turbine cylinder can be necessary to feed the CO_2 capture systems (Xu and others, 2014). The loss of power output from the turbine typically accounts for about two thirds of the overall energy penalty of post-combustion capture, the remainder consisting of electrical power needed for the pumps, fans and compressors. However, there is considerable scope to lessen the energy penalties, particularly through utilising in the water-steam cycle some of the low-grade sources of heat that will exist within the capture plant. This will then reduce the required rate of steam extraction and associated drop in gross power. This report looks at the studies by various workers to achieve this improved heat integration. A literature search of papers and other proceedings from the last five years showed that there was considerable activity in the field up to about 2013. There was work at a reduced level in the following few years, with less activity currently, as the main issues have been identified and commercial demonstration plants are needed to develop them further.

The main scope for better heat integration lies in exploiting the low-grade heat availability in certain streams of the CO_2 capture and compression systems. Some recent studies have considered the application of heat pumps in different forms. Different situations, locations and coal types will have marked effects on the possibilities for integration. For example, in some locations, very low temperature heat availability could be used as part of the input to district heating systems, while, in tropical regions, the availability of cooling in the condenser is more limited, increasing condensate temperature and reducing the amount of heat that can be recovered. In others, for example Australia, taking in additional heat from solar thermal equipment has shown promise for limiting the increase in specific coal requirement.

There are also ways to reduce energy usage in solvent scrubbing through changing to alternative solvents that have lower chemical energies of regeneration, but the MEA solvent appears still to be widely regarded as very suitable for first generation capture plants. For example, it was selected in the FEED (front end engineering and design) study of CCS demonstrations at Longannet power station in the UK (IEAGHG, 2013) and for the ROAD project at Maasvlakte Power Plant 3 in Rotterdam in the Netherlands. It was selected for the latter as representing the most extensively characterised solvent (for example, with respect to degradation and emissions) (GCCSI, 2012). Changing the solvent changes the temperatures of heat requirements and availability also. In the majority of the studies reviewed in this report, MEA was the solvent.

Ahn and others (2013) summarise the situation regarding using alternative solvents with lower heat of reaction in order to reduce the energy consumption for solvent regeneration as follows:

While significant effort has been devoted to [alternative solvents], such approaches mostly result in an increase in the size of columns and other equipment in the amine process to compensate for the weak reactivity. This makes it difficult to apply these solutions to large sources emitting flue gases at very high flow rates. In this respect, MEA (monoethanolamine), which is relatively cheap and has very strong reactivity to CO_2 even at very low CO_2 partial pressures, is still being considered as a first choice in designing an amine process for CO_2 capture from coal-fired power plants.

Neveux and others (2013a and 2013b) have pointed out that improved heat integration and consideration of alternative absorbents should be considered together, because solvent properties affect the integration possibilities: for example, the solvent's temperature of thermal degradation may limit conditions that can be used in the stripper column.

Table 1 shows the inlet and outlet temperature ranges of some major heat sources and sinks for a pulverised coal combustion plus CO_2 capture plant from a heat integration assessment by Hanak and others (2014) of a 660 MWe supercritical unit in India. Associated heat availabilities or sinks are included in the table.

Table 1 Temperatures of heat sources and sinks for a pulverised coal combustion plus CO_2 capture plant of 660°MWe (Hanak and others, 2014)

Stream	Inlet temperature, °C	Outlet temperature, °C	Associated heat change, MW
Hot streams			
Lean solvent	122.3	40.0	−928.45
CO_2 compressor intercooling (8 stages)	82.1–84.5	40.0	Total of −46.38
CO_2 cooling	82.1	33.0	−6.31
Stripper overhead condenser	107.8	40.0	−278.44
Cold streams			
Rich solvent	50.7	105.9	642.00
LP feedwater	46.5	151.5	71.20

The temperatures here apply to the particular situation, naturally, but they are broadly similar to data from other sources (for example, from Harkin and others, 2012a; Pfaff and others, 2010). The table is included here to illustrate the challenge with utilisation of the heats, in that there are large quantities available, but that their temperatures are not high.

In their paper, Hanak and others (2014) provide a valuable summary of integration improvements by several workers to date. The position of steam extraction greatly influences the performance of the integrated system, and the point at which the reboiler condensate is returned to the steam cycle is also important. The reboiler condensate has particularly to be returned at a point of similar temperature range to minimise the exergy (available energy) loss. Duan and others (2012) highlight that, while an optimal option for obtaining the saturated steam for stripper heating may be to extract it from the LP turbine within a pressure range between 0.18 and 0.28 MPa, so using the lowest quality steam available to match the energy requirements, most existing steam turbines do not have an extraction point in this pressure range. As already observed, taking steam at a higher pressure from the crossover pipe that connects the IP and LP turbines is the generally accepted solution.

Novel CO_2 compression systems could potentially reduce the cost and overall efficiency penalty of CO_2 capture. An example of this is shown later (in Chapter 4), where revisions to heat integration configurations can then be made, as the temperature ranges of available heat are changed.

3 Integration studies

This chapter consists of a review of detailed studies (all in simulation) of heat integration of post-combustion solvent scrubbing CO_2 capture plants on pulverised coal power units. The work, by its nature, can involve complex modelling and calculation procedures. The accounts here are necessarily abbreviated introductions to such studies, to illustrate as far as possible the principles involved and progress achieved, while minimising detail that might otherwise obscure.

3.1 General integration studies

The various investigators in the field have tended to arrive at similar key areas to consider, but there are naturally variations. This first section discusses, as examples, the work of four research groups that have worked on integration. The work of other researchers appears in succeeding sections.

The interplay of different factors on the CO_2 capture retrofit efficiency penalty is shown in work by Liebenthal and others (2011) at Hamburg University of Technology, Germany. These researchers modelled a state-of-the-art 1015 MW (net output, before capture) 28 MPa/600°C/620°C USC plant with an IP/LP crossover pressure of 0.39 MPa, retrofitted with 90% CO_2 capture. Commercial software (EBSILONProfessional® 8.00) was used to develop a detailed model of the overall process. They calculated the effect of using different stripper reboiler temperatures in the range 70–160°C and steam extraction rates between 190 and 960 MWth.

This work can be used to illustrate the way the extraction steam pressure is selected. For the typical reboiler temperature of 120°C, Liebenthal and others (2011) assumed the feed steam at the reboiler to be at 130°C, assuming a (conventional) 10°C temperature approach in the heat exchanger. This temperature corresponds to a pressure for the saturated steam of 0.27 MPa at the inlet. For a typical pressure loss of 0.04 MPa in the connecting pipe, a steam pressure of 0.31MPa would then be required at the crossover. The temperature would be above saturation. To ensure that steam could be provided at the necessary pressure, a throttle and/or a pressure control (or, as called in this paper, a pressure maintaining valve – PMV) would normally be needed (*see* Figure 2). The throttle would take the pressure down for use by the reboiler if it operated at a lower temperature, while the pressure control valve would keep pressure to the reboiler higher if a higher reboiler temperature were needed (Liebenthal and others, 2011). The valves would also allow variable load operation, while keeping to a required steam condition at the reboiler. This is discussed in Section 3.2. Note that many modellers have referred to the pressure control valve added before the LP cylinders as a throttle, also. Since the crossover steam is above saturation temperature, energy in this superheated steam may be exploited using a heat exchanger for LP feedwater heating or a let-down turbine – *see* Section 3.3.1.

Incorporation of the above components can have effects on the overall energy penalty that may not be immediately expected. For example, for reboiler temperatures between 130°C and 160°C, the power generation loss actually decreased with increasing rate of steam extraction due to lower losses in the pressure control valve. For reboiler temperatures below 130°C, the power generation loss still decreased with increasing steam extraction when the pressure in the IP/LP crossover pipe was sufficient for solvent regeneration, but when the pressure control valve needed to be activated, the generation decrease increased with increasing steam extraction (Liebenthal and others, 2011).

An interesting observation was that using a plant's existing cooling system to provide the required additional 30% in cooling duty from adding CO_2 capture could result in an increase in condenser pressure. However, if instead an additional cooling system were to be installed, the condenser pressure could decrease because steam flow to the condenser is lower with CO_2 capture. Either of these possibilities could require modifications to the LP turbine.

Not all is unexpected: the power drawn by the CO_2 compressor decreased for the higher reboiler temperatures associated with higher inlet pressures, and, as a result, the cooling duty of the CO_2 compressor decreased at higher inlet pressure (Liebenthal and others, 2011). But it was also noted that power plants with different design pressures in the IP/LP crossover pipe exhibited different characteristics with regard to generation decrease and that operation at part load would affect the results.

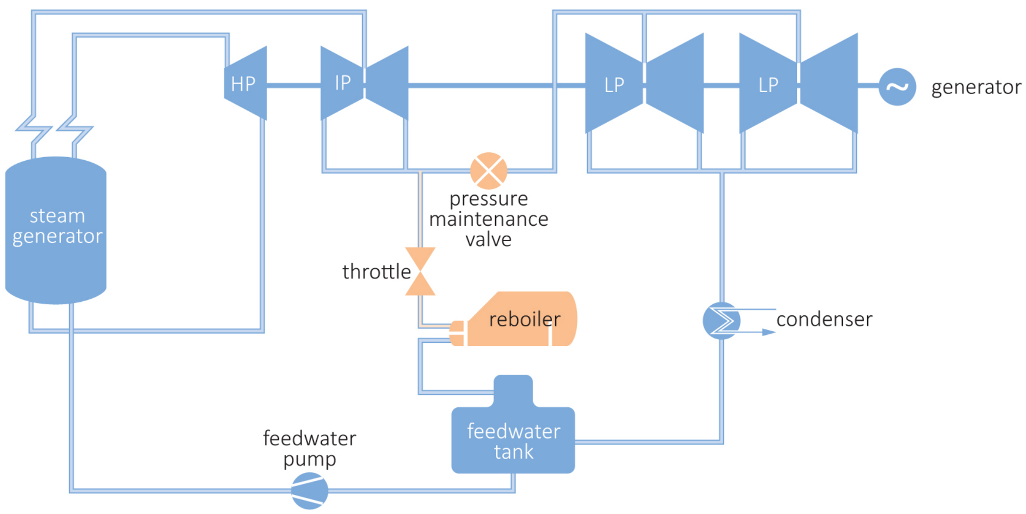

Figure 2 Location of throttle and pressure control (maintaining) valve (Liebenthal and others, 2011)

Lucquiaud and Gibbins (2011a), at the University of Edinburgh, UK, showed that advances in integration had, by 2011, resulted in the electricity penalty decreasing from 410–470 kWh/tCO_2 to 280–320 kWh/tCO_2. They then carried out further analyses in considering, among other aspects, the assessment of alternative chemical absorption solvents. Their model was used to calculate the overall net electrical output penalty as total kWh of lost output per tonne of CO_2 captured, including ancillary power and compression, for likely example combinations of solvent energy of regeneration, solvent regeneration temperature and desorber (stripper) pressure. The range of solvent regeneration temperatures considered was actually similar to those examined by Liebenthal and others (2011) – from 90–170°C.

Integration features included return of the reboiler condensate to the water circuit of the power plant at as high a temperature as possible at an intermediate point in the LP feedwater heating train, rather than the main condenser, and using low-grade heat from the compressor intercoolers and from the reflux condenser cooling the CO_2 leaving the solvent desorber to heat feedwater leaving the condenser (*see* Figure 3). The temperature of the condensate return will depend on the solvent used and on the pressure ratio of the compression train, and this would affect the position for addition back to the feedwater flow.

Lucquiaud and Gibbins (2011a) also showed that use of vapour recompression on the moist CO_2 product stream (while omitting the use of the stripper overhead condenser shown in Figure 1) could be worthwhile, but was unlikely to be advantageous for solvents regenerated at lower temperatures (120°C and below).

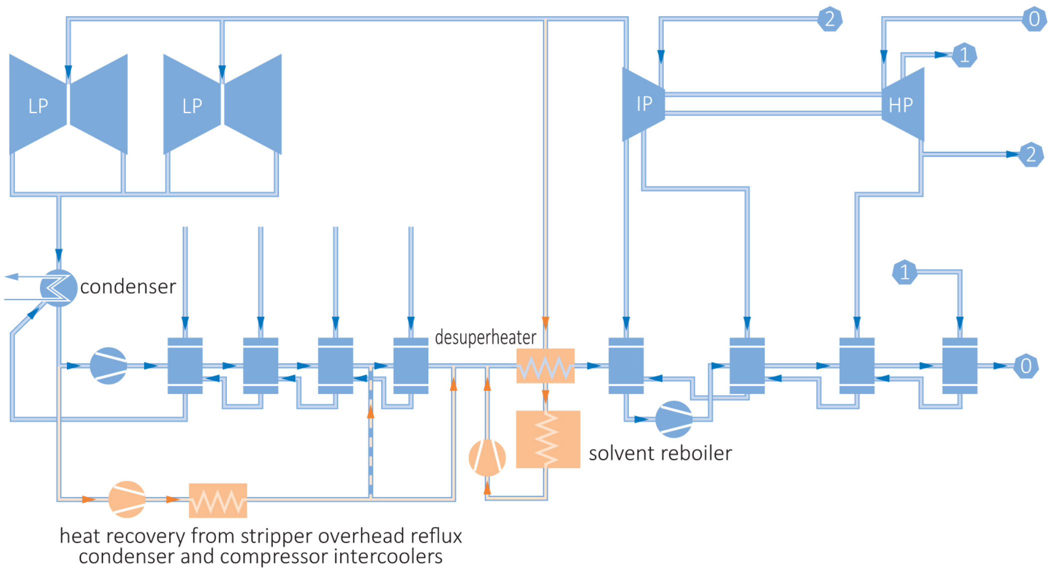

Figure 3 Steam cycle of plant with heat integrated from the capture and compression plant (Lucquiaud and Gibbins, 2011a)

Pfaff and others (2010), at Hamburg University, also identified the intercoolers of the CO_2 compressor and the stripper overhead condenser as suitable locations to extract waste heat from CO_2 capture systems at reasonable temperature levels (*see* Figure 4 and Table 2). The water wash cooling was necessary to ensure water balance. The results and data on the compressor intercoolers are discussed later in Section 3.8. Without integration, Pfaff and others (2010) had predicted a moderate efficiency penalty of 10.63% points compared with the equivalent non-capture plant. Recovering the waste heat of the stripper overhead condenser by preheating the LP boiler feedwater stream to a temperature of ~90°C, and by bypassing LP feedwater heaters 1 and 2, reduced the energy penalty and increased the efficiency of the overall capture retrofitted plant by 0.31% points.

