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**OPTIMISATION OF COAL FIRED POWER PLANT
PERFORMANCE WHEN USING FLUE GAS SCRUBBERS FOR
CO₂ CAPTURE**

FINAL REPORT

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Executive Summary

This project has spanned, and to some extent contributed to, a period of significant development in the technical, industrial and political aspects of carbon dioxide storage and capture. At the time of writing, publication of the UK government's Carbon Abatement Technology Strategy document has been held up by the election, but the growing awareness of the potential for CCS as a climate change mitigation measure, both in the UK and the world as a whole, was highlighted in the recent speech to the G8 plus Energy and Environment Ministerial Roundtable by Gordon Brown [HMT, 2005]:

It is now clear that - as well as renewable sources of energy - cleaner fossil fuel technologies, including the capture of carbon dioxide and its long-term storage underground, are likely to become crucial elements of carbon reduction strategies over the next few decades, particularly for emerging economies. These technologies have the potential to provide a step change in reducing emissions.

I can therefore announce today that as part of the UK Government's continuing support for research and development in this field we will now examine the potential of economic incentives to encourage carbon capture and storage.

The summarised aims of BCURA project B70 were:

- To examine optimisation strategies for integrated amine scrubber systems for CO₂
- To investigate the practicality of implementing promising retrofit plant configurations
- To compare retrofit performance with published data for other options
- To estimate the potential market for retrofit applications in the UK and worldwide
- To explore, for new plant, the effect of varying steam conditions on performance
- To estimate likely thermodynamic limits for amine-based solvent performance
- To collaborate with leading research groups, particularly in Canada, USA and Japan.

These objectives have all been achieved and the project has contributed to a general reassessment of post combustion CO₂ capture from pulverised coal (PC) plant. A 'standard' CO₂ capture pulverised coal power plant configuration has been developed and analysed using Mathcad and IPSEpro (and has also been analysed in recent industry-led studies). Depending on the type of commercial amine solvent used, this approach gives a capture penalty of 8 to 9 percentage points off the plant LHV efficiency and appears to represent the thermodynamic limit without new solvent formulations. No benefit has been found for alternative configurations. This compares favourably with penalty values of ~12 percentage points in most of the previous literature. Given the very widespread existing and scheduled deployment for PC plant globally, this has obvious strategic relevance for climate change mitigation using CCS.

Direct output from the project has included refereed papers describing new retrofit options [Gibbins, 2004c] and optimisation strategies for post-combustion capture [Gibbins, 2004a] and conference presentations on work in progress on the 'capture ready' concept for new build PC plants [Gibbins, 2004b; Ball, 2005]. Results from the project have also been applied in an IEA study with BCURA industrial sponsors Mitsui Babcock and Alstom [IEA GHG, 2004;] confirming significantly improved performance for post-combustion amine capture. These developments were all completed in time to be considered for inclusion in the forthcoming IPCC special report on CCS [IPCC, 2005] and the UK G8 initiative on climate change respectively.

Optimisation strategies for post combustion capture systems have been formulated as a set of six rules, as presented at the 7th Greenhouse Gas Technology conference in Vancouver in September 2004 [Gibbins, 2004b]:

1. Add heat to the steam cycle at as high a temperature as possible (i.e. be prepared to use best available steam conditions if commercially justified).
2. Reject heat from the steam cycle, in the steam extracted for solvent regeneration, at as low a temperature as possible.
3. Produce as much electricity as possible from any additional fuel used, consistent with rejecting heat at the required temperature for solvent regeneration.
4. Make use of waste heat from CO₂ capture and compression in the steam cycle.
5. Use the latest solvent developments.
6. Exploit the inherent flexibility of post-combustion capture.

While perhaps appearing obvious, these rules have frequently not all been followed in published studies of post combustion CO₂ capture. This does not mean that the detailed results obtained in these studies were in any way incorrect, but it does mean that the results that were obtained represent sub-optimal performance. The optimisation principles are employed in recently started DTI projects, CC407 "Coal-fired Advanced Supercritical Boiler/Turbine Retrofit with CO₂ Capture (ASCBTR) " and " Future CO₂ Capture Technology Options for the Canadian Market " as well as the IEA study already cited.

The DTI "ASCBTR" project will extend the general approach suggested by this project [Gibbins, 2004c], that electricity costs with capture could be significantly reduced if plant performance was upgraded at the same time by retrofitting an advanced supercritical steam cycle to the plant, to detailed site-specific studies at three UK stations. As shown in Table S1 below, this may be a competitive upgrade route for existing UK power plants, compared to the other obvious alternative of new build IGCC.

Table S1 Electricity costs for future UK coal generation options with CCS

based on *Carbon Dioxide Capture and Storage - A Win-Win Option?*, DTI Report ED 01806012, May 2003

Additional values/changes shown in italics

Original Power Plant	Case 1 PF Coal	Case 1a ASCR +MEA	Case 1b ASCR +KS	Case 1c ASCR +KS 90% LF	Case 1d Reblade +KS	Case 3 IGC C	Case 3a IGCC (IEA)
Original Generation Efficiency of plant (%LHV)	36	<i>43.5</i>	<i>43.5</i>	<i>43.5</i>	<i>39</i>	41	<i>38</i>
Generation Efficiency with CO ₂ capture (%LHV)	24	<i>31.5</i>	<i>34.5</i>	<i>34.5</i>	<i>30</i>	35.5	<i>31.5</i>
Efficiency penalty for capture (%LHV)	12	<i>12</i>	<i>9</i>	<i>9</i>	<i>9</i>	5.5	<i>6.5</i>
Summary costs with capture:							
Capital charges (p/kWh)	1.08	<i>1.26</i>	<i>1.15</i>	<i>1.02</i>	<i>0.93</i>	1.34	<i>1.47</i>
Opex Fixed (p/kWh)	0.30	<i>0.23</i>	<i>0.21</i>	<i>0.19</i>	<i>0.24</i>	0.33	<i>0.37</i>
Opex Variable (p/kWh)	0.11	<i>0.08</i>	<i>0.07</i>	<i>0.07</i>	<i>0.08</i>	0.00	<i>0.00</i>
Additional Opex of capture plant (p/kWh)	0.80	<i>0.61</i>	<i>0.56</i>	<i>0.56</i>	<i>0.64</i>	0.00	<i>0.00</i>
Fuel (p/kWh)	1.79	<i>1.37</i>	<i>1.25</i>	<i>1.25</i>	<i>1.44</i>	1.21	<i>1.37</i>
Cost of electricity with capture (p/kWh)	4.08	<i>3.54</i>	<i>3.24</i>	<i>3.09</i>	<i>3.33</i>	2.88	<i>3.20</i>

ASCR = Advanced SuperCritical Retrofit

MEA = conventional 30% aqueous monoethanolamine solution (plus oxidation & corrosion inhibitors)

KS = Mitsubishi proprietary 'designed' amine solvents

Reblade = reblade turbine to improve isentropic efficiency plus other efficiency improvements to existing (subcritical) plant

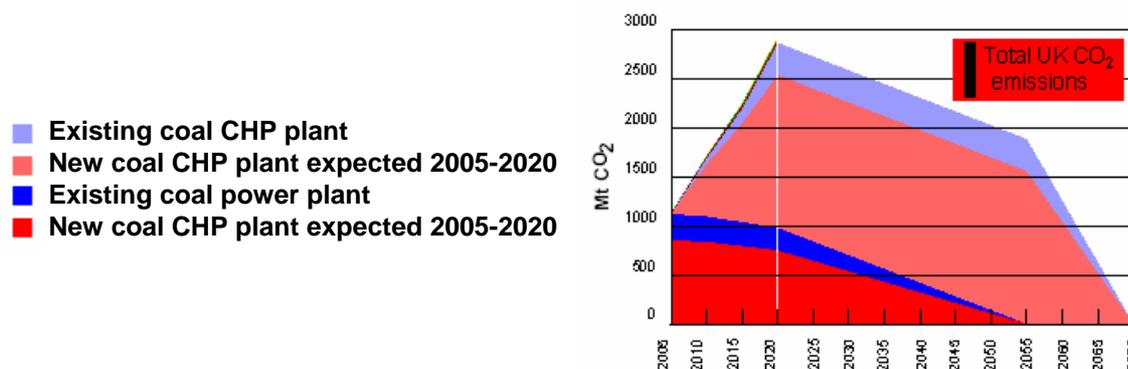
IGCC options = original DTI report costs and IEA PH4/19 costs

A very important development of the retrofit studies is the 'capture ready' plant concept. For minimal additional cost, new supercritical pulverised coal plants can be built so that CO₂ capture equipment can be added later without wasted capital expenditure, significant lost generation or unnecessary efficiency penalties. This concept will be examined in detail in the DTI "Canadian Market" project and a specific plant feasibility study by the Canadian utility SaskPower. Making new build supercritical PC plant 'capture ready' is both the largest and strategically the most important market for post combustion capture technology. As Fig. S1 shows, CO₂ emissions just from new coal plants planned to 2020 in China will exceed total UK emissions several times over - the majority of this is likely to be supercritical steam plant rather than IGCC. It is critical that all new fossil plant is built capture ready to minimise obstacles to the transition to low carbon utilisation of fossil fuels.

Figure S1 Estimates for CO₂ emissions from current and future Chinese coal power plants

based on Guo Yuan and Zhou Dadi, *Low emission options in China's electric power generation sector*,

ZETS Conference, Brisbane, Feb 2004.



Significant benefits have arisen through informal collaboration and discussions with colleagues from overseas energy research groups during the course of the project, including SaskPower and the Universities of Regina and Waterloo in Canada, Carnegie Mellon, University of Texas and SFA Pacific in the USA and Mitsubishi Heavy Industries in Japan. The IEA GHG series of CO₂ Capture Network Workshops has been an invaluable forum to exchange and develop ideas in the field, and to meet overseas researchers. In the UK, assistance from Mitsui Babcock, Alstom, Fluor (Camberley) and the DTI is gratefully acknowledged.

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1. INTRODUCTION

Capture and storage of carbon, probably as carbon dioxide, is likely to have an important role in any carbon constrained future. The Royal Commission on Environmental Pollution Report (RCEP, 2000) on meeting the challenge of a 60% reduction in CO₂ emissions by 2050 identified a possible role for *either nuclear power stations or large fossil fuel power stations at which carbon dioxide is recovered and disposed of* for baseload generation in scenarios without large amounts of conservation and/or renewable generation. In all RCEP scenarios, however, significant amounts of *fossil fuel plants to back up intermittent renewables (capacity 40 MW)* and *fossil fuel plants for meeting peak electricity demand (capacity 400 MW)* were required. Preliminary research at Imperial (Gibbins, 2002, 2003) suggested that suitable carbon capture and storage (CCS) systems could also be deployed to give further capture and storage and reduced costs in these two latter duties.

The Energy White Paper (DTI, 2003) recognised CCS as the key to allowing continuing use of coal, provided that an number of obstacles could be overcome (including the performance, and hence economic, limitations addressed by this study):

6.57 If ways could be found cost-effectively to handle the carbon, keeping coal-fired generation in the fuel mix would offer significant energy security and diversity benefits. Coal is easy to store and transport and can be sourced from diverse of stable suppliers both domestically and worldwide.

Loads in coal-fired stations can also be varied relatively easily, so coal fired generation is particularly useful in meeting peak demand or covering for supply intermittencies in other fuels. This may encourage generators to keep some coal-fired plant so as to give themselves the capacity to meet demand under a variety of circumstances. But by itself this would be unlikely materially to increase UK energy security more generally.

6.58 If coal is to play more than a marginal role in the mix beyond around 2015, generators will need to find economic ways of dealing with the consequential carbon dioxide emissions. One option is to capture and then store the carbon dioxide. The most promising approach at present would be to lock the gas away in geological structures such as depleted oil and gas fields. There is significant international interest and effort going in to carbon dioxide capture and storage, especially in the USA and Canada, where many of the technical obstacles to economic implementation are being researched. The UK North Sea offers a potentially very valuable resource in this respect, as do other offshore reservoirs.

6.59 Carbon capture and storage (CCS) - and the potential value of carbon dioxide injection for enhanced oil recovery (EOR) as a means of extending the life of the North Sea oil reserves - is described in detail ... below. The recent review of cleaner coal technologies, shows that CCS is currently constrained by a number of significant legal and technical issues. Measures to address these are the subject of a number of current follow-up projects.

As part of one of these follow-up projects the DTI undertook an authoritative 'Review of the Feasibility of Carbon Dioxide Capture and Storage in the UK' (DTI, 2003). In the world as a whole, capture and storage of carbon dioxide from suitable capture plant is expected to be deployed from about 2020 onwards, as part of the activities required to stabilise atmospheric CO₂ concentrations some time in the next century. Local opportunities and needs may, however, lead to earlier deployment in the UK.

