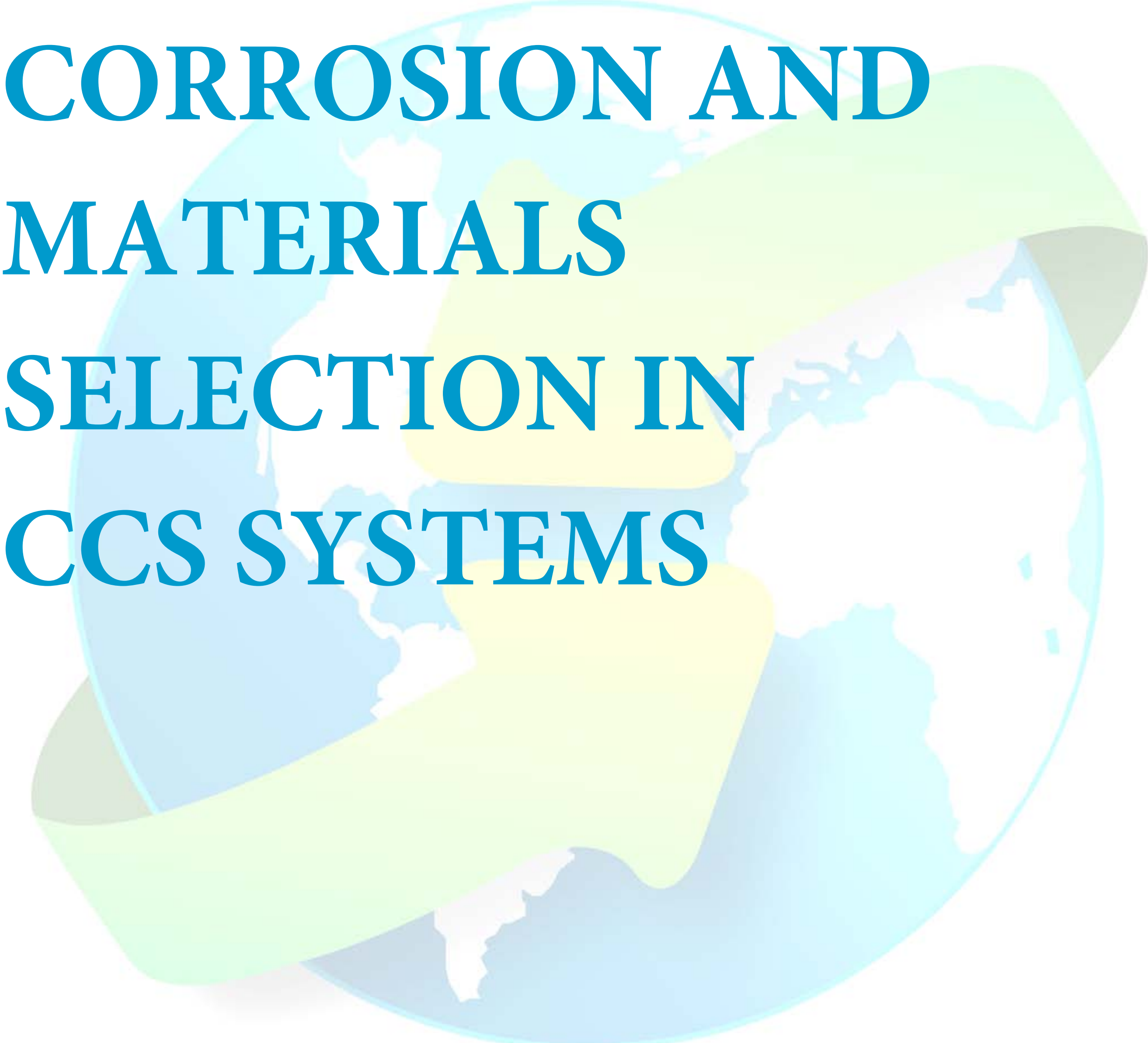
CORROSION AND MATERIALS SELECTION IN CCS SYSTEMS



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CORROSION AND MATERIALS SELECTION IN CCS SYSTEMS

Background

Corrosion and materials selection are key issues in the practical design and operation of power plant, chemical plant, pipeline transport and wells. These all form part of Carbon Dioxide capture and storage (CCS) systems. IEAGHG has produced studies on many aspects of CCS systems and there is now a considerable body of knowledge on the main elements of the process. However while the selection of materials of construction and management of corrosion may be touched upon in these studies the subject has not yet been addressed in any detail.

Study Approach

To select materials it is essential to first know the complete stream compositions and the full range of operating conditions to which all equipment will be exposed. A competitive tender from a consortium comprising Intetech, a specialist corrosion consultancy, and EoN Engineering, actively engaged in developing designs for a variety of power plant CO_2 capture systems was accepted for this study. Eon Engineering developed flow schemes and heat and material balances for oxy-, post- and pre- combustion schemes paying particular attention to defining levels of trace components. All major items of equipment were characterised and all parts of the process affected by addition of CCS were identified. The conditions for transport pipelines and injection wells were also defined by their work. Intetech used this information to establish the main corrosion circuits. A description of all the main corrosion mechanisms likely to apply to CCS systems was drawn up and for each circuit and equipment within the circuit a table of recommended materials was produced.

Results and Discussion

General

Material selection is based on the composition of the streams to which various pieces of equipment, piping and fittings are exposed as well as the temperatures, pressures and velocities which prevail. The steady state conditions of operation are important but equally any excursions which occur during start-up, shut-down or upsets can be key determinants of materials selection and corrosion management. Furthermore the composition of the fuel which is used in the process affects the stream compositions which will be encountered. It is all to easy to develop designs which are later found to have significant corrosion and materials selection issues.

Process flow scheme selection

In view of the forgoing the development of flow schemes, equipment descriptions and heat and mass balances was performed with close co-operation between specialist corrosion engineers and process engineers from the start. Typical schemes for capture from a large power plant using post-, pre- and oxy- combustion were drawn up. Where appropriate both coal fired and gas fired schemes were developed. A single specification for natural gas was used but two coals, a low sulphur (South African, Douglas[1]) and a high sulphur (USA, Bailey[2]) were considered, with composition bracketing the Eastern Australian Drayton[3] coal normally used as standard in IEAGHG studies. During this process careful consideration was given to details of the process line up which might affect corrosion and in some cases alternative arrangements were explored so that the possible effects on material selection could be checked.

Schemes for both coal fired and gas fired pre-combustion capture were drawn up. These processes were based on conventional IGCC and gas reforming technologies for which materials selection is well established. The study considered only those parts of the process which are additional or changed by CCS these being essentially a shift reaction to convert CO to CO_2, a CO_2 absorption unit and a CO_2 compression and drying system. A physical solvent consisting of mixture of di-methyl ethers of polyethylene glycol was specified for the absorption typical of that marketed as Selexol™ by UOP. For the coal fired pre-combustion process it was recognised that capture with and without sulphur compound removal resulted in significantly different process line ups and corrosion conditions within the capture plant and for the pipeline and injection wells. Hence two variants of the coal fired scheme were developed. In one scheme sulphur compounds are captured mainly as H_2S along with the CO_2. In the other a separate concentrated H_2S stream is produced which is then routed through a sulphur recovery unit.

Oxy-combustion schemes were drawn up for coal firing only since gas fired oxy-combustion does not currently appear to be an economic option. Two variants were developed delivering low (97%) and high (99.99%) purity CO_2 respectively. In both schemes a process in which nitrogen oxides and sulphur dioxide undergo oxidation reactions to be removed as dilute nitric acid/sulphuric acid is specified. This is typical of schemes proposed by Air Products Ltd. After this purification step the CO_2 is dried and further purified cryogenically.

Conditions in the hot gas path of oxy-combustion depend on the chosen arrangements for CO_2 recirculation. For this study two variants were examined with recirculating gas passing/not passing through an FGD unit.

Post-combustion schemes were drawn up for gas and coal fired operation and in all cases are based on CO_2 absorption in an amine solvent (MEA). However a list of other potential amines which might be used in the solvent is indicated. For the coal cases an SO_2 polisher is included upstream of the amine unit. Various locations for the ID fan were considered as these affect materials selection for this component.

Corrosion mechanisms

Based on the full range of process conditions and compositions identified in the material and heat balances the various corrosion mechanisms which might be encountered in CCS systems are identified and described. This forms a useful compendium of information

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[1] Douglas coal 0.54% Sulphur, 0.01% Chlorine

[2] Bailey coal 1.97% Sulphur, 0.11% Chlorine

[3] Drayton coal nominally 1.1% Sulphur, 0.03% Chlorine

which is essential background knowledge for engineers and operators of CCS systems. This information when combined with the details of the various processes forms the basis for detailed materials selection and corrosion management for all parts of the system.

The key corrosion considerations and mechanisms which apply in CCS are summarised below.

Free water phase.

There are many process conditions in which free water can be present in CCS systems and these are generally in the zone of what are considered "low temperature" corrosion mechanisms. A free water phase has to be present to form the electrolyte required for such corrosion reactions. Some information is presented on water solubility in gaseous and supercritical CO_2. Solubility is significantly higher in supercritical CO_2 so that a specification of a few hundred ppm is needed to keep gaseous CO_2 "dry" compared with over 1000 to 2000 ppm in supercritical CO_2. Typical solubility limits determined in conjunction with the Dynamis[4] project are shown in a diagram. However these levels could be greatly reduced when other substances, particularly acid or alkaline components are present. The Dynamis work found that below about 10^0C avoidance of hydrate formation requires more stringent water specifications. More work on mixtures of CO_2 with typical contaminants is needed to cover all the conditions which are likely to be encountered.

CO_2 corrosion of carbon steel

Strong acid corrosion of carbon steel involves reaction between iron and hydrogen ions and hence is dependent largely on pH. CO_2 corrosion involves a similar reaction but also reaction with carbonic acid so that it is not pH alone which determines the corrosion rate. Flow conditions have an influence on corrosion rate and also the formation of protective films, notably iron carbonates at temperatures above around 60^0C and iron sulphide when pCO_2/pH_2S ratios are less than about 200:1. Various models are available for prediction of CO_2 corrosion rates under wet conditions. Rates may vary from 1-2mm/yr to 18mm/yr depending on circumstances. Thus given that some parts of CCS processes, for example inlets to absorbers and coolers/knock out vessels in CO_2 compression systems are exposed to wet CO_2 conditions, it is clear that alternatives to carbon steel are needed in some places.

Oxygen corrosion of carbon steel

General oxygen corrosion occurs in wet conditions with rates dependent on dissolved oxygen concentration. These are typically a fraction of mm per year for a few ppm dissolved O_2 and is dependent on temperature. Clearly ductwork in flue gas systems below the dew-point would be vulnerable in CCS processes. Whilst these rates are relatively small a much greater problem is pitting or crevice corrosion which can proceed at a much higher rate accelerating as the process develops. The total rate of general corrosion is expected to be roughly the sum of that due to CO_2 and oxygen.

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[4] Dynamis is an EU project which studied co-production of hydrogen and electricity with CCS.

Corrosion Resistant Alloys (CRAs)

These rely on a protective oxide film to prevent corrosion. Various conditions can attack and breakdown the protective film resulting in localised corrosion which can be at rates even higher than would occur with carbon steel. Erosion is one such mechanism which can be avoided by keeping velocities below standardised limits. However these apply only to solid free systems, the presence of solids can exacerbate erosion of the protective film.

Stress-corrosion

Combinations of mechanical stress and corrosive conditions can lead to cracks developing through materials with little actual corrosion. Both carbon steel and alloys are susceptible in this way to, for example, alkaline environments including amines and for carbon steel at higher temperatures also nitrates. Chlorides even in very small quantities can promote breakdown of the passive film protecting stainless steel and nickel alloys. Presence of other substances such as oxygen can exacerbate the effect. Correct material selection, control of stresses induced by welding and forming and control of the stream compositions can be used in conjunction to avoid this type of failure.

Hydrogen damage

A number of cracking mechanisms involve the behaviour of atomic hydrogen and all may be relevant in certain parts of CCS processes. The effects are; Hydrogen Induced Cracking (HIC), Sulphide Stress Corrosion Cracking (SSCC) of carbon and ferritic steel alloys, Stress-Oriented Hydrogen Induced Cracking (SOHIC) and Sulphide Stress Cracking (SSC) of CRAs. In brief HIC involves recombination of hydrogen diffusing through steel within inclusions. The resulting build up of pressure causes cracks. SSCC occurs when hydrogen produced through corrosion reactions of H_2S dissolves in the carbon steel matrix reducing ductility to the point that the material cracks under stress. SOHIC involves a combination of HIC and SSCC with the two types of cracks linking together. SSC involves stress induced cracking of corrosion resistant alloys with minimal corrosion per se. Areas of the CCS process where hydrogen or hydrogen sulphide are present may susceptible to these corrosion mechanisms.

High temperature corrosion

Oxidation, Sulphidation, Metal dusting and High temperature damage by hydrogen are all corrosion mechanisms which may affect selected high temperature sections of CCS plants. These are briefly described in the report and where relevant are mentioned in sections dealing with specific material selections for high temperature components.

Liquid metal embrittlement

This occurs wherever a lower melting liquid metal destroys the protective coating allowing corrosion to occur. For CCS this only appears relevant in the oxy-combustion process cryogenic clean up process where there is a risk of mercury derived from coal contacting the aluminium heat exchangers. It is noteworthy that certain stainless steels are also susceptible so care has to be taken if these are selected as alternatives for any parts in this part of the system.

Degradation of non-metallic parts.

The main mechanism of polymeric materials degradation in the presence of CO_2 is through swelling of the material especially when exposed to high partial pressures. The report explains how industry uses a special solubility parameter for solvents and plastics which if similar is usually an indication that swelling could be a problem. This as well as good service experience forms the basis for selection of non-metallic materials resistant to swelling.

Rapid Gas Decompression (RGD) is another form of damage which can occur to polymeric materials. It happens when pressure is rapidly reduced and absorbed CO_2 or other gas within the polymer matrix expands and damages the material by blistering or tearing it. Polymeric materials may also suffer from chemical ageing in the presence of aggressive chemical species.

Available materials for specific CCS application areas

The report goes on to consider the various materials which are available for use in wet CO_2, Flue gas and amine environments.

Wet CO_2

The main locations where wet CO_2 will be encountered are in discharge coolers and KO drums of compressors and at the end of injection tubing into CO_2 wells. The materials available include carbon steels, martensitic and austenitic stainless steels, duplex stainless steels, Nickel alloys and Titanium. Whether or not the conditions are “sour”, i.e. whether H_2S is present, and the presence of oxygen influences the choice and performance.

Carbon steel

Despite the corrosion rates which occur when carbon steel is exposed to wet CO_2 it can be a preferred material because of its low cost. In the presence of H_2S corrosion rates may be reduced due to the formation of a protective iron sulphide film. Low temperature carbon steels are also available and are sometimes used to avoid embrittlement when low temperatures might be encountered during blowdown. The corrosion resistance is similar to that of carbon steel.

Martensitic Stainless Steel

These steels typically contain 13% Chromium and have good resistance to wet CO_2 conditions. The safe operating envelope is temperature and NaCl concentration dependent. It is not considered suitable above 200g/l NaCl but the temperature limit rises progressively from around 80C towards 160C as salt concentration reduces. However at high CO_2 concentrations especially those with pH below 3.5 there is a risk of pitting. The report contains a chart which illustrates the safe operating ranges.

In sour environments, martensitic stainless steel is susceptible to SSC below a pH of 3.5. As the partial pressure of H_2S increases above 0.05bar the lower pH limit rises and the safe operating regime is also indicated on a chart in the main report. Super strength 13% chromium steels have been developed and have been shown to have reduced resistance to SSC. The steels can tolerate some oxygen but in the presence of H_2S may lead to pitting and would not be recommended if salt is also present, due to the expectation that pitting would occur.

Austenitic Stainless Steels

These cover the AISI 300 series as well as some other higher nickel/chromium steel compositions. These materials have some limitations. In sweet service there are limiting combinations of maximum temperature, CO_2 partial pressure and NaCl concentration. To which these materials can be exposed. For example for AISI 316 the maximum allowable temperature drops progressively from around 180C with no salt present to only about 80C at 200gm/l. The maximum allowable temperature falls off markedly above a CO_2 partial pressure of about 80bar and the material is thus not suitable for high CO_2 partial pressures combined with high salt concentrations. The report includes a chart illustrating the safe operating conditions for this particular alloy.

In sour service the 300 series steels have significant limitations as set out in ISO 15156. (Note that this standard is subject to frequent revisions). Maximum temperature, H_2S partial pressure, chloride level and pH are the main limitations. Changing alloy compositions can extend limits for some of these but may reduce the limits for the rest. The presence of even traces of oxygen is considered to affect the results of tests and hence wider limits have been indicated by more recent more rigorously conducted experiments. In the presence of significant amounts of oxygen these steels are prone to high rates of pitting and crevice corrosion and are unsuitable for use in such environments.

Duplex stainless steels

These consist of roughly 50/50 ferritic and austenitic material and have the high strength of ferritic steel combined with the corrosion resistance of austenitic. In sweet service these materials are suitable at temperatures around 200+C even for very high salt concentrations. In sour service susceptibility to Sulphide stress cracking is found to be highest at 80C and hence limits are established at this condition. No SSC occurs below an H_2S partial pressure of 0.01bar even at high chloride levels and low pH. This increases toward 1 bar as salt concentration reduces towards zero. The report contains a chart illustrating the limits. In the presence of oxygen duplex steels would be susceptible to pitting corrosion in the presence of chloride ions and as with the Austenitic steels would be unsuitable for use in this environment.

Nickel alloys and titanium

Nickel alloys are those containing >40% nickel. These are expensive materials but do have excellent resistance to pitting corrosion. In the presence of oxygen and chlorides there are temperature limitations which mean that above 90^0C titanium and its alloys may be required.

Flue gases

The main areas where corrosion of materials exposed to flue gases will occur is in the section of plant upstream of absorbers in post combustion plant. Extensive experience has been obtained in this environment from the operation of FGD units. In dry conditions carbon steel is an adequate material but conditions will not be dry in the relevant parts of

CCS systems. pH is expected to be low due to the presence of sulphur and nitrogen oxides and chlorides may also be present in the water phase. The main choices are to use corrosion resistant alloys, non-metallic linings are ceramic tile clad concrete.

Corrosion resistant alloys

Because of the cost and the large sizes of ductwork the preference is to line carbon steel with thin sheets of alloy. Austenitic and duplex steels face some limitations depending on pH and chloride concentration. The report shows a chart indicating the types of alloy which are appropriate for the various combinations of chloride content and pH. Alloy lining has been a relatively successful approach with the main problems arising from failures associated with the method of weld attachment of the sheets with vibrations being the main cause fatigue leading to failure and corrosion of the carbon steel structure. Because rather thin sheets can be “wall-papered” to carbon steel surfaces, lining can be quite economical

Non-metallic linings.