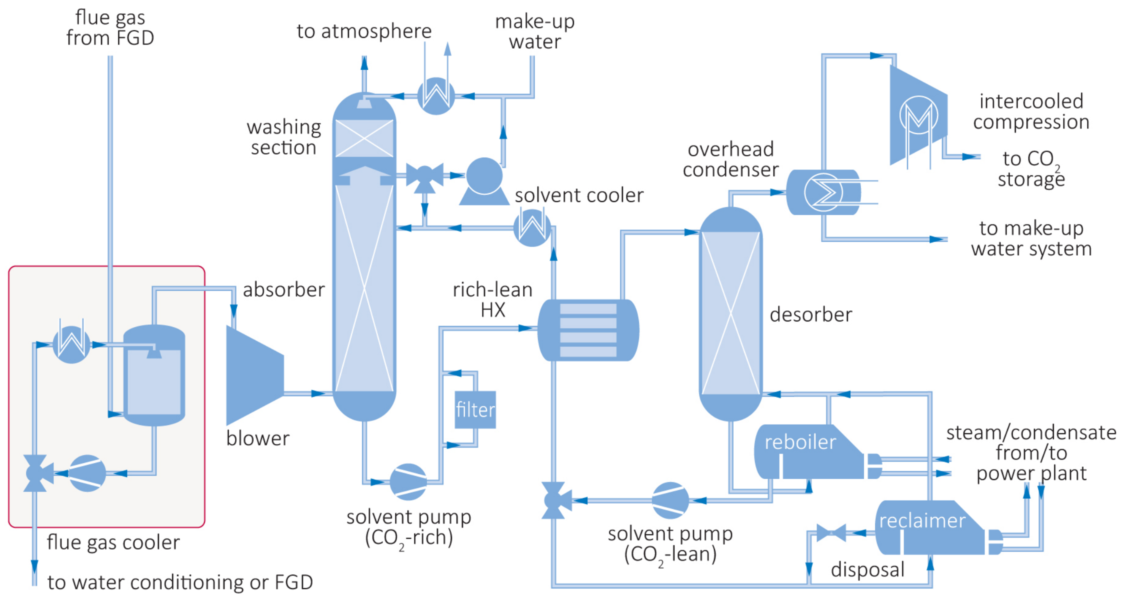

Figure 4 Simplified flowsheet of CO_2 capture unit (Pfaff and others, 2010)

Table 2 Quantities and temperatures of available heat from CO_2 capture on a 600 MWe gross reference plant (Pfaff and others, 2010)

Location (*see* Figure 4)	**Upper temperature, °C**	**Lower temperature, °C**	**Available heat, MWth**
Flue gas cooler	29.8	23.0	79.7
Water wash cooler	46.8	24.4	210.0
Solvent cooler	49.3	40.0	48.8
Stripper overhead condenser	105.7	40.0	98.2
Total			436.7

There was found to be a limited choice of places to use the waste heat because of the low LP feedwater flow, but preheating the combustion air was identified as a possibility. In combination with feedwater preheating, the gain in efficiency was up to 1.02% points. To achieve heat transfer to combustion air, LP feedwater would be heated in the stripper condenser then passed to a heat exchanger to heat the air before being returned to the water-steam-cycle. This would allow the steam bleed to the normal steam air heater to be closed, leading to an increase in power output as well as an efficiency gain of ~0.29% points. The flue gas would need to be split so less was used for air heating, with some of it used to preheat feedwater. By maximising the use of the waste heat for heating the combustion air, the efficiency gain could be raised to 0.52% points.

It was found that the total heat rejected to cooling water was higher by 39.0% than for the same plant without capture. Only one third of the total cooling duty of the CO_2 capture-fitted plant occurred in the main condenser of the plant, since only about half of the steam mass flow remained after extraction for expansion in the LP turbine. The remaining cooling duty was for the CO_2 capture and compression systems. An increase in the cooling water temperature gain from 10°C in the base case to 25°C (considered possible, and corresponding to a cooling water outlet temperature of 43°C) would lead to an increase in net efficiency of 0.23% points (Pfaff and others, 2010).

Ahn and others (2013), at the University of Edinburgh, used process flowsheeting in Honeywell UniSim to evaluate ten configurations, eight of them based on literature and two using alternative systems, for amine post-combustion CO_2 capture on a subcritical (16.7 MPa/565.6°C/565.6°C) unit. The plant was based on a detailed configuration described in a major US DOE study including CO_2 capture (US DOE, 2007). The IP/LP crossover pressure was 1.2 MPa, and this was reduced to 310 kPa by a let-down turbine and a desuperheater in the bleed steam flow to the reboiler, to suit the stripper reboiler temperature of 120°C, with an approach temperature of 14°C.

The base case absorber/stripper configuration, including the let-down turbine, reduced the net HHV efficiency of the power plant, compared with no capture, by 9% points (from 36.9%). One of the alternative designs, using an advanced amine process, and combining many of the enhancements in the literature configurations (*see* Figure 5), achieved the same 90% capture rate with a reduction in steam consumption of up to 37% as a result of these perhaps rather complex changes. However, CO_2 compressor power was increased, and the overall net efficiency of the cycle was just 0.9% points higher than for the base CO_2 capture case.

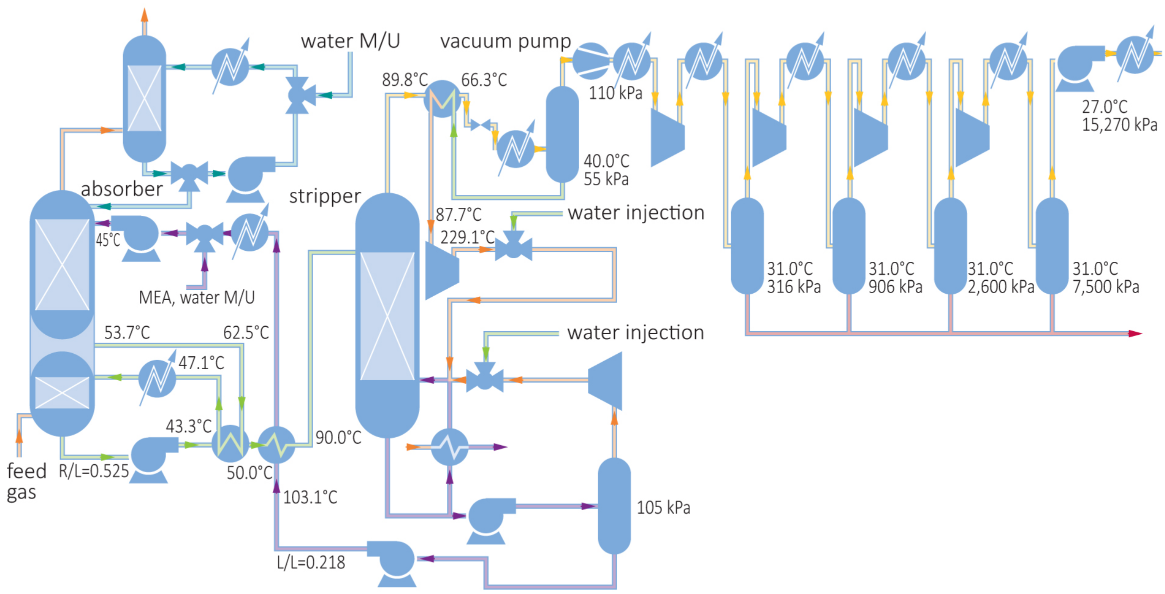

Figure 5 Schematic diagram of multiple modifications (absorber intercooling, condensate evaporation and lean amine flash) (Ahn and others, 2013)

3.2 Allowing for plant flexibility

Variable load operation is associated with steam turbine pressure changes, and this has to be allowed for in the design of a CO_2 capture plant, to avoid unacceptable variations in the quality of steam supply to the stripper reboiler. For the planned Maasvlakte 3 ROAD CO_2 capture retrofit, this will be achieved by taking the steam supply from different available extraction points as the load changes (GCCSI, 2012). However, designing for operation at variable load would normally be done by keeping to the crossover as the point of steam extraction and using other means. Pfaff and others (2010) suggest installing pressure governing (control) and throttling valves, both to protect the turbine and to optimise efficiency (option (c) in Figure 6). In their modelling work, on a new 600 MWe gross (before capture) unit, this was assumed, together with spray injection of reboiler condensate for attemperation for a crossover pressure of 0.55 MPa. They decided not to use a let-down turbine, a method frequently suggested, citing reduced flexibility and greater investment cost. This is in contrast to a suggested advantage of let-down turbines for providing flexibility with *retrofitted* CO_2 capture, as described by Lucquiaud and Gibbins (2011b) (*see* Section 3.3.1).

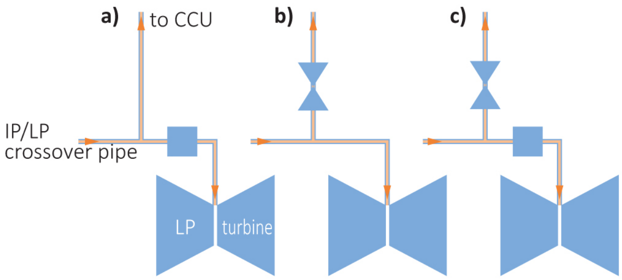

Figure 6 Options to maintain the reboiler steam pressure at different loads. a) steam extraction pressure governing valve; b) steam bleed with control (throttling) valve at reboiler branch pipe; c) combination of a) and b) (Pfaff and others, 2010)

3.3 Retrofitting CO_2 capture to existing units

Lucquiaud and Gibbins (2011b) have examined the retrofitting of post-combustion capture to coal-fired plants that had not been specifically designed to accommodate CO_2 capture (ie not 'capture-ready'). The extracted steam would first be passed through a heat exchanger to recover the superheat available for feedwater heating (similar to the configuration shown in Figure 3), before use of its latent heat in the reboiler to release the CO_2. The condensate from the reboiler would be returned to the water-steam cycle at a point after the low pressure feedwater heater train. Again, as other workers such as Pfaff and others (2010) have found, some heat would also be recoverable from the CO_2 stream leaving the stripper column and from the CO_2 compressor intercoolers, for feedwater heating.

3.3.1 Effect of steam turbine parameters of original plant on efficiency penalty from CO_2 capture

While low plant efficiency and poor performance with capture, compared to new-build projects, are often regarded as barriers to CO_2 capture retrofits, the work of Lucquiaud and Gibbins (2011b) indicated that steam turbine retrofits could allow surprisingly good integration for a wide range of steam turbine designs. Another conclusion was that, with effective heat integration, the abatement costs were independent of initial plant efficiency, rendering a wider choice of retrofit sites as suitable than had hitherto been assumed, including at subcritical plants. This was for using the same coal, with constant boiler efficiency and cooling system conditions and identical steam extraction pressures and capture unit designs. Then, the amount of heat extracted from the steam cycle and the ancillary power for capture for the same fuel input remained the same. The analyses showed that initial plant efficiency, could have no significant direct effect on the efficiency penalty in percentage points of a capture retrofit. Moreover the effects of site-specific parameters were said to be likely to be small compared to the influence of the capture system characteristics.

However, note the condition that the steam extraction pressure is the same for the subcritical and supercritical plants. That condition appears unlikely to be met in many cases, because existing coal-fired plants have a wide range of crossover pressures. This can necessitate adding valves, as discussed earlier. However, backpressure let-down turbine(s) may alternatively be incorporated (*see* Figures 7 and 8). For maximum upgradability, flexibility and efficiency, CO_2 capture retrofits need to leave the full steam swallowing capacity of the LP turbine available without using additional valves. Using a pressure control valve leads to part-load efficiency being reduced more at part load than at full load, as throttling losses at the LP turbine inlet increase because less steam is flowing to the turbine at part-load (Lucquiaud and Gibbins, 2011b; Linnenberg and Kather, 2009).