- Capture and storage combined with Enhanced Oil Recovery (EOR) is currently the only permitted option for offshore disposal of CO₂ from land-based power generation and offers the scope for significant cost reductions due to the additional oil production. EOR schemes will run for several decades, but need to be started before the end of conventional production. Given the maturity of many UK oil fields, this means that some schemes have to be initiated before about 2010.
- The normal replacement of life-expired electricity power plants may require the construction of plant suitable for carbon capture to begin before 2020 to avoid supply shortfalls.

The DTI report identifies the following areas for further work:

- legal and regulatory issues
- environmental impact
- economic barriers and emissions trading
- acceptance in the context of international emissions inventory methodologies
- further development of the technologies, critically to reduce costs

- better understanding by the public of what CCS means for them.

Further implementation plans for EOR and CCS in the UK may be included in the delayed DTI Carbon Abatement Technology Strategy document.

The current project addresses principally the penultimate objective, technology development for cost reduction. The cost of capture is the major element in the overall costs for CCS projects. CCS involving EOR also may involve significant costs for CO₂ transport and modifications to wells and processing facilities (Chalmers, 2003), but this is offset by the value of the oil produced. The immediate objective for cost reductions in CO₂ capture technology is to make the introduction of EOR financially attractive enough with near-term technology (~ 5 -10 years) to avoid the abandonment (and probably consequent 'sterilisation' for CCS) of many UK North Sea hydrocarbon reservoirs. While time-scales to large scale worldwide implementation may be of the order of decades, immediate work is required if coal power plants with CO₂ capture are to be presented as a viable component of future UK energy policy and UK industry is to establish a presence in the area.

There are three main options for coal power plant with CO₂ capture, flue gas scrubbing with an amine solvent, oxyfuel combustion and gasifier/shift. Pulverised coal with amine scrubbing is generally considered to be the most technically-proven combination, but also the most expensive due to the large energy input required for solvent regeneration. Preliminary work by the applicants (Gibbins, 2002, 2003) has shown, however, that, through the use of new solvents and the extension of thermodynamic optimisation principles already used in the steam cycle to the combined steam/scrubber system, the loss in power output can be reduced by nearly 30%. Under these conditions the scrubber system would possibly be the most cost-effective capture technology currently available, as well as offering RAMO advantages over the other options. The work completed under this project B70 has extended this preliminary study and contributed to the UK gaining a technical lead in this important area.

2. RESULTS AND DISCUSSION

2.1 Post combustion capture background and features of the basic CO₂ capture system

As the name implies, post combustion capture involves removing CO₂ from the flue gases of power station. For this reason it is sometimes derogatively referred to as a 'tailpipe technology' that simply cleans up the pollution, rather than the more elegant approach of avoiding making it in the first place by using pre-combustion capture of CO₂. Pre-combustion CO₂ is, however, something of an oxymoron since CO₂ is a product of coal combustion, not a natural precursor! To obtain CO₂ from coal requires an additional CO to CO₂ water gas shift stage upstream of the gas turbine in an IGCC plant. The thermodynamic penalty of this shift, together with the reduced mass flow in the turbine, are changes to normal IGCC operation that are not paralleled in PF plant, which requires no combustion modifications. Thus, as shown in section 2.7, although the actual capture and compression of CO₂ in a precombustion IGCC/shift plant requires lower energy than in a post combustion plant, due to the much higher CO₂ partial pressure, the overall efficiency penalty is not much lower for the IGCC plant, especially for IGCC systems which have not already taken an energy penalty (and cost reduction) through the use of a wet quench system at the gasifier exit instead of using a boiler (e.g. wet quench GE (Texaco) gasifier).

As currently envisaged, post combustion CO₂ capture processes would use an aqueous solution of an amine, which undergoes a reversible chemical reaction with CO₂. At low temperatures (~40°C) CO₂ physically dissolves in the water and then reacts with the amine in an exothermic process. The amine solvent trickles downwards through an absorber column filled with either random or structured packing to maximise gas/liquid contact and give sufficient liquid hold-up time for reactions to take place. The flue gas flows up through the column. Before it enters the column SO₃, SO₂ and NO₂, all of which react irreversibly with amines, (but not NO) must be removed to ideally less than 10 ppm total (although there is an economic trade-off between gas cleaning efficiency and solvent consumption, with the balance depending on solvent costs). This is beyond the demonstrated capability of most current FGD systems, since there has previously been no need to achieve such low residual levels. At least one system has been operated routinely at these levels, however, the Alstom Flowpak system (see Figure 2.1) has been installed on only one (oil burning) plant to date.

As shown in Figure 2.2, the 'rich' amine solution from the bottom of the absorber column is first heated against the hot stream of 'lean' regenerated solvent coming from the reboiler then enters the top of a stripping column. CO₂ is progressively removed from the solvent as it flows down the stripper until it enters the reboiler and is heated by steam coils to its saturation temperature to complete the CO₂ release process. The CO₂ leaves the top of the stripper at about 80°C saturated with water vapour and the mixture is cooled and water condensed, possibly in several stages to maximise the temperature at which heat can be recovered. The CO₂ is then compressed in a multi-stage process, the last stages of which may involve pumping of high density liquid/supercritical CO₂ rather than gas compression. Additional heat can be recovered during the compression process and the remaining water is removed.

2.2 Post combustion capture optimisation rules

To give a formal framework for assessing how likely new and previous post combustion capture studies are to give the best possible results, six rules that must be followed to achieve optimum post combustion capture plant thermodynamic and economic performance have been formulated as part of this project. The rules as framed below apply particularly to systems using liquid solvents (typically, but not exclusively, aqueous amine solutions) that require low-grade heat (100-150°C) for solvent regeneration, but are likely to be at least partly relevant for the application of other post combustion capture technologies (e.g. CO₂ adsorption on solids).

1. Add heat to the steam cycle at as high a temperature as possible (i.e. be prepared to use best available steam conditions if commercially justified).
2. Reject heat from the steam cycle, in the steam extracted for solvent regeneration, at as low a temperature as possible.
3. Produce as much electricity as possible from any additional fuel used, consistent with rejecting heat at the required temperature for solvent regeneration.
4. Make use of waste heat from CO₂ capture and compression in the steam cycle.
5. Use the latest solvent developments.
6. Exploit the inherent flexibility of post-combustion capture.

These rules may appear obvious, but have often not been followed in their entirety in published studies of post combustion CO₂ capture. This does not mean that the results obtained in these studies were in any

way incorrect, but it does mean that the results that were obtained probably represent sub-optimal performance or economics when compared with more recent studies based on better plant design assumptions and/or more appropriate post combustion capture applications.

2.3 Steam cycle optimisation options for post combustion capture (rules 1 - 4)

2.3.1 Single/double reheat options

A possible steam cycle, in this case for a double reheat system, is shown in Figure 2.3. The turbine's four cylinders are designated by VHP, HP, IP and LP (very high pressure, high pressure, intermediate pressure and low pressure). Steam is reheated twice, after the VHP and HP cylinders. This arrangement can give the highest efficiency in some applications, but relies on having low temperature cooling water available and is also more expensive. Most modern plants therefore use single reheat (i.e. no VHP cylinder and associated reheater). Single reheat also makes efficient steam abstraction for solvent regeneration simpler and cheaper, as discussed below.

A process flow diagram and section through a typical single reheat steam turbine system configured for post combustion capture is shown in Figure 2.4. Approximately half the steam flow to the LP turbine may be required for solvent regeneration, equivalent to the flow to one of the two LP cylinders shown. Discussions with steam plant suppliers have determined that the best practicable option for steam abstraction in pulverised coal steam cycles is at the IP/LP crossover (LP inlet). This is also the only configuration that will readily allow the steam flow balance between the reboiler/LP turbine to be varied without any significant effect on the rest of the plant (e.g. boiler temperatures).

Steam at the IP/LP crossover is superheated and must be cooled to saturation temperature to avoid the risk of overheating the solvent. The LP inlet pressure must be around 3-4 bar (absolute) to match the temperature of about 120°C required for regeneration of water-based solvents at atmospheric pressure. As can be seen in Figure 2.5 (based on Mathcad steam cycle analysis calculations), for typical double reheat cycles the steam temperature at the LP inlet approaches 400°C, but is close to 200°C for single reheat cycles. The simplest method to cool the extracted steam is to spray desuperheat using reboiler condensate, but this makes no use of the elevated steam temperature. Alternatively the superheat in the extracted steam can be used to heat additional boiler feed water, as shown in the dotted high pressure feed water heating (HPFWH) option in Figure 2.3. This reduces the need for high pressure steam to be extracted from the turbine to be condensed for feed water heating (in FWH6-8 in this example) and allows some of the superheat energy to be recovered as additional work (i.e. generated electricity). As can be seen in from the Mathcad steam cycle calculation results in Figure 2.6, the LP inlet temperature varies significantly with the LP exit dryness fraction. At an exit dryness fraction on 0.95, corresponding to double reheat, with high LP inlet temperatures, nearly 3% of the heat to the reboiler can be recovered as work with no extra penalty, but this falls by a factor of 4 for a dryness fraction of 0.89. The overall conclusion is that, while simple spray desuperheating involves acceptable irreversibility losses for single reheat plant, a dry desuperheater/feed water heater - effectively a gas/liquid counterflow heat exchanger - would be required to avoid unacceptable losses in a double reheat plant. No examples of such a heat exchanger at this scale are in common steam plant service and costs are likely to be significant.

Such a heat exchanger would also be required if the IP/LP crossover pressure was too high and a pressure reducing valve had to be used. Alternatively the steam could be expanded through an auxiliary turbine to the required 3-4 bar pressure, but the turbine and associated steam ducts would be large and a relatively expensive 'special' design, and an additional alternator, would be required. In theory it might be possible to use this turbine to drive a CO₂ compressor or even a circulating pump, but this is likely to cause problems starting up the plant.

2.3.2 Effect of reduced LP steam flow on turbine efficiency

There is a general problem of matching the LP steam flow to the LP steam cylinder. In principle if the amount of steam to be extracted for solvent regeneration is known from the outset then the LP turbine can be sized to match the steam flow and maximum efficiency will be obtained. Even for plants built with capture from the outset, however, this is difficult to justify in practice since it can be expected that solvents will improve over time and less extracted steam will be required. Without special provisions the LP turbine will not be able to accommodate more than perhaps 5-10% extra steam flow, so may need to be over-sized initially. The main condenser(s) and alternator will also need to be oversized to take advantage of improved solvents through increased electricity output for the same coal input. Alternatively it might be possible to reduce coal input and boiler evaporation rates slightly and operate the HP/IP

sections at reduced flows and keep the power output constant but with increased overall plant efficiency with capture (or even take the improved solvent benefit as higher CO₂ capture rates).

The most likely situation, however, will be where capture is fitted to a plant with an LP cylinder designed to take all of the steam flow from the IP cylinder. This could be the case where a plant is designed for capture from the outset, but there is a requirement to be able to operate the plant without capture to achieve a higher power output. It is also the normal case when capture is retrofitted to a plant (see section 2.8). When the steam flow through the LP cylinder is throttled, the power output will decrease at a faster rate than the steam flow, as shown in Figure 2.7 (a relationship known as the Willans line). This causes a reduced LP turbine efficiency, compared to having an LP turbine sized to match the steam flow exactly. The fractional LP power loss compared to an LP turbine sized to the steam flow is shown as the upper line in the Mathcad steam cycle calculation results in Figure 2.8. Typically, though, the LP cylinder will provide only about 40% of the turbine power output, and this reduces even further as steam is abstracted, so the fraction of the total turbine power output lost due to throttling the LP flow is unlikely to exceed 3% of the total - see the lower line in Figure 2.8. This still represents a serious financial penalty, however, and ways to reduce it are the subject of specialised turbine designs by industrial partners in the recently-started DTI projects that include post combustion capture.