These have proved equally effective but eventually suffer from water vapour permeation which then leads to corrosion. The main contenders are rubber and higher grades of filled resin with good water vapour permeation resistance. Rubber linings require extensive preparation of the surface to be successful whereas resin based linings are more tolerant. Glass flake filled vinyl ester resin has been particularly successful.

Non-metallic construction

Filament wound glass reinforced plastic (GRP) is an option for large ducts and has been used for large inlet/outlet piping in the US with favourable results.

Ceramic lined concrete

If concrete is the structural material the use of acid resistant grades for exposed surfaces with tiles linings could be considered.

Amines

In general carbon steel can be used in the amine environment. Stress corrosion can occur so that post weld heat treatment may be needed depending on the amine selected. Austenitic stainless steel is typically used in refinery amine environments for higher temperature parts, including heat exchangers re-boilers, stripper overheads. Martensitic steel, copper and aluminium is to be avoided in amine environments.

Oxygen degrades amines through oxidation reactions and leads to formation of acids. This process if controlled with inhibitors, amine reclamation etc. allows the same typical materials to be used. As oxygen will be present to a greater extent in CCS amine systems controls of degradation and corrosion will need to be re-enforced.

Non-metallic lining materials for amine systems if used would need careful selection as amines are strong solvents. There is limited but successful experience with selected linings in amine service.

Material selection for CCS systems

General

The key part of the report is the recommendations for materials and corrosion management to be used in the various sections of CCS systems. Only those parts of the system which might be different in some way to conventional power generation systems are covered. Thus all general utility systems such as cooling water are not covered. Standard industry practice can be used for these. Also the following elements are considered to be "standard" from the industry materials selection viewpoint.

- The ASU for oxy-combustion and pre-combustion applications,
- The main boiler, HRSG, ESP and conventional FGD in post-combustion systems,
- The gasification sections of pre-combustion processes up to the low temperature shift for removal of CO.

In all these parts of CCS systems existing materials selection and corrosion management practices can be used. Also excluded from this study, after some debate, is the hydrogen burning gas turbine power generation system. The parts which might be affected such as burners and blades involve highly specialised metallurgy and are the domain of turbine manufacturers. Suffice it say that manufacturers are reasonably confident that they will be able to offer suitable machines and that the precise material selection is likely to be proprietary in nature.

All of the materials selections were performed by Intetech apart from those for the hot gas path of oxy-combustion processes which were performed and reported in a separate section by EoN Engineering based on their wider experience in this particular area. The selection made by Intetech are presented in the form of three elements; a corrosion circuit diagram, an equipment table and an accompanying narrative. The narrative expands on the more general summaries of material considerations for the three main generic corrosive environments.

Highlights of the material selection recommendations

In this section of the overview the intention is to highlight the key areas where corrosion expertise will have to be deployed in CCS systems. This is important for two main reasons:-

- To prevent development of unsafe situations
- To optimise capital and operating costs of the system

It is clearly vital that unexpected and sudden failures do not occur and that where slower corrosion process are possible that the necessary monitoring and inspection is carried out at appropriate intervals. Optimisation of capital and operating costs on the other hand requires careful trade-offs between the high initial costs of corrosion resistant materials the expense of regular repairs, replacements as well as potential revenue losses due to shutdowns.

Post-combustion process – absorber vessel

This vessel is challenging from the materials point of view because of the huge size, estimated to be around 15-20m diameter and 40-50 m high. Structurally the best choices appear to be stiffened carbon steel or slip formed concrete. Other forms of construction would require too large a wall thickness. The stiffened carbon steel option would require a lining which would have to be resistant to the solvent properties of amines. The best option might be FGV if adhesion can be maintained in amine service. The slip formed concrete option would require an acid tiled lining and is expected to give long maintenance free service.

Post-combustion – flue gas path

This consists largely of low pressure ducting, an induced draft fan, direct contact cooler (DCC) and polishing scrubbers for SO_2 and residual amines. Because conditions are wet and CO_2 and oxygen are present carbon steel is not suitable without lining. For ducting the choice is between stiffened steel with a rubber or flake glass vinyl-ester (FGV) coating (FGV preferred) or for circular cross sections spiral wound GRP. Scrubber and DCC towers will also need lining and coated steel using FGV is preferred although some maintenance may be needed. A CRA lining could be considered for these if maintenance free service for the full design life is wanted. The casings of fans can be constructed of lined carbon steel but higher chromium steel (25% austenitic or duplex) is proposed. Shafts can either be coated or lined with similar alloy.

Post-combustion process – rest of amine system

The presence of oxygen in the flue gas will most likely result in formation of some organic acidic components. Hence it is recommended that the parts exposed to rich amine or high temperatures are constructed in corrosion resistant alloy. Specifically the bottom part of the stripping system which in conventional systems is often of carbon steel will need additional protection. Costs can be minimised by cladding rather than using solid CRA wherever possible. Chloride levels should be low since these should be scrubbed out of the flue gas in the FGD and SO_2 polishing processes. Make up water and chemical should also be specified and maintained chloride free so that a low cost CRA such as AISI304L can be used. At the top area of the stripping system acid components may be present, some residual SO_2 is indicated in the coal fired H&MB,s, so that a higher alloy CRA is recommended.

Pre-combustion process – -Shift reactors

The materials in this section have to be resistant to high temperature hydrogen attack and in the case of coal fired processes also to sulphidation. In the gas fired case the HT shift reactor can be a 1%Cr – 0.5%Mo steel and the LT shift carbon steel. For coal fired systems a suitable grade of 18 – 10 stainless steel is required. At the higher temperature of the HT shift there is expected to be slow corrosion and here a higher chromium grade may be desirable to achieve acceptable component lifetime. Metal dusting is not likely to be a problem and the H_2S will give additional protection against this in coal fired systems.

Pre-combustion process – -Solvent system

Two types of system were evaluated, one in which sulphur species are co-captured with the CO_2 and the other in which the sulphur is removed from the CO_2. In the former system there are some areas where wet CO_2 will require a CRA and here typically AISI 316L has a proven track record. The presence of H_2S in the coal cases reduces corrosion rates extending the parts for which carbon steel is adequate. In order to recover sulphur it is necessary to concentrate the recovered H_2S stream in an H_2S concentrator which has to be supplied with a stripping gas, either nitrogen or a recycle of the hydrogen product. In the scheme evaluated nitrogen was chosen. It should be noted however that if nitrogen is chosen it **must be free of oxygen** (<5ppm) to avoid significant corrosion in this section of the process. It should also be noted that CRA selection is based on the processes upstream of the solvent capture being effective in removing any chlorides.

Oxy-combustion – CO_2 clean up

Raw wet CO_2 from the oxy-combustion plant containing SO_2 and NOx is first processed at intermediate pressure and the sulphur and nitrogen is largely removed as dilute acid streams. The process equipment consists of reaction vessels and low pressure compressors. CRA or organic coated carbon steel vessels will be adequate. As pressures and are low, GRE piping could be considered although the temperatures in the H&MB are close to the limit for this material. Otherwise higher grade CRA is proposed. The dilute acid outlet system could best be constructed in non-metallic piping

Oxy-combustion – Cryogenic separation unit

Streams are completely dried before entering this unit to prevent blockages from ice or hydrates. Conditions are thus non-corrosive and the main selection criteria are low temperature properties and for heat transfer equipment the thermal conductivity. Low temperature carbon steel can be used for some sections of this unit and for the lower temperature sections austenitic stainless steel such as AISI 316L or 304L. Brazed aluminium fin-plate heat exchangers are favoured because of the good thermal conductivity of aluminium which allows compact and complex constructions. However AISI 316L is an alternative which could be considered since a variety of compact exchanger designs can be fabricated in this material. In the presence of mercury aluminium is at risk of liquid metal embrittlement, corrosion and stress-corrosion hence an upstream mercury guard bed is recommended as a precaution.

Oxy-combustion – Hot gas path - Furnace

The key corrosion effect is fireside corrosion of the high pressure boiler parts which is already a complex issue in air fired systems. Reducing conditions result in greatly increased corrosion rates so that the first requirement in oxy-combustion is to ensure that with the different conditions and staging of oxygen flows to the burners reducing conditions are avoided. For the large part this reason for corrosion can be managed in the same way as for air-fired counterparts. This may prove easier to do for oxy-combustion systems as there is not the same need to minimise NOx formation. Deep staging of combustion to avoid NOx is implicated in creation of conditions which favour fireside corrosion.

Another key factor in fireside corrosion is the chlorine content of the coal which results in levels of HCl in the combustion gases. It is particularly damaging in reducing atmospheres. Any HCl in the flue gases will be scrubbed out in the FGD so that if the recycle is taken after this unit HCl levels in oxy-combustion systems should be similar to those in air fired systems. If on the other hand the FGD is outside the recycle loop HCl will be concentrated and more severe limits will have to be placed on coal chlorine content. In all systems the concentrations will be somewhat higher if oxygen enrichment levels are high as the total combustion gas flow carrying the HCl will be reduced. A secondary effect is that with lower flows there may be higher heat flux rates which further increase fireside corrosion rates due to presence of HCl. A second key design requirement is thus to carefully specify a suitable combination of coal chlorine content and flue gas recycle arrangements.

In summary designs with the FGD inside the recycle loop are expected to have similar corrosion behaviour to their air fired counterparts. If the FGD is outside the recycle loop special attention will need to be given to the build up of corrosive species, mainly HCl, but also sulphur species.

Oxy-combustion – Hot gas path – superheater/re-heater

A significant corrosion process is that caused by deposition of molten alkali sulphates which react to form alkali iron tri-sulphates in this area of power plant. The process occurs only in the hotter areas of the super-heaters where these compounds are molten. These effects are expected to be similar to those encountered in air-fired plants except that they could be worsened by build up of HCl or sulphur compounds where the FGD is outside the recycle loop. No further advice on how to deal with this issue is available and further study is needed.

Oxy-combustion – Hot gas path – cooling prior to FGD

Whether the FGD is within or without the recycle loop the flue gases have to be cooled before they enter the scrubbing tower. When outside the loop the gases have to be cooled either by direct contact cooling or a heat exchanger. When inside the loop the desulphurised gases from the FGD are used to cool the incoming feed in a gas-gas re-heater analogous with the air pre-heater of a conventional air-fired plant. Alloy materials or coatings will have to be used to protect against corrosion as the cooled stream is expected to fall below the sulphuric acid dew-point. With the higher water content of flue gas in oxy-combustion there is a possibility of dropping below the water dew-point which results in further accelerated corrosion and the need to use higher grades of alloy.

Oxy-combustion – FGD plant

Corrosion protection of the FGD system is not expected to be any different to that used in conventional systems. The report details the various materials in common use. One point of note is that air sparging within the tower is often used to convert sulphite to sulphate enabling the resulting gypsum to be sold. This would not be appropriate for oxy-combustion so either an additional treatment of the slurry or possibly use of oxygen sparging may be needed. Although this will slightly change the FGD for an oxy-combustion CCS system it does not present any new material selection issues.

Oxy-combustion – Recycle Gas Ductwork and fans

Some elements of the recycle system will be cool enough to be below the sulphuric acid dew-point and will need to be protected by suitable lining or cladding. Once above the dew-point conventional materials for higher temperature ductwork can be used. After oxygen is injected into the recycle the partial pressure will be slightly higher than that in air and may be even higher locally. Metallic materials will not be affected but a check should be run on the compatibility with non-metallic materials and lubricants to ensure that there are no issues of flammability or degradation.

Oxy-combustion – Coal Mills

The recycled gas to the mills will contain elevated amounts of water vapour largely dependent on the temperature to which they are equilibrated against water. When mixing with the coal the temperature will drop and may fall below the dew-point. The resulting corrosion could be excessive and careful attention to the water content of the recycle stream will be essential since constructing the mills of more corrosion resistant materials is not considered to be viable.

Oxy-combustion – CO_2 compression

CO_2 from the various capture processes has to be compressed to supercritical conditions for pipeline transport. From pre-and post- combustion processes it has to be compressed from around atmospheric pressure or slightly above but will be water saturated at the start of the compression process. The wet parts of the compression system are the after-coolers, suction KO drums and piping for all stages up to the point that the gas is dried typically in a glycol system. Chlorides are absent and austenitic stainless steel is proposed for these wetted parts with higher grades recommended as the pressure increases. For the compressors martensitic stainless steel is a common choice combining high strength with some corrosion resistance which helps if there are short periods when conditions are wet during start up and shutdown. Downstream of the drying unit carbon steel can be used.

CO_2 pipelines

The key issues relating to corrosion and materials selection are water content, steel strength/toughness and sour service if H_2S is co-captured.

CO_2 pipelines – Water content

CO_2 captured in the various CCS processes is not corrosive to carbon steel provided it is dry, which typically means that the dew-point needs to be reduced to at least 10^0C below the minimum expected temperatures in the pipeline system. Water content in supercritical CO_2 can be significantly higher than in gaseous CO_2 before a second phase is present. The phase boundary is affected by the presence of impurities but for non-acid impurities the effects are moderate. Recent information is available from the Dynamis project on the water and hydrate phase equilibria and this shows that avoidance of hydrate formation may generate the stricter requirement. Whilst pipelines in West Texas have been operated successfully with water specifications of around 600ppm a level of around 250ppm would appear to be more appropriate in colder climates where hydrate formation which only occurs below around 10^0C, is possible.

CO_2 pipelines – Steel strength and toughness

The design and materials selection requirements for CO_2 lines can be based on existing codes. However because of the phase properties of CO_2 there is a greater requirement for material toughness to prevent running ductile fractures. The recognised method for determining requirements is the Batelle Two Curve Model (BTCM). If a ductile fracture starts in a high pressure gas line there is rapid depressurisation along the line which continues until a liquid phase forms. At this point, the “saturation point”, the rate of pressure drop falls off until the liquid phase is exhausted. The running ductile fracture propagates relatively slowly and will arrest when the hoop stress at the tip of the crack is lower than that needed for propagation. The BTCM calculates both the advance of the crack tip and the path of the pressure reduction to determine whether and where the fracture will stop. Unfortunately the BTCM has some restrictions to its applicability and validity for high toughness and high strength materials. The saturation point for supercritical CO_2 may be as high as the critical pressure which is high compared to the saturation point of high pressure gas lines or LPG lines. This means that design to avoid running ductile fracture is more onerous for CO_2 pipelines.

The report reviews the issue in more depth concluding that there is little point in using high strength steels beyond X-60 to X-65. Also the toughness requirements in larger diameter pipelines become progressively higher and move into the realm where the BTCM model is no longer validated. Authorities are likely to require full scale rupture tests to approve such designs.

For larger diameter lines it seems likely that minimum wall thickness will be determined by crack arrest requirements rather than hoop stress making use of high strength steels pointless.

CO_2 pipelines – Sour Service

If H_2S levels are above a partial pressure of 0.05psia sour service materials, as specified in the ISO 15126 standard, have to be used following the common practice in oil field systems. This will apply to transport of captured CO_2 in the case of pre-combustion with co-capture where with the high sulphur coal a partial pressure of about 27psi will occur for a line running at 150bar. Also any mixtures of this gas even with large quantities of sweet CO_2 can be expected to exceed the partial pressure limit. The principle effects are that the hardness of the materials, fittings and welds has to be assured to be below specified limits.

Wells

Corrosion resistant materials are needed for the lower part of injection tubing as maintaining the dry status of the CO_2 cannot be guaranteed. CO2 EOR operations have established some experience with tubing materials in wet conditions as water is often injected intermittently in the so called “WAG” water and gas injection system. Coated tubing has been used successfully but has proved to have a limited lifetime. For CCS the lower section of tubing will need to be of corrosion resistant alloy of grade depending primarily on the presence of oxygen, to some extent on the concentration of salt in the formation, and to a lesser extent on whether H_2S is present. In oxygen free, low chloride sweet conditions a 13% Cr material is adequate whereas when oxygen is present and chloride is high a Hastelloy 625 may be required. It is thus of particular importance to note that presence of even traces of oxygen introduces the risk of pitting corrosion and the need for significantly higher grades of alloy. As an alternative the possibility of using suitable oxygen scavengers could be investigated.

Attention needs to be given to seals in tubing connections as leakage of CO_2 into the annulus should be avoided. There have been problems with tubing connection sealing in CO2 EOR operations but satisfactory solutions are available.

On the basis that dry conditions prevail at the well head, conventional materials can be used for Christmas trees. Any non-metallic components for gaskets would however need to be selected for CO_2 compatibility.

Expert Review Comments

Expert reviewers found the report to be thorough and made a number of minor comments which were incorporated into the text. Key observations were as follows. It was stressed by one reviewer that a careful distinction needs to be made between sour service conditions for which materials have been validated in corrosion tests for the ISO 15156 standard and those which would require corrosion tests under the expected conditions to be fully compliant with this standard. This would have to be catered for in the planning of CCS projects. Other reviewers stressed the extremely high corrosion rates which would prevail if normally dry supercritical CO_2 became wet due to upset conditions. Also that the water phase might linger for a long time in crevices or dead spots once dry conditions were restored. Good procedures will be needed to recover from such events and these may trigger the need for post event corrosion inspection. One reviewer felt that the report might be enhanced of the material selection tables contained pointers to the specific sections of text which support the selection decision. Specific comments were received on material selection for the Selexol™ process in the pre-combustion capture application and appropriate adjustments made to better reflect practical experiences.

Conclusions

There are many areas of CCS systems where careful selection of materials will be required to ensure safe and economical operation. This study has not revealed any areas where a suitable and reasonably economical solution for materials choice and corrosion monitoring is not possible.

The presence or otherwise of even trace amounts of oxygen in certain parts of CCS systems needs to be fully understood in order to make proper material selections and either the process should ensure absence of oxygen if it could be present or an appropriate corrosion resistant alloy material should be selected.

There are some areas where further research would be helpful, in particular the establishment of toughness requirements for very large diameter high pressure CO_2 pipelines or those made of very high strength steel. Also the efficacy of oxygen scavengers in the wet supercritical CO_2 environment and conditions under which free water will be present for all combinations of impurities which may be encountered should be determined.

Recommendations

Operational experience and the results of material and corrosion tests are both valuable sets of information which can improve confidence and minimise costs of CCS systems. IEAGHG should explore ways in which it can encourage the required additional research and the dissemination of operational experiences with material performance and corrosion.

CORROSION AND SELECTION OF MATERIALS FOR CARBON CAPTURE AND STORAGE

INTETECH REPORT
FOR
IEA GREENHOUSE GAS RESEARCH AND DEVELOPMENT PROGRAMME

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EXECUTIVE SUMMARY

The IEA Greenhouse Gas R&D Programme (IEAGHG) has studied many aspects of Carbon Dioxide Capture and Storage (CCS). As part of this programme, the current study investigates the potential corrosion risks in the CCS processes and proposes suitable materials of construction to mitigate those risks. The scope of this study covers all aspects of the CCS systems, including the carbon capture plants, transport of CO_2 and injection wells.