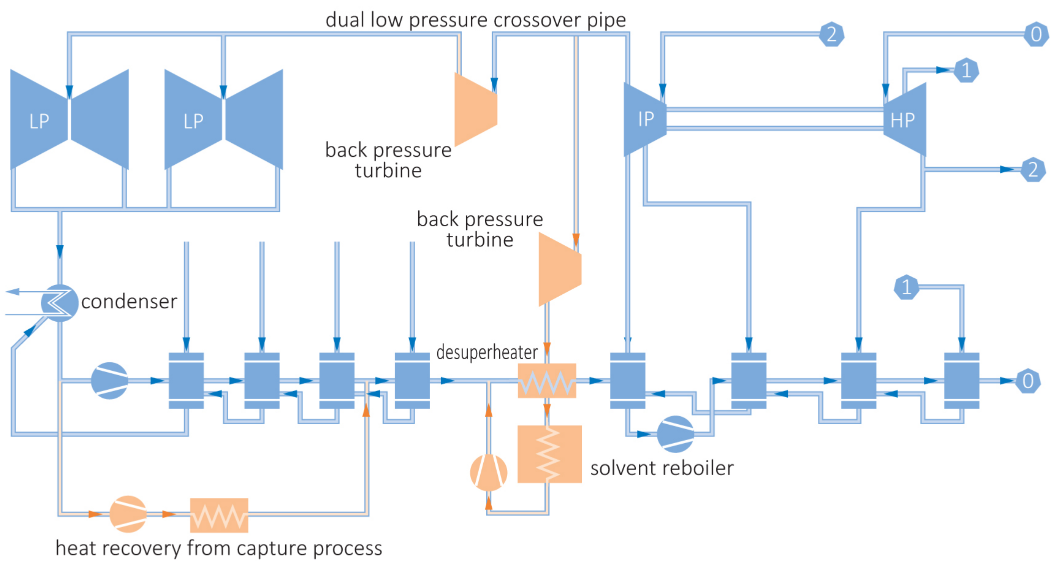

Figure 7 Steam turbine CO_2 capture retrofit with a fixed IP turbine outlet and two let-down back-pressure turbines (Lucquiaud and Gibbins, 2011b)

In the configuration shown in Figure 7, with a fixed IP turbine outlet pressure, the let-down turbine at the inlet of the LP turbine would be bypassed if capture were to be temporarily suspended for a short term increase in power. At capture levels between 0 and 90% both additional turbines would be partially bypassed. In the configuration shown in Figure 8, the supply pressure to the reboiler is not controlled by a valve but rather by the amount of steam extracted at the IP outlet. At intermediate capture levels the crossover pressure would float, and the let-down turbine would be throttled. To keep the figures simple, the bypasses and valves are not shown.

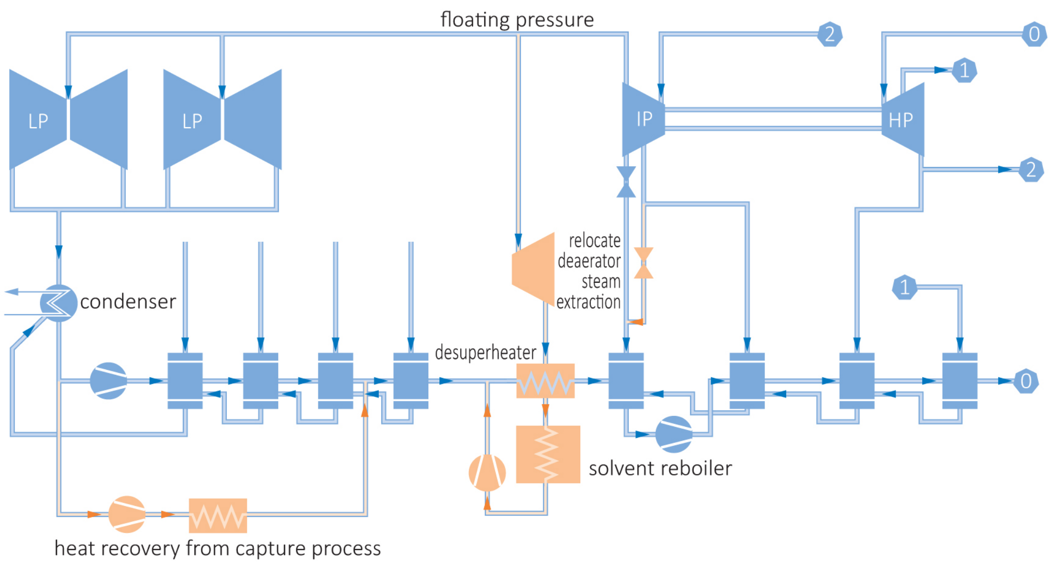

Figure 8 Steam turbine CO_2 capture retrofit with a floating intermediate pressure turbine and a let-down back-pressure turbine (Lucquiaud and Gibbins, 2011b)

Lucquiaud and Gibbins (2011b) analysed these options using gPROMs software. The solvent regeneration temperature was the typical 120°C, the temperature difference in the reboiler was 15°C and the pressure drop from the turbine to the reboiler was 0.05 MPa. The modelling results at a 90% capture rate are shown in Figure 9 for a range of initial (before capture) crossover pressures, both with and without heat recovery from the capture and compression units.

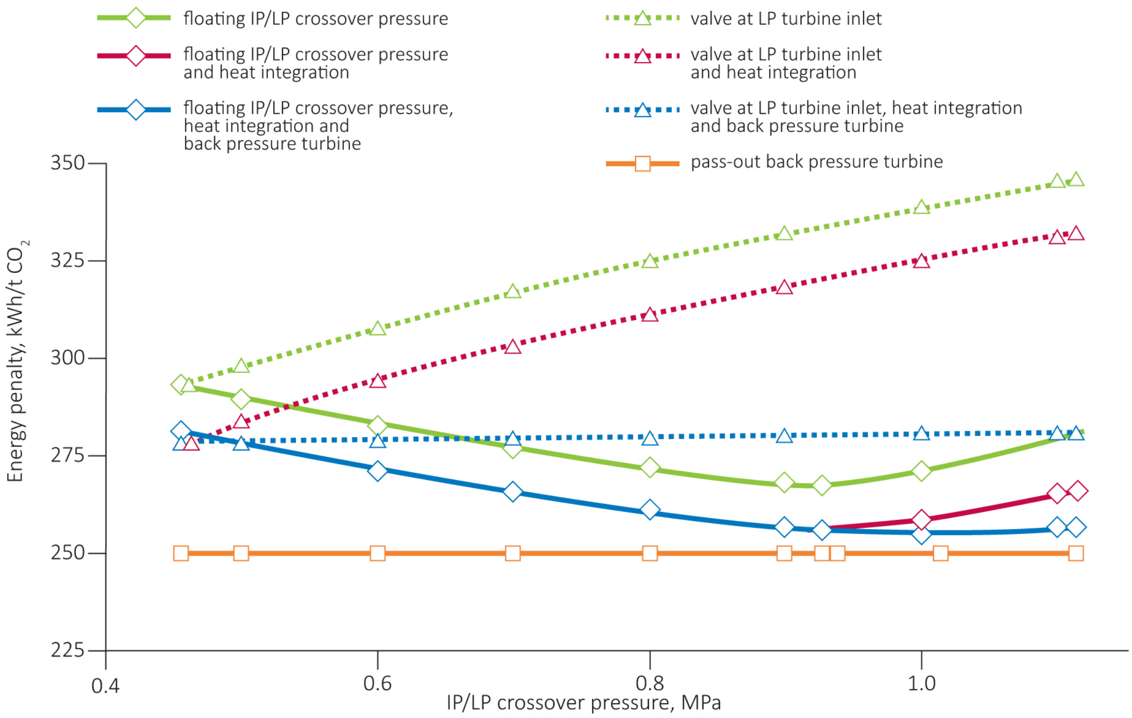

Figure 9 Comparison of performance of steam turbine CO_2 capture retrofit options for a range of steam cycle configurations (Lucquiaud and Gibbins, 2011b)

Included in Figure 9 are the results of analysis of another option using a pressure control valve, based on a study by the US DOE, described by Ramezan and others (2007). In that case, flow through the LP turbines was throttled using a pressure control valve to maintain the IP outlet pressure (*see* Figure 10). The energy penalty was independent of the IP turbine outlet pressure. There was a throttling loss in the valve of 30 kWh/tCO_2 compared to the option in Figure 7 with two let-down turbines. The floating pressure system with a back-pressure turbine in Figure 8 provided a constant energy penalty of 257 kWh/tCO_2 for pressures above 0.9 MPa.

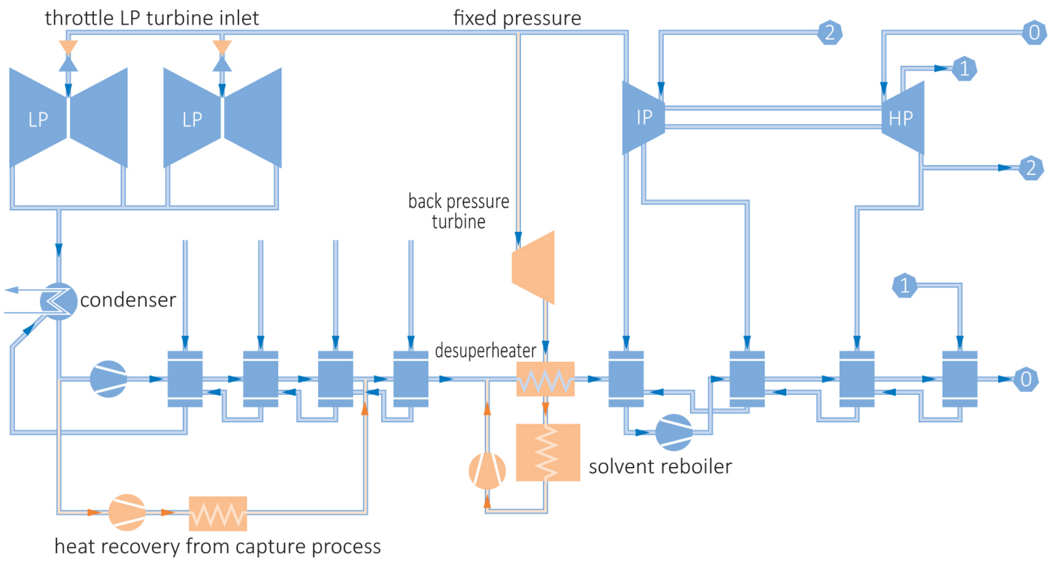

Figure 10 Steam turbine CO_2 capture retrofit with a fixed crossover pressure and a let-down back-pressure turbine (Lucquaud and Gibbins, 2011b)

The dual back-pressure turbine system could provide spinning reserve to the grid if the LP back-pressure turbine were bypassed, allowing more steam flow to the LP turbine. The floating pressure system would also be able to change the steam flow to the LP turbine. In both cases, flow to the reboiler would also need to be regulated by a throttle valve upstream of the back-pressure turbine. In retrofits, allowing the IP outlet pressure to float could put excessive stresses on the blading and, for single-flow systems, could lead to excessive end thrust, so this would need to be addressed in design.

Sensitivity studies showed that an increase in pressure drop along the pipework to the reboiler of 0.05 MPa increased the energy penalty, so the authors suggested that the possibility of locating the solvent stripper close to the turbine island could be considered.

3.4 Incorporation of heat pumps

The effect of raising the temperature of recovered heat by employing heat pumps has also been assessed. Duan and others (2012) used Aspen Plus software to develop models of a power plant with MEA-based CO_2 capture in various configurations. One of these (i) included a let-down turbine in the bleed steam supply, while another (ii) used a let-down turbine together with AHT (Absorption Heat

Transformer) and AHP (Absorption Heat Pump) equipment. AHT is a modified form of AHP. The work showed that the efficiency of a 600 MW coal-fired power unit (based on one of the 24.2 MPa/566°C/566°C supercritical units at Guigang, Guangxi Province, China), when retrofitted with MEA systems for 85% CO_2 capture, could be penalised by as little as 6% points.

In the first arrangement, incorporating the let-down turbine only (Figure 11), a throttling (pressure control) valve is also used to protect the IP and LP turbines, as discussed earlier. Crossover pressure was around 0.9 MPa.

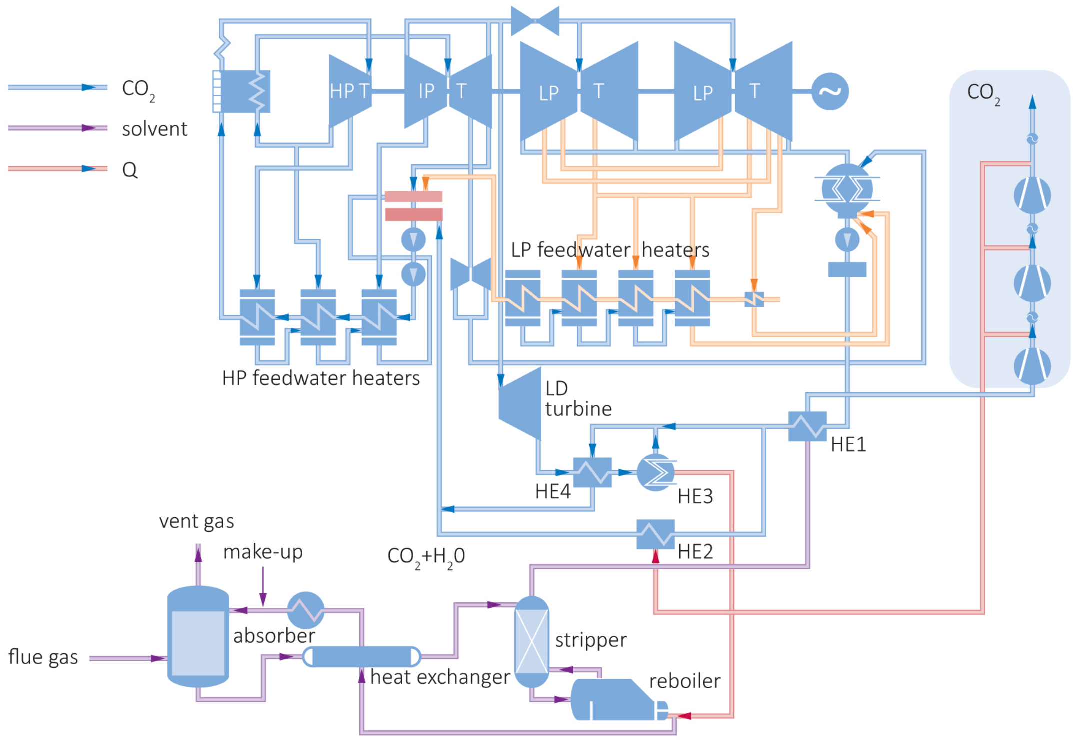

Figure 11 Steam-water schematic for PCC + CO_2 capture using let-down turbine (Duan and others, 2012)

New heat exchangers (HE1-HE4, using heat from the CO_2 compressors and trimming the reboiler steam temperature) take the place of the existing LP feedwater heaters, which here are taken completely out of use.