2.3.3 Low pressure feed water heating options (LPFWH)

Irrespective of other aspects of the steam turbine system, reboiler condensate will always be returned at a temperature corresponding to the normal condensate temperature after the highest temperature low pressure feed water heater (corresponding to FWH4 in Figures 2.3 and 2.4, but actual numbers of LP cylinder heaters may vary in practice). This reduces the LP feed water heater duties by an amount corresponding to the abstracted LP steam flow. Additionally, low grade heat recovered from the reflux condensers cooling the CO₂ after the stripper column can be used to heat the condensate immediately after the condenser. Higher temperature heating can be undertaken using heat from the compressor intercoolers. The overall result is that all steam bleeds from the LP cylinder for feed water heating can be avoided, giving a very efficient way of recovering the low grade heat available from the CO₂ capture system into extra power (Rule 4). This arrangement can now be regarded as standard practice. Whether or not LP feedwater heaters are provided or retained will depend on how the plant is to be operated. The plant can operate without them at reduced efficiency, and it is not feasible to totally remove them from service and then bring them back on line due to the resulting presence of corrosion products in the feed water; a small steam and water flow (~10%) would have to be maintained. So for plants that are usually operated with capture, it is likely that conventional LP feedwater heaters would not be installed. In this case operation without LP feedwater heating during start up would result in higher steam consumption in the first remaining feedwater heater (corresponding to FWH5 in Figures 2.3 and 2.4 - and possibly the next feedwater heater if FWH5 is size-limited) and hence reduced efficiency. This is not, however, likely to present any problems for such relatively short operating periods.

2.4 Some other amine heating options considered and rejected

Flue gases have to be cooled close to ambient temperatures before the FGD plant and CO₂ scrubber and there is probably no need for heat exchange with the cleaned gases to give plume buoyancy. It is likely that the very clean flue gas mixture leaving the CO₂ absorber vessel, predominantly nitrogen and oxygen, can safely be vented through the cooling towers (as in continental practice). This leaves the heat in the flue gases from ~150-200°C available for use, although with associated acid corrosion problems requiring special construction such as PTFE sleeved tubes. Solvent heating using this heat in the flue gases has been discussed with Fluor technical staff, but was discounted because of the high risks of solvent degradation due to overheating. Furthermore most of the heat is required at constant temperature, 100-120°C, which does not suit low temperature heat recovery from flue gases at a range of temperatures as the flue gas is cooled.

Because 'waste' heat is also available from the CO₂ product reflux condensers and the CO₂ compressors it is likely that in an amine capture plant there will be more low grade heat available below the 110-120°C 'pinch' temperature of the reboiler than can be used in the steam cycle, for low temperature feed water heating. Heat above that pinch temperature can, however, probably be used just as effectively for feed water heating as for reboiler heating (indeed more effectively if used at a higher temperature and with a cooling gradient matched to the heating gradient of the boiler feed water).

2.5 Latest amine solvent capture options (Rule 5)

During the course of the project it became apparent that rapid advances beyond 'traditional' MEA CO₂ capture systems were being undertaken by the principal suppliers, Fluor and MHI, using proprietary solvents and process configurations.

The original Fluor scrubber system flowsheet is shown in Figure 2.9 (Reddy, 2003) and the revised Fluor Econamine FG Plus system in Figure 2.10 (IEA, 2004). The principal changes in the improved flowsheet are the use of intercooling in the absorber to increase the CO₂ loading in the rich solvent and the use of heat in the lean solvent from the reboiler to preheat part of the rich solvent going to a flash drum, the latter reducing the solvent throughput in the stripper and hence the thermal load on the reboiler. The Fluor Econamine solvent is reportedly based mostly on MEA, with proprietary additives to improve stability, minimise steel corrosion and possibly give other process advantages.

The MHI KS series of solvents (Mimura, 2002) use proprietary sterically hindered amines to achieve intrinsic regeneration energy requirements approximately 25% lower than MEA. They are also reported to have lower losses in use, which helps to offset their higher cost. The MHI absorber system appears to employ a conventional flowsheet but does use structured packing in the absorber vessel. This reduces the gas pressure loss, and hence the required booster fan work, but appears to give increased capital cost. It has been reported that KS series solvents can use lower regeneration temperatures but published values do not appear to differ significantly from the value of approximately 120°C generally used for MEA.

Both absorber systems apparently give similar overall system performance, the higher energy penalty with the Fluor system (~10% with the new flowsheet) being offset by a lower capital cost (IEA, 2003). An obvious question is whether combining the best features of these two systems would lead to further improvements, but so far commercial restrictions appear to have prevented this.

2.6 Scope for cost reductions through increased plant flexibility (Rule 6)

Provided that additional LP turbine and generator capacity is available, the power output from a post combustion capture plant can be increased by up to an extra 20-25% of normal output by temporarily stopping solvent regeneration and CO₂ compression. The flue gases may be vented without scrubbing, in which case a 'carbon tax' or similar penalty will be incurred. Alternatively additional stored solvent can be used and be regenerated later. Simple venting can be continued for any length of time. Solvent storage would probably be limited to a 2-8 hours each day, to shift the cost penalty for 'lost' electricity output associated with solvent regeneration from periods of high electricity prices during the day to periods of low electricity prices during the night. This might also have the advantage of avoiding the need for 'two shift' boiler operation.

In order to use this flexibility it must be possible to interrupt the supply of CO₂ for limited periods and also for there to be provision to cope with higher CO₂ flows at certain periods if solvent is stored. This will require additional reboiler and compressor capacity on plant (possibly providing useful equipment redundancy). Intermittency in CO₂ despatching from an individual power station may be ameliorated if a lengthy pipeline system can be used as buffer storage. CO₂ production from sources other than power generation (e.g. increased CO₂ output from gas reforming during the day for H₂ vehicle fuelling) may also provide some compensation.

If solvent is stored and regenerated later no CO₂ penalty is incurred, and the principal marginal cost for providing this additional capability is likely to be that of the solvent itself. Published data (Chapel, 1999) for the price of MEA and corrosion inhibitor and typical CO₂ capacity for 30% w/w MEA loading indicates a cost of approximately \$8,000/tonne CO₂ capacity for additional solvent plus approximately 10% for storage tanks and pipework (assuming carbon steel tanks). For an increase in plant output of approximately 0.4 MWh/tonne CO₂ this translates into a cost of \$22/kWh for electricity 'storage', although the life of the solvent is a critical (and unknown) factor.

The cost of providing additional solvent must be paid for by the difference between electricity prices at periods of high and low price (i.e. not absolute electricity prices), and the economics are improved significantly if the solvent can be reused frequently. For example, if used 250 times a year (i.e. once during every week day peak) with an average electricity price differential of \$11/MWh a simple payback period for a solvent cost of \$22,000/MWh is 8 years, but this halves to 4 years for use twice a day (i.e. periods of morning and evening peak demand). It is also interesting to note that a post combustion capture plant could add or extend this capability very quickly at any time if electricity price differentials increased. Storage (i.e. solvent) costs are likely to be significantly higher with KS solvents, however, and might preclude matching the longer-term storage capability of pumped storage. The choice of solvent could then depend on whether the plant is to be optimised for base load operation with maximum efficiency, or for maximum flexibility and electricity 'storage' capability.

Even relatively small amounts of solvent storage would, however, be of great value in allowing larger rates of change in power plant output with appropriate control systems. This is particularly important for plants involved in grid frequency regulation, which can be called on to provide extra power very quickly to match increased demand (or fault conditions), with payment for this service determined by the rate and amount of load pick-up that the plant can accommodate. Over very short timescales, output changes due to variation in LP steam extraction and CO₂ compressor power will be approximately additive to changes that can be affected by opening the main turbine control valve and drawing down on the stored thermal energy in the boiler. But the rapidly-increased higher loads can also be sustained for much longer periods than when only the stored energy in the boiler is available, giving sufficient time to bring additional burners into service.

New control strategies could also allow plants operating in frequency response mode to avoid the need to bring mills in and out of service so frequently, by using the solvent storage facility to smooth out the demand on the boiler. Predicting future load changes would allow the rate of solvent regeneration to be optimised within the constraints on storage (Gibbins, 2004d).

2.7 Post combustion capture plant performance and potentially competitive retrofit applications for post combustion capture

When following the 'rules', post combustion capture from supercritical pulverised coal plant appears to be able to approach the efficiencies of the main competing technology, IGCC, (Table 2.1, Figures 2.11 and 2.12). As discussed in section 2.1, capture efficiency penalties are not as low as for wet quench IGCC systems, but overall plant efficiencies are higher. This is a highly significant result and has led to a renewed interest in pulverised coal plants with CO₂ capture globally, an important development given the widespread deployment of this technology - it simply cannot be ignored.

Electricity costs with capture are, however, higher for new PC plant with post combustion capture, due principally to the capital cost of the large absorber vessels. It is interesting to what extent this may be reduced in the future, by analogy with reductions in FGD costs. There is perhaps also a further advantage compared with FGD in that there are many more possible variations in the basic process chemistry. The area has seen little development to date, but new research (e.g. the FP6 CASTOR project) is under way.

With current absorber costs, however, the most competitive applications for post combustion capture appear to be retrofit applications in which some of the capital cost of the plant as a whole can be discounted. Two types of retrofit applications have been examined: a retrofit to a relatively old sub-critical pulverised coal plant upgraded to supercritical steam conditions (see below) and to a new supercritical plant built 'capture ready' (see section 2.8).

Estimated retrofit application performance and costs for a range of post combustion capture options and alternative new IGCC plants are shown in Table 2.2. Plant performance and economic parameters for a PF plant (Case 1) and an IGCC plant (Case 3) from (DTI, 2003b) are shown in Table 2.2. The numerical values for 'Opex Fixed' and 'Additional Opex of capture plant' for Case 1 have been changed to reflect the basis on which they are presented in Table 2.2, but these values are consistent with those used in the original calculations and the independently-calculated COE values agree. Additional values (Cases 1a and 1b) are given for the same PF plant, but with an advanced supercritical boiler/turbine retrofit (ASCR). This was identified as an option in (DTI, 2003b) but not investigated further. A capital cost of £100M has been reported from an ASCR case study on a 600MW unit. In the calculations in Table 2, ASCR was conservatively assumed to add £200/kW to the original power plant capital cost, and to give an efficiency of 43.5% LHV. It was also assumed that after refitting plant life would be extended for a further 25 years instead of 20 years. Other costs were assumed to be reduced in proportion to the additional power that could be obtained for the same fuel consumption. Interestingly, the COE was unaffected for an ASCR plant without capture. This suggests that a supercritical retrofit alone would not be an attractive investment for the conditions assumed unless additional credits for reduced CO₂ emissions through improved efficiency could be taken into account.

When solvent (amine) scrubbing costs and performance changes are included, however, COE values are significantly reduced for the PF plant with ASCR. This reduction is achieved principally through a combination of reduced capital and operating costs for the CO₂ capture plant and significantly reduced fuel costs. Three solvent scrubbing options are considered: Case 1a assumes a 'conventional' monoethanolamine (MEA) based solvent, with a 12 percentage point LHV efficiency penalty as in (DTI, 2003b) Case 1b assumes an advanced low-energy solvent (e.g. a KS series solvent) and some degree of thermal integration. Previous work by the authors (Gibbins, 2004d) has shown that this can reduce the efficiency penalty to approximately 9 percentage points LHV. Case 1c additionally shows costs for a load factor of 90%, a reasonable value for modern baseload supercritical plant.

COE estimates for Case 1b are higher, at 3.24 p/kWh, than the Case 3 value for IGCC of 2.9 p/kWh. These are all central values, however, with an estimated uncertainty of +/- 30%, the large range reflecting the fact that no such CO₂ capture plants have yet been built. The reported efficiencies in Case 3 are also somewhat higher than those reported for a similar IGCC plant with CO₂ capture (Texaco gasifier, quench cooling, sour shift) in a recent comprehensive IEA study. A detailed discussion of these differences is beyond the scope of this note (differences between IGCC studies are planned to be covered in a future IEA publication) but they appear to be at least partly due to a high proportion of ungasified carbon (4%) assumed for an imported Australian coal in the IEA study and the lack of recently-introduced thermal optimisation flow schemes. Capital costs are also slightly higher in the IEA study (\$1187/kW = £742/kW without capture, \$1495 = £934 with capture). With these simple modifications to the DTI cost calculations the COE for IGCC is predicted to rise to 3.2 p/kWh, although this is still lower than IEA study value of ~ 6c/kWh (= 3.75 p/kWh) for an equivalent energy cost of \$1.9/GJ.

2.8 Case study - a capture ready power plant in Saskatchewan (Ball, 2005)

2.8.1 Background

SaskPower is the principal supplier of electricity in Saskatchewan, Canada, operating 15 generating facilities, with an installed capacity of about 3 GW. Fossil generation is used to supply the majority of the electricity produced by SaskPower, with the remainder coming from hydroelectric and wind facilities. A new fossil plant with between 350 and 450 MW output may be required in the next decade and, because of expectations of high natural gas prices, there is serious interest in using local lignite as the fuel. Currently gasification technology options for lignite are limited so combustion plants, either pulverised coal or fluidised bed, with a supercritical steam cycle are being examined. No firm requirement to capture CO₂ emissions from the plant can be anticipated but, since Canada is already a signatory to the Kyoto Treaty, future CO₂ capture options are needed to avoid the risk of it becoming a stranded asset – it needs to be 'capture ready'.