E.ON Engineering modelled generic CCS process schemes for Post Combustion, Pre-Combustion and Oxy-Fuel technologies. Based on the Heat & Mass Balance (H&MB) data from this modelling, Intetech Consultancy Ltd have evaluated corrosion risks and proposed material selections which take into account the scale of plant equipment. A general review of potential corrosion mechanisms relevant to CCS operations is provided and relevant industry experience from existing similar applications is assessed. Areas where further research or study is needed to optimise materials selection are identified.

From a corrosion point of view, there is a wide range of environments amongst the different CCS processes. In general, the high CO_2 levels mean that wet process environments tend to be acidic with high corrosion rates estimated for unprotected carbon steel. There are acid-oxidising conditions in some streams which present particular risks to stainless steels and corrosion resistant alloys.

The presence of significant halide levels in process streams would require significant changes in some material selections, typically to much higher alloy CRAs. Control of the quality of water and treatment chemicals introduced into the process streams is critical in this respect.

The presence of oxygen is potentially challenging for

- Amine CO2 removal for Post Combustion capture
- Downhole materials in the injection well (Post-combustion and possibly Oxy-fuel)

In the Pre-combustion (IGCC) schemes, oxygen control is critical for streams containing hydrogen sulphide.

In all these cases, high-performance, expensive, materials may have to be used if the environment is not controlled within suitable limits. These situations require further study on the process conditions and materials performance to optimise materials selection. Further work is also expected to be necessary to qualify specific polymeric materials and coatings for service with high CO_2 pressures.

Major items where there is a choice of competing material solutions include ducting for the main process streams and the CO_2 absorber vessel in Post-Combustion capture. The options require finalising in the context of a specific plant design.

1 INTRODUCTION

IEAGHG has had studies performed on many aspects of Carbon Dioxide Capture and Storage (CCS). These have more recently included studies of specific issues such as the impurity levels in captured CO_2, and ongoing studies of the safety of CCS, and processes for clean up and purification of captured CO_2. It became apparent that there is a need to investigate the potential corrosion risks in the CCS processes and material selection issues as these will affect the construction costs, operability and general safety of CCS systems.

A conceptual study was awarded to Intetech Consultancy Ltd by IEAGHG to evaluate the associated corrosion risks in the CCS processes, and to propose appropriate corrosion mitigation procedures and materials of construction. The scope covers the carbon capture plant, transport of CO_2 and injection wells.

E.ON Engineering modelled generic CCS process schemes, and the input data for the corrosion study is primarily based upon the Heat & Mass Balance (H&MB) data from this modelling. However, a wider range of conditions has been considered where appropriate to allow for likely fluctuations in operating conditions and shut-down or upset-conditions. Indication of the scale of the plant equipment was also provided by E.ON, as this impacts the material selection options.

It was IEAGHG's aim to cover the alternative CCS processes as fully as possible. Thus, seven processes have been considered in this study, they are differentiated by the fuel type, combustion technology and process configuration as listed below:
- Post-combustion capture with coal
- Post-combustion capture with natural gas
- Pre-combustion capture with coal (co-capture)
- Pre-combustion capture with coal (separate capture)
- Pre-combustion capture with natural gas
- Oxy-fuel combustion (low CO_2 purity)
- Oxy-fuel combustion (high CO_2 purity)

Process descriptions for each of these are provided in Chapter 5.

A general survey of potential corrosion mechanisms relevant to CCS operations is provided in Chapter 6. Industry experience from some existing applications relevant to parts of the CCS plants is discussed in Chapter 7. Material selection for the carbon capture plants is covered in Chapters 8 to 12. Transport and injection are common to all the processes, and are treated separately in Chapters 13 and 14.

2 GENERAL INFORMATION

2.1 Abbreviations

BTC	Battelle Two Curve model
CA	Corrosion allowance
CBP	Constant bottomhole pressure
CCS	Carbon capture and storage
Cl^-	Chloride ion
CP	Cathodic Protection
CRA	Corrosion resistant alloy
CS	Carbon steel
DCC	Direct contact cooler
DSS	Duplex stainless steel
DWTT	Drop-weight tear test
E.ON	E.ON Engineering
ECE4	Electronic Corrosion Engineer® version 4
EFC	European Federation of Corrosion
EOR	Enhanced oil recovery
ER	Electrical resistance
ERW	Electric resistance welded
FBE	Fusion bonded epoxy
FeS	Iron sulphide
FGD	Flue gas desulphurisation
FGV	flake glass vinylester
H&MB	Heat and mass balance
H/M/LP	High/Medium/Low pressure
H_2S	Hydrogen sulphide
HE	Heat exchanger
HFI	high-frequency induction
HIC	Hydrogen induced cracking
HT	High temperature
IEAGHG	International Energy Agency Greenhouse Gas R&D Programme
IFE	Institutt For Energiteknikk
IGCC	Integrated gasification combined cycle
IP	Injection pressure
J	Joule
KO	Knock out
LME	Liquid metal embrittlement
LTCS	Low temperature carbon steel
max	maximum
MEA	Monoethanolamine
MIC	Microbial influenced corrosion
MMscf	Million standard cubic feet
MSD	Material selection diagram
MSS	Martensitic stainless steel
NOx	Mono-nitrogen oxides (NO and NO_2)
PED	Pressure Equipment Directive
PFD	Process flow diagram
p	partial pressure (eg pCO_2)

pH	Acidity index
PL	Pipeline
ppb	Part per billion
ppm	Part per million
PWHT	Post weld heat treatment
RGD	Rapid gas decompression
RP	Recommended Practice
S	Sulphur
SAW	submerged-arc welded
SCC	Stress corrosion cracking
SIAP	shut-in annulus pressure
SITHP	shut-in completion string pressure
SOHIC	Stress-Orientated Hydrogen Induced Cracking
SOx	Sulphur oxides
SSC	Sulphide stress corrosion
SWC	Stepwise cracking
Syngas	Synthesis gas
temp	temperature
V_{cor}	corrosion rate
V_m	reaction kinetics
V_r	rate of mass transport
WAG	Water-alternating-gas

2.2 Process Simulation

The simulation of the following processes has been completed by E.ON

- Post-combustion capture with coal
- Post-combustion capture with natural gas
- Pre-combustion capture with coal (co capture)
- Pre-combustion capture with coal (separate capture)
- Pre-combustion capture with natural gas
- Oxy-fuel combustion (low CO_2 purity)
- Oxy-fuel combustion (high CO_2 purity)

The complete E.ON report can be found in Appendix A.

3 SCOPE OF WORK

Three combustion technologies with different fuel types were selected by IEAGHG for the study, namely post-combustion capture with coal and with gas; pre-combustion capture with coal and with gas; and oxy-fuel combustion with coal. Each of the combustion technologies is presented by a distinct process scheme. Chapter 5 gives more detail on the different process schemes. Further, an additional process scheme for pre-combustion capture has been included to cover the alternative process for separate-capture of CO_2 and H_2S from the syngas; whilst two variations in the CO_2 purification plant of the oxy-fuel combustion process have been included, producing either a high CO_2 concentration (99.9%) or low CO_2 concentration (97%). The full list of design cases for the materials study is therefore:

- Post-combustion capture with coal
- Post-combustion capture with natural gas
- Pre-combustion capture with coal (co capture)
- Pre-combustion capture with coal (separate capture)
- Pre-combustion capture with natural gas
- Oxy-fuel combustion (low CO_2 purity)
- Oxy-fuel combustion (high CO_2 purity)

3.1 Fuel types

In addition to natural gas, two coal types have been considered by E.ON in the process modelling, namely South Africa Douglas coal and USA Bailey coal. Bailey coal is characterised by higher sulphur and chloride contents than Douglas coal. Table 3.1 shows the properties of the two different coal types.

Table 3.1 : Comparison between South Africa Douglas and USA Bailey coals.

Coal name	Douglas	Bailey
Origin	South Africa	USA
Moisture (% total)	7.8	8.2
Ash (% as received)	14.5	7.2
Volatile matter (% as received)	22.9	35.4
Net calorific value (kJ/kg as received)	25079	28398
Carbon (% as received)	67.00	71.16
Hydrogen (% as received)	3.60	4.71
Nitrogen (% as received)	1.66	1.35
Oxygen (% as received by difference)	4.90	5.31
Sulphur (% as received)	0.54	1.97
Chlorine (% as received)	0.01	0.11

The main corrosive species in most of the CCS process streams is CO_2, but the severity of corrosion threats is often sensitive to the presence of minor components, such as O_2, SO_2, H_2S and chlorides. In the Post-combustion capture and Oxy-fuel combustion processes, the flue gases are passed through the FGD plant before entering the Carbon Capture plant. The FGD systems remove much of the sulphur and other contaminants, and as a consequence, the difference between levels of corrosive species in the Douglas and Bailey cases is reduced so far as the carbon capture plant is concerned.

For the purpose of this study, only one coal type was selected for each combustion process based upon the corrosive species and water contents in the gas entering the carbon capture plant. The Bailey coal was selected for the Pre-combustion capture and Oxy-fuel combustion processes, as this resulted in slightly more aggressive conditions. For the Post-combustion capture process there was very little difference between the two coal types and the Douglas coal case was selected.

The natural gas case is generally a ‘cleaner’ option (in terms of environmental emissions as well as regards corrosive species) for the combustion process, containing lower concentrations of sulphur and halides.

3.2 Process Streams and Equipment

This study considers the major items of process equipment and pipework that are in contact with the process fluids. Issues generic to process plant such as external corrosion and corrosion risks in common utility services, such as cooling water, are not considered in detail as standard industry practices exist to deal with these risks.

The corrosion assessment and material selection task applies to the process units in which the operating conditions will be changed by implementing a CCS project. For instance, the carbon capture process of the Post-combustion capture and Oxy-fuel combustion processes begins immediately downstream of the FGD system; whilst that of the Pre-combustion capture commences after the gasification unit. The FGD and the gasification systems are not affected by the implementation of the CCS and hence, are not in the scope of this study.

4 METHODOLOGY

4.1 CCS design basis

For the purpose of the study, the design life for all the carbon capture processes is taken to be 25 years. This is consistent with the IEAGHG technical and financial assessment criteria for Greenhouse Gas appraisal studies. Pipelines and wells are expected to operate for longer than individual power stations, and a design life of 30 years with a sensitivity check for 50 years is specified. This basis is used to estimate the likely wall thickness loss due to corrosion attack, e.g. CO_2 corrosion and O_2 corrosion, by the end of the design life and to specify corrosion allowances for the process vessels and pipework. It is also used to assess material options (such as coatings) where periodic maintenance is expected to be necessary. Recommendations of material selection in this report are based on the life-time integrity for the required equipment design life, while minimising maintenance downtime and maximising safety.

4.2 Corrosion risk assessment

The CCS systems handle multiphase process fluids including gases, liquids and supercritical liquids. They operate from atmospheric pressure up to 150 bar and at temperatures from cryogenic into high temperature regimes. Generally, the process fluids in the CCS systems include the flue gas, syngas (for pre-combustion), process solvents (eg amines), raw (impure gaseous) CO_2, wash and drain waters, relatively pure gaseous, liquid or supercritical CO_2, and utilities fluids.

The key features of these fluid groups, on which the corrosion analyses are based, are:

- Partial pressure of corrosive gases, e.g. CO_2, H_2S, NOx, SOx, oxygen
- Concentration of corrosive impurities such as chlorides
- water content and presence or absence of a free water phase
- fluid temperature and velocity

The input data for assessment of corrosion threats and material selection and corrosion study in this report is primarily based upon the H&MB and process schemes modelled by E.ON. A wider range of conditions has been considered where appropriate to allow for likely fluctuations in operating conditions and shut-down or upset-conditions. For example, probable water ingress to nominally dry steams has been considered. However, the guidance is not exhaustive as regards possible upset conditions, and assessment of these would be a part of detailed design phases.

If a stream is identified by the vapour fraction in the H&MB to have zero liquid (and hence to be dry), or the operating temperature is significantly higher than the dew point, then the corrosion rate can be assumed to be zero in normal operation. Often, carbon steel is proposed without a corrosion allowance, or with minimal corrosion allowance in some cases to allow for occasional upset conditions. Normally, gas streams from separator vessels, flash drums, knockout drums and the like, have been treated as water-saturated and at risk of condensation. Likewise, the possibility of water carry-over as droplets or mist has been considered. In these cases, the lines have been treated as potentially wet, even if identified as dry in the H&MB calculations. In some cases, mitigation measures are suggested to avoid or eliminate the presence of free water such as fitting mist eliminators in vessels or trace heating to keep line temperatures above dew point.

Corrosion can be very sensitive to trace levels of aggressive species, including oxygen and chloride ions, at levels which may not appear in the H&MB calculations. Trace mercury can also present a risk. If present in the flue gases, soluble species like chlorides can often be assumed to be washed out in upstream processes before the carbon capture plant. In general, a chloride ion content of less than 50 ppm has been assumed throughout the CCS facilities. Specific cases where contaminants may be introduced with process chemicals have been considered.

In general it has been assumed that all hot streams (e.g. syngas, steam and lean amine) and cold streams (compressed CO_2, refrigerants) are insulated.

4.2.1 Corrosion Loops

The processes have been split into corrosion loops based on the H&MB information. A corrosion loop is a section of the process that is exposed to a broadly similar environment, i.e. similar fluid compositions and temperatures. The corrosion threats and their severity are similar within the same corrosion loop. There is a common rationale for the material selections and corrosion mitigation methods within the loop.

4.2.2 CO_2 corrosion rate estimation

Corrosion rate analysis and material selection of carbon steel (CS) utilised Intetech's in-house Electronic Corrosion Engineer® version 4 (ECE4) software. The ECE4 corrosion model incorporates all the CO_2 corrosion evaluation steps outlined in Sections 6.4.1 as well as CRA selection rules discussed in Section 7.1. This software enables estimation of carbon steel corrosion rates in CO_2- and H_2S-dominated systems; and additionally evaluation of various CRAs in different fluid characteristics. Details of the software package can be found elsewhere [1]. There are a number of other different tools for estimating CO_2 corrosion rates. In practice, the high CO_2 partial pressures and moderate temperatures in many of the CCS environments mean that wet conditions are very corrosive to carbon steel, and all evaluation tools would predict unacceptable corrosion rates. There are typically more significant differences between different corrosion models in the handling of sour conditions and protective effects from sulphide films.

Corrosion rate estimations were generally made at a standard fluid flow rate of 1 m/s. Flow rates of 1 m/s were taken as the basis for purposes of material selection in process plant because:

- Line diameters are not all defined, and in practice flow rates will vary, so reliable estimates of the mass transfer contribution to corrosion rates are not available.
- There may be local turbulence in facilities because of piping diameter changes, valves, other components which affect fluid flow conditions so that nominal flow conditions may give a non-conservative estimate of corrosion rates.

Evaluating the reaction-rate controlled element of corrosion rates is slightly conservative, but not excessively so, and is consistent with the approach taken by most materials engineers at this stage in design.

For liquid full streams (solvents or water), the concentrations of acid gases (CO_2 and H_2S) evaluated were the values for the equilibrium gas stream. The corrosion rate calculations (and also the evaluation of SSC risk) are based on the partial pressure of acid gases in the equilibrium gas stream and not on the dissolved gas concentration in the liquid water phase. For example, the acid gas concentrations in the liquid outlet stream from a knock-out or separator vessel are considered to be in equilibrium with the vapour phase outlet from the top of the vessel.

In cases where H_2S is present, two corrosion rates are estimated for each flow: the generalised corrosion rate which occurs when iron sulphide “filming” takes place and the “pitting” corrosion rate, which is the corrosion rate which applies when the iron sulphide film breaks down.

In general, the tendency for pitting is reduced when:

- the ratio of $CO_2 : H_2S$ is less than 200, because with a high concentration of the stability of the sulphide film is greater, which inhibits the onset of pitting;
- the chloride content is low, i.e. < 50 ppm;
- the fluid is flowing rather than stagnant.

4.3 Material Selection

Carbon steel is the base-case material of construction in the process industries. Despite moderate resistance to corrosion, this material is preferred owing to its relatively low price, good mechanical properties and ready availability. Extra corrosion allowances are used to extend the range of application of carbon steel into conditions where moderate rates of attack are expected.

Where the corrosion rate was considered to be too high for the use of carbon steel, or where additional corrosion allowance is undesirable (e.g. heat exchanger tubes), protective coating, linings, or the use of corrosion resistant alloys or non-metallic materials were considered.

In many cases it is not necessary to use a solid CRA. The corrosion resistant properties of the CRA can be obtained by applying the material as a lining on the surface of carbon steel (eg “wallpapering”, widely used in the FGD industry). Since the pressures in much of the CCS plant are very low, CRA lining of carbon steel structural framework may also be suitable for some equipment. For other equipment carbon steel clad with CRA may be more effective: cladding implies a metallurgical bond to the base carbon steel, achieved by processes such as roll-bonding, explosive cladding or weld-overlaying. The particular selection of the fabrication method is highly dependent upon the dimensions and criticality of the equipment in question. From the point of view of corrosion resistance carbon steel clad with CRA and solid CRA are usually equally acceptable and the more cost-effective alternative can be chosen.

The selection of carbon steels and CRA materials are based on international codes and standards, e.g. the NACE MR0175/ISO 15156 [2] document for sour service. However, there is a general shortage of materials performance data directly relevant to the conditions with high CO_2 partial pressures envisaged for the downstream end of CCS systems. Service experience in similar conditions in other industries has been evaluated and the limitations of various materials are discussed in Chapter 7. Specific areas where inadequate information exists for a sound material selection have been identified.

The lowest grade of stainless steel selected for piping and general use is 316L. Detailed design may identify areas where conditions would allow the use of the lower grade 304L, for example when very low chloride levels can be guaranteed. In practice, some contractors have a philosophy of using 316L even in these cases for extra security and to avoid the risk of mixing two very similar materials during construction.

5 PROCESS DESCRIPTIONS

This section outlines the key aspects of all the CCS technologies studied; a more detailed process description can be found in E.ON report (Appendix A).

5.1 Pre-combustion Capture Processes

Also known as integrated gasification combined cycle (IGCC); this process involves production of synthetic gas (syngas), which is essentially a mixture of hydrogen, CO_2 and CO that is generated from natural gas or coal. The gasification reaction in the IGCC process is an established technology and not included in the scope of this study [3].

In the CCS power plant version of the IGCC, however, the syngas shift reactors are added downstream of the gasification, in order to convert CO to CO_2 as show below:

$$CO + H_2O \Leftrightarrow CO_2 + H_2$$

The CO_2 generated from the shift reactors can be extracted further downstream in the CO_2 absorber; any unconverted CO will eventually be converted to CO_2 in the gas turbine and be emitted to atmosphere.