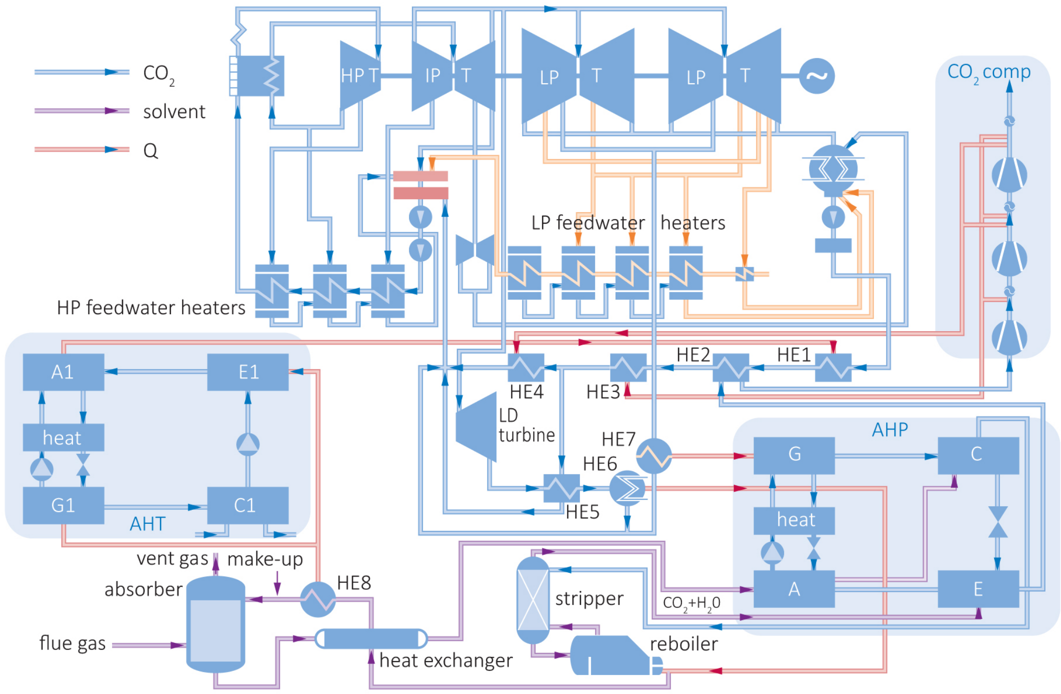

Figure 12 Steam-water schematic for PCC + CO_2 capture using AHT/AHP (Duan and others, 2012)

Features of the second configuration (Figure 12) include heat extraction from the gases leaving the stripper to supply heat to the evaporator of the AHP then to HE2 for heating the feeding water leaving HE1. Heat to the latter comes, via the AHT, from the solvent feed to the CO_2 absorber column. The AHP, driven by the steam extracted from the turbine, converts part of the lower grade heat from the stripper gases to higher grade heat for raising the temperature of rich solvent before it enters the stripper. The simulations showed that this reduced the energy needed for solvent regeneration from 2.83 GJ/tCO_2 to 2.14 GJ/tCO_2. The extraction steam flow was decreased from 30% of the original specified flow to the LP turbine cylinder to only 18%. The latter also obviated the need for throttling, with its attendant losses. Another feature was the utilisation of the CO_2 compressor inter-cooling heat in two ways as shown in the diagram. Table 3 shows the results of the simulations of the two configurations. Efficiencies are believed to be on an LHV basis. The heat pumps increased the net efficiency by around 2% points.

Table 3 Predicted performance of configurations with and without heat pumps (Duan and others, 2012)				
	Unit	PC	PC+CCS	PC+CCS+AHT
Gross power	MW	604.30	533.16	564.6
Aux power consumption excl CO_2 capture	MW	30.22	30.22	30.22
CO_2 capture	MW	–	21.28	25.69
CO_2 compression	MW	–	28.62	28.62
Aux power consumption including CO_2 capture	MW	30.22	80.12	84.53
Net output	MW	574.09	453.04	480.1
Net efficiency	%	40.28	31.79	33.69
Efficiency penalty	% points	–	8.49	6.59
CO_2 removal ratio	%	–	85	85
CO_2 emissions (gross)	g/kWh	566.3	94.9	89.6
CO_2 avoided (gross)	g/kWh	–	535.3	505.5

Another approach to reducing the steam requirement for the CO_2 stripper reboiler employing heat pumps was assessed in preliminary simulations by Reddick and others (2014a,b). Here, steam ejectors were woven into a heat pump arrangement with the CO_2 stripper and reflux condenser system, with some steam injection directly into the stripper. Figure 13 shows the basic configuration of an ejector heat pump. The primary working fluid, at a relatively high pressure, enters the ejector through the primary nozzle along the central axis. The secondary fluid (from the evaporator), at a pressure lower than the primary fluid, enters the annular chamber around the primary nozzle and is drawn in by the flow of primary fluid. Thermal energy applied to the generator causes heat from the lower temperature at the evaporator to be moved to the higher temperature at the condenser inlet.

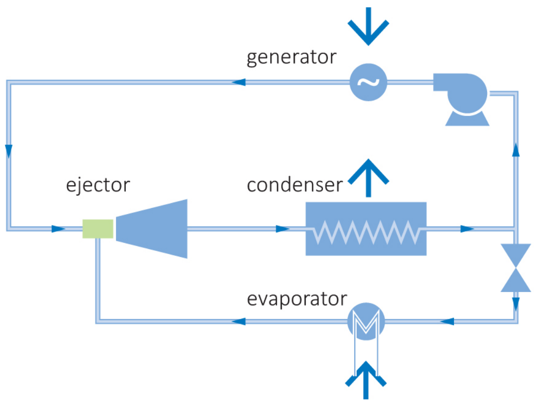

Figure 13 Ejector heat pump (Reddick and others, 2014a)

Figure 14 shows the ejector heat pump integrated into the CO_2 stripper systems. The waste heat is assumed to be available at up to 100°C. A flash tank, heated with the waste heat and used to create the secondary steam to the ejector, here plays the role of the evaporator. The motive steam entering the primary nozzle of the ejector originates from the stripper overhead reflux condensate, first preheated with waste heat in the primary steam preheater, and further vaporised using plant steam in the primary steam generator. The stripper overhead condenser serves the same purpose as the condenser in Figure 13. The thermal energy entering the primary steam generator causes heat at the lower temperature of the flash tank to be fed at a higher temperature to the stripper.

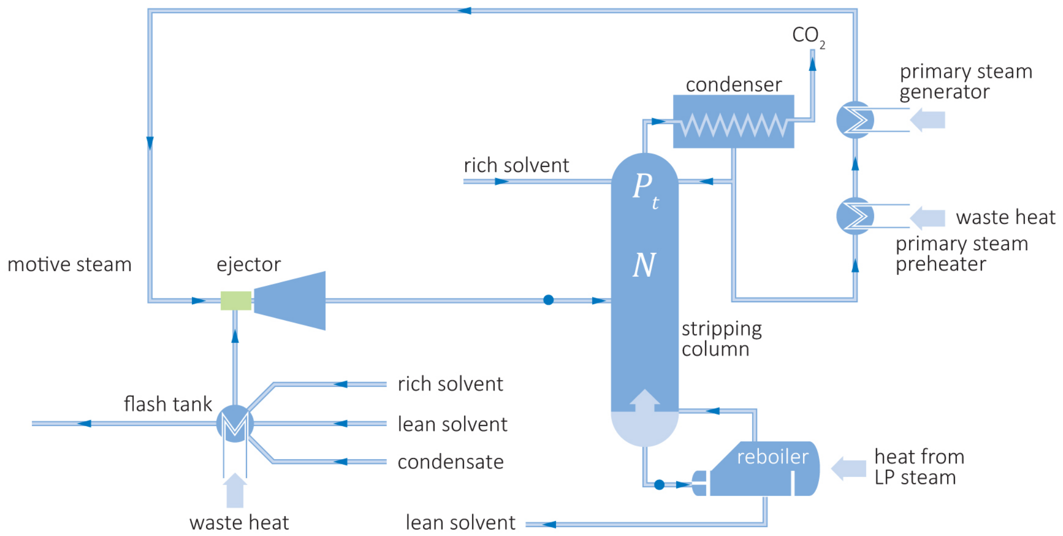

Figure 14 Ejector heat pump integrated into CO_2 stripper (Reddick and others, 2014a)

Modelling showed that ejector integration could give 10–25% reductions in the amount of steam required from the power plant. The best results occurred when the steam injected into the stripper was sent to the bottom of the tower. Three alternatives for the source of the liquid to the flash tank were considered: stripper reflux condensate, CO_2-lean solvent and CO_2-rich solvent. Of these, the last was not worthwhile. Various proportions of lean solvent taken off for sending to the flash tank were simulated. Results indicated that the greater the ejector outlet flow rate, the lower the quantity of valuable steam requiring extraction from the main water-steam cycle.

The use of steam ejectors to upgrade the heat in CO_2 capture systems has also been examined in Aspen Plus simulations based on a reference plant (before CO_2 capture) of 1000 MWe by Xu and others (2014). In this case, the low pressure steam to be upgraded in the inter-connected steam ejectors was from existing LP feedwater bleed steam extraction points on the LP turbine as well as steam flashed from the reboiler condensate (*see* Figure 15 for the configuration). Steam extracted from the 1.11 MPa crossover provides the higher pressure steam feed (the working fluid) to the ejectors, while a portion (14%) of flash-off water is mixed with the emerging steam (by then at a pressure of 0.27 MPa) before feeding to the reboiler of the flash tank to utilise the steam's surplus heat. Table 4 shows the parameters (temperatures, pressures and mass flows) of the steam ejectors.

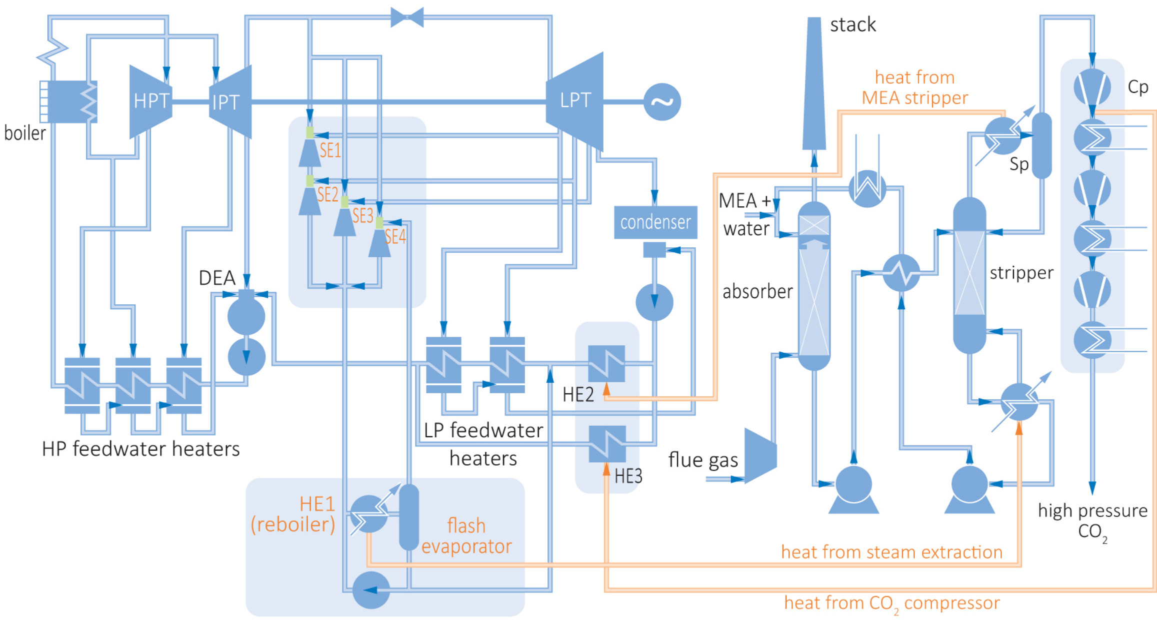

Figure 15 Use of steam ejectors in heat integrated flowscheme (Xu and others, 2014)

Table 4 Steam ejector parameters (Xu and others, 2014)

Item	Stream	Temperature, °C	Pressure, MPa	Flow, kg/s
Steam ejector 1	4^{th} stage extracted steam	393	1.11	36.94
	5^{th} stage extracted steam	306	0.39	32.50
	Mixed steam, ejector 1	351	0.5	69.44
Steam ejector 2	Mixed steam, ejector 1	351	0.5	69.44
	6^{th} stage extracted steam	227	0.19	40.00
	Mixed steam, ejector 2	305	0.27	109.44
Steam ejector 3	4^{th} stage extracted steam	393	1.11	47.22
	7^{th} stage extracted steam	155	0.089	9.17
	Mixed steam, ejector 3	351	0.27	56.39
Steam ejector 4	4^{th} stage extracted steam	393	1.11	64.44
	Flash vapour	96.4	0.089	13.50
	Mixed steam, ejector 4	338	0.27	77.94

The rest of the flash-off water is sent to the inlet of one of the LP feedwater heaters. Low-temperature heat from the CO_2 capture process would also provide input heat, as indicated in the diagram.