CO₂ storage for the power plant may be achieved by use of CO₂ for enhanced oil recovery (EOR) or injection in an aquifer adjacent to the plant, depending on the prevailing economics and regulations when capture is added. Although detailed geological site assessments and the appropriate authorization procedure would be required before any CO₂ storage option was used it appears likely that sufficient storage capacity will be available for the project as envisaged.

SaskPower is assessing both pulverized coal and CFB options. The goal is to identify the technical and economic differences between pulverized coal and CFB options and their potential for future CO₂ capture. Preliminary lab work has indicated that there may be some advantage in a CFB option due to the inherent SO₂ capture resulting from the alkalinity of Saskatchewan lignite.

2.8.2 Emission Clean-up

SaskPower is conducting a state of the art survey of current emission control technology. This will include a review of vendors and user experience relating to SO_x, NO_x particulate and mercury control. Based on this review preferred options will be selected by SaskPower. A consultant will then develop capital and operating cost estimates, material balances and layouts.

At this time it is assumed that a supercritical PC unit will employ a best of class wet scrubber for control of SO_x emissions and overfire air for NO_x emission control. It is assumed that a CFB unit will employ a polishing process to achieve SO_x emissions targets required for an amine CO₂ scrubbing plant. The majority of SO_x control will be achieved through capture in the bed.

2.8.3 CO₂ Recovery Facility Placement

It is envisaged that the large CO₂ absorber vessel would be located adjacent to the stack. Flue gas would be diverted from the base of the stack into the base of the absorber. A suitable connection point into the stack at the height of the top of the absorber would be incorporated during construction. The reboiler would be sited adjacent to the turbine to minimise both the length of LP steam ducting required and simplify the connections between the CO₂ cooling system and the condensate/feedwater heating system. Lean and rich liquid solvents can be pumped between the two locations.

2.8.4 Thermodynamic integration and performance limits with current capture technology

The economic and thermodynamic performance of power plants designed from the outset for capture probably represents the potential limit for capture ready plant performance. The objective is to add as little as possible to the additional CO₂ capture cost that would be incurred with a 'built as capture' plant. Starting with recent data from a comprehensive IEA study of post combustion capture (IEA, 2004) and a representative estimate of the cost of electricity for a plant without capture based on a previous study [unpublished CCPC reports] the components for the additional cost of electricity with capture were

estimated. The preliminary results are shown in Table 2.3. It is interesting that, as previously observed in the IEA study (see Table 2.1), both leading current capture technologies give similar overall results, although with differences in sub-components of the costs. These differences appear to be due to mainly to typical cost/performance tradeoffs in most cases, but the large differences in capital cost were noted by IEA GHG as perhaps needing further examination.

From the values in Table 2.3 it appears that optimised capture ready plant is limited to a minimum cost increase of about 27.50 CAD (\$ Canadian) when capture is added. Further losses in performance may, however, need to be taken into account. The example shown would occur if steam for solvent regeneration was taken from the IP/LP crossover and the IP exit pressure was maintained by throttling the steam flow upstream of the LP cylinder(s), with a loss of about 2% in the overall turbine power output. This is the simplest option for removing the steam, requires no modification to the turbine and would allow the unit to revert to full load operation without capture if required (or take advantage of improved solvents in the future). As Figure 2.13 shows, however, performance and economic calculations show that LP turbine flow mismatching imposes a relatively small additional penalty on the capture cost and, while optimisation of this aspect of capture ready plant design is very worthwhile, it cannot have major consequences for costs.

More serious uncertainties exist with respect to solvent consumption due to the formation of heat stable salts with SO_x and NO₂ in the flue gas. Although advanced FGD plants with single digit ppm SO_x concentrations are available they have not yet been demonstrated in conjunction with amine capture plant. Trials on a range of coals using full scale flue gas cleanup trains with ultra-high efficiency FGD equipment are urgently needed to establish amine absorber performance. These could take place using any representative PC or CFB plants and do not need to include significant amounts of CO₂ capture; solvent life could be assessed adequately in plants capturing approximately 100 tonne/day of CO₂. It is highly desirable that any flue gas cleanup problems are debugged at this scale rather using full size absorbers. Similarly new capture plants may wish to commission on cheaper MEA-based solvents and then replace this with more expensive 'designer' solvents when reliable operation has been established.

2.84 Interim Case Study Conclusions

Normal due diligence considerations now require the impact of a possible future carbon emission pricing to be assessed for any prospective fossil power plant project. The ability to add CO₂ capture places a limit on the financial risk involved and making the plant 'capture ready' reduces this risk limit to the minimum possible value.

No undue obstacles have been identified to making a new lignite power plant in Saskatchewan capture ready. Fortunately a range of options appear to exist for geological storage of the captured CO₂ in the vicinity of the power plant. As a general consideration, it would, however, be advantageous to verify the successful operation of amine solvents in flue gas from coals plants fitted with full scale ultra-high efficiency FGD equipment as soon as possible.

Using current amine technology, adding CO₂ capture to a power plant with an initial electricity cost of 65 CAD/MWh would, at best, add approximately 27.50 CAD/MWh. The corresponding CO₂ value is about 40 CAD/tonne. This assumes that losses and efficiency penalties arising from the reconfiguration of the plant can be avoided, the thrust of the 'capture ready' aspects of the pre feasibility project. The most obvious of these penalties, mismatched flow in the LP turbine, results in an additional cost of approximately 2 CAD/MWh. In practice, capture costs are expected to be reduced in the future due to improvements in this relatively undeveloped application.

2.9 IPSEpro modelling and steam abstraction from the HP turbine exit

Simtech's IPSEpro modelling package was used to investigate and validate steam cycle performance with CO₂ capture in addition to specially-written open-architecture Mathcad programmes written in conjunction with IAPWS 1997 Industrial Formulation steam property routines [Gibbins, 2003b]. Performance predictions made by Alstom for the single reheat steam cycle in the recent IEA GHG study [IEA GHG, 2004] were confirmed using IPSEpro; the IPSEpro model configuration is shown in Figure 2.14 [Patel, 2005]. The same model was also adapted to examine the possibility of abstracting steam from the HP exit, before the reheater, instead of the IP exit. This steam would then be expanded through an auxiliary turbine to the reboiler pressure. This option avoids the need for reheat in the abstracted steam from the IP exit but, because the steam flow through the reheater is reduced, it reduces the average temperature of heat addition in the cycle. The result is that there is no thermodynamic advantage, as shown in Figure 2.15. Given the need for a special auxiliary turbine and the likely inability to be able to operate the plant without capture due to the large variation in reheater duty it appears that this steam abstraction configuration is inferior to the 'conventional' IP/LP crossover configuration.

3. CONCLUSIONS

- Principles for effective post combustion capture have been developed and formalised into a set of six rules:
 1. Add heat to the steam cycle at as high a temperature as possible (i.e. be prepared to use best available steam conditions if commercially justified).
 2. Reject heat from the steam cycle, in the steam extracted for solvent regeneration, at as low a temperature as possible.
 3. Produce as much electricity as possible from any additional fuel used, consistent with rejecting heat at the required temperature for solvent regeneration.
 4. Make use of waste heat from CO₂ capture and compression in the steam cycle.
 5. Use the latest solvent developments.
 6. Exploit the inherent flexibility of post-combustion capture.
- Generally-applicable plant process flow diagrams for optimised integration of post combustion capture with pulverised coal plant have been developed and analysed using a combination of specially written Mathcad programmes and Simtech's IPSEpro cycle modelling package and appear to be becoming the industry standard.
- Results for power plant performance with post combustion capture have been confirmed by subsequent industrial studies, particularly a reduced energy penalty for post combustion capture which is now competitive with that for IGCC.
- Depending on the type of commercial amine solvent used, the 'standard' CO₂ capture pulverised coal power plant configuration developed in this project gives a capture penalty of 8 to 9 percentage points off the plant LHV efficiency and appears to represent the thermodynamic limit without new solvent formulations. No benefit has been found for alternative configurations. This compares favourably with penalty values of ~12 percentage points in most of the previous literature.
- Electricity costs for new PF plant with post combustion capture are still predicted to be higher than for IGCC, principally due to the capital costs of the absorber vessels. Post combustion CO₂ capture technology is, however, still at a very early stage and fundamental developments in solvent technologies, more detailed engineering design and practical experience can all be expected to contribute to significant cost reductions in the future.
- Trials on a range of coals using full scale flue gas cleanup trains with ultra-high efficiency FGD equipment are urgently needed to establish amine absorber performance. These could take place using any representative PC or CFB plants and do not need to include significant amounts of CO₂ capture; solvent life could be assessed adequately in plants capturing approximately 100 tonne/day of CO₂. It is highly desirable that any gas cleanup problems are debugged at this scale rather using full size absorbers.
- Even with current post combustion technology options, suitable retrofit applications may still be competitive with new IGCC; the particular option identified in the study, combining an advanced supercritical boiler/turbine retrofit with post combustion capture, is now one of the options being considered under a new DTI Cleaner Coal project.
- There is a very large and immediate 'market' for 'capture ready' plant technology, in contrast to no current demand for CO₂ capture from coal generation plant. The value of this technology, particularly for pulverised coal plant, has been demonstrated by this study and possible design approached suggested. Further, more detailed, industrial studies are under way.
- Results from the study have been widely disseminated to industry, the carbon capture and storage community and other stakeholders and have contributed to the inception and delivery of a completed IEA GHG project, several new DTI projects and other industrial work.
- The work has been particularly timely, since results have been available in time to be considered directly and indirectly through the results of industrial follow-on studies, for the forthcoming authoritative IPCC report on carbon capture and storage.
- The project also addresses issues of current interest for the G8 and other climate change initiatives given the rising level of industry and government interest in carbon capture and storage and the very widespread utilisation of the pulverised coal technology. The capture ready plant concept and analyses are probably the most relevant project outcomes in this respect.

4. SUBSEQUENT WORK - IN PLACE AND SUGGESTED

Projects/proposals arising from this study

Sponsor	Title	Status
IEA GHG	Improvement in power generation with post-combustion capture of CO ₂	Completed IEA GHG PH4/33
DTI	Project 407 Coal-fired Advanced Supercritical Boiler/Turbine Retrofit with CO ₂ Capture	Started Dec 2004
DTI	Future CO ₂ Capture Technology Options for the Canadian Market	Started May 2005
SaskPower	Pre-feasibility study for capture ready coal fired generation options	Started April 2005
TSEC	Preliminary amine absorber optimisation studies with U. of Regina, part of UK CCS Consortium proposal	Due to start 1 June 2005
BCURA	Proposal 05/05a, Improvements In Amine Flue Gas Scrubbing Systems For Coal Fired Power Plants	Submitted to 4th call for proposals (see below for outline)

Proposed work not yet started

i) Improvements in Amine Flue Gas Scrubbing Systems for Coal Fired Power Plants (BCURA 4th Call Proposal 05/05a)

Key areas for improvement in amine CO₂ capture systems are:

- a) process optimisation and effective integration with the main (and possibly ancillary) power cycles to maximise electricity output (a somewhat different objective than traditional 'chemical plant')
- b) minimisation of capital cost, especially the cost of the large absorber vessels required to handle the relatively large flue gas volumes

The proposed work under Proposal 05/05a will address both of these areas through:

- a) the application of advanced thermodynamic, process modelling and optimisation techniques to combined absorber and power cycle systems
- b) the investigation of alternative absorber systems for capture plant capital cost reduction over conventional column packing for the absorption of CO₂ from flue gases
- c) the optimisation and use of advanced amine (and promoter) mixtures

ii) Collaborative research work on capture ready plant with Chinese institutions

Assessment of changes required in current Chinese coal plants to improve 'capture readiness'. Identification and assessment of possible indigenous equipment for appropriate gas cleanup and CO₂ capture.