The high temperature streams (containing syngas) exiting from the shift reactors are cooled and the condensed water is removed before the dried syngas enters the capture plant proper. Two separation process configurations have been considered within the carbon capture plant for coal-fired cases, namely separate-capture and co-capture of H_2S and CO_2 gases. The natural gas-fuelled process was modelled only with the co-capture configuration, as the H_2S content in the natural-gas-based syngas is minimal. A physical solvent process was assumed using a mixture of dimethyl ethers of polyethylene glycol, as opposed to a chemical solvent process (e.g. using amines).

In the separate-capture configuration (Figure 5.1 a), two absorber vessels are used, although the same solvent is used in both absorbers. The first absorber preferentially removes H_2S which is concentrated, then stripped out and sent to a sulphur recovery unit. The second absorber removes CO_2, which is then flashed off from the rich CO_2–loaded solvent at lower pressures in a series of flash drums and fed to the compression train.

In co-capture configuration (Figure 5.1b), one absorber vessel is used and both CO_2 and H_2S are removed from the syngas stream in the same vessel. Gas (predominantly CO_2) is flashed off the solvent in a train of flash-drums, and then acid gases (H_2S and some CO_2) are extracted in the stripper vessel and all fed to the compression train. Co-capture results in a higher H_2S content in the export CO_2 gas steam.

The scrubbed fuel gas from the absorber is nearly pure H_2, and has to be diluted with either nitrogen or steam in order to control the combustion temperature in the gas turbine.

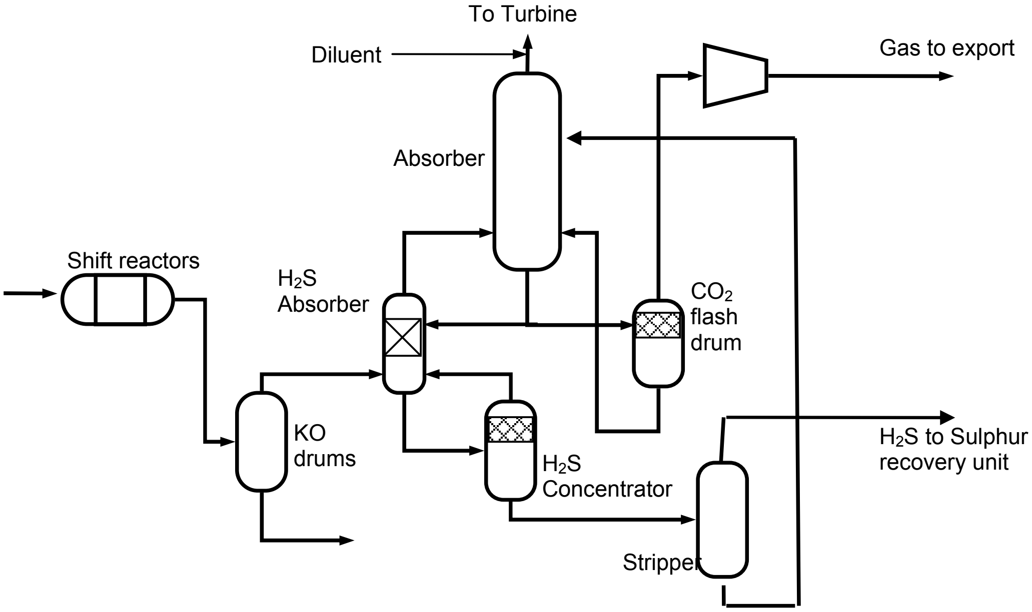

Figure 5.1 (a) : Schematic Diagram of Pre-combustion separate capture

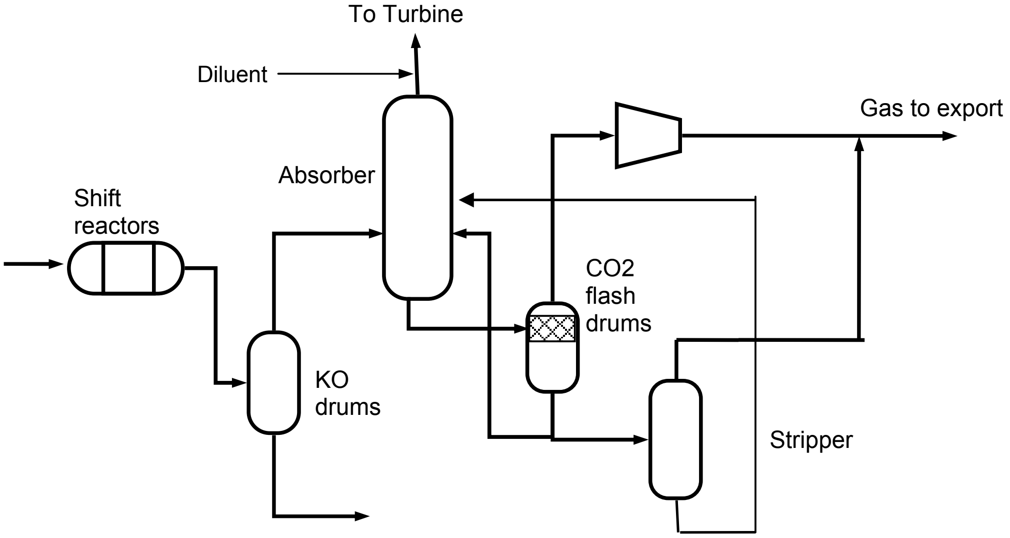

Figure 5.1 (b) : Schematic Diagram of Pre-combustion co-capture

5.2 Post-combustion Capture Processes

Post-combustion capture refers to the CCS process in which CO_2 is separated from the flue gases downstream of the combustion. Figure 5.2 shows the simplified flow diagram of the post-combustion capture process. At the front of the carbon capture plant, the direct contact cooler reduces the temperature of the saturated flue gas before it enters the absorber. This reduces the temperature of the gas stream and increases the efficiency of the subsequent CO_2 absorption. In addition, highly soluble components (such as SOx and HCl), particulates and liquid carryover are also removed from the flue gas. The SO_2 polisher is only required for the coal-fired combustion and is omitted from the gas-fired case.

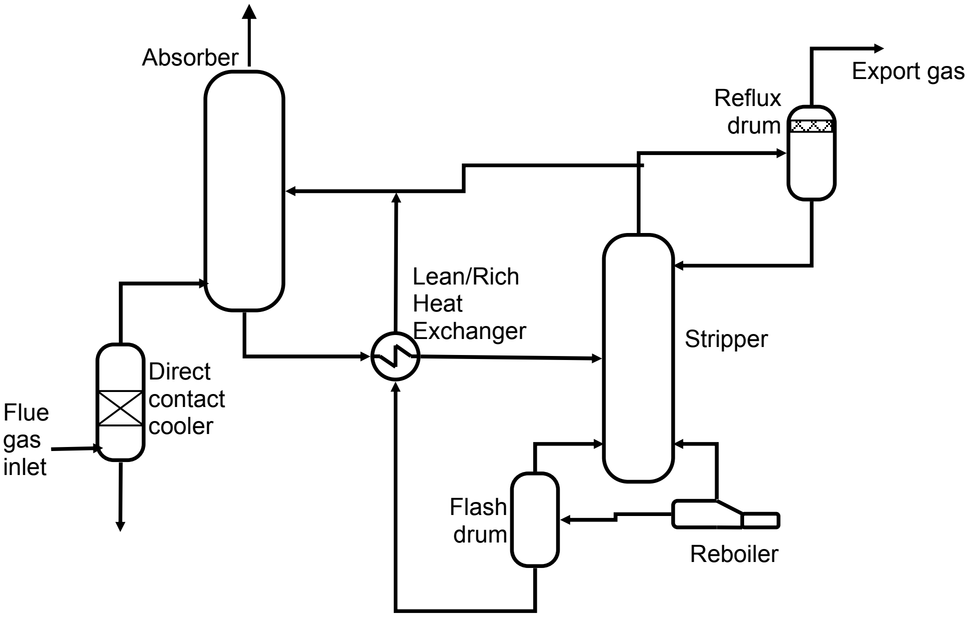

Figure 5.2 : Schematic diagram of Post-combustion capture process

A monoethanolamine (MEA) solvent has been used as the basis for process modelling. MEA absorbs CO_2 from the gas stream in the absorber vessel at around 40°C; heat is extracted from amine in a side-stream loop on the absorber vessel. There is also a water wash cooler at the top of the absorber. Rich, CO_2–loaded, amine is heated and CO_2 driven off in the stripper vessel. A reboiler loop provides heat for the stripper vessel. Also to improve efficiency, hot gas is flashed off the lean amine leaving the reboiler, and the hot vapour fed back to the stripper. The recovered CO_2 from the stripper is passed though a condenser and reflux drum to cool it and remove water before entering the compression train.

Two fuel types have been studied in this combustion technology, i.e. coal- and gas-fired. The typical composition of both fuels is described in the E.ON report. The flue gas generated by coal- and gas-fired post-combustion capture process, contains CO_2, water, N_2, O_2 and in the case of coal-firing, other impurities such as Hg, chlorides, and SO_2.

5.3 Oxy-fuel Combustion Processes

Oxy-fuel combustion refers to a combustion technology that uses pure oxygen instead of air, in order to maximise the CO_2 and heat output from the combustion process. Figure 5.3 shows the schematic diagram of the CO_2 capture plant of the oxy-fuel combustion. This carbon capture plant is located downstream of the oxy-fuel combustion process and the FGD plant. Flue gas from the FGD plant contains only about 60% CO_2 and therefore requires further purification, drying and removal of impurities before entering the compression train and pipeline system.

Hot wet gases from the FGD plant are cooled and compressed to intermediate pressure. SOx and NOx are removed as acids with water in successive vessels. The stream is then dried through molecular sieves, and if necessary, mercury may be captured at this point. After the molecular sieves, the gas is virtually dry. To reach the low CO_2 specification case, two stages of cryogenic phase separation are used, whilst for the high purity specification, a single stage of separation and a distillation column are used.

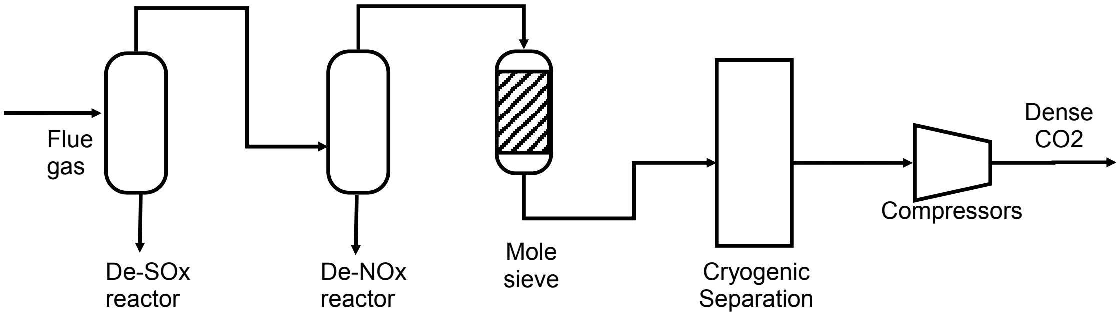

Figure 5.3 : Schematic diagram of Oxy-fuel combustion CCS process

Two different configurations have been considered in the oxy-fuel combustion, i.e. the high CO_2 (99.99%) case and the low CO_2 (97%) case. The two configurations have a different layout only in the CO_2 purification process, which does not affect significantly the corrosion analysis and material selection.

5.4 Compression trains

The objectives of the compression trains are to compress the pure CO_2 to the desired pressure for the pipeline, and where necessary to remove excess water, aiming to achieve a sufficiently low dew point prior to entering the export pipeline.

Figure 5.4 shows the schematic diagram of one of the compression stages in the train; the CO_2 stream entering the compressor must to be kept dry and above the dew point. The outlet stream from the compressor is dry. If water condenses in the cooler, the cooler and pipework up to the subsequent knock-out drum requires corrosion resistant material. The dry CO_2 stream from the knockout drum enters the next compressor, and the material selection pattern is repeated.

The configuration of the compression trains differs in the different combustion systems, depending on the number of incoming CO_2 streams, their pressure and the level of water present. For example, the gas stream in oxy-fuel combustion case is extremely dry, so no further water removal is necessary, whereas in the other two cases combinations of water knock-out vessels and glycol dehydration are used in order to produce a sufficiently dry gas stream for export.

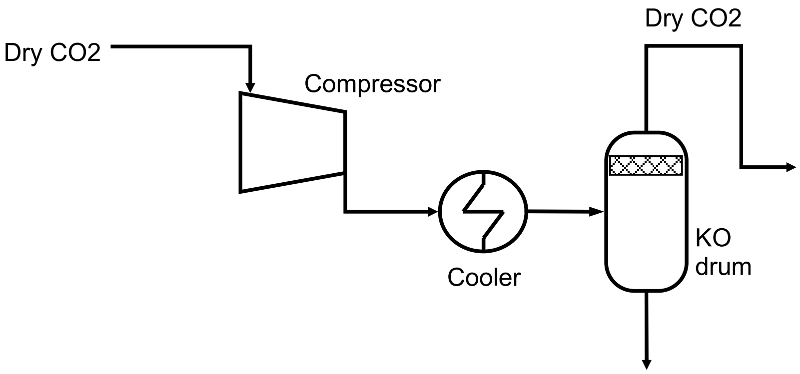

Figure 5.4 : Schematic diagram of compression train element

5.5 Pipeline and Wells

The pipeline will connect the carbon capture plant to the well-head at the storage location. A pig launcher and receiver will probably be needed for running inspection pigs. Depending on pipeline route and hydraulic design, intermediate compression stations may or may not be necessary.

Design requirements for the CCS well design differ significantly from those of typical gas injection wells because of the need for the pressure barriers to remain intact for much longer after injection has been completed and the well closed in and abandoned. Injection operations will continue for several decades: 30 or 50 years is assumed as for the pipeline. A high level of availability is required, although the well may be temporarily shut-in for periods, for example if upstream capture plant is shut-down. Materials are selected for the injection phase. Thereafter, the well will be closed-in and suitable permanent pressure barriers put in place as part of abandonment: this is outside the scope of this report.

6 CORROSION MECHANISMS

6.1 General Comments

The corrosion assessments in this report concerns the potential corrosion aspects specific to the CCS processes only. Issues generic to process plant such as external corrosion and corrosion risks in common utility services, e.g. cooling water, utility gas and steam, are not considered in detail as standard industry practices exist to deal with these risks. This chapter assesses all the potential corrosion risks caused by the CCS process fluids, explains the cause and source of corrosion and discusses the associated mitigation procedures.

6.2 Conditions for corrosion

The bulk of the CCS processes take place at pressure and temperature conditions at which water is present as a liquid phase. These conditions are considered to be "low-temperature" in corrosion terms, with corrosion reactions primarily taking place in the aqueous phase. Corrosion involves separate anode and cathode reactions which occur at two different positions on the metal surface. An electrolyte, usually water, is required for movement of ions and electrical charge to and from the anode and cathode reaction sites. The anode reaction causes loss of material, for example in steels, oxidation of elemental iron to ions occurs:

$$Fe \rightarrow Fe^{2+} + 2e^{-}$$

Other metallic elements in alloys may also be oxidised in analogous reactions.
Hydrogen evolution is the common cathode reaction in organic and inorganic acids:

$$2\ H_3O^{+} + 2e \rightarrow H2$$

Oxygen reduction is another common cathode reaction where oxygen is present:

$$\tfrac{1}{2}\ O_2 + H_2O + 2e^{-} \rightarrow 2\ OH^{-}$$
$$\tfrac{1}{2}\ O_2 + 2\ H_3O^{+} + 2e^{-} \rightarrow 3\ H_2O$$

However, other cathode reactions are possible for example involving sulphur or carbonic acid

$$S + H_2O + 2e^{-} \rightarrow HS^{-} + OH^{-}$$
$$2\ H_2CO_3 + 2e^{-} \rightarrow 2\ HCO_3^{-} + H_2$$

The corrosivity of environments in CCS plant will be affected by the availability of reactants including CO_2, other acids, oxygen and sulphur. Free water is a necessary requirement for low temperature corrosion [i]: corrosion will not occur in gas streams above the dew-point or where no liquid water phase (or some other electrolyte) is present. The solubility and behaviour of water and CO_2 mixtures is therefore of critical importance for corrosion in CCS plant.

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[i] See below for comments on high temperature corrosion

6.3 Water and CO_2

Figure 6.1 shows the phase diagram for pure CO_2. Conditions in CCS systems may be in gas, liquid or supercritical phase fields.

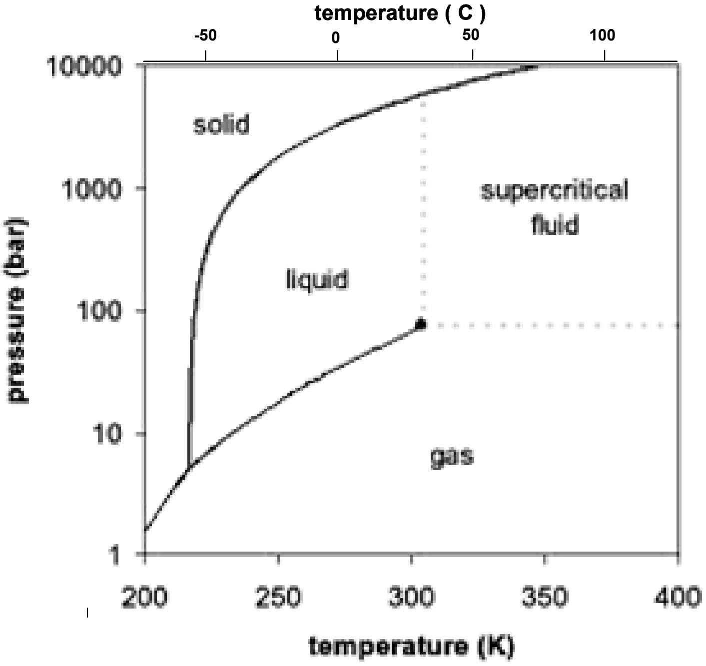

Figure 6.1 : CO_2 phase diagram

The corrosion behaviour of carbon steel in a liquid water phase in contact with CO_2–containing gas has been studied in detail and can be quite accurately predicted, see Section 6.4.1 below.

Corrosion rates in a free water phase in contact with liquid or supercritical CO_2 are not so well established but are expected to be relatively high, certainly high enough to rule out the use of carbon steel in most cases. Reported experimental corrosion rates in a free water phase in contact with liquid CO_2 are from 1 – 2 mm/y to around 18 mm/yr, depending on temperature and pressure [4,5]. Critically, corrosion rates in the water-saturated (but not super-saturated), liquid CO_2 phase in the same tests are reported to be practically zero. In other words, liquid CO_2 containing dissolved water does not act as an electrolyte, does not support corrosion and can be regarded as a dry, non-corrosive, environment.