The net LHV efficiency of the CO_2 capture configuration without the ejectors, at 27.2%, was 16.3% points lower than that of the non-capture plant, which was 43.6%. In this totally non-integrated case, no heat from the CO_2 stripper condenser or from the CO_2 compressors was used. With the integration of such heats and the use of the ejectors, the efficiency penalty of CO_2 capture was reduced by 4.91% points, compared with non-integration, and net power was increased from 596.7 MW to 704.3 MW.

An economic analysis indicated that the system would add only 0.31% to the total investment cost, so that the cost of CO_2 avoided would be 33% lower. Of course, not all of the benefit came from the ejectors, as CO_2 compressor and stripper overhead condenser heats were also used.

3.5 Studies based on an Indian supercritical plant

Hanak and others (2014) used Aspen Plus to simulate a 660 MW supercritical (24.22 MPa/537°C/565°C) coal-fired power plant in India fired on indigenous high ash coal, with CO_2 capture using aqueous MEA solvent. The general configuration modelled is shown in Figure 16. The location at which the reboiler condensate was returned to the steam cycle was shown to be important.

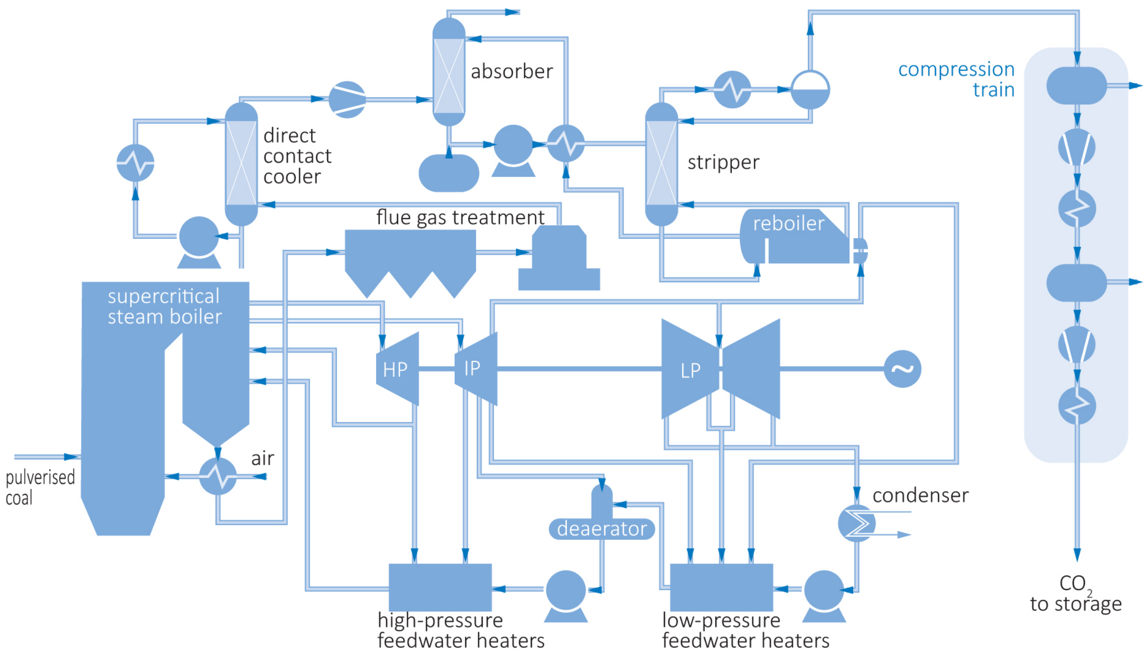

Figure 16 Simplified process flow diagram of CO_2 capture connected to a reference Indian supercritical plant (Hanak and others, 2014)

Initial assessment showed that the highest gross power was obtained when the reboiler condensate was returned to the fourth LP feedwater heater, so this was adopted for investigation of the integrated designs.

For the latter, Hanak and others (2014) considered the temperatures of the various streams (*see* Table 5) and used Aspen Energy Analyser to perform a pinch analysis and to plot composite curves for a mean temperature difference of 10°C for all the heat exchangers. Section 3.11 has more information on composite curves. The analyses showed that LP feedwater heating could be provided partially by waste heat from the capture and compression plant and that there was an opportunity also to use waste heat to preheat the rich solvent entering the stripper. No let-down turbine was mentioned in the descriptions.

Table 5 Hot and cold streams identified in advanced heat integration analyses on a 660 MWe supercritical plant in India (Hanak and others, 2014)

Stream	Temperature,°C		Specific heat, kJ/kg°C	Heat capacity rate, kW/°C	Heat load, MWth
	Inlet	Outlet			
Cold streams					
Rich solvent	50.7	105.9	3.48	11630.41	642.00
LP feedwater	46.5	151.5	4.25	677.80	71.20
Hot streams					
CO_2 intercooling 1	82.1	40.0	0.92	118.99	−5.01
CO_2 intercooling 2	81.6	40.0	0.92	117.6	−4.89
CO_2 intercooling 3	81.9	40.0	0.92	117.52	−4.93
CO_2 intercooling 4	82.3	40.0	0.93	118.74	−5.02
CO_2 intercooling 5	82.7	40.0	0.96	121.80	−5.20
CO_2 intercooling 6	83.3	40.0	1.01	128.29	−5.55
CO_2 intercooling 7	84.0	40.0	1.13	143.74	−6.32
CO_2 intercooling 8	84.5	40.0	1.67	212.40	−9.46
CO_2 cooling	82.1	33.0	1.01	128.50	−6.31
Direct contact cooling water	56.4	25.0	4.51	4186.86	−131.48
Lean solvent	122.3	40.0	3.51	11276.82	−928.45
Flue gas	130.0	35.2	1.06	702.50	−66.56
Stripper overhead condenser	107.8	40.0	17.8	4105.71	−278.44

Five scenarios were analysed in detail:

Case 1: Basic combination of supercritical plant with MEA CO_2 capture (no integration);

Case 2: Utilisation of the CO_2 compression unit waste heat for feedwater heating;

Case 3: Utilisation of flue gas waste heat for feedwater heating;

Case 4: Utilisation of the flue gas and CO_2 compression unit waste heat to preheat the rich amine solvent and for feedwater heating.

Case 5: A network developed for a mean temperature difference in the heat exchangers of 5°C, to explore best performance with respect to energy saving and total cost.

Pinch analysis was performed to identify heating and cooling targets, and thus, waste heat available for recovery in the system. Figure 17 is an example of the heat exchanger network design utilising flue gas and CO_2 compression unit waste heat to heat the rich amine solvent and feedwater (Case 4).

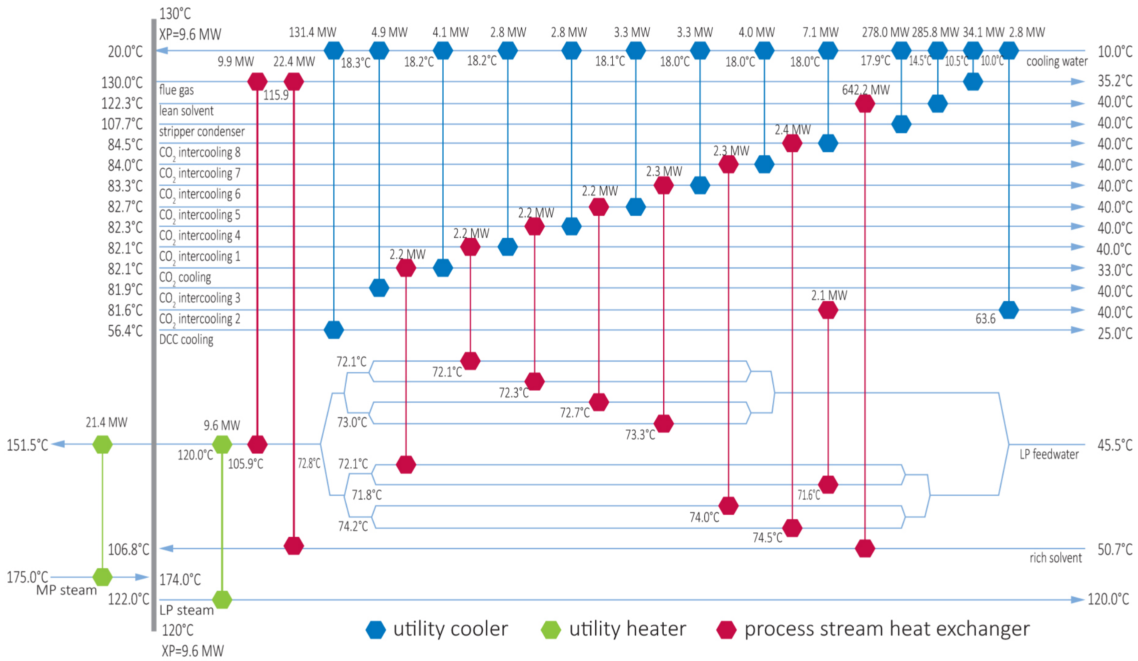

Figure 17 Heat exchanger network design for utilising flue gas and CO_2 compression unit waste heat to heat rich amine solvent and feedwater (Hanak and others, 2014)

Table 6 shows the predicted performance for all five cases. Without integration, the energy penalty was calculated at 25% (Case 1). Application of heat integration was limited by the high ambient temperature in India, so energy penalty savings from these measures were not major. The best design with respect to performance and economics utilised the waste heat from the flue gas (Case 3). Net efficiency was higher than for Case 1 by 0.41% points. Case 5 was slightly more efficient, but the additional capital cost related to reducing the mean temperature difference in the heat exchangers was not compensated by the higher revenue resulting from the reduced energy penalty.

Table 6 Predicted performance for reference Indian 660 MWe supercritical unit and CO_2 capture cases (*see text*) using various heat integration options (Hanak and others, 2014)

Parameter	Reference plant	Case 1	Case 2	Case 3	Case 4	Case 5
Gross power, MWe	660.11	548.65	549.87	555.09	553.55	555.84
Auxiliary power, MWe	49.26	90.46	90.50	90.56	90.54	90.97
Net power, MWe	610.84	458.19	459.37	464.53	463.01	464.87
Gross efficiency, %, LHV	42.20	35.08	35.16	35.49	35.39	35.54
Net efficiency, %, LHV	39.05	29.29	29.37	29.70	29.60	29.72
CO_2 specific emissions, g/kWh	829.75	110.62	110.35	109.11	109.47	109.03
Net efficiency penalty, % points	–	9.76	9.68	9.35	9.45	9.33
HEN indicators						
Heating utility fraction of target	–	3.333	2.498	1	1.448	0.841
Cooling utility fraction of target	–	1.065	1.042	1	1	0.996
Total cost indicator	–	0.823	0.798	0.656	0.736	0.677

3.6 Studies involving changes to the capture system configuration

Le Moullec and Kanniche (2011) compared various MEA CO_2 capture configurations from the literature, modelled as added to a supercritical plant of efficiency 44.5% LHV, net, in absence of capture. Different cases were compared to a reference MEA CO_2 scrubbing case representing good performance, with an 11.95% points efficiency penalty. This included the commonly suggested combination of a let-down turbine and subsequent heat exchange to feedwater, to leave saturated steam suitable for a reboiler operating at about 120°C. The study was mainly concerning modifications to the MEA process itself, for example including staged feed of the stripper: the following summary discusses those variants most relevant to this report.

An improved approach temperature for the lean/rich solvent heat exchanger (5°C instead of 10°C) was shown to allow a gain of approximately 0.15% points in overall efficiency. Used in conjunction with a stripper staged feed (*see* Figure 18), indications were that it could even offer a much greater gain of 1.5% points. Most of this would come from the revised stripper feed arrangement, which would be able to take advantage of the closer pinch. The latter involved heating only part of the rich solvent and feeding the cold flow near to the top of the stripper column.

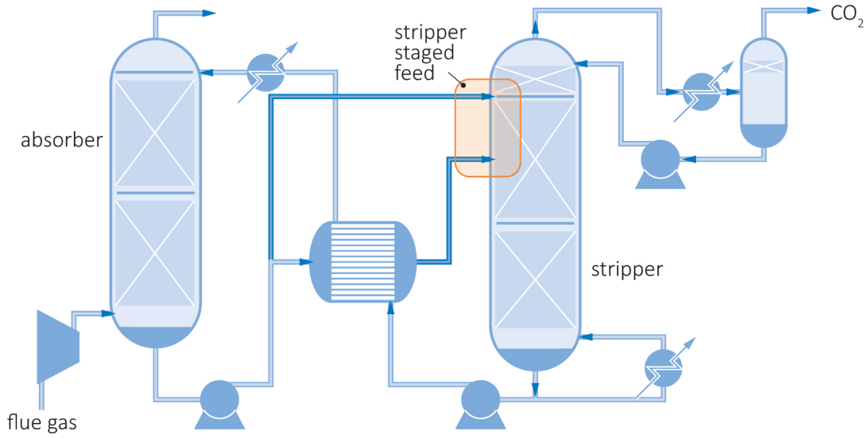

Figure 18 Stripper staged feed arrangement for a CO_2 capture system (Moullec and Kanniche, 2011)

Stripping under partial vacuum, to allow low pressure steam to be used to boil the solvent, resulted in more power being produced by the let-down turbine. Negative effects were increases in CO_2 compression energy and in the amount of steam needed for regeneration. Optimum pressure was 0.075 MPa (that is, a little below atmospheric), giving a gain of efficiency of approximately 0.7% points. The temperature to which the flue gas was pre-cooled before the absorber had a limited impact, resulting in a change of approximately 0.1% points for a 10°C change.