5. PUBLICATIONS ARISING FROM THE PROJECT AND OTHER DISSEMINATION ACTIVITIES

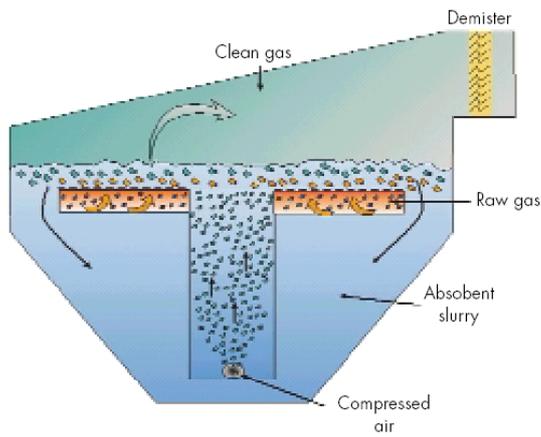
Refereed Journal Papers
Gibbins, J. and Crane, R., A preliminary assessment of electricity costs for existing PF plant retrofitted with an advanced supercritical boiler and turbine and solvent CO ₂ capture, Proc. I.Mech.E, Vol. 218, Part A, J. Power and Energy (2004), accepted for publication.
Gibbins, J., "Capture ready pulverised coal power plants", in preparation
Refereed Conference Papers
Gibbins, J.R., Crane, R.I., Lambropoulos, D., Booth, C., Roberts, C.A. and Lord, M., "Maximising the effectiveness of post combustion CO ₂ capture systems", Proc. GHGT7, Vancouver, Sep. 2004
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Turbulent bed absorber
- air keeps slurry in suspension

Karlshamn plant (Sweden)
One of 3x340MWe units retrofitted in 1996

Source: Alstomenvironmental.com



	Design	Measured
SO₂ inlet concentration [mg/Nm ³]	5,500	4,000
SO₂ outlet concentration [mg/Nm ³]	150	30
SO₂ removal [%]	97,4	99+

Figure 2.1 Alstom Flowpak high-efficiency flue gas desulphurisation plant

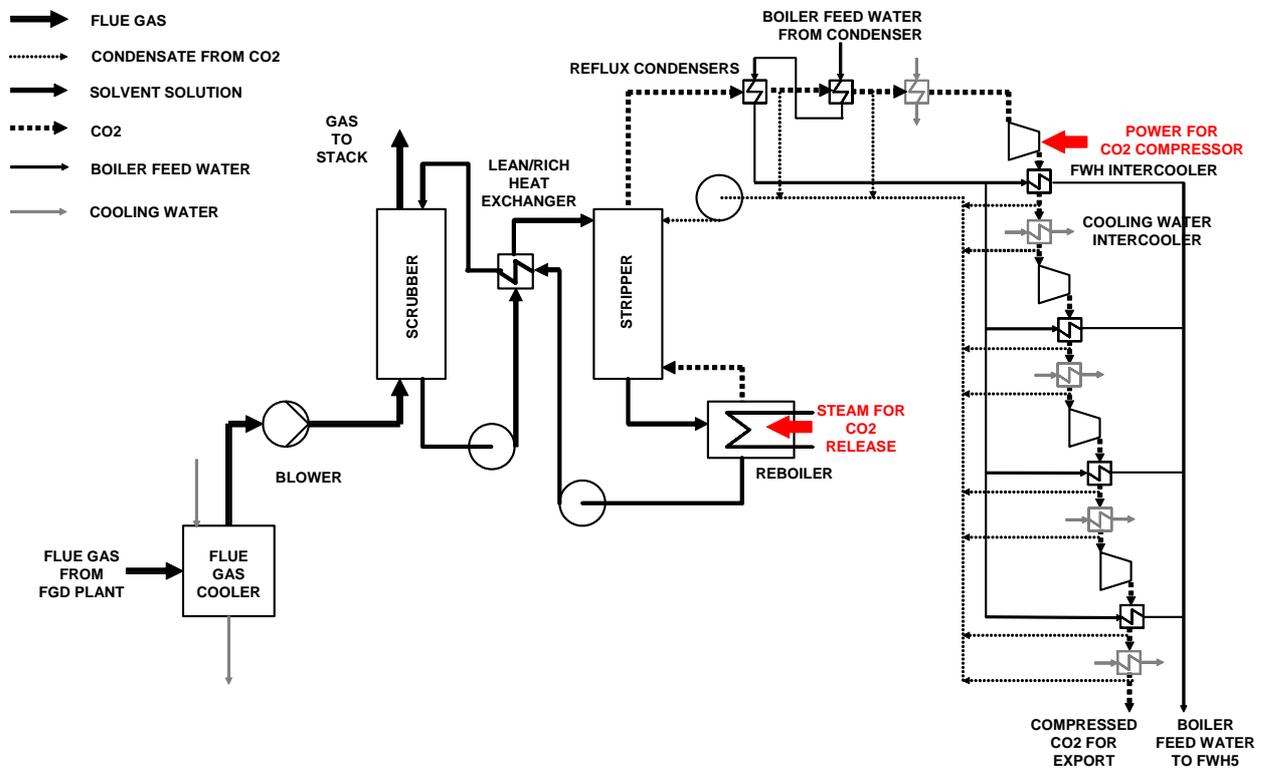


Figure 2.2 Amine CO₂ capture system process flow diagram

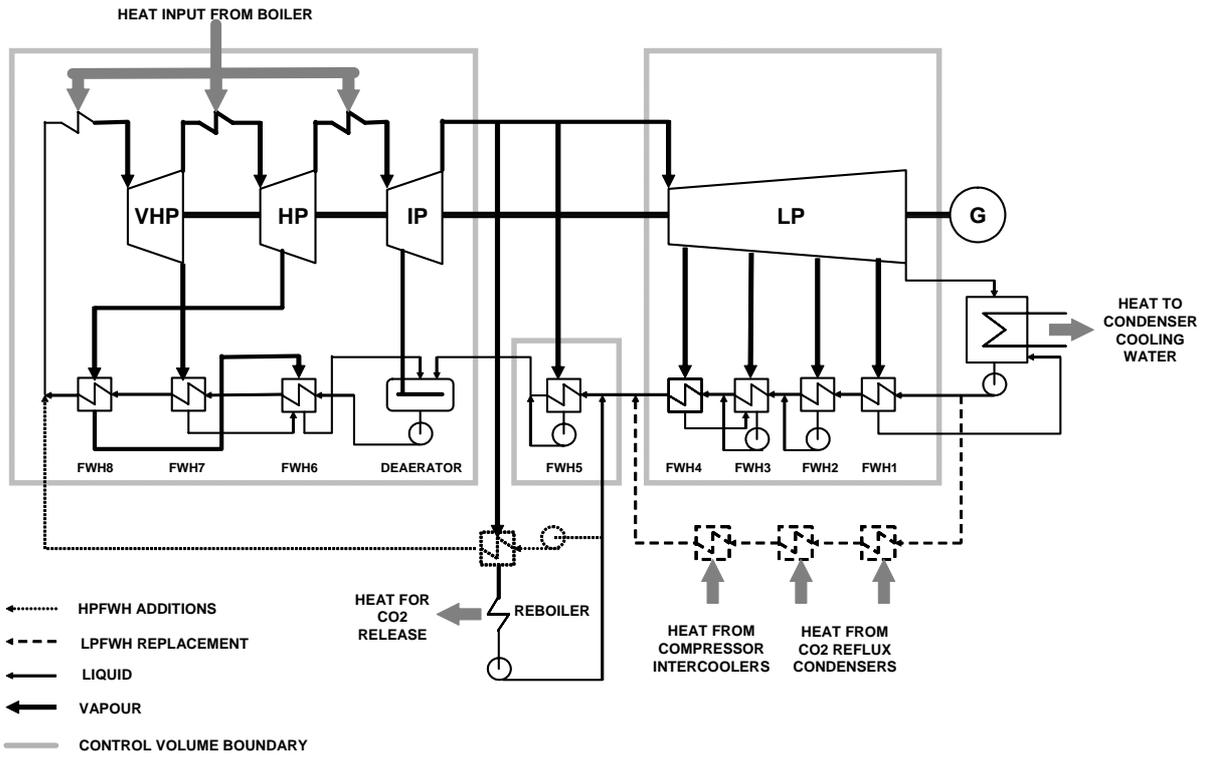
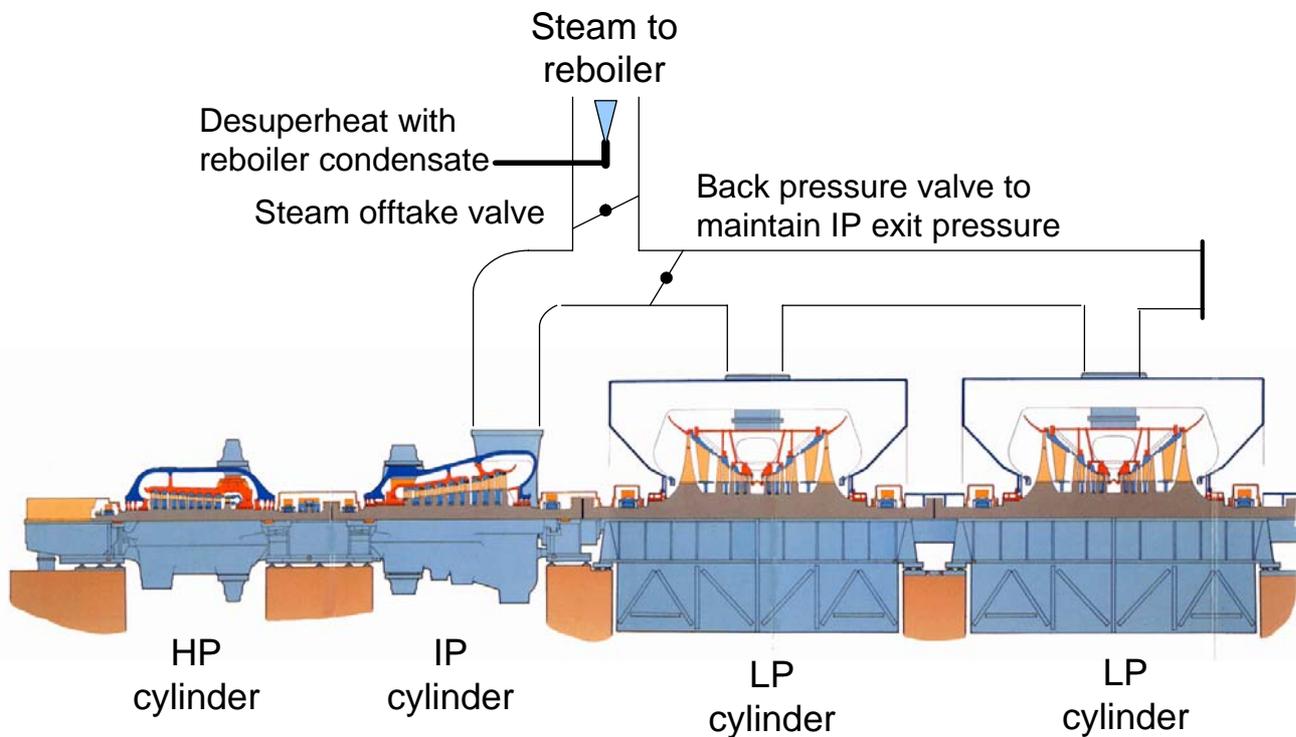
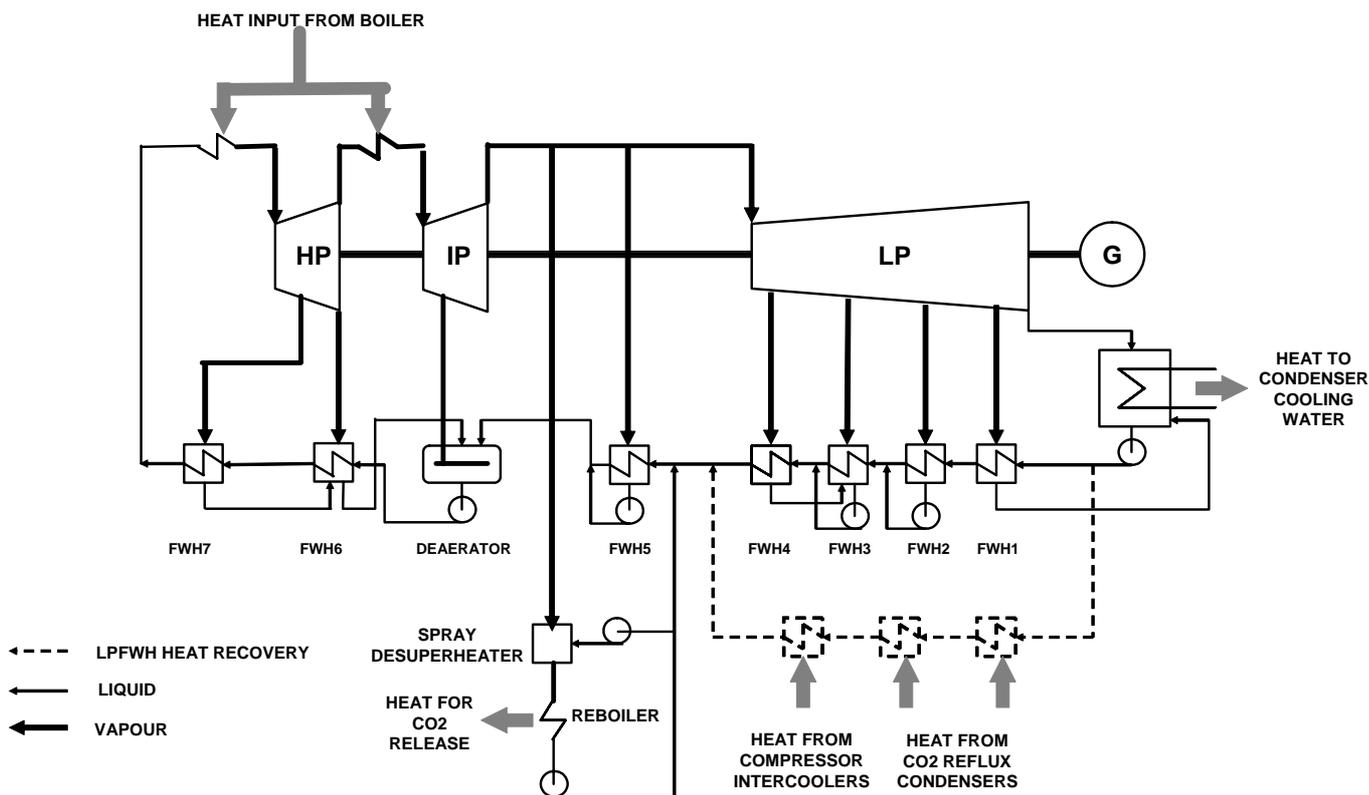