In the supercritical state the density of CO_2 approaches and can even exceed the density of liquid water at high pressures as shown in Figure 6.2. Depending on the exact conditions, a separate water phase could wet the lower or upper surfaces of pipes etc.

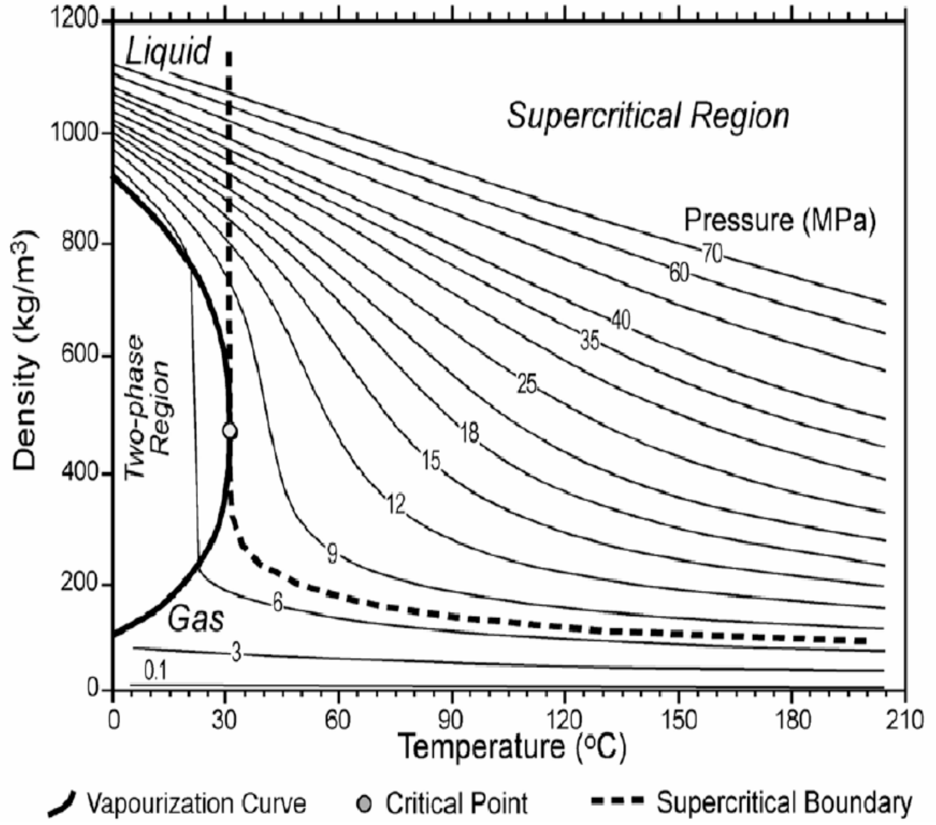

Figure 6.2 : Variation of carbon dioxide density with temperature [6].

The maximum solubility of water in liquid CO_2 is important, as this defines the maximum water content that can be tolerated in the export CO_2 stream without corrosion problems. An example of water solubility data from the Dynamis project is given in Figure 6.3, showing the solubility of water (ppm w/w) at different temperatures and pressures [7].

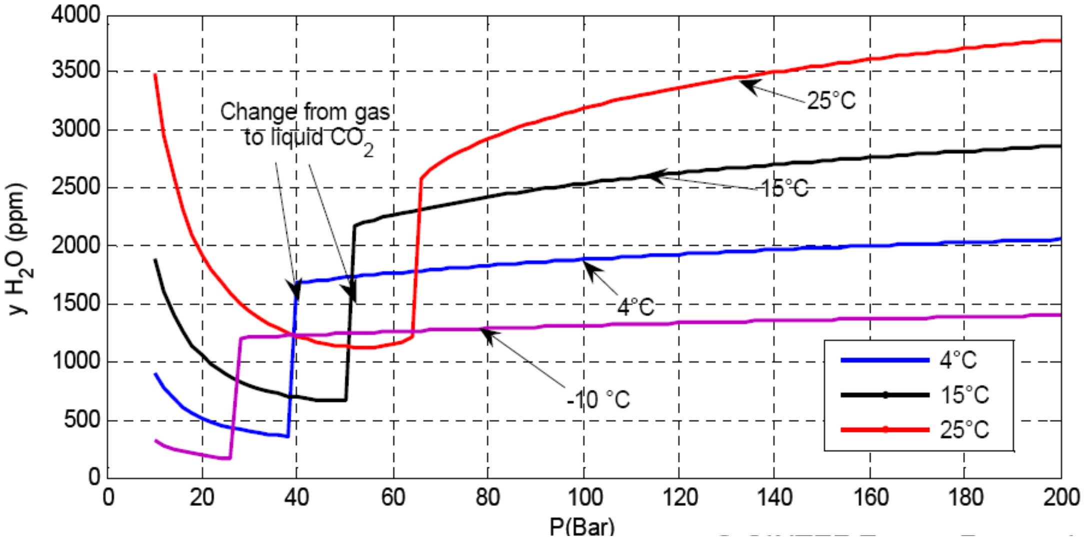

Figure 6.3: Solubility of water in pure CO_2 as a function of pressure and temperature [7]

From Figure 6.3 it can be seen that the solubility of water in CO_2 increases significantly when CO_2 changes from a gas to liquid phase, and is thereafter relatively unaffected by increases in pressure in the liquid CO_2 phase. The maximum CO_2 pressure modelled in the export CO_2 stream in the present design cases is 150 bar. The above data suggests that water contents up to about 1300 ppm (w/w) will remain in solution in pure CO_2 at this pressure and at -10 °C (taken to be the minimum design temperature for the pipeline). However, if there is a drop in pressure, then the solubility in the gas phase region is much less and there is a risk of water condensing: this is a potential risk at valves or during depressurising events.

Impurities may have some effects on the solubility of water in CO_2 .The impact of methane on water solubility was studied in the Dynamis project [7]. Their results showed, for example, that 5% methane results in a decrease in water solubility of around 30%. Both acid (HCl) and alkali (NaOH) are also reported to promote condensation of a distinct water phase [4]. Other contaminants could also affect water solubility, so a conservative approach should be taken, or specific testing performed.

The Dynamis project has also studied gas hydrate formation in pure CO_2 and with impurities: for the particular pipeline conditions simulated, a maximum 250 ppmw water content was needed to avoid condensation or hydrate formation at chokes [8]. Hydrate formation rather than condensation of free water was the limiting factor in many conditions studied, particularly in the CO_2 gas phase region at lower pressures.

In practice, existing long-distance US CO_2 pipelines typically operate with maximum specified water contents around 25–30 lb/MMscf (approximately 200-245 ppm w/w) and are normally dry while containing a total of up to about 5 mol% of impurities including hydrocarbons, CO, H_2S, N_2, O_2 etc.. The Weyburn CO_2 pipeline is unusual in operating with a much lower water content of less than 10 ppm w/w (20ppmv), due to the particular separation process used to extract the CO_2 .

6.4 General corrosion

General corrosion refers to corrosion attack characterised by widespread metal loss across the surface; this is common for carbon steels in a wide range of environments. This corrosion type occurs progressively over the majority of the surface of a metal, often at a predictable and more or less uniform rate. Compared with some other forms of corrosion, general corrosion is relatively easily detected, for example by inspection or various monitoring techniques. The most basic mitigation method is to provide a “corrosion allowance”, that is excess material thickness that can be consumed during the lifetime of the component.

6.4.1 CO_2 Corrosion

When CO_2 dissolves in water it forms carbonic acid, H_2CO_3. This is a weak acid, in other words it is not fully dissociated into its ions, unlike a strong acid such as HCl, which dissociates nearly entirely to H+ and Cl- ions.

$$H_2O + H_2CO_3 \rightarrow HCO_3^- + H_3O+$$

The mechanism of CO_2 corrosion of carbon steel differs in one major aspect from corrosion by strong acids like HCl. Corrosion by acids generally involves reactions such as :

$$Fe + 2H^+ \rightarrow Fe^{++} + H_2$$

The rate of this corrosion reaction is highly dependent on the concentration of hydrogen ions, H^+, which is measured by the pH. Although this reaction does happen with carbonic acid, there is also an additional mechanism:

$$Fe + 2\ H_2CO_3 \rightarrow Fe^{++} + 2\ HCO_3^- + H_2$$

Here the carbonic acid is directly reduced, with a rate which also depends on the amount of dissolved but undissociated carbonic acid, and not directly on pH. It follows that, for the same pH, the weak carbonic acid is more corrosive than a strong, fully dissociated acid.

The rate of corrosion of steel due to CO_2 is very important in the oil and gas industry, where CO_2 is the principal corrodent in many reservoir fluids and modeling and prediction of CO_2 corrosion has been extensively studied since the 1970s [1].

For the CO_2 corrosion reaction, the rate of the reaction can be expressed by means of the "resistance model":

$$\frac{1}{V_{cor}} = \frac{1}{V_r} + \frac{1}{V_m}$$

where V_{cor} is the corrosion rate, V_r is mainly determined by reaction kinetics of the reduction processes, and V_m is determined by the rate of mass transport of carbonic acid to the steel's surface and therefore dependant on factors including the concentration of CO_2 and the fluid flow conditions. In general, at high velocities (V_m large), V_r is controlling the corrosion rate V_{cor}, and the pH has a large effect. At low pH values, V_r is large, and mass transfer (velocity) becomes controlling.

The equations in CO_2 corrosion rate models have been fitted to laboratory data such as flow loop data measured at IFE (Institutt For Energiteknikk) in Norway, where test conditions and environments were strictly controlled. With the application of the Electronic

Corrosion Engineer (ECE4) model in the field, actual in-service corrosion data has been used to further refine and develop the model [9].

The basic CO_2 corrosion rate model can be modified to account for further factors affecting the corrosion rate. Above a certain temperature, the solubility of iron carbonate is low, and an iron carbonate film forms on the metal surface, providing some protection to the metal. The "scaling temperature" at which this occurs is typically around 60 °C, but does depend on CO_2 concentration.

If sufficient H_2S present, an insoluble iron sulphide film may form, which provides protection to the metal surface and reduces the corrosion rate [10]. The ratio of CO_2 to H_2S partial pressures is often used as a guideline in predicting if protective sulphide films will be formed [11]: for example, sulphide filming generally dominates at pCO_2/pH_2S of less than 200. The FeS layer is largely protective; however, this film can sometimes suffer isolated breakdown and the subsequent occurrence of pitting corrosion. The occurrence of pitting is sensitive to several factors, including the flow regime, the presence of solids and deposits, and the presence of oxygen, sulphur or high levels of chloride ions (considered to be above 10,000 ppm). The rate of pitting corrosion in such circumstances has been shown to be comparable with the CO_2 corrosion rate, ignoring the influence of H_2S. The critical issue is to establish if the type of corrosion which will occur will be dominated by FeS scale formation, or localised, CO_2-dominated, pitting. The likelihood for the occurrence of pitting cannot be fully predicted, however more H_2S (i.e. a lower ratio of pCO_2/pH_2S) will tend to reduce the occurrence of pits.

Other modifying factors to the CO_2 corrosion rate are considered in oil and gas applications, such as the presence of oil, but are not applicable to carbon capture and storage.

6.4.2 Oxygen corrosion

Oxygen can cause both uniform and localised pitting corrosion; like CO_2 corrosion, uniform O_2 corrosion of steel is relatively predictable being dominated by mass-transfer of oxygen. However pitting and crevice corrosion associated with oxygen presents an additional risk of localised corrosion, see below. For a given flow rate, the rate of uniform oxygen corrosion of carbon steel depends primarily on the concentration of dissolved oxygen, the pH and the temperature of the water. Figure 6.4 shows examples of uniform O_2 corrosion rates at different temperatures in near neutral water[12].

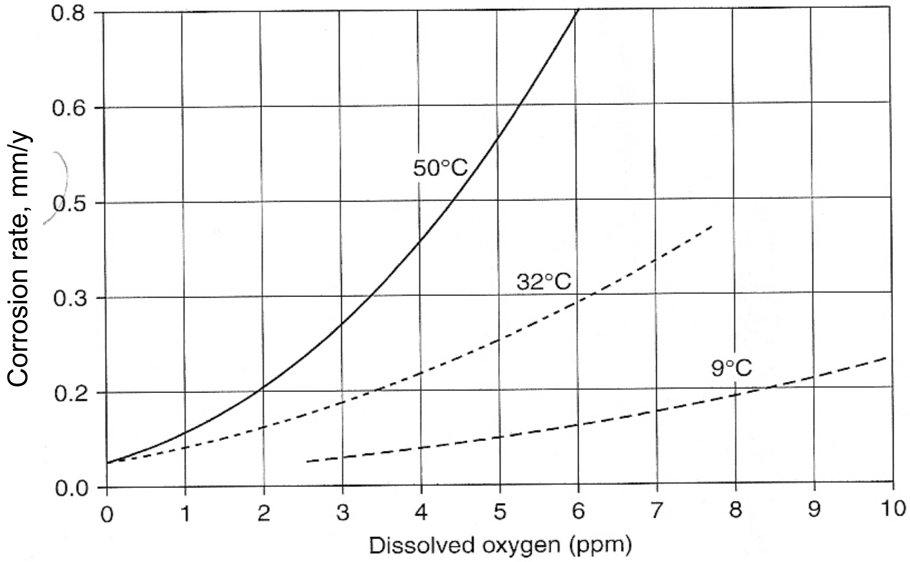

Figure 6.4 : Effect of oxygen concentration on the corrosion rate at different temperatures

Where both CO_2 and O_2 are present, then the total corrosion rate is assumed to be a sum of both O_2 and CO_2 corrosion rates. In this case, no protective effect from any carbonate scaling is assumed.

Trace oxygen can have a very significant effect in CO_2 - H_2S environments. Reactions between oxygen and H_2S can form elemental sulphur and sulphur acids, creating extremely corrosive conditions for both carbon steels and CRAs.

6.4.3 Sulphur Corrosion

Although S is not very soluble in water, it is more soluble when sulphide ions (HS^-) are present, particularly in neutral or slightly alkaline conditions, and in these conditions can act as a corrodent in a similar way to oxygen [13]. Conditions with free elemental sulphur, either solid or dissolved, are extremely corrosive to carbon steels, and sulphur also promotes pitting and stress-corrosion cracking of CRAs in wet chloride-containing conditions [14, 15].

6.5 Localised Corrosion

Localised corrosion is characterised by high penetration rates at specific sites, and low or near-zero corrosion rates over the majority of the metal surface. Compared with general corrosion, localised corrosion is generally more difficult to detect, monitor, predict and design against.

Crevice corrosion describes a special form of localised corrosion that occurs at shielded areas with limited access of the environment, examples include under washers, at flange faces and also under deposits. In oxygen-containing environments, crevice corrosion is driven by differences in oxygen concentration in the crevice and at the open metal surfaces. Oxygen reduction occurs on the open surfaces as the cathode reaction, and metal dissolution as the anode reaction in the crevice. The combination of large cathode area and small anode area can lead to high penetration rates.

Once localised corrosion is established, conditions within active pits or crevices can become much more severe than in the environment generally and to some extent independent of the wider environment. Even if the general environment becomes less aggressive, established pits can continue to propagate. Hence, relatively short upset conditions may establish long-term attack.

6.5.1 Pitting of CRAs

Stainless steels, nickel alloys and some other CRAs such as titanium rely on a protective oxide film (the passive film) to prevent corrosion of the underlying metal. Breakdown of the protective film (“depassivation”) is generally promoted by low pH, high temperatures and the presence of aggressive species such as chlorides, H_2S, sulphur and oxygen. If conditions are severe enough, film breakdown will occur firstly with localised pitting, and in more extreme conditions, more widespread corrosion. Localised penetration rates once film breakdown occurs are hard to predict and can be very high, often higher than corrosion rates of carbon steel in the same conditions. Pitting can also be associated with stress-corrosion cracking in CRAs.

6.6 Erosion and Erosion–Corrosion

Erosion is the physical removal of wall material by the flowing process fluids. Erosion is a complex issue dictated by fluid phase, flow regime, velocity, density, solid content, solid hardness and geometry. Erosion-corrosion is the accelerated corrosion of a metal surface in a corrosive environment due to the removal or modification of protective surface films by shear or the impingement of liquid, gas bubbles and solid particles.

The primary method to avoid erosion and erosion-corrosion in nominally solid free systems is to design the facilities with velocity below the limit given by API 14E [16]. The secondary method is to reduce the susceptibility of the system to erosion by minimising the use of small radius bends and any turbulence promoters wherever possible.

6.7 Stress-corrosion

Stress- corrosion is a general term for failure under the joint effect of load and corrosive conditions. Typically, it is characterised by cracking through the material but without significant corrosion (or indeed often any detectable corrosion) on the surface. The special case of sulphide stress-corrosion (SSC) of ferritic steels is covered separately below. There are many specific material–environment combinations in which stress-corrosion can occur, those anticipated to be important in relation to CCS are mentioned here.

Carbon and alloy steels can suffer stress-corrosion in various alkaline environments, including amine systems and also in caustic or carbonate chemicals that may be used for pH control or desulphurisation etc. Stress-corrosion of carbon steels can also occur in nitrates, particularly at high temperatures, and in wet $CO-CO_2$ systems.

The chloride ion is particularly effective in promoting the breakdown of the passive film on stainless steels and nickel-base alloys. These alloys are therefore potentially susceptible to stress corrosion cracking in a wide range of chloride-containing environments. Chloride-induced stress corrosion cracking is exacerbated by other factors such as the level of oxygen or other oxidants present, acidity and high temperatures. Depending on the alloy involved and other conditions, even trace levels of chlorides can be significant.
Stress-corrosion can be tackled by methods including :

- controlling the environment
- controlling stresses, including residual stresses
- material selection and processing

For example heat treatment can be effective in relieving residual stresses after welding or cold-forming, and welded constructions with a high degree of constraint (and therefore high thermal stresses after welding) should be avoided so far as possible: this can be an issue with CRA wall-papering for example. In general, high hardness, low ductility materials are at more risk of stress-corrosion. In some materials such as duplex stainless steels, control of metallurgical micro-structure may be very important.

6.8 Hydrogen Damage at Low Temperature

6.8.1 Hydrogen Cracking Mechanisms

The presence of hydrogen in steels and CRAs can cause various forms of damage and loss of mechanical properties. Hydrogen can enter from many sources, including steel-making, welding, galvanic coupling to less noble metals, cathodic protection and corrosion. Only corrosion is considered further here as the other mechanisms are not specific to CCS process conditions.