The authors found that an efficiency penalty of 9% points was achievable with the 'classic' MEA process by using combinations of modifications, but further gains, for example to reach many utilities' target of a maximum efficiency loss of 5% points, would need innovative solvents and configurations that would have the disadvantages of increased complexity and cost as well as low flexibility.

3.7 Future A-USC plants with CO_2 capture and heat integration

Stępczyńska-Drygas and others (2013) studied the incorporation of amine-based CO_2 capture on conceptual 900 MW advanced ultra-supercritical (A-USC) coal units (employing 700°C+ steam), for single and double reheat) using Ebsilon simulation software. For these future plants also, this confirmed that the crossover pressure had a significant impact on overall efficiency when CO_2 capture was incorporated *(see* Figure 19). At a reduced design crossover pressure of 0.33 MPa, the efficiency of the CO_2 capture-fitted units would be around 10.5–10.7% points lower than for the non-capture single reheat and double reheat plants, respectively. For partial load operation, throttling was again needed to ensure correct reboiler steam pressure, as was application of a pressure control valve to ensure appropriate steam pressure to CO_2 capture systems. The recovery of waste heat by preheating feedwater was also modelled, returning it before the third LP feedwater heater, with the other LP heaters bypassed. Waste heat from the CO_2 compressor intercoolers and stripper overhead condenser was also incorporated to increase the efficiency.

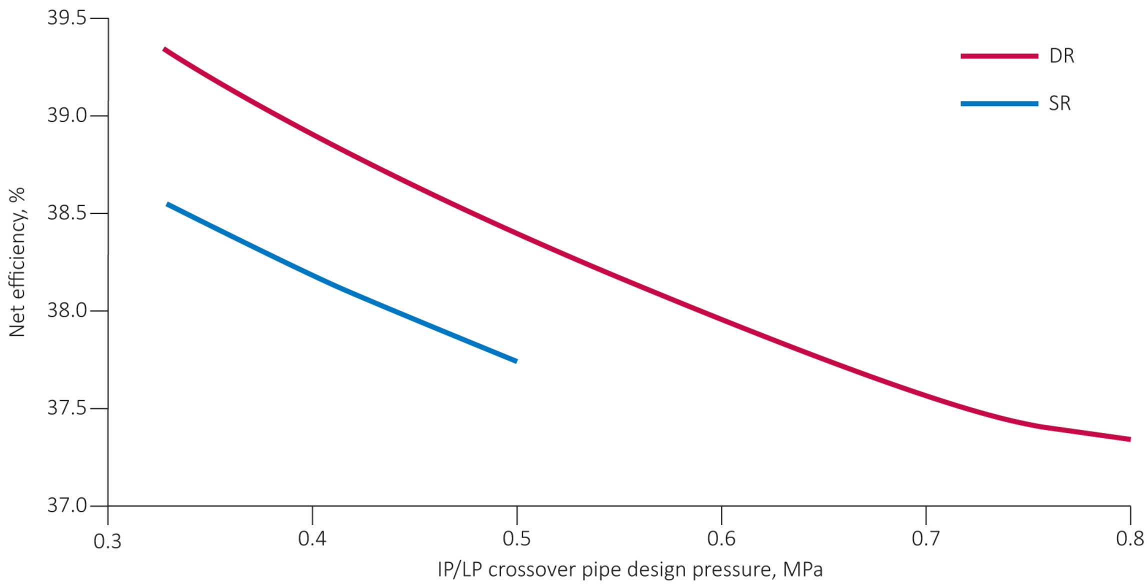

Figure 19 A-USC unit fitted with CO_2 capture – net efficiency as a function of IP/LP crossover pressure (Stpęczyńska-Drygas and others, 2013)

3.8 Utilising CO_2 compression heat effectively

Pfaff and others (2010) examined the effect of using different compression intercooling arrangements (Table 7). Omitting some intercoolers enabled the temperature level for waste heat recovery to be increased, although at the cost of higher power consumption by the compressor. Four cases of this were assessed:

- IC8_T40: Intercooling after each stage to 40°C (base case), with no waste heat recovery;
- IC8_T55: Intercooling after each stage to 55°C;
- IC4_T40: Intercooling after stage 2, 4, 6 and 8 to 40°C;
- IC2_T40: Intercooling after stage 4 and 8 to 40°C.

Using waste heat from the CO_2 compressor intercoolers raised the power plant net efficiency by up to 0.31% points. Using heat from the stripper condenser as well as the compression heat gave a net efficiency of 35.6% (LHV).

Table 7 Effect of varying the number of CO_2 compressor intercoolers in heat integration analysis of the CO_2 capture on a 600 MWe gross reference plant (Pfaff and others, 2010)

Identifier	No of coolers	Inlet temperature, °C	Outlet temperature, °C	Compressor power, MWe	Heat available, MWth
IC8-T40 (base case, no waste heat recovery)	8	76.7–86.7	40	28.8	53.8
IC8-T55	8	85.7–108.4	55	30.8	55.7
IC4-T40	4	80.4–133.3	40	31.6	56.5
IC2-T40	2	85.4–237.6	40	37.5	62.2

Witkowski and Majkut (2012) looked at various CO_2 compression options for post-combustion CO_2 capture applications for a 900 MW PCC plant to quantify their energy consumptions and usable heats of compression. To obtain heat at a sufficiently high temperature for useful integration, for example, in providing heat for the reboiler or boiler feedwater, the final stage of intercooling in the compressor was omitted in some of the options. This reduced the efficiency of the compressor, but it was compensated by the advantage of greater heat recovery and power optimisation in the plant.

CO_2 compression before liquefaction followed by pumping was among the variants analysed. This allowed compression and pumping energy to be lower than for compression only options, but the compression power reduction would be offset by the power decrease in the steam turbine (not assessed) as a result of steam extraction required to drive the refrigeration cycle. Another system examined used Ramgen's developmental advanced shock wave compression technology. This compressor has a very high pressure ratio, necessitating only two stages, and a potentially lower capital cost. The discharge temperature is moreover high (eg 250°C), aiding heat integration. Ramgen's compressor is described in Section 4.3.

3.9 Combined heat and power

The suitability of combined heat and power (CHP) as a means to improve heat utilisation is an option that is dependent on the available heat market. A study by Ziębik and others (2013) of CO_2 capture on a combined heat and power (CHP) plant with a back-pressure turbine simulated three cases:

- a reference system – coal-fired CHP plant with an extracting back-pressure turbine and oil-fired boiler covering the peak loads and providing stand-by;
- the above system plus CO_2 capture unit without recovery of waste heat;
- a CHP system with a back-pressure turbine of higher back-pressure than in the reference plant and with a peak oil-fired boiler: integrated with a CO_2 capture unit, recovering the waste heat both from the stripper reflux condenser and from the CO_2 compressor inter-stage coolers.

The CHP system's Energy Utilisation Factor, EUF (a measure of its overall efficiency), depended both on waste heat recovery and on the specific regeneration energy of the solvent. In the variant without waste heat recovery the index EUF dropped by 23–25% points, depending on the solvent's regeneration heat requirement (3.15–4.0 MJ/kgCO_2 removed). With waste heat recovery, the decrease of EUF was less severe, at 3.5–13.5% points, depending on the regeneration heat.

Kärki and others (2013) also examined the possibilities for CO_2 capture waste heat utilisation in CHP systems for municipal district heating supply and in steelmaking. The paper focused on the economics of these systems. The simulations included use of heat from CO_2 compression intercoolers to preheat district heating return water.

Xu and others (2013) included the possibility of integration of the heat from CO_2 capture for heating the circulating water used in neighbouring floor district heating systems to make use of the large quantity of heat released by the solvent cooler, which is at only 40–65°C (*see* Figure 20). Heat from the CO_2 compressor intercoolers was included for feedwater heating. The efficiency penalty of CO_2 capture was reduced from 14.8% points to 10.9% points by introducing CHP and heat integration measures in which the heat from the solvent cooler and the remaining energy from the CO_2 condenser were used to provide heat to the floor heating system. The configuration, including other heat integration links, is shown in Figure 21.

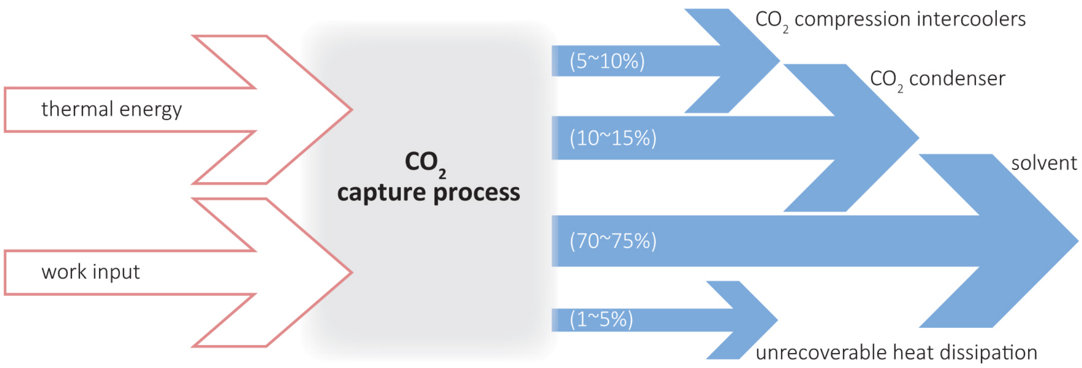

Figure 20 Relative energy flows of MEA-based CO_2 capture (Xu and others, 2013)

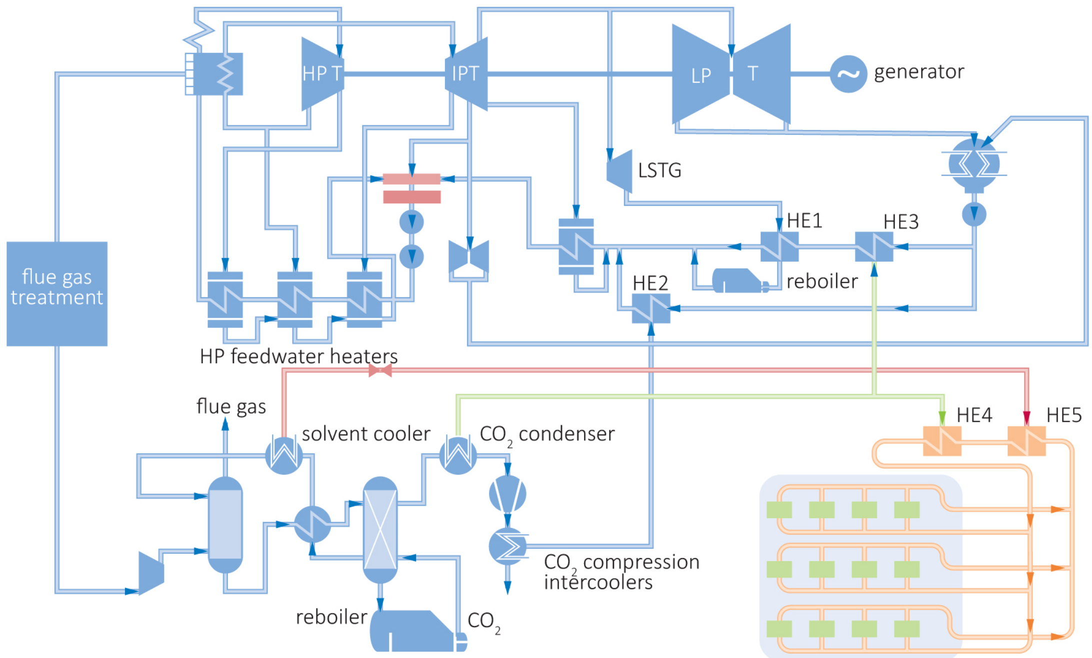

Figure 21 Integrated system with power generation, CO_2 capture, and district heating supply (Xu and others, 2013)

3.10 Addition of a low-temperature power generation cycle

Another way to use the low-grade heat from the CO_2 capture systems may be to add a separate, low-temperature turbine driven by a low boiling point fluid. A few years ago, Stankewitz and others (2009) simulated the incorporation of an ammonia cycle in a preliminary study (*see* Figure 22) for this purpose. However, there does not appear to be a great deal of activity in that sphere currently. The overall efficiency penalty of the capture systems on a new plant of efficiency 45.9% was predicted to be reduced from 12–13% points to 10% points.