Figure 2.3 Double reheat steam cycle configured for integration with an amine capture system



Alstom Large Steam Turbines brochure

Figure 2.4 Possible arrangements for taking steam for amine reboiler from a single reheat steam turbine

IP exit / LP inlet pressure 3-4 bar to suit 120°C saturated steam for the reboiler

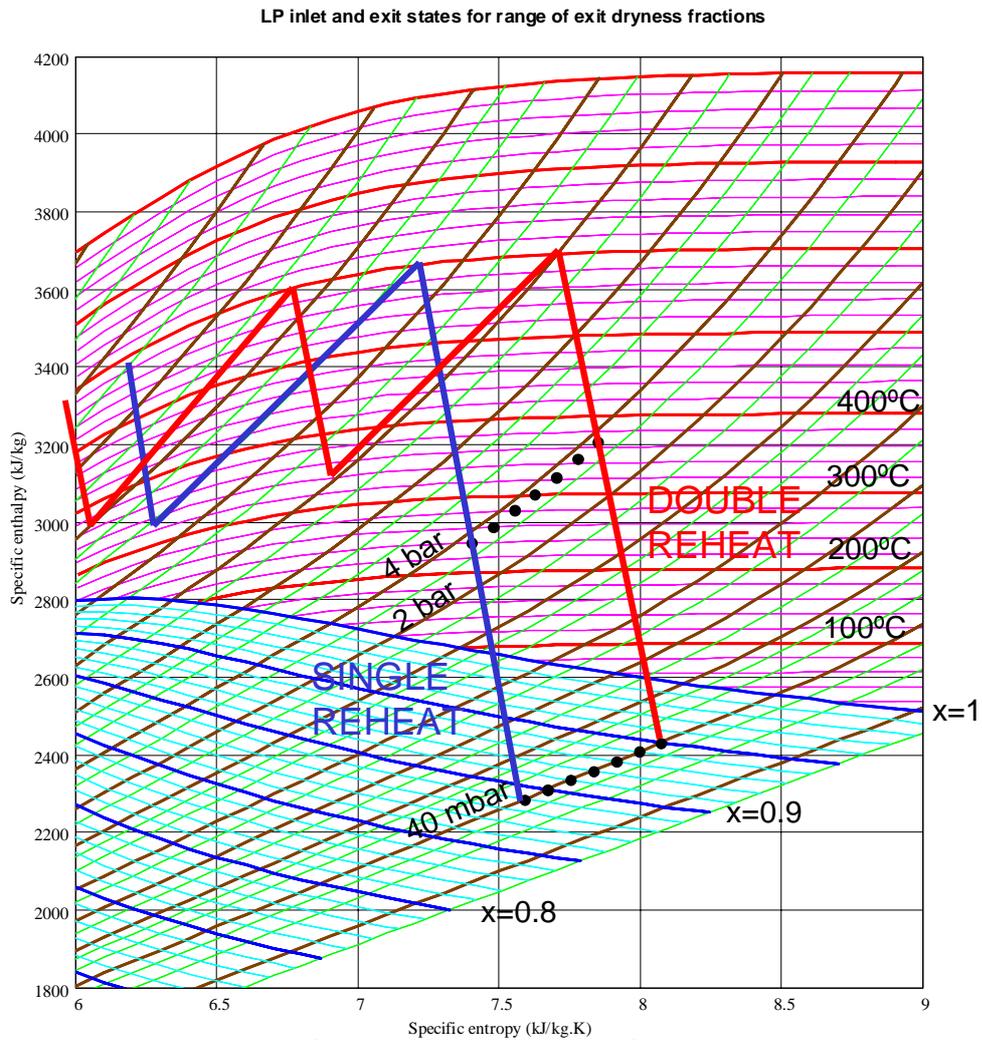


Figure 2.5 Enthalpy-entropy diagrams for double and single reheat steam cycles
 LP inlet pressure must be around 3-4 bar to match temperature required for regeneration of water-based solvents at atmospheric pressure. LP exit dryness fraction should also be as low as possible to minimise superheat in extracted steam - suits single reheat supercritical cycles rather than double reheat (Mathcad routines used to calculate cycle endpoints and h-s plot)

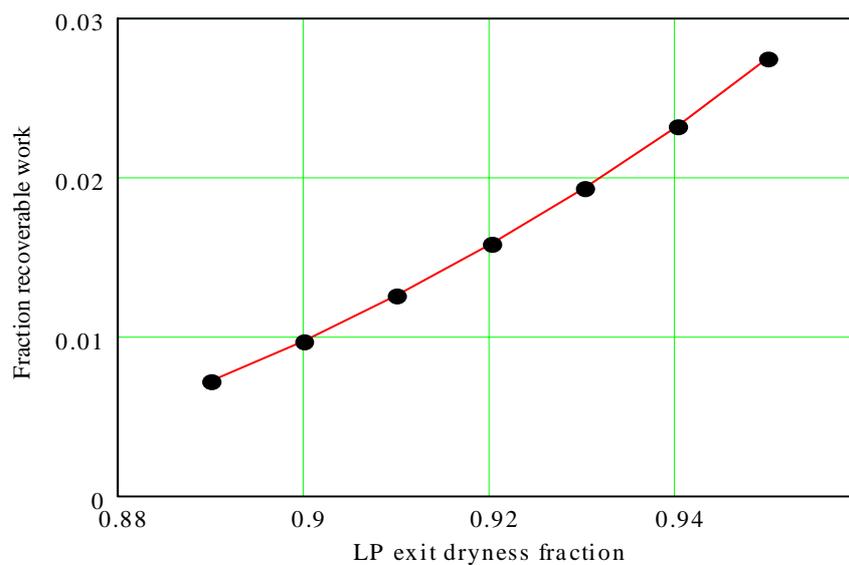


Figure 2.6 Fraction of heat to reboiler theoretically recoverable as work by using extraction superheat instead of spray desuperheating (the 'Rule 3 penalty').
 (Mathcad calculations based on exergy of extracted steam)

Typical Willans line for throttled steam turbine

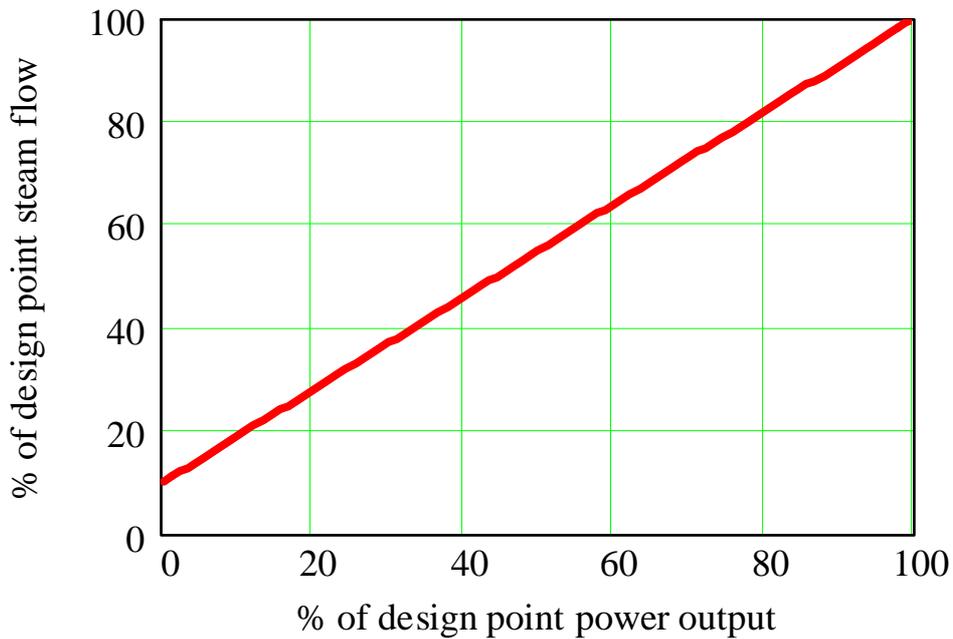
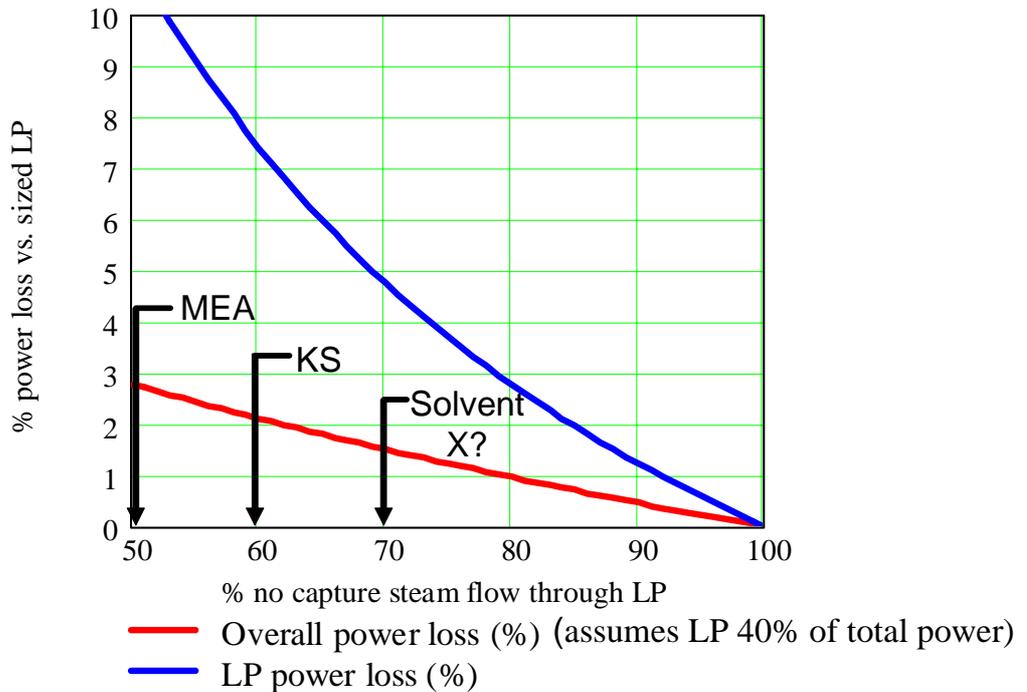


Figure 2.7 Effect on the LP cylinder work output when the steam flow is throttled to maintain the IP exit/steam extraction pressure at a constant value
(Mathcad calculations and plotting)

Figure 2.8 Effect of throttling to achieve reduced LP steam flow, compared to LP steam turbine sized for steam flow.
(Mathcad calculations and plotting)