When corrosion occurs in the presence of sulphides, these promote absorption of atomic hydrogen (from the cathodic part of the corrosion reaction) into the steel. Some other species such as arsenic salts and cyanides can also promote hydrogen absorption.

6.8.2 Hydrogen Induced Cracking (HIC)

Hydrogen Induced Cracking (HIC) occurs in carbon steels when absorbed hydrogen recombines to hydrogen molecules at internal defects. This causes internal cracking due to the pressure of the hydrogen gas. Typical initiation points for cracking are elongated non-metallic inclusions such as sulphides. Cracking is typically lamellar, along microstructural features like pearlite and segregate banding. Cracking does not require an external applied stress, and the orientation of cracking is not related to the applied stresses

Rolled products such as plates and also welded pipe made from plate or coil, are at most risk from HIC. Seamless pipe and cast or forged products are generally at lower risk of HIC. CRAs are not susceptible to HIC.

Requirements for HIC resistant materials are outlined in ISO 15156-2 [2] and EFC Document nr. 16 [17]. For seamless pipe, cast and forged products it is normally sufficient to specify a restricted S content in the steel. In the case of plates and welded pipe, HIC resistance is affected by many processing variables and there are not general values of composition or other parameters applicable to all manufacturing routes. Some measure of quality control testing is necessary to ensure HIC resistance.

Cold-working above 5% strain should be avoided. Cold-worked items such as dished vessel ends must be heat-treated after forming.

6.8.3 Sulphide Stress Corrosion (SSC)

Hydrogen dissolved in the carbon steel matrix reduces the ductility and toughness of the material. Under tensile stresses, the embrittled material may crack to form sulphide stress corrosion cracks. This process can be very rapid in susceptible materials. As well as carbon steels, ferritic and martensitic stainless steels such as AISI 410 grades are also susceptible to SSC. SSC is a form of hydrogen embrittlement, and is fundamentally different from other forms of stress-corrosion, for example being most severe around room temperature.

Guidance on materials selection in H_2S containing conditions is provided by ISO 15156-2/NACE MR0175 for upstream oil and gas service, and by NACE MR0103-2003 for downstream refining service [18]. Whilst these documents are specific to other industries, their guidance can be used in comparable environments within CCS processes.

The risk of SSC is increased by hard microstructures and, other factors being equal, is greater in high strength, low toughness materials. Prevention of SSC is achieved primarily by control of hardness in the base material and also in welds. ISO 15156-2/NACE MR0175 specifies maximum hardness limits for carbon steel products in H_2S service to avoid SSC: for example 22 HRC / 248 HV10 for general carbon steel products. Welding standards such as BS 4145 and NACE RP0472-2000 also contain limits on weld hardness values for sour service. Cold-working should also be avoided and cold-worked items such as dished vessel ends must be heat-treated after forming.

SSC is generally a much reduced risk at operating temperatures above 80°C. However, it is strongly recommended to follow the ISO 15156-2 / MR0175 requirements for all the facilities exposed to H_2S, irrespective of the operating temperature, because there is a risk of cracking of hydrogen saturated materials during, for example, shut-downs at ambient temperature.

6.8.4 Stress-Orientated Hydrogen Induced Cracking (SOHIC)

Stress-Orientated Hydrogen Induced Cracking (SOHIC) is related to both HIC and SSCC. SOHIC appears as stacks or chains of hydrogen induced cracks, linked through the wall thickness of the steel by intermediate sulphide stress corrosion cracks. The orientation of SOHIC is related to residual or applied stresses. Typically, SOHIC is associated with welds. Qualification of materials against SOHIC is not well established, and common oil and gas industry practice considers that the measures taken to ensure steels are resistant to HIC and SSC are adequate for avoiding SOHIC as well.

6.8.5 Stress Corrosion Cracking (SCC) of CRAs

Many CRAs are susceptible to stress-cracking in the presence of sulphides. This is distinct from SSC of ferritic steels: SCC of CRAs occurs with minimal corrosion and is generally more severe at higher temperatures.

ISO 15156-3/NACE MR0175, EFC 17 [19] and NACE MR0103-2003 provide guidance on selection of CRAs to avoid SSC in sour environments. ISO 15156-3/NACE MR0175 lists environmental limits within which particular CRAs are considered to be acceptable for use: in other words listed materials can be regarded as pre-qualified for the conditions in the standard. It is important to note that ISO 15156-3/NACE MR0175 often places requirements on materials for sour service additional to the basic properties for the grade, for example restrictions on maximum hardness, or on processing conditions.

The standard also allows the possibility of qualifying a material for specific conditions outside these limits based either on service experience or test evidence. In some cases, the standard limits may be rather conservative, and qualifying materials for service outside the standard limits is a useful option.

Further guidance for specific CRAS has been incorporated in Chapter 7.

6.9 Microbially influenced corrosion (MIC)

Microbially influenced (or induced) corrosion depends upon the presence of a variety of organisms such as sulphate reducing bacteria. These organisms critically require a food supply (organic compounds) and specific environmental conditions (temperature, acidity, water content) within which they can flourish. Conditions within the main process streams in CCS plants are considered to be unsuitable for supporting micro-organisms. MIC may be an issue in utility streams, such as cooling water, or in drains, but this is not specific to the CCS processes.

6.10 High Temperature Corrosion

The shift reactors and the front end of the Pre-combustion carbon capture process involve temperatures up to 490 °C, while higher temperatures occur in the turbines and exhaust stream (520°C). Temperatures elsewhere in the CCS processes are not high enough to be classified as “high temperature” in this context. High temperature corrosion is a wide and complex subject area and a general survey is not attempted here: materials for the shift reactors, turbines and the exhaust stream are individually discussed as part of the Pre-combustion Capture materials selection. Unlike most of the processes discussed here, high temperature degradation mechanisms do not require the presence of water or moisture.

6.10.1 Oxidation and Sulphidation

Resistance to oxidation at high temperatures is affected by the properties of the metal oxide scale that is formed, including transport properties through the scale and chemical and mechanical stability of the scale. Increased levels of chromium provide increased resistance to high temperature oxidation in iron-base alloys, but even carbon and low alloy steels have useful resistance to oxidation at the temperatures expected in the CCS processes [20].

Similar considerations apply to resistance to sulphidation in sulphur-containing gases, and again chromium additions are generally beneficial in iron and nickel base alloys. Without hydrogen present, sulphidation rates reduce as the Cr content is increased. In contrast, in the presence of hydrogen, there is only slight beneficial effect of Cr up to 9 wt%, however sulphidation rates are much lower in 18Cr-8Ni stainless steels. Data on sulphidation rates for steels is collated in the McConomy and Couper –Gorman curves for hydrogen-free and hydrogen-containing conditions respectively [21,22,23 24]. Nickel and high nickel alloys are at potential risk of sulphidation due to the formation of the low melting point nickel-sulphur eutectic [25].

6.10.2 Metal Dusting

Carburisation involves internal carbide formation, comparable to internal oxidation or internal sulphidation, which occurs mainly at above 900°C and hence beyond the temperatures in CCS plant [26,27]. However, metal dusting, a form of catastrophic carburisation in carbon-rich, reducing atmospheres, can occur in the lower temperature range of 400–850°C [28, 29]. In an environment with low oxygen partial pressure, it is difficult for a complete protective oxide scale to develop, even if the oxide is thermodynamically stable in the environment. These conditions apply to the syngas shift reactors in the Pre-Combustion CCS process [30]. Metal dusting causes disintegration of the metal into a dust of graphite, metal oxide, metal carbide and metal particles; leading to a corrosion product consisting of metal, carbides and oxide particles, together with a carbonaceous deposit. It may take the form of localised pitting, uniform thinning, heavy carbon deposits with exfoliation, or combinations of all three [31]. The resulting metal loss decreases component lifetimes, ultimately leading to failure [32, 33].

Strategies for avoiding or limiting metal dusting corrosion are intended to decrease deposition of graphite on the metal surface, to decrease the ingress of carbon into the metal matrix, or reduce the diffusion rate of carbon [34,35,36]. Resistance of CRAs to dusting generally improves with increased Cr content [37]. The continuous presence of sufficient levels of H_2S or other sulphur compounds can also inhibit metal dusting; references should be consulted for further detailed information.

6.10.3 High Temperature Hydrogen Damage

High-temperature hydrogen attack on steels is a form of internal decarburisation. Hydrogen reacts with carbon, forming methane which coalesces and produces ruptures at grain boundaries, inclusions and flaws in the material. Damage is permanent and irreversible, resulting in reduction of strength and toughness. Attack can occur above approximately 200 °C in carbon steels. At higher temperatures, steels with additions of Cr and Mo are used to resist hydrogen damage, for example 1Cr0.5Mo and 2.25Cr1Mo grades. Cr and Mo inhibit decarburisation by forming carbides which are more stable than iron carbide and therefore tie up carbon so it does not react with hydrogen so readily. Guidance on the selection of steels to resist hydrogen damage is provided by API RP 941 “Steels for Hydrogen Service at Elevated Temperatures and Pressures in Petroleum Refineries and Petrochemical Plants” [38].

6.11 Liquid-metal embrittlement

Liquid-metal embrittlement (LME) results in either a loss of ductility of a solid metal or its fracture below the normal yield stress when the surface is wetted by some lower-melting liquid metal, for example mercury, which may be present in flue gases from coal combustion. Intimate contact of the liquid with the solid is required – even an intact oxide film is sufficient to prevent embrittlement. Thus, plastically-deformed surfaces with fresh metal exposed or stress raisers which lead to easy rupture of surface protective films are likely initiation points for LME [39]. Erosion or abrasion may also expose fresh metal surfaces.

Susceptibility to LME is unique to specific combinations of metals. The purity of the liquid or solid metals can be critical, e.g. pure copper is usually regarded as not being embrittled by mercury, but many copper alloys are highly susceptible. Important engineering materials that are highly susceptible to mercury embrittlement include grade 304 stainless steel and aluminium alloys in general. Note that 316L stainless steel is usually not susceptible to mercury embrittlement.

6.12 Degradation of non-metals

Many polymers are susceptible to swelling and changes in physical properties due to absorption of CO_2. Swelling is not necessarily a serious problem for O-rings and gaskets, but is potentially critical for items like valve seats that have to retain specific clearances.

The Hildebrand solubility parameter for liquid CO_2 is 10-11 $(\text{cal cm}^3)^{1/2}$, similar to that of many common elastomers, which indicates that CO_2 dissolves readily in these materials, Table 6.1. Other factors being equal, more severe swelling will tend to occur in polymers with similar solubility parameters as the environment. Gross swelling is unlikely if the difference in solubility parameters is more than about 1-2 units. Many commercial elastomers, such as nitrile rubbers (NBR, HNBR) are optimised for resistance to hydrocarbons (represented by iso-octane and toluene in the Table), and have similar solubility parameters to CO_2. Other substances present in the process streams need to be considered, for example water which causes swelling in many polyamides.

Table 6.1 : Solubility Parameters for selected solvents and elastomers [40]

Substance	**Solubility parameter, $(\text{cal cm}^3)^{1/2}$**
Iso-octane	6.9
Toluene	9.0
Liquid CO_2	10-11
Methanol	14.5
Ethylene glycol	14.5
water	23
NBR	8.5-11
HNBR	8.5-11.5
FKM	9-12.5
FEPM	8.5-10
EPDM	7.5-9

As an example, EPDM has been reported to be more successful than many other elastomers in field experience with CO_2 [41]. This is consistent with the solubility parameter of EPDM which is significantly lower than that of CO_2. However, it is never used in Oil and Gas applications due to its poor resistance to hydrocarbons. There are other factors involved in successful elastomer performance beside gas solubility [40], and specific HNBR and FKM (Viton®) grades have also been reported as suitable for liquid CO_2 service. Nevertheless, theory does suggest potential problems with certain elastomer classes, and careful selection of specific formulations, preferably backed by testing or service experience, is advocated. Statoil have used PTFE-based seals on liquid CO_2 pumps. PTFE is normal for valve seats and packings etc for handling liquid CO_2 service in cryogenic and general industrial service [42].

Dissolved CO_2 in polymers can also lead to damage on rapid gas decompression (RGD). The near-ambient and moderate operating pressures in many of the CCS plant systems are not high risk in this regard, but pressures after compression and in the injection well are high enough to present a risk to susceptible materials. In general, RGD resistance is favoured by high elastomer modulus (hardness) and tear strength and by low absorption of CO_2 [43].

While swelling is reversible, chemical aging involves permanent changes to the polymer properties, typically embrittlement and loss of ductility. Chemical aging is progressive and generally accelerated by high temperature. Some species such as H_2S and SO_2 cause chemical aging in a wide range of polymers, while other species are more specific to individual polymers.

7 MATERIAL SELECTION AND EXPERIENCE

This Chapter summarises materials selection and experience of materials performance in environments which are particularly relevant to CCS systems. It is necessarily an overview of several diverse and complex subjects, and the references should be consulted for more details on any particular topic.

7.1 Material Selection in Wet CO_2 Environments

This section considers the materials selected for handling wet corrosive environments of various types containing CO_2. The terms “sweet” and “sour” are commonly applied within the oil and gas industry to describe CO_2–containing fluids respectively lacking or containing hydrogen sulphide. The materials selection “rules” described in this Chapter have been drawn from other industries (principally Oil and Gas) and have formed the basis for material selection for the various carbon capture processes within this report.

So-called “sweet” environments characteristically cause corrosion which is dominated by the presence of CO_2, as described in Section 6.4.1.

The addition of hydrogen sulphide to a CO_2-containing stream changes not only the form of corrosion in carbon steels, but also affects the choice of materials applied for mitigating the corrosion process. ISO 15156/NACE MR0175 provides the starting point for materials selection in these “sour” conditions, although strictly the scope of the standard is restricted to oil and gas production environments. The standard does allow the use of materials outside the published limits on the basis of suitable experimental data or service experience.

ISO 15156/NACE MR0175 only covers oxygen-free environments. The combination of CO_2 and H_2S with oxygen present is also considered in this section. Corrosion in partially deaerated brines has been studied in connection with seawater handling and downhole injection, and also with downhole storage of natural gas in salt caverns, among other situations [44, 45]. The CCS conditions are more severe in some respects due to the high CO_2 levels and acidity.

7.1.1 Carbon steel

Carbon steel is used in this report in the context of corrosion properties to refer to mild steel, C-Mn steels, micro-alloyed steels and also low alloy steels where the alloy content does not produce a significant difference in corrosion behaviour from that of mild steel. Carbon steel is common as the material of construction in non-corrosive environments; even in moderately corrosive conditions this material is still preferred owing to its relatively low price, strength and ready availability internationally.

Bare carbon steel is vulnerable to CO_2 corrosion and O_2 corrosion; the corrosion rates of carbon steel can be estimated using the approach explained in Sections 6.4.1 – 6.4.2.

The threshold of H_2S concentration at which an environment is considered to be “sour” for carbon and low alloy steels is defined by ISO 15156/NACE MR0175. In oxygen-free, sour environments, the corrosion product (iron sulphide) can be highly protective and carbon steel can be remarkably successful as long as the guidance of ISO 15156/NACE MR0175 is followed for avoiding SSC and HIC cracking, sections 6.8.2-6.8.4.

Corrosion rates of carbon steel in wet sour conditions with trace oxygen are difficult to predict, but are typically these are very severe conditions for carbon steel. Elemental sulphur and sulphur acids may be produced by reaction of H_2S and O_2, leading to high rates of corrosion, often with severe localised corrosion, section 6.4.3. Carbon steel is usually unsuitable, and other materials or modification of the environment have to be considered.

7.1.2 Low temperature carbon steel

From a corrosion viewpoint, low-temperature carbon steels (LTCS) behave identically to the standard carbon steels; they have been developed chiefly for use in low-temperature equipment which may have low minimum design temperature. This usually includes higher pressure equipment especially for welded pressure vessels, high pressure flare and some pipe systems where a sudden depressurisation could result in temperature drop. Selection of particular steel grades for any item of equipment depends upon the specified low temperature properties.

7.1.3 Corrosion Resistant Alloys

Where predicted corrosion rates for carbon steel are too high and where lining or other protection of the carbon steel is not practicable, Corrosion Resistant Alloy (CRA) materials will be selected in place of CS. Corrosion Resistant Alloys (CRAs) are essential for providing long term resistance to corrosion for many components exposed to corrosive environments. There are many CRAs to select from and this discussion is limited to the common options.

Key environmental parameters influencing the corrosion properties of CRAs are:

- Temperature
- Chloride ion concentration
- Partial pressure CO_2
- Partial pressure H_2S
- Environment pH
- Presence of other contaminants, principally oxygen and other acidic or oxidising contaminants.

Between them these parameters influence

- the stability of the passive film (initiation of pitting)
- ease of repassivation of initiated pits
- rate of dissolution of metal from pits (pitting rate)
- the risk of stress corrosion cracking (SCC) initiating and propagating (or SSC in ferritic & martensitic CRAs)

The aim in selecting CRAs for a given environment is to choose the most cost-effective one for which there is no risk of passive film breakdown. So the choice of alloy should be one for which the expected operating conditions are within the safe operating envelope of no pitting or cracking. The following sub-sections discuss the safe operating envelope for several standard CRA grades. In all cases, the environment is considered to be wet.

7.1.4 Martensitic Stainless Steel

7.1.4.1 Sweet Conditions

Martensitic stainless steel is usually used for non-welded components such as forged parts in compressors or as seamless threaded pipe for downhole production/injection tubing. It is not used for welded items such as piping or vessels as it requires a lengthy 2-stage post welding heat treatment which is often inconvenient or costly. The typical 13%chromium containing grades have good resistance to carbon dioxide. Figure 7.1 represents the safe operating envelope for API 13 Cr stainless steel exposed to wet CO_2 containing NaCl but without any contaminants present [46]. Review of published data suggests that the proprietary S13Cr alloys, referred to as Super 13Cr, Hyper 13Cr or Modified 13Cr and generally stronger than the basic API 13Cr grade, are suitable up to about 30˚C higher operating temperature than the standard 13Cr grades in H_2S -free environments.