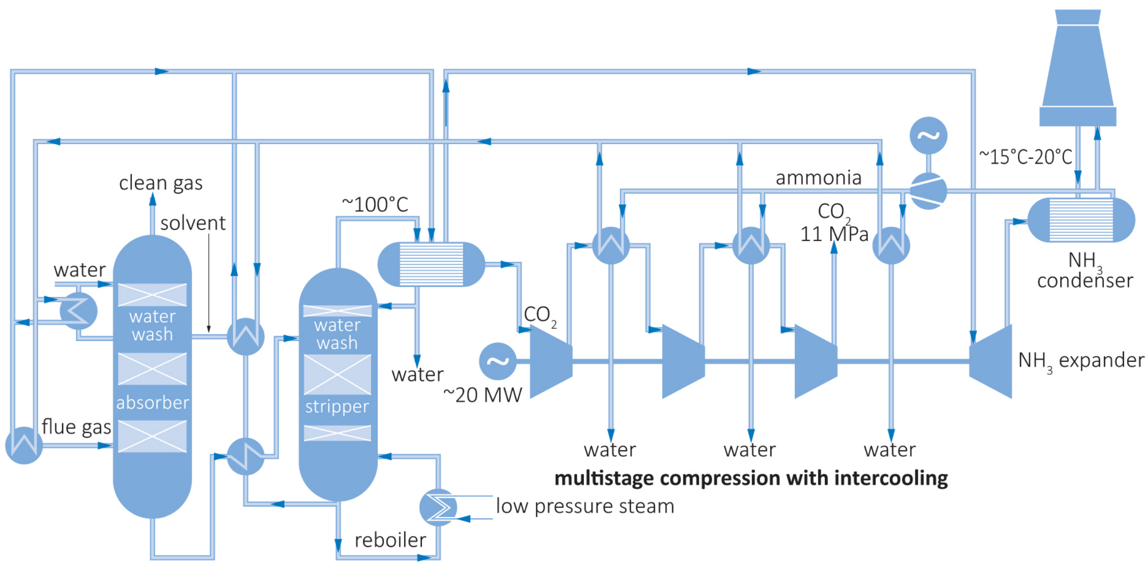

Figure 22 Incorporation of a low temperature ammonia cycle for low-grade heat utilisation (Stankewitz and others, 2009)

3.11 Lignite plants

Modelling studies carried out by Harkin and others (2009, 2010) used as a basis the 200 MWe and 500 MWe lignite-fired power units in operation in Australia. Aspen Plus was used in the first part of the analysis to develop models of the plants with CO_2 capture. Composite curves and pinch analyses were then employed to determine the potential for reducing the energy penalty and cost of retrofitted CO_2 capture. Composite curves place all hot and cold stream data on a single temperature-enthalpy diagram (*see* Figure 23 for an example). Pinch analysis allows energy flows from the hot streams to the cold streams to be maximised, while the use of the composite curves allows the utility requirements to be minimised for specified pinch temperatures.

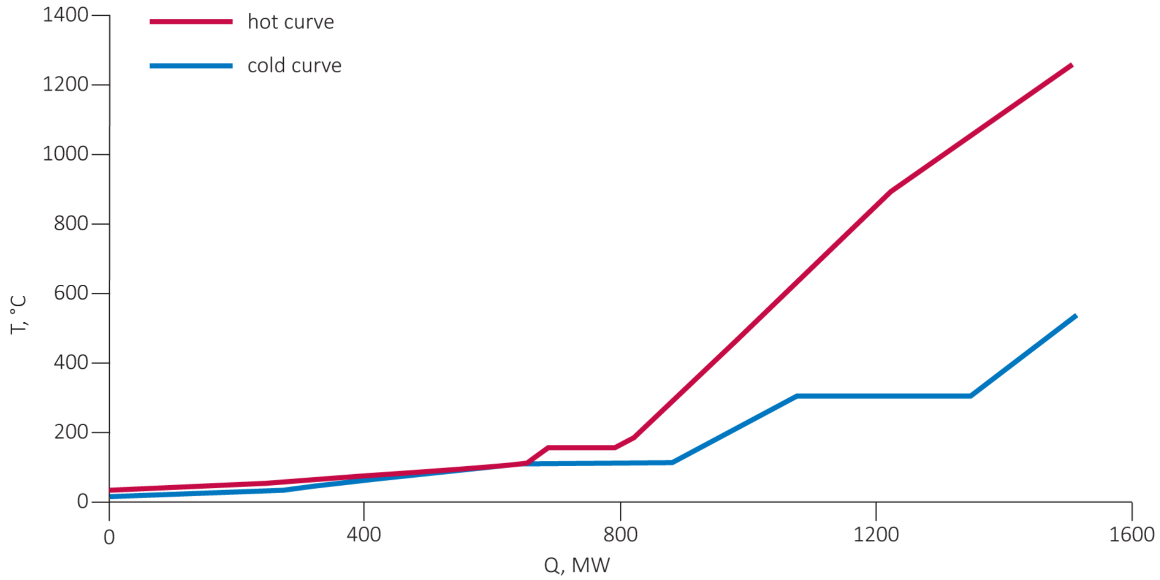

Figure 23 Example of composite curves (Harkin and others, 2010)

Because the extracted steam for providing the reboiler heat rejoins the steam cycle as condensate, this complicates the pinch analysis. An iterative approach to determining the outcome was therefore employed and it was assumed that all extraction steam would be cooled to the main condenser temperature.

Linear programming was used to minimise the amount of power decrease from the turbine, subject to a series of inequality equations based on the requirements that the extraction steam provides the energy at sufficiently high temperatures. The only variables were the flow rates of steam extracted at each steam condition.

A number of cases were examined for each size of unit:

1. Base case –existing plant with no FGD or CO_2 capture;
2. CCS – CO_2 capture and FGD with no heat integration;
3. Integrated CCS – CO_2 capture and FGD with maximum heat integration;

4. Retrofit – CO_2 capture and FGD but only allowing modifications downstream of the economiser on the flue gas and up to the deaerator on the boiler feedwater;
5. CCS and drying – lignite dewatering and CO_2 capture with maximum heat integration;
6. CCS/drying/increased steam – additional heat content in the pre-dried lignite used to produce steam which is utilised in an auxiliary turbine for additional heat and power.

For each case the amount of raw lignite fed to the plant was held constant and the amount and quality of steam produced from the boiler was constant for all but Case 6.

The results showed (*see* Table 8) that the energy penalty associated with CO_2 capture could be reduced by redesigning the power stations' heat exchanger networks and good use of the available waste heat and that, with heat integration and lignite pre-drying, a CO_2 capture retrofit may not incur the large energy penalties hitherto predicted.

Table 8 Predicted energy penalties for steam extraction to amine-based CO_2 capture for various options at two lignite-fired plant sizes (A=200 M; B=500 MW) (Harkin and others, 2010)

Case	Plant A						Plant B					
	1	2	3	4	5	6	1	2	3	4	5	6
Moisture content to mill, wt%	61	61	61	61	45	45	61	61	61	61	45	45
Steam production, kg/s	208	208	208	208	208	248	433	433	433	433	433	491
Steam extraction rates, kg/s – optimised using linear programming method												
HP exhaust	11	112	54	54	42	53	46	46	2.0	46	2.0	39
IP bleed 1	–	–	–	–	–	–	20	20	21	20	4	23
IP bleed 2	–	–	–	–	–	–	15	15	4	15	0	3
LP bleed 1	11	11	0.2	0.2	7	7	14	14	3	0	0	2
LP bleed 2	9	9	0	0	0	0	26	207	201	134	213	144
LP bleed 3	–	–	–	–	–	–	15	15	0	0	0	0
Power output – based on steam extraction rates given												
Gross power, MWe	220	172	205	205	208	203	520	441	509	484	524	481
Auxiliary power excluding compressor, MWe	14	22	22	22	22	23	30	44	44	44	44	44
CO_2 compression power, MWe	–	25	24	24	25	2*	-	45	45	45	45	2*
Net power, MWe	206	125	158	158	161	178	490	352	420	435	435	436
Efficiency, %net, HHV	23	14	18	18	18	20	28	20	24	25	25	25
Energy penalty, %	–	39	23.5	23.5	22	14	–	28	14	19	11	11
CO_2 emissions, kg/kWh	1.46	0.24	0.19	0.19	0.15	0.14	1.15	0.16	0.13	0.14	0.13	0.13

* offset by addition of auxiliary turbine

In a later study, examining the trade-off between costs and net power from addition of CO_2 capture, Harkin and others (2012a) carried out multi-objective optimisation (MOO) for a 500 MW lignite-fired unit. Aspen was used to develop enthalpy/temperature curves for the process streams. The overall model then worked out the sensible heat in the generation and use of steam and used linear programming to calculate the mass flow rates for maximum power. The study assumed equal ΔTmin values for all heat exchangers, optimised either for minimum cost or minimum loss of net power. Capital and operating costs were calculated from the output of the heat integration step.

In the final stage, the MOO program was used to analyse the trade-off between competing objectives. The case study assumed a CO_2 absorption system employing 30% potassium carbonate solution with rate-promotion, because it offered some advantages compared to amine processes for Australian lignite plants, although having a disadvantage of a higher energy of regeneration. The nine variables studied are shown in Table 9. Two optimisations were carried out, both including maximising the capture rate, one minimising efficiency penalty and the other minimising the differential cost of electricity (DCOE).

Table 9 List and range of variables used in the optimisations for potassium carbonate-based capture on a 500 MW lignite plant (Harkin and others, 2012a)

Variable	Unit	Range minimum	Range maximum
Solvent lean loading	mol HCO_3^-/mol K^+	0.11	0.416
Solvent flow rate	kg/s	800	5910
Solvent temperature	°C	40	71.5
Absorber feed gas temperature	°C	40	71.5
Stripper pressure	MPa	0.05	0.8165
Stripper feed temperature	°C	70	133.5
Absorber packing height	m	10	47.5
Stripper packing height	m	10	47.5
Heat exchanger approach temperature	°C	6	36

The study showed that 90% CO_2 capture without heat integration gave an energy penalty of 38% of value, with net power reduced to 310 MW. However, with maximum integration and optimisation, the energy penalty could be reduced to 14–16%. For minimal DCOE and cost per tonne of CO_2 captured the energy penalty was 25–30%. One oddity was that, because the original units were not designed for highest efficiency, it was found to be possible, when optimising for maximum net power, to add up to 40% CO_2 capture, yet achieve a *higher* efficiency than for non-capture. This was because of the opportunities for increased heat utilisation. In practice, such an approach was considered unlikely because it would require modifications to the turbine and generator.

Harkin and others (2012b) also carried out a multi-objective optimisation study of a 200 MW lignite-fired unit, but without an economic analysis. The MOO (*see* Figure 24 for structure) identified that the lean solvent loading and stripper pressure will have a large impact on net power output and amount of CO_2 captured.

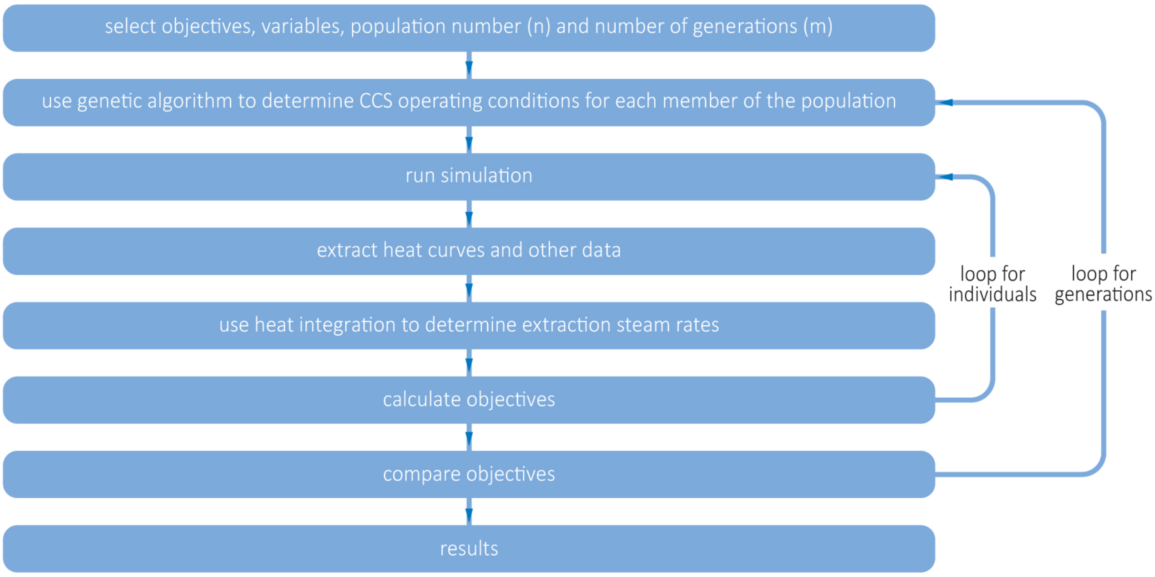

Figure 24 Structure of multi-objective optimisation sequence (MOO) using simulation and heat integration (Harkin and others, 2012b)

The paper showed the importance of optimising the whole process simultaneously. Both studies were rather specific to the types of plant studied, with their lack of FGD, low sulphur fuels and therefore particular appropriateness for use of potassium carbonate absorption for CO_2 capture. The 200 MW unit type was also an old non-reheat system, with no IP turbine.

3.11.1 Effect of incorporating lignite pre-drying

Lignite pre-drying is being developed to enable higher efficiencies, and so lower specific CO_2 emissions, in power generation from the fuel, as latent heat losses can be reduced. For information on lignite drying processes, the reader is referred to recent IEA Clean Coal Centre reports by Zhu (2012) and Dong (2014). Some of these processes, such as RWE's WTA fluidised bed lignite drying technology in its open cycle variant, use low pressure steam extracted from the power plant to perform the drying. This can make integration with amine-based CO_2 capture more difficult as there may be insufficient LP steam left to run the LP turbine, although another version of WTA uses compression of much of the liberated vapour for heat release and so would use less steam. Popov (2011) examined another lignite drying system, the DryFining process that does not need any steam and could utilise low temperature waste heat from the capture plant. His simulation of a 210 MW plant using such a system showed that all of the heating energy for drying the lignite (within the range 10–90% removal of the moisture) could be provided by the waste heat from the MEA scrubbing process. The penalty from addition of the CO_2 capture at 90% drying was consequently only 9.3% of value (efficiency was reduced from 32.9% LHV net to 29.8%). Further capacity and efficiency penalties reductions were predicted through using low-grade heat from the stripper reflux and compressor intercoolers and the condensate of the reboiler heating steam for combustion air preheating. Combustion air preheating could allow the high pressure feedwater heaters to be replaced by an additional economiser, allowing additional power to be generated from non-extracted steam. The net effect was predicted to be that the power plant's net efficiency (LHV) would fall only modestly, from 32.9% to 30.7% (Popov, 2011).