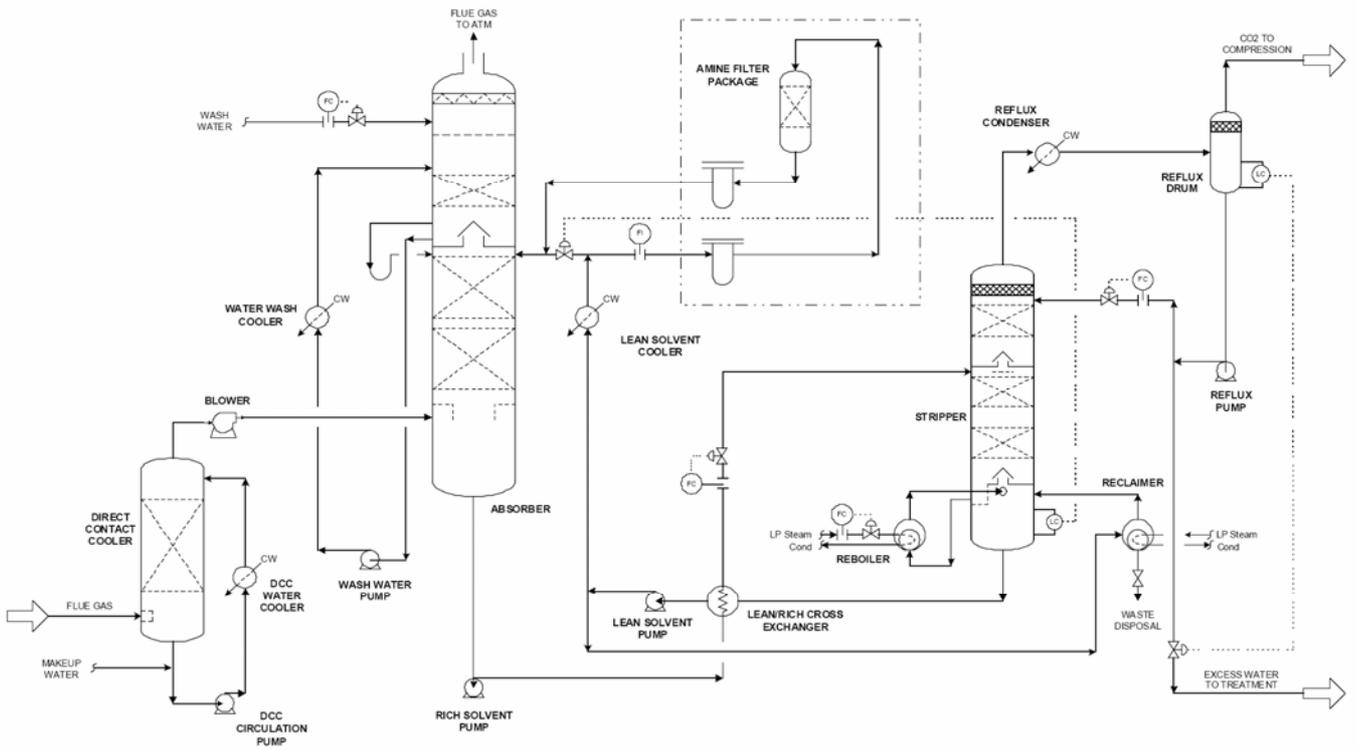


Figure 2.9 Original Econamine FGSM Flowsheet (Reddy, 2003)

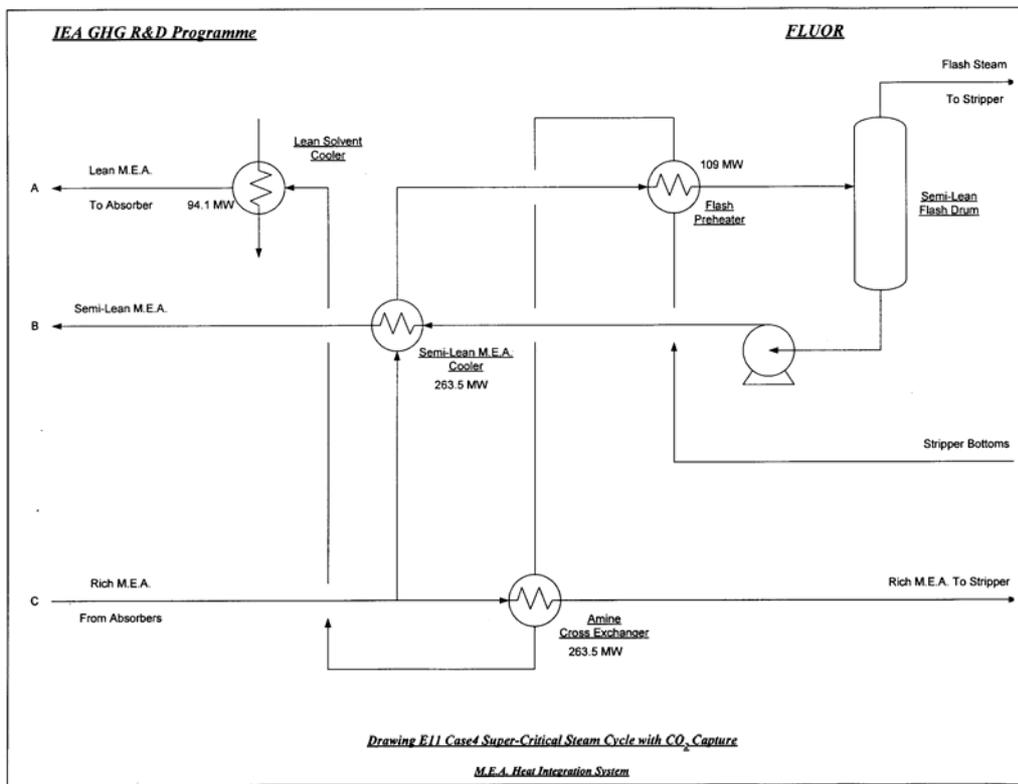
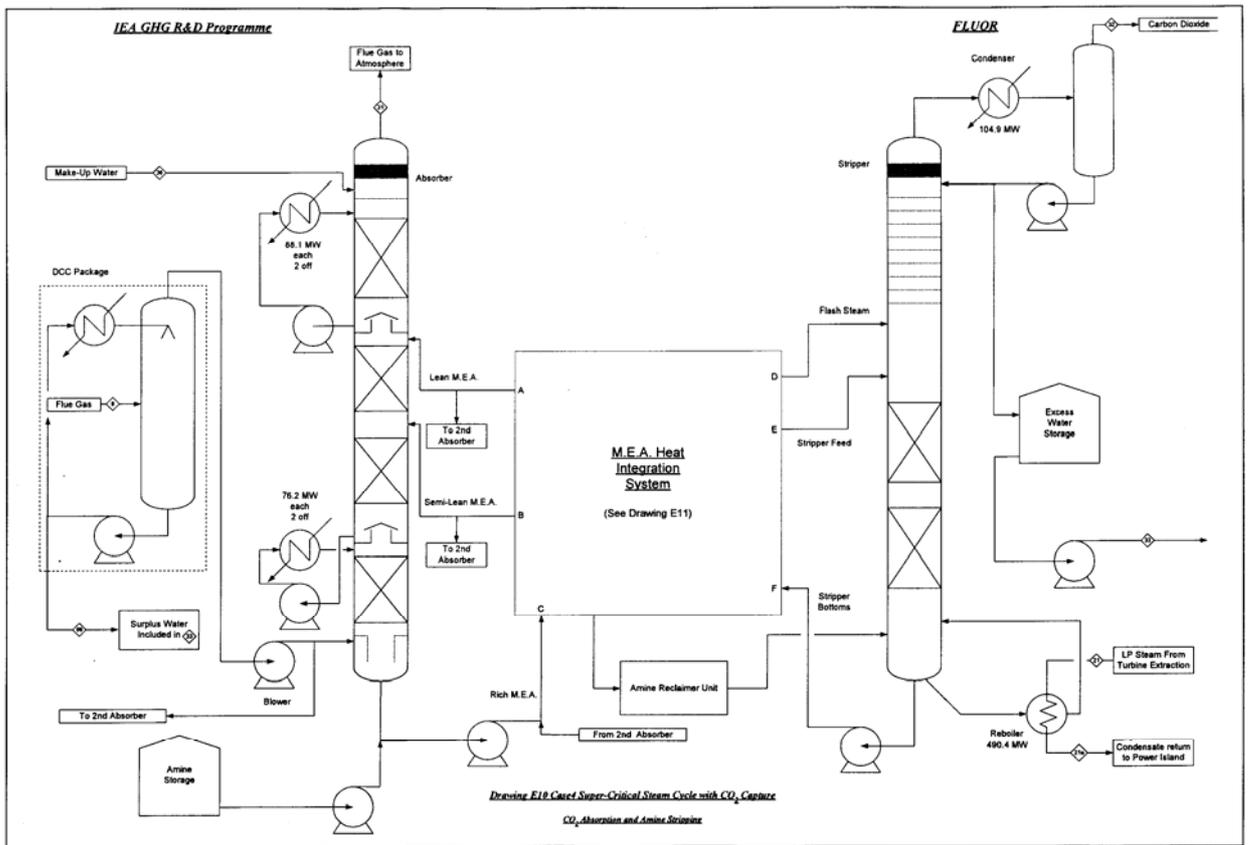


Figure 2.10 Fluor Econamine FG Plus flowsheet (IEA, 2004)

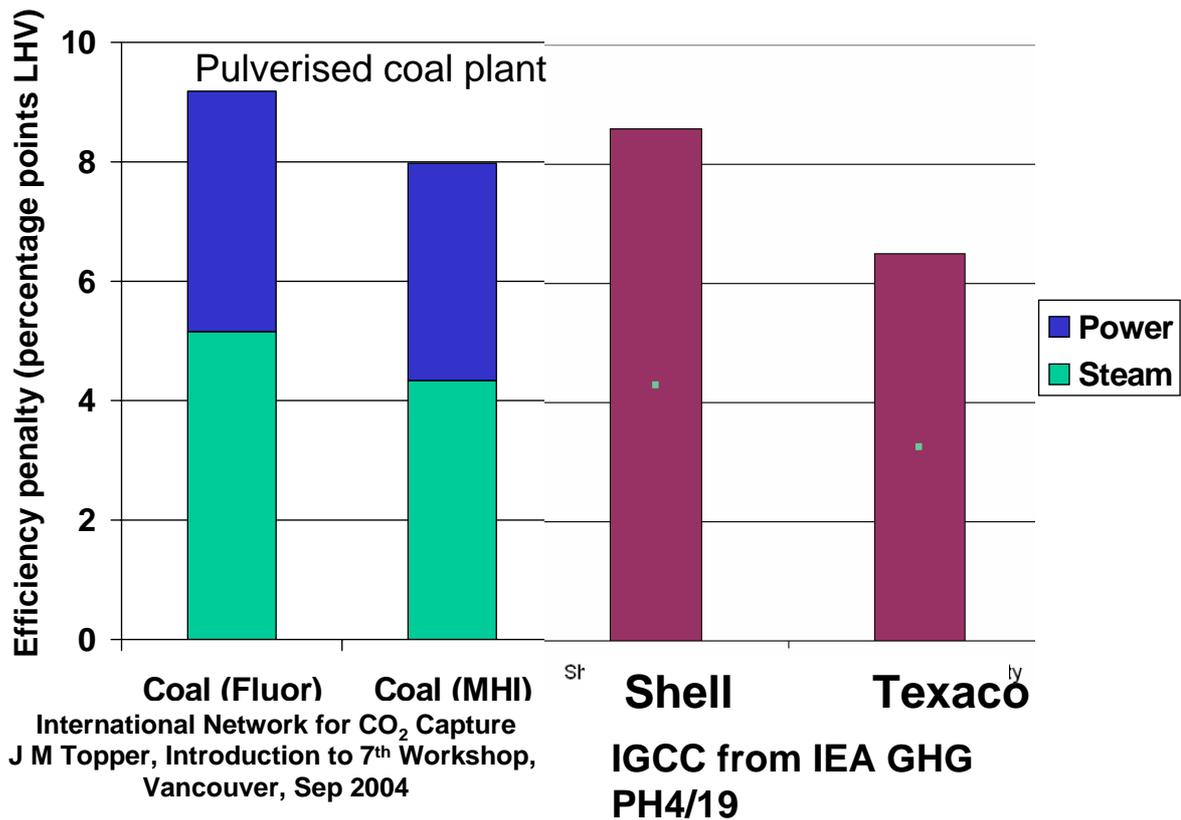
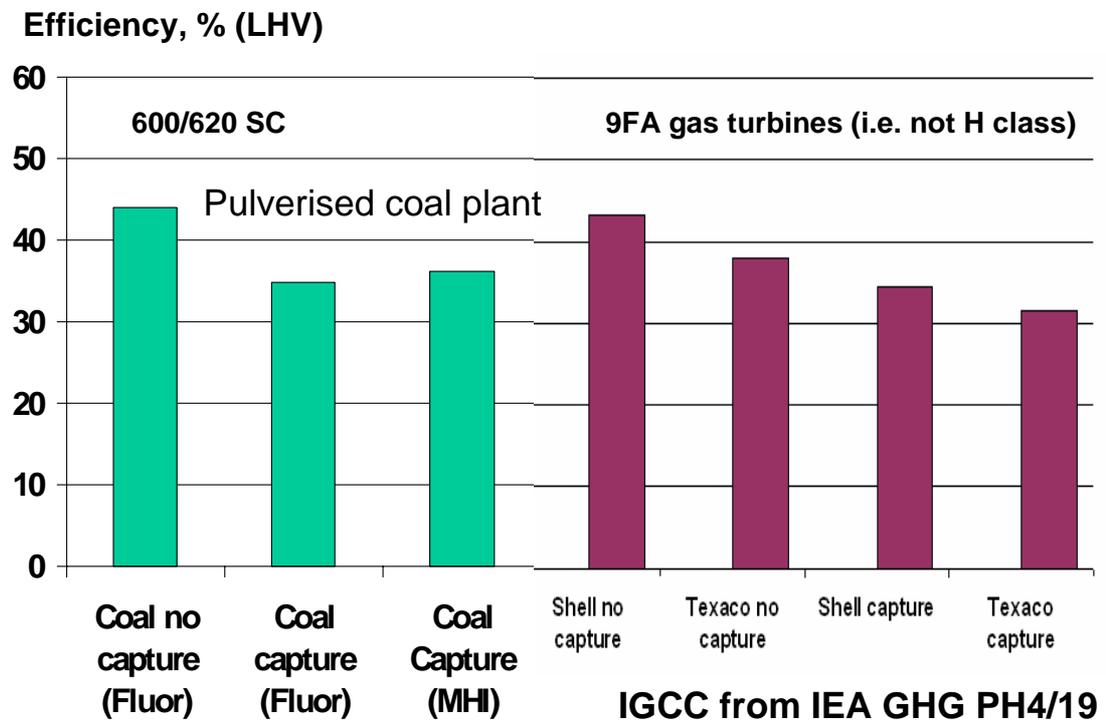