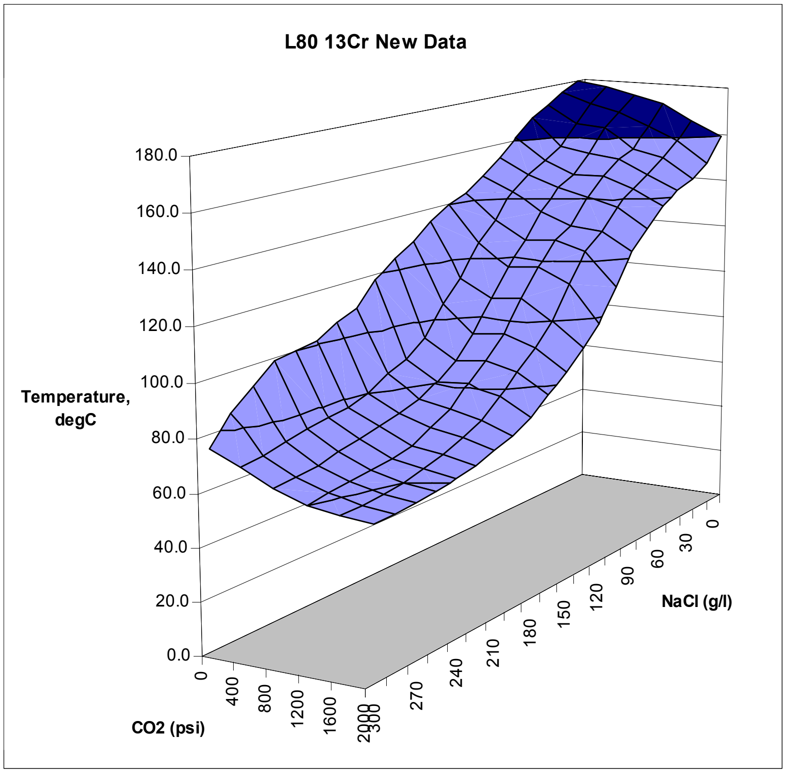

Figure 7.1 : Safe operating envelope for of 13Cr stainless steel in sweet service (based on a limiting corrosion rate of 0.05mm/yr).

In high CO_2 concentrations the environment pH can drop below 3.5 and then there is a high risk of pitting because of the ease of breaking down the passive film in the martensitic stainless steels. Initiation of pitting is also affected by the presence of chloride ions at high concentration, so above 200g/l sodium chloride, the 13Cr group of materials cannot be considered. Such extremely concentrated chloride levels may arise under upset conditions at times within plant (by evaporation of a water phase with high level of dissolved solids leaving a hygroscopic salt deposit), or, more commonly, at the bottom of injection wells disposing into concentrated brine aquifers.

7.1.4.2 Sour Conditions

NACE MR0175/ISO15156-3 specifies a maximum H_2S content of 0.1bar (1.5 psi) and minimum pH of 3.5 for martensitic stainless steels in tubing and general equipment. This also applies to the low carbon, “supermartensitic” stainless steel grades. The latest consensus from laboratory work and field data is that standard martensitic API 13Cr L80 can tolerate a little higher H_2S than early publications seemed to suggest or than NACE MR0175/ISO15156-3 allows [ii]. Figure 7.2 shows the range of conditions where data indicates the material is resistant to sulphide stress cracking (SSC) and the region at low pH or higher H_2S where the material will crack in standard SSC test conditions. This figure is based on a variety of data at chloride levels >50,000ppm, and different service ranges can be expected for extremely low or extremely high chloride contents.

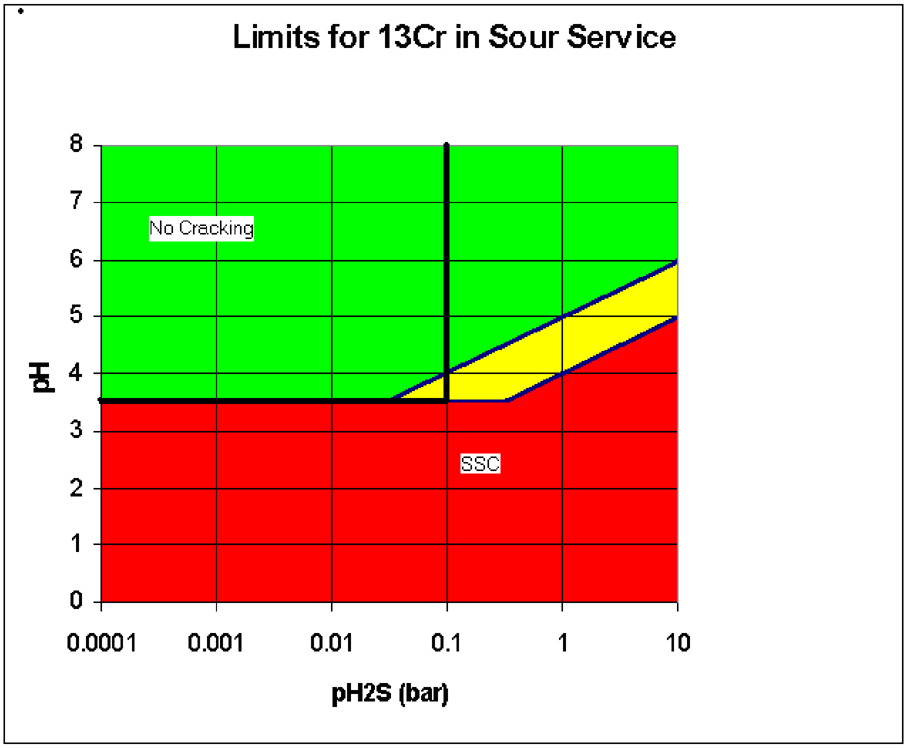

Figure 7.2 : API L80 13Cr; sulphide stress cracking (red region); resistant (green region); yellow area represents conditions requiring further checking of alloy behaviour. ISO15156-3 limits shown by heavy black lines

The critical feature of this Figure 7.2 is the transition between no cracking and cracking which arises at pH 3.5 (test data established at room temperature). Recent publications also confirm the tendency for 13Cr family of materials to depassivate at below about pH 3.5 depending upon heat treatment condition and alloying composition [47].

The higher strength Super-13Cr grades have been found to be *more* susceptible to H_2S than the standard 13Cr grade, probably reflecting its higher strength. One publication indicates the influence of material yield strength on performance, illustrating that the

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[ii] Intetech internal review of cracking data published in the period 1998-2008

higher strength material has a greater risk for enhanced initiation of pitting, hydrogen embrittlement and sulphide stress cracking (Figure 7.3).

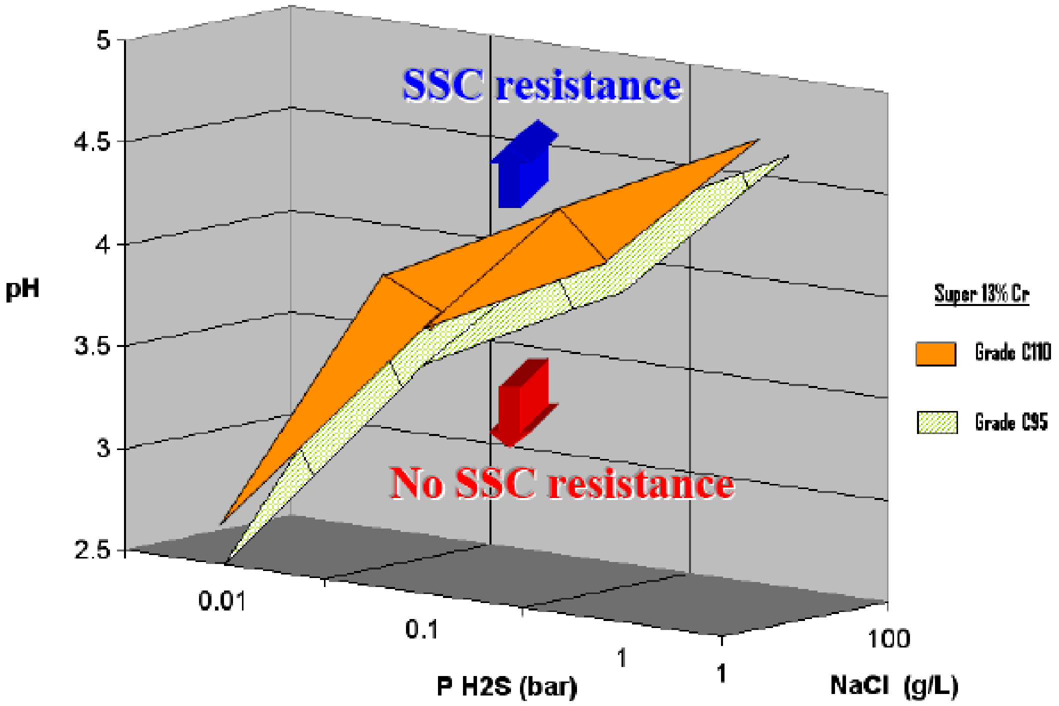

Figure 7.3 : 3-Dimensional SSC susceptibility diagram of a Super 13% Cr SS (specimens were stressed at 90% AYS). [47]

7.1.4.3 O_2 – containing conditions

In the presence of oxygen the 13Cr stainless steels are considered to be “just” passive, but over time the surface does rust.

In the complex environment of CO_2 plus some H_2S and oxygen there is a significant pitting risk because the oxidised hydrogen sulphide forms sulphur on the steel surface which is a potent pit initiator. Martensitic stainless steels would not be considered suitable for corrosive (wet) service in the presence of H_2S and O_2 with chloride ions as pits would readily initiate. There is also an greatly increased risk of SSC with oxygen present.

7.1.5 Austenitic Stainless Steels

7.1.5.1 Sweet Conditions

The 300 series - stainless steels are a broad range of materials based around the standard AISI 304L grade and the higher Molybdenum-containing Alloy 316L. All these materials are resistant to corrosion in sweet environments; the more Mo-rich grades having a more stable passive layer and therefore being more suitable for CO_2 environments with chloride ions present. The limits of environmental parameters for Alloy 316L in terms of NaCl%, partial pressure of CO_2 and temperature are shown in Figure 7.4.

This graph indicates a rather high sensitivity to chloride contents when the partial pressure of CO_2 is very high.

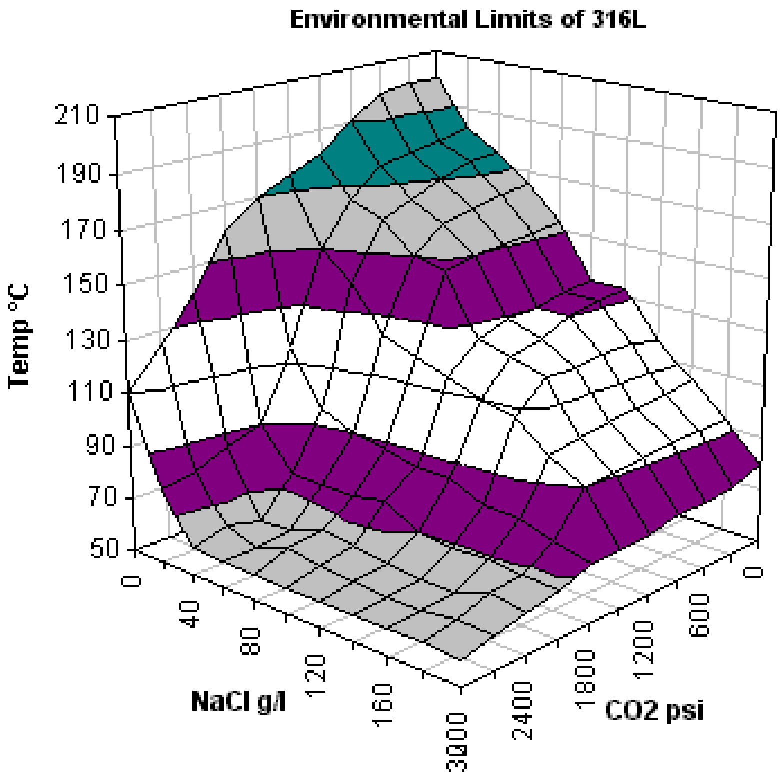

Figure 7.4 : Limits of use of AISI 316L stainless steel in sweet environments

7.1.5.2 Sour Conditions

ISO 15156-3 was published in first edition on 15/12/2003. It is subject to continuous revision with Technical Corrigenda being published from time to time and these have frequently affected the limits for austenitic steel. The table below summarises the *currently* published operating limits of austenitic stainless steels applicable in ISO 15156-3. Values stated are *maximum* limits of parameters allowed. The testing required for alloys to be included in ISO15156 nowadays requires rigorous exclusion of air from the test medium. Alternatively, materials are listed because of proven long experience in service.

Table 7.1 : SAFE OPERATING LIMITS 15/12/2007
(Source: NACE MR0175/ISO 15156-3:2003 Technical Circular 1)

Material Type	Temperature, °C	Partial pressure H_2S (psi)	Chloride conc. (mg/l)	pH
Austenitic stainless steels (including 304L)	60	15	Any	Any
	Any	Any	50	Any
S31600, S31603	93	1.5	5,000	≥5
	149	1.5	1,000	≥4
S20910	66	15	Any	Any

Note that these materials are not suitable in sour conditions with elemental sulphur present.
The limits of use of Alloy 316L in environments containing H_2S and high chloride levels were established in an extensive review by TWI [48]. In principle these tests were made with oxygen purging, but they pre-dated rigorous laboratory controls and it is considered that the lower limits they obtained are indicative of the impact of some (undefined small quantity) of air. This indicated that for chloride contents of 10 g/l the limiting partial pressure of H_2S above which there was a likelihood of sulphide stress cracking was 0.9 bar over a wide temperature range from room temperature to about 225 °C.

At higher chloride contents the amount of H_2S which could cause cracking was much less and is also sensitive to temperature; increasing the temperature increased the risk of cracking up to about 100 °C. Thus the maximum sensitivity to cracking was found to be with chloride contents above 100g/l at a temperature of 100 °C. At these conditions only 0.009 bar H_2S was sufficient to cause sulphide stress cracking. Between room temperature and 100 °C the maximum tolerable partial pressure of H_2S decreased from 0.9 bar to 0.009 bar when the chloride content is 100 g/l.

At temperatures continuously higher than 100 °C laboratory test data shows that the material can tolerate exposure to higher levels of H_2S. However, in applications at temperatures above 100 °C it is considered dangerous to assume a higher limit for H_2S because the equipment may experience lower temperatures at certain times, and cracking could arise in these periods, even if only fairly short in duration.

So for temperatures at or above 100 °C, the maximum allowed level of H_2S is taken to be 0.009 bar when the chloride content is above 100 g/l.

7.1.5.3 O_2 – containing conditions

In the complete absence of chloride ions the AISI 300-series materials remain passive in environments rich in CO_2 and with oxygen and hence there can be useful niches where AISO 304L stainless is appropriate. However, such environments are rare as chloride ions are ubiquitous.

Where there is any substantial amount of oxygen present in the environment, along with chloride ions, AISI 300-series materials readily pit and crevice corrode at a high rate, even at temperatures as low as 10 °C. This class of materials is considered unsuitable for application where there is oxygen in the environment with chlorides, and particularly where there is also H_2S or other sulphide species or acids.

Possible austenitic grades which may be considered for conditions with oxygen and low chloride-ion concentrations are those with increased molybdenum content relative to 316L (2.0%Mo), such as AISI 317 (3.0%Mo) and AISI 904L (4.5%Mo).

7.1.6 22 Cr and 25Cr (Duplex Stainless Steel)

7.1.6.1 Sweet Conditions

In sweet environments the resistance of 22Cr duplex stainless steel is very good. There is no risk of pitting or stress corrosion cracking of duplex stainless steels at up to 200 °C, even with sodium chloride content in the brine of 200 g/l (200,000 ppm). This equates to a chloride ion concentration of about 125 g/l.

The Superduplex 25Cr steels have a greater resistance to pitting than the 22Cr duplex steels, adding probably around 30 °C generally at any set of conditions compared to the 22Cr grade (Figure 7.5).

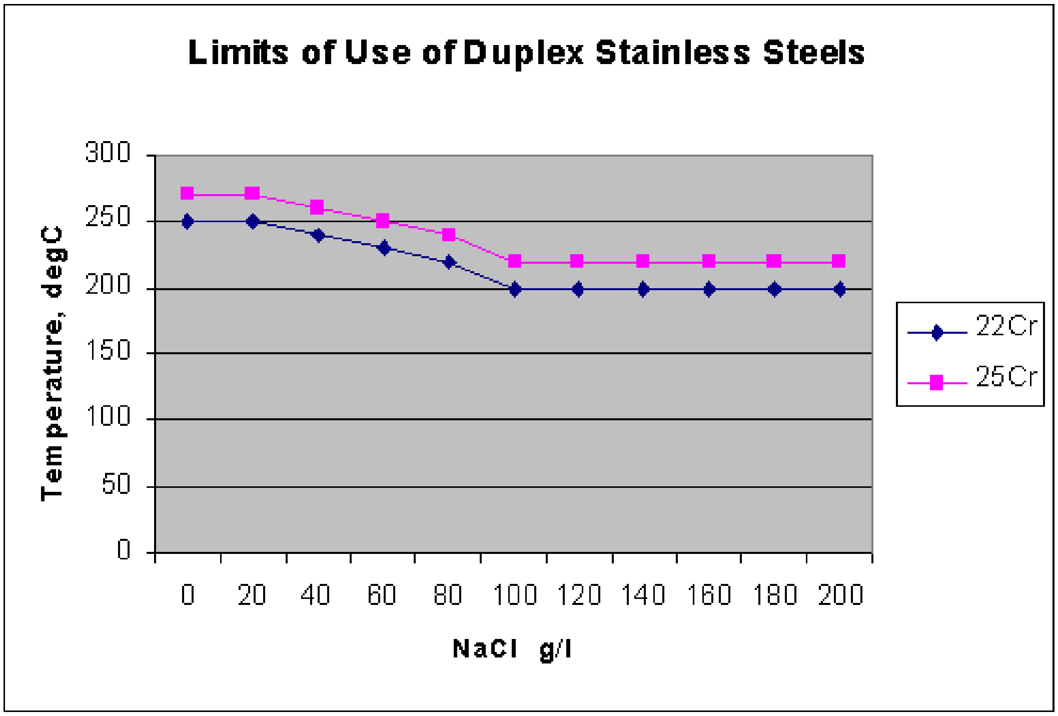

Figure 7.5 : Temperature limits for duplex stainless steels as a function of sodium chloride concentration (<0.05mm/yr corrosion and no SCC or SSC, based on [46])

At more extreme chloride ion concentrations made from mixed sodium, magnesium and calcium chloride salts evaporated to form a concentrated brine slurry (230 g/l Chloride ion concentration), it was shown that both 22Cr and 25Cr duplex stainless steels were susceptible to stress corrosion cracking in the absence of oxygen at 140°C. These conditions were estimated to have arisen in some duplex stainless steel topside piping downstream of a choke valve with a high pressure drop and carrying a small volume of concentrated brine in the gas stream. Internal stress corrosion cracking was observed associated with the concentrated brine formed by evaporation of the produced water [49].The cracking problem was mitigated by upgrading material to Alloy 625. In the CCS context, similar conditions might occur within the injection well.