3.12 Comments

The heat integration work discussed here shows that the efficiency penalty of adding CO_2 capture using the most widely assessed system of aqueous MEA scrubbing on a pulverised coal power plant can be brought down by employing better heat integration by around a third. Actual outturn efficiencies depend strongly on the type of plant assumed and other circumstances such as location. Lignite-fired plants may offer additional opportunities for integration, especially if certain types of lignite drying can be applied. Simulations of the use of heat pumps using different implementations have also shown their potential. It should also be possible to accommodate flexibility in plants fitted with MEA CO_2 capture.

MEA scrubbing is likely to be the most frequently selected system in the first wave of commercial CCS plants. Further improvements will probably be achievable eventually by using more advanced solvents, but many of the same energy-saving principles currently identified are likely to remain applicable.

4 Alternative technologies for heat exchangers and compressors

The originally proposed scope of this study included consideration of new developments in heat exchangers and compressors, as possible technologies to use in improving heat integration in CO_2 capture systems.

Information from the preceding chapters shows that the types of heat exchangers that are needed have to use 'hot' streams with low to moderate upper temperatures (around 80°C to 120°C) for available heat and 'cold' streams with minimum temperatures higher than the temperatures to which the 'hot' streams need ultimately to be cooled. So there will always be a need also for cooling water streams. Heat duties are considerable, from the order of 10s of MWth to hundreds of MWth, (*see* Table 5 in Chapter 3). This does not present a problem with utilising conventional heat exchangers *per se*, but moving to very close temperature approaches could increase the heat utilisation and so improve efficiency somewhat, and the types of innovations briefly covered in this chapter may enable the costs normally associated with achieving close pinches to be moderated.

In a study for the US DOE of opportunities for waste heat recovery in industry (BCS, 2008), the authors identified a number of areas for RD&D in the field of heat exchanger development. Of these, those of relevance to post combustion CO_2 capture included:

- developing and demonstrating low temperature heat recovery technologies, including heat pumps, low temperature electricity generation, and new working fluids for more efficient recovery of low temperature heat;
- improving heat transfer through novel heat exchanger designs with increased heat transfer coefficients, including gas liquid heat exchangers;
- application of new recovery technologies such as solid state generation (thermo-electric devices).

The suggestions under the first bullet point have formed the subject of work by Reddick and others (2014a), Xu and others (2014) and Stankewitz and others (2009), discussed in Chapter 3. The items under the other two bullet points are briefly discussed below.

4.1 Micro-channel heat exchangers

Micro-channel heat transfer devices have smaller fluid channels than traditional systems, for example less than 1 mm diameter. Micro-channel heat exchangers may be made of metals, ceramic (such as alumina) or ceramic composite materials, and channels can be typically of 250–500 micrometre size. Manufacturing methods for the ceramic systems include LIGA processing, tape casting or injection moulding, followed by sintering. Manufacturing methods for metal heat exchangers include chemical etching and LIGA processing (Sommers and others, 2010; Le Pierres and others, 2011).

Attributes of micro-channel heat exchangers have been described (MBI, 2015) as including:

- volume reduction factors of 5 to 10 with weight reduction factors of 2 to 5;
- low pressure drops, enabling reduced pumping power;
- expanded integration possibilities, from using complex networks in a single device.

More particularly of use here, they can also permit achievement of very small temperature pinches. These characteristics mean that they might give a benefit in providing the heat exchange components within CO_2 capture plants. The overall effect on efficiency of a employing such components for closer temperature approaches would depend on the particular design of the system. An example where greater sensitivity has been predicted is for integration options employing modifications to the conventional CO_2 stripper system. This is the split feed arrangement referred to in Section 3.6 in the discussion of work by Le Moullec and Kanniche (2011).

Further development in micro-channel heat exchangers would be needed to scale up the technology for such applications. The current scale reached in the designs of such heat exchangers from research institutes such as MBI is of the order of 5–10 kW, for example in modules that use heat at rather higher temperatures. So despite their offering more compact modules with low pressure drops, their application in the area that we are concerned with is still some time away and they are not discussed further here.

4.2 Other methods of heat utilisation

Among other technologies not currently widely applied that could be used to recover the low grades of energy encountered in CO_2 capture systems, thermo-electrics and low temperature turbine cycles are possibilities if their economics can be improved. An example of the latter, using ammonia, was described in Section 3.10. Organic Rankine cycles are another possibility but unlikely to be sufficiently efficient in using the low temperature heat availability that concerns us here (around 120°C maximum).

4.3 CO_2 compression developments

Compression of the CO_2 is the necessary final step before the gas can be piped to geological disposal. Compression to supercritical conditions is likely to be the norm. The gas from the stripper overhead condenser would generally be at a pressure of around 0.15 MPa, while the final delivery pressure, ready for CO_2 transportation as a supercritical fluid, will be typically 11 MPa. For practical reasons, several stages of compression are needed to cover this overall pressure ratio of over 70:1 using normal equipment, with cooling after each stage. The intercoolers are needed not only to reduce the working temperature of the compressors, but also to reduce the electrical energy required (Harkin and others, 2010). Utilisation of the heat from the coolers was included in many of the integration studies described in Chapter 3.

The electrical energy consumed by CO_2 compression is considerable (for example, for a 400 MWe net plant, around 30 MWe), so it is worth evaluating alternative systems for their possible advantages. An alternative type of compressor to the conventional geared types has been designed that reduces the number of stages. This is the Ramgen system, based on ramjet aerospace technology. It uses shock wave compression to offer a high efficiency of compression, a very high pressure ratio, necessitating only two stages, and reduced capital cost. The discharge temperature is high (around 250°C), aiding heat integration (Ramgen, 2008).

The Ramgen system has been described by IEAGHG (IEAGHG, 2011). The gas (here, CO_2) flows into a space between a rapidly rotating disc and its casing (*see* Figure 25), where three raised sections suddenly constrict the flow. The rapid rotation of the disc acts analogously to the entry of air into the obstructed chamber of a ramjet.

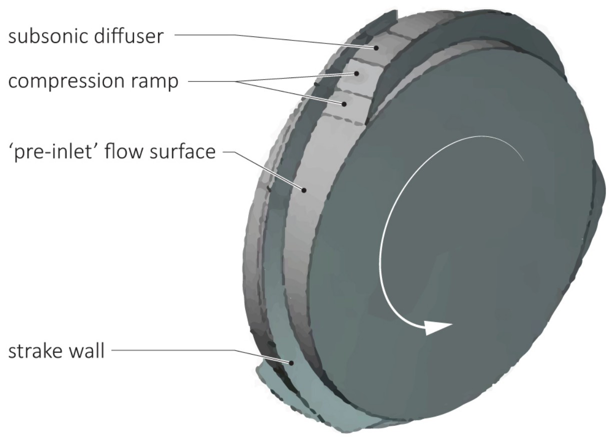

Figure 25 Principle of Ramgen compression system (IEAGHG, 2011)

The effect is to create shock waves giving a sudden pressure increase. Two stages of compression are used, with pressure ratios each of 10:1. The temperature rises by around 200°C per stage, so higher grade heat can be extracted by the compressor stage coolers. The compressor is also physically smaller and so potentially less expensive than conventional systems.

The temperature of the heat (around 230°C), allowed it to be optimally employed for part of the CO_2 capture stripper's reboiler energy as well as for LP feedwater heating in the IEAGHG (2011) study. Some cooling water was still needed (*see* Figure 26).

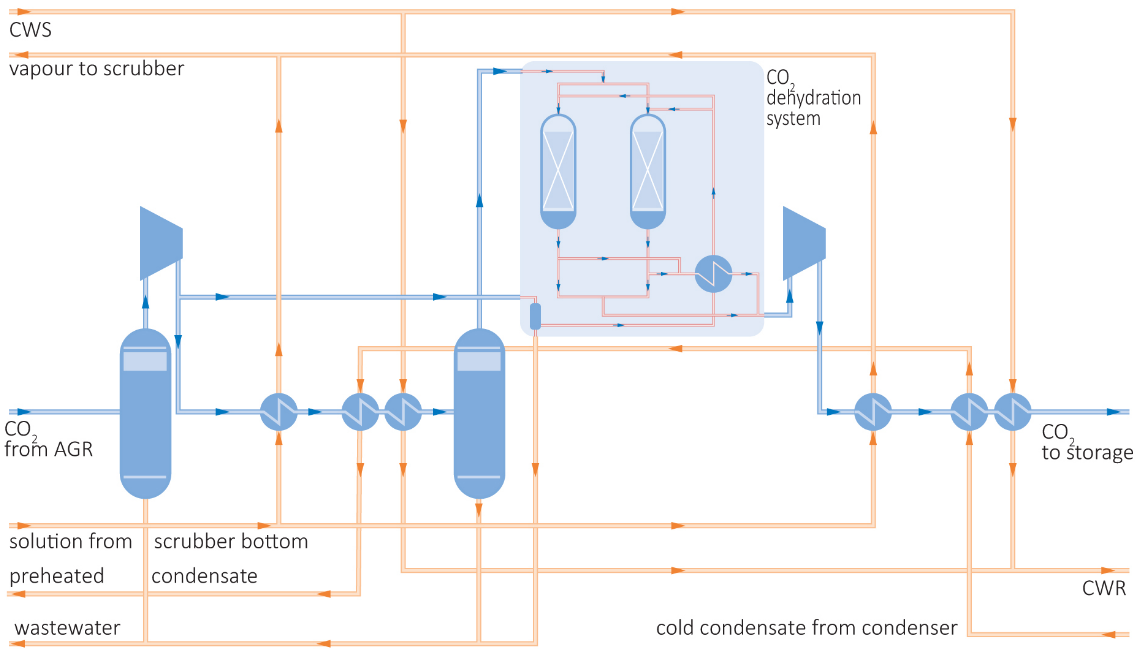

Figure 26 Integration of Ramgen compressor intercooler heat production (IEAGHG, 2011)

The study showed that, while electrical power demand for compression would actually be increased, less steam would need to be taken from the water-steam cycle for heating the reboiler. The net effect was an increase in overall net power from the CO_2 capture-equipped power plant compared with when it had more conventional compressors (Table 10). The basis for the comparison was a PCC-CO_2 capture plant of 827 MWe gross, 666 MWe net output. Economic gains could make the benefits more significant, but commercialisation of the technology will need deployment of CO_2 capture on a significant scale.

Table 10 Effect on overall electrical output of using Ramgen compressor in comparison with use of integrally-geared and in-line compressors (IEAGHG, 2011)

	Comparison with integrally geared compressor		Comparison with in-line compressor	
Steam for LP feedwater heating	+9.4 MWth	+2.5 MWe	−7.1 MWth	−1.9 MWe
Steam for stripper reboiler	−35.3 MWth	+9.3 MWe	−35.3 MWth	+9.3 MWe
Cooling water consumption	0 t/h	0 MWe	−1905 t/h	−0.2 MWe
Change in compressor electrical consumption		+5.4 MWe		+11.1 MWe
Total change, whole plant		−1.4 MWe		−0.3 MWe

5 Summary and conclusions

The output and efficiency of a coal-fired power station unit fitted with CO_2 capture equipment will be significantly lower than that of a similar plant without capture because some of the energy produced by burning the fuel will be needed to operate the added systems. Incorporating an aqueous amine-based CO_2 scrubbing system in a simple arrangement on a bituminous coal-fired supercritical or USC plant could decrease the efficiency considerably, by up to 30%, or typically 12–13% points.

Simulation work at various research institutes and universities shows that the decrease in performance could be reduced by using innovative ways of heat integration and other techniques. The present report has reviewed these studies, and main findings are as follows:

The available heat is low grade, and only part of it is re-usable.

Local ambient conditions may restrict options or offer greater opportunities for improvements in efficiency.

The efficiency penalty of adding CO_2 capture to a bituminous coal-fired pulverised coal power plant could be brought down to around 8% points, or even lower in some cases.

CO_2 compression will be required before pumping as a supercritical fluid to geological storage. Compression in eight stages is typically envisaged. Heat from the interstage cooling is at similar levels (temperatures) to the other sources of waste heat from the process and would be incorporated into integrated systems.

Heat pumps could aid waste heat utilisation and could be integrated in various ways.

Lignite-fired plants may offer more options for heat integration, especially if certain types of lignite drying can be applied.

New designs of heat exchanger with micro-channels could allow closer temperature approaches, and so, if used for this application, potentially increase the degree of heat transferable with some benefit, though not major. This may also enable the costs normally associated with achieving close pinches to be moderated. However, the key issue is not the lack of systems to give such close temperature approaches, more the low temperature of the waste heat in the CO_2 capture system. In any case, micro-channel heat exchangers are currently too small in scale to use.

Low temperature bottoming cycles and thermo-electrics would introduce too much complication and cost for the degree of likely benefit.

A two-stage CO_2 compressor that is being developed offers simplicity and would provide higher temperature heat than conventional compressors. It would reduce the loss of gross power, but would use greater power for compression. The net effect would probably be a small gain in overall net efficiency, with possible cost savings.

It should be possible to accommodate flexibility in plants fitted with MEA CO_2 capture, while improving integration.

MEA scrubbing is the system most likely to be selected in the first wave of commercial CCS plants – hence this report concentrates on it. Although further improvements will probably be achievable eventually by using more advanced solvents, many of the energy-saving principles currently identified are likely to remain applicable.

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