Figure 2.11 Efficiency penalty for CO₂ capture and compression from PC and IGCC plants, percentage points



International Network for CO₂ Capture
J M Topper, Introduction to 7th Workshop, Vancouver, Sep 2004

Figure 2.12 Overall plant efficiencies for PC and IGCC plants with and without CO₂ capture

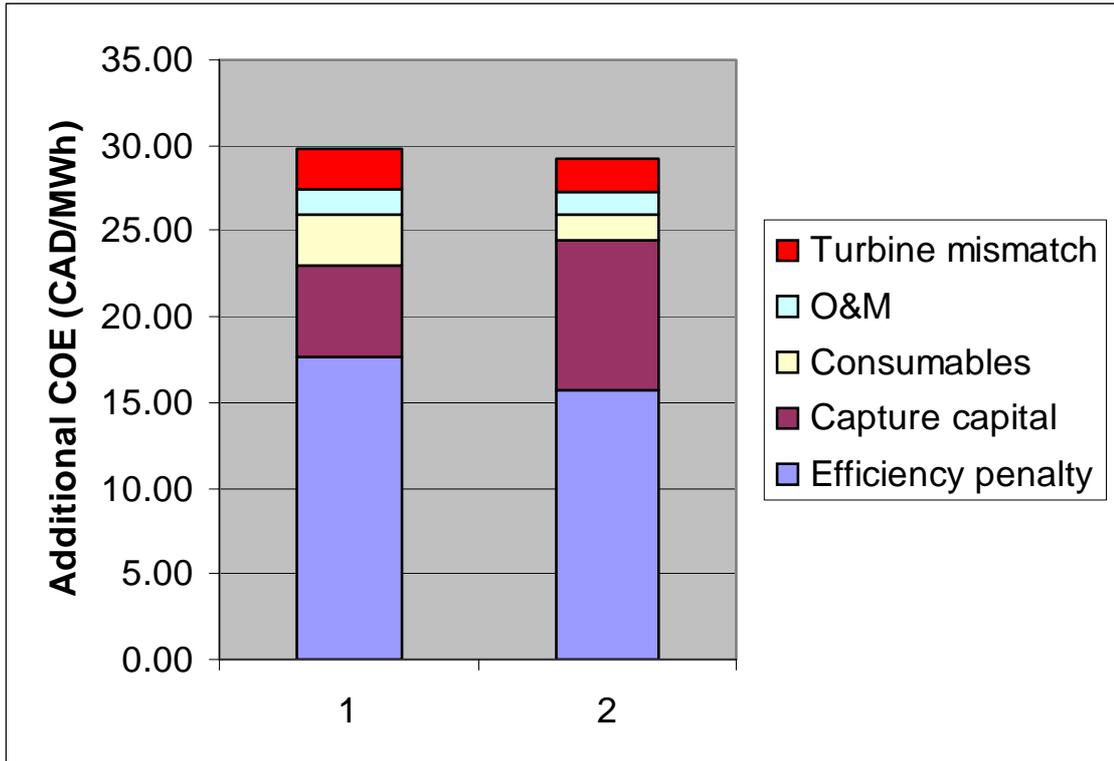


Figure 2.13 Preliminary breakdown for additional COE with capture
(from Mathcad and Excel performance and cost calculations)

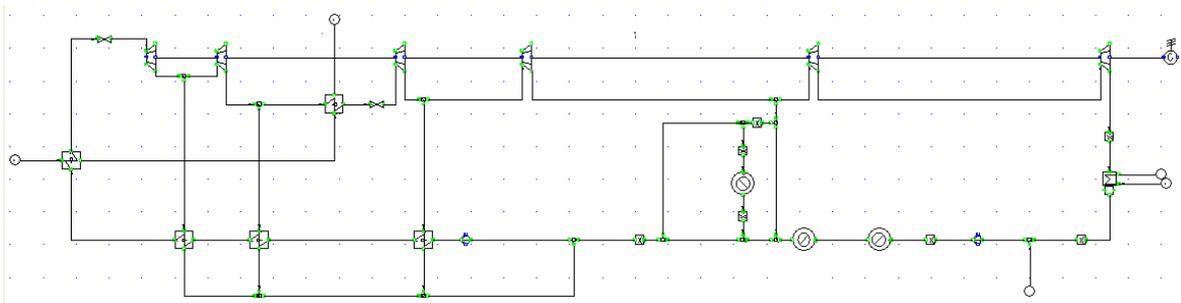


Figure 2.14 IPSEpro model configuration for single reheat capture steam cycle with steam abstraction from the IP cylinder exit – see Figure 2.4 for analogous system diagram (Patel, 2005)

Performance of different cycle arrangements

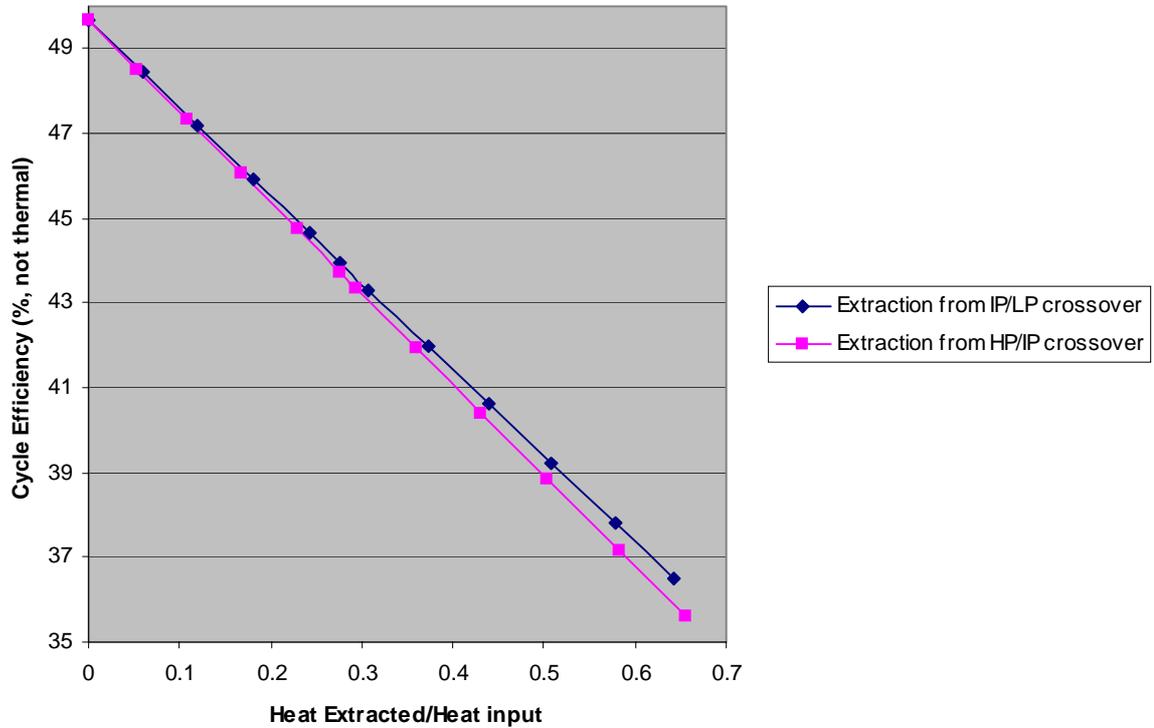


Figure 2.15 Comparison between abstracting steam for solvent regeneration at the HP exit (and then via an auxiliary turbine) and the IP/LP crossover undertaken using IPSEpro modelling. Steam cycle efficiency is virtually identical for both options over a wide range of heating duties; it appears that the 'conventional' IP/LP crossover option would therefore be preferred because of its ability to accommodate a range of steam abstraction flows, including operation without capture and operation with up to ~90% steam abstraction to regenerate stored solvent at night. (Patel, 2005)

Tables

Table 2.1 Summary results from IEA GHG studies on IGCC and PC with CO₂ capture

IEA GHG PH4/19, Potential for improvement in gasification combined cycle power generation with CO₂ capture, May 2003.

Base case plants

Performances and costs of the base case state-of-the-art plants with and without CO₂ capture are shown in table 1.

Table 1: Base case cost and performance summary

	Shell gasification			Texaco gasification		
	Without capture	With capture	Capture penalty	Without capture	With capture	Capture penalty
Net power output, MW	776	676		826	730	
Efficiency, % (LHV)	43.1	34.5	8.6	38.0	31.5	6.5
Capital cost, \$/kW	1371	1860	489	1187	1495	308
Electricity cost, c/kWh	4.8	6.3	1.5	4.5	5.6	1.1
CO ₂ emissions, g/kWh	763	142		833	152	
CO ₂ captured, g/kWh	-	809		-	851	
Cost of CO ₂ avoidance, \$/tCO ₂			24			16

IEA GHG PH4/33, Improvement in power generation with post-combustion capture of CO₂, November 2004

Table 1: Cost and performance summary, Fluor current technology

	Pulverised coal			Natural gas combined cycle		
	Without capture	With capture	Capture penalty	Without capture	With capture	Capture penalty
Plant performance						
Fuel input (MW, LHV)	1723	1913		1396	1396	
Gross power output (MW)	831	827		800	740	
Ancillary power consumption (MW)	73	161		24	78	
Net power output, MW	758	666		776	662	
Efficiency and emissions						
Thermal efficiency, % (LHV)	44.0	34.8	9.2	55.6	47.4	8.2
Increase in fuel use due to capture, %			26			17
Fuel for capture, kWh/t CO ₂ avoided			0.96			0.99
CO ₂ emissions, g/kWh	743	117		379	66	
CO ₂ captured, g/kWh		822			378	
Costs						
Capital cost, \$/kW net power	1222	1755	533	499	869	370
Electricity cost, c/kWh	4.39	6.24	1.85	3.13	4.40	1.27
Cost of CO ₂ avoidance, \$/tCO ₂			29.5			40.7

Table 2: Cost and performance summary, MHI current technology

	Pulverised coal			Natural gas combined cycle		
	Without capture	With capture	Capture penalty	Without capture	With capture	Capture penalty
Plant performance						
Fuel input (MW, LHV)	1723	1913		1396	1396	
Gross power output (MW)	831	838		800	758	
Ancillary power consumption (MW)	77	162		24	66	
Net power output, MW	754	676		776	692	
Efficiency and emissions						
Thermal efficiency, % (LHV)	43.7	35.3	8.4	55.6	49.6	6.0
Increase in fuel use due to capture, %			24			12
Fuel for capture, kWh/t CO ₂ avoided			0.83			0.69
CO ₂ emissions, g/kWh	747	92		379	63	
CO ₂ captured, g/kWh		832			362	
Costs						
Capital cost, \$/kW	1171	1858	687	499	887	388
Electricity cost, c/kWh	4.28	6.30	2.02	3.13	4.29	1.18
Cost of CO ₂ avoidance, \$/tCO ₂			30.9			37.2