7.1.6.2 Sour Conditions

ISO15156-3 / NACE MR0175 allows 22Cr duplex alloys (Pren > 30) with upto 0.1 bar H_2S and 25Cr superduplex alloys (Pren > 40) with up to 0.2 bar H_2S, and without limits on chloride content or pH. Various published data has shown that the H_2S levels can be extended with restricted pH or chloride levels [50]. On the other hand, at low pH values below pH 3 (which are unusual in oil and gas production), the materials are less resistant than ISO15156-3 / NACE 0175 suggests [iii].

Duplex stainless steels are most sensitive to sulphide stress cracking at around 80-100 °C and so test data at that temperature has been checked to establish the safe environmental limits. Cracking is also dependent on the pH and on the chloride content. The pH value is taken at room temperature since this is the value reported for the laboratory test data on which the limits are based. The limits of H_2S as a function of pH and chloride content are given by the following graph (Figure 7.6).

[iii] ISO 15156-3 wording is "*any combination of chloride concentration and in situ pH occurring in normal production environments are acceptable*": CCS environments with high CO_2 pressures are arguably more severe than "production environments".

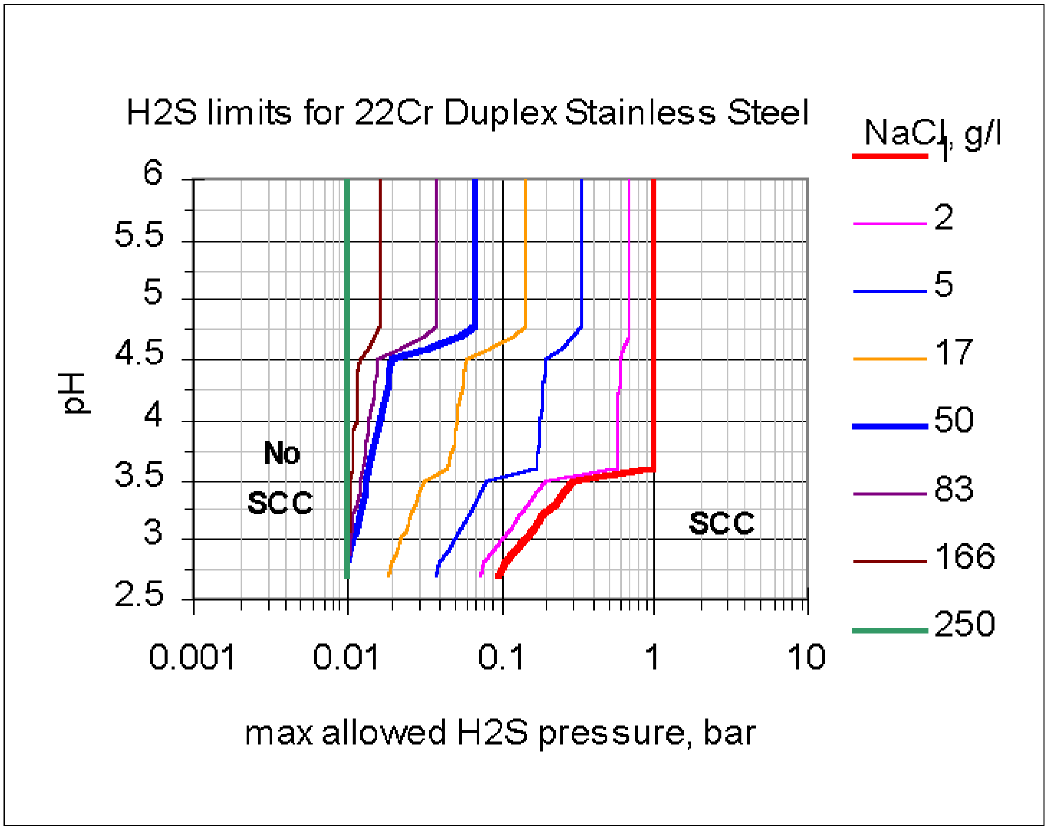

Figure 7.6 : Safe operating envelope of 22Cr duplex stainless steels in CO_2 environments containing H_2S and chloride ions.

Considering the 25Cr superduplex stainless steel, this is more resistant to hydrogen sulphide in general, but, as with the 22Cr grade, the limits of H_2S all converge together at high chloride content and low pH (Figure 7.7).

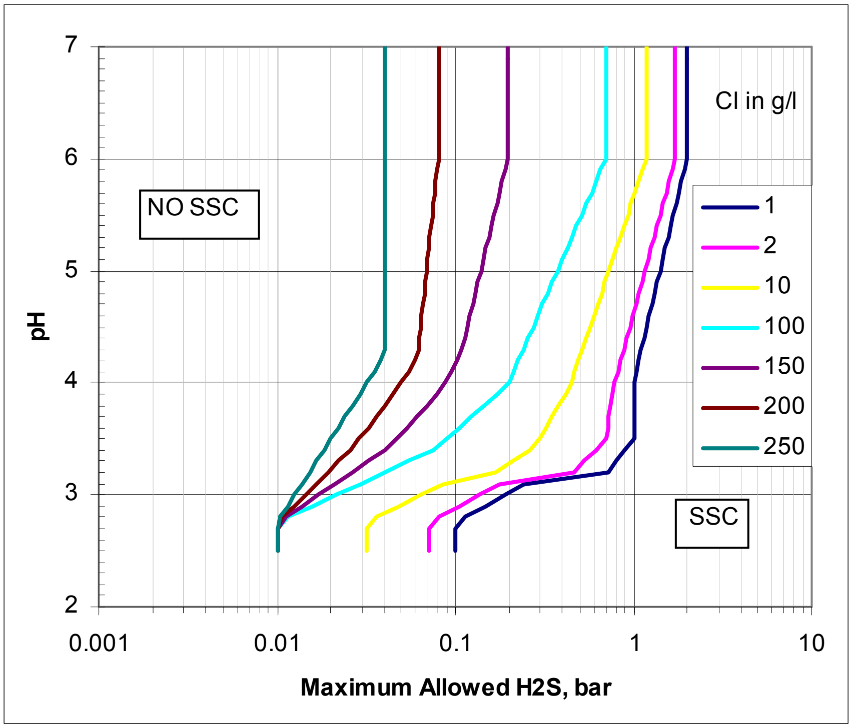

Figure 7.7 : Safe operating envelope of 25Cr duplex stainless steels in CO_2 environments containing H_2S and chloride ions.

7.1.6.3 O_2 – containing conditions

The 22Cr duplex stainless steels are not highly pitting resistant and would not generally be selected for conditions containing oxygen if chloride ions were present at temperatures above 10 - 20 °C. The super-duplex (25Cr) grades are used up to 30 °C in aerated seawater and so would provide pitting resistance in some combinations of chloride ions and oxygen. As with the other stainless steels, the combination of CO_2 / H_2S and O_2 could be dangerous if elemental sulphur was formed and adhered to the steel surface as it will initiate pitting in the duplex grades, with or without chloride ions present.

7.1.7 Nickel Alloys and Titanium

The nickel alloys (generally considered to include the 40%Ni-containing Alloy 825 and more highly alloyed grades) are effectively immune to CO_2-corrosion and highly resistant to the presence of H_2S as they have a strong passive layer which is relatively pitting-resistant.

However, in the presence of oxygen and chlorides, even these materials have limits as regards pitting and stress-corrosion cracking. In fully aerated warm brines, Alloy 625 is resistant to about 60 °C and Alloy C276 up to about 80 °C. Above 90 °C it is generally necessary to consider pure titanium or its alloys for handling hot aerated brines.

In the combined presence of H_2S and oxygen, there is a significant pitting risk, because of the potential formation of elemental sulphur, a potent pitting agent. Where this arises, the most highly pitting resistant grades, such as Alloy C22, Alloy C276 and Alloy 59 have to be considered.

7.2 Material Selection for Flue Gas Environments

Materials performance in parts of flue gas desulphurisation (FGD) plant is relevant to CCS plant, particularly the FGD outlet stream, which in some processes is the inlet stream for the CCS plant. The distinguishing feature of the flue gas environments compared to the sweet and sour CO_2 environments is considered to be the presence of the oxidising acid species NOx and SOx. These are absent in the reducing conditions typically found in oil and gas production or other CO_2-handling industries.

The inlet for FGD absorbers is between 50 °C (coal) and 70 °C (lignite) whereas the inlet for the post-combustion CCS plants is between 30 °C and 50 °C. Although the SO_2 has mostly been removed from the flue gas in the FGD plant before reaching the CCS plant, there is still sufficient SO_2 to contribute significantly to the acidity of the inlet to the CCS plant in the coal fired processes. In addition to this, the CO_2 level has been enhanced and there may be carry-over of adipic acid from the FGD plant (used to increase SO_2 absorption and reduce water flow and erosion by slurry). Dew point, acidity (pH), temperature, halide concentration (chlorides and fluorides), crevice conditions, and gas velocity all must be considered in defining the corrosivity of the environment. Where the conditions drop below the dew point there is a risk of condensation of concentrated acids, and this is normally the cause of corrosion encountered in FGD systems.

7.2.1 Carbon steel

Carbon steel has been used unprotected for parts of the FGD systems which are operating above the dewpoint. There are examples of inlet ductwork to absorbers in carbon steel which have operated successfully, however there are reported [51] to be some instances of blow-back of gas from the scrubber into the inlet section and serious corrosion arising. Thus the use of carbon steel is entirely restricted to parts of the plant that will operate above the dew point throughout the life of the plant.

It should be noted that many power stations re-heat the FGD exit flue gas to around 110 °C to reduce stack corrosion and the visible condensation plume from the plant. Such outlet streams which are free of any liquid water phase are non-corrosive and carbon steel has been used with success for such locations in FGD plants. This option of keeping the outlet stream above the dew point is not done in the CCS case because CO_2 absorbers need to operate at low temperature, so the flue gases remain water-wetted and hence very corrosive. For example, the wet flue gas of the coal-fired Post-combustion capture process contains around 10% water and dissolved acid gases will give pH values around 3. When the flue gas temperature falls below its dew point, or where water droplets are present, then suitable protection will be needed to prevent corrosion of ductwork from the acid water.

7.2.2 Corrosion Resistant Alloys

A wide range of CRAs have been used for FGD outlet ducting (the inlet to the CCS process): the most common choices include high alloy stainless steels, (317LMN, 904L and 6-Mo grades) and nickel alloys (C276, Alloy 625 etc), although some plants have used 316L. Nickel alloys are relatively more popular for inlet ducting (with its higher SO_2 content). Nozzles and connections are often solid, rather than clad or lined, and in a higher grade alloy than the ducting linings.

7.2.2.1 Austenitic Stainless Steels

The most basic AISI 304-type austenitic stainless steels do not have a sufficiently strong passive film to withstand typical flue gas conditions. Austenitic grades which may be considered for conditions with moderate pH and low chloride-ion concentrations are those with increased molybdenum content relative to 316L (2.0%Mo), such as AISI 317 (3.0%Mo), AISI 317LMN (3.5%Mo) and AISI 904L (4.5%Mo). None of these grades would be considered suitable for streams where there is either significant chloride ion carry-over, or capability for chloride ions to concentrate by recirculation or stagnation of the streams. As a guide, chloride ion concentration above 1000ppm may be sufficient to induce pitting attack in the presence of oxidising acid species. As an example, AISI 317LMN stainless steel used in wallpapering outlet ducts in one instance has failed [52] and been replaced with a 6Mo-containing super-austenitic grade (UNS N08367).

For chloride ion concentrations lower than 1000ppm the consensus of experience indicates that it would be advisable to switch from a selection of AISI 317LMN to higher Mo content alloy options when the pH drops below about 3. Thus, higher SO_2-content streams would tend to be in AISI 904L or potentially 6Mo grades and lower SO_2 content streams are acceptable to handle with AISI 317LM grades.

7.2.2.2 Duplex Stainless Steels

Duplex stainless steels are available in a variety of forms, but they are particularly useful as casting alloys for pumps. The standard UNS S31803 22Cr grade would be considered to be equivalent in corrosion performance to the AISI 317LM material.

The 25Cr duplex stainless steels (including several grades like UNS S32750) are generally considered to be more resistant to acids than 22Cr duplex as they have a stronger passive film. Zeron 100, UNS S32760, (a 25Cr super duplex stainless steel of Rolled Alloys UK) has been tested in the laboratory for some mining applications at 200 °C, 100,000 ppm chloride ion and pH 2. Under these conditions it did not pit or corrode. At pH values less than 2, however, passivity was lost and corrosion damage took place. [53].

It is concluded that conditions which are free of NOx and SOx, or with only traces which would not reach extremely low pH values below 3, the choice of 25Cr duplex stainless steel may be appropriate. However, in the presence of higher quantities of the oxidising and acidic species (O_2, NOx and SOx) the additional pH reduction may make the choice of 25Cr duplex stainless steel a marginal material selection with risk of loss of passivity (and hence pitting attack) in wet conditions.

7.2.2.3 Nickel Alloys

The nickel alloys with high molybdenum content have been used for many years for extremely corrosive applications in both the oilfield (highly sour gas fields) and flue gas desulphurisation applications.

The key to their performance is that they retain their molybdenum-rich passive film in the high chloride and low pH conditions. Figure 8.9 gives suggested usage limits of various stainless steels and nickel alloys as a function of chloride (halide) concentration and pH. This indicates that for an environment with chloride ion concentration greater than 100,000 ppm (100 g/l), the appropriate nickel alloys to consider at pH values around 2 - 3 are Alloy 59 and Alloy C276. Whilst there tend not to be such high chloride ion concentrations anticipated in most of the CCS processing plant, such high chloride conditions may arise when the CO_2 gas is injected into a saline aquifer. These alloys have a track record of positive experience for use in such conditions in the chemical and flue-gas industries for over 20 years. Alloy C276 is also well established for tubulars in the most aggressive deep sour wells.

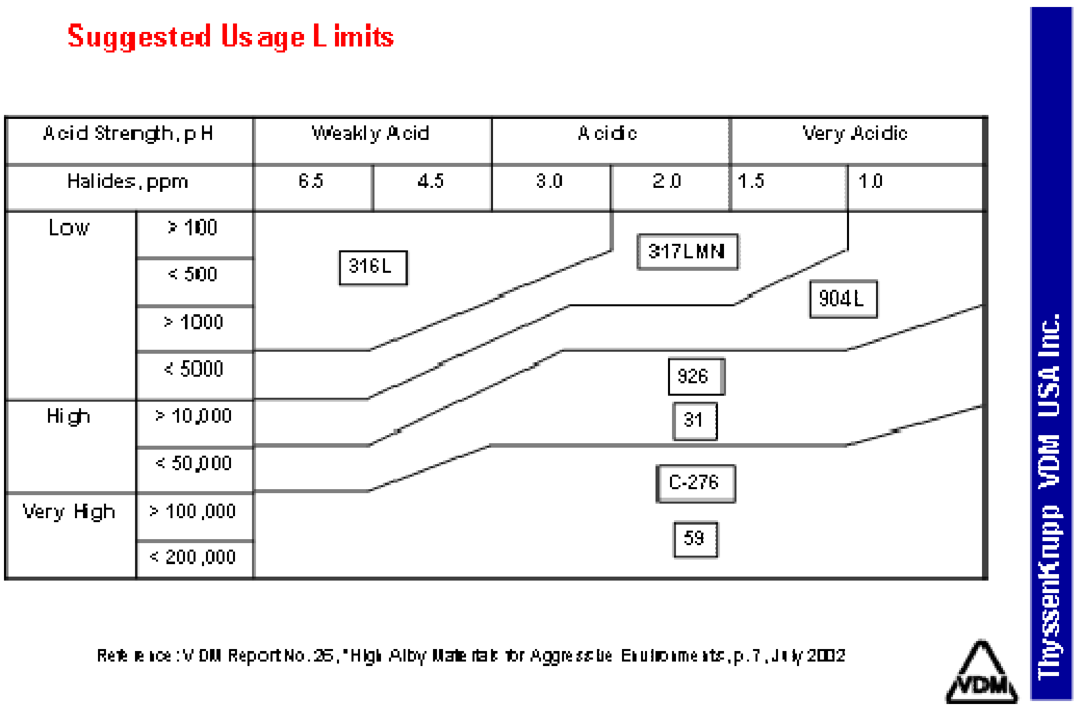

Figure 7.8 : Alloy usage limits for aggressive corrosion conditions (ThyssenKrupp VDM)

Substantial use of very highly alloyed metals has been made cost-effectively in FGD systems by using the “wallpapering” technique of welding alloy sheets onto carbon steel.

The service experience of the nickel alloys has been good; early failures of leaks at welds have been considered to be fabrication problems rather than material deficiencies. Metallic cladding applied by fillet welding allows the ‘wallpaper’ to vibrate which eventually causes fatigue and allows galvanic corrosion of the steel substrate; the time to failure depends on the number of securing welds. In some cases CRA wall-papering has been replaced with solid clad sheet. Properly applied (with a large number of slot welds to mitigate fatigue), CRA wall-papering is a lifetime solution but may be more expensive than the other corrosion mitigation methods depending on current alloy prices. Attention to detail in construction and fabrication steps is critical to success and vital when expensive materials are selected.

7.2.2.4 Non-metallic Materials and Linings

The option of using carbon steel with non-metallic lining has frequently been considered (for reduced capital outlay reasons) and applied in parts of FGD plants. Traditionally, FGD ductwork was constructed of flat externally stiffened mild steel, keeping internal surfaces as flat and smooth as possible to allow for rubber lining, flake-glass vinylester coating (FGV), or CRA wallpapering. A less conventional approach for ductwork, with initially larger capital outlay than rubber or FGV, is to use large diameter filament wound glass reinforced plastic (GRP) pipe; many of the newer US FGD units [54] use this for the outlet from the absorber and the stack flue, and increasingly for the inlet as well as confidence in GRP grows.

All polymers allow some permeation of water vapour and other species including CO_2 and H_2S, and eventually this will lead to disbondment of the lining and corrosion of the steel substrate; the time to failure depends on the polymer density, filler and bond strength. For coating, only resins which are resistant to water vapour at over 70 °C in immersion service should be considered. This precludes the cheaper resins such as polyester, polyurethane and pure epoxy, and fillers such as Aluminium or zinc phosphate. In most existing cases vinylester resins are used [55]. Some coating suppliers favour mica flake rather than glass flake, or use phenolic-epoxy (novolac). Only test- and service-qualified products should be considered.

Preparation of carbon steel for rubber coating requires substantial grinding, since welds must be convex in shape and edges rounded to allow adhesion [56]; the bond strength of the rubber depends on the effectiveness of curing (requiring in-situ steaming or the use of self-curing adhesives). During application of FGV it is only necessary to remove sharp edges and stripe-coat welds and edges; weld shape is not crucial and the flake glass or mica filler greatly reduces water permeability compared with rubber coating, while a higher bond strength is achieved compared with either in-situ cured or self-curing rubber [57].

As reported by Schwarz and Mueller [58] both rubber and CRA wall-papering have suffered early damage (within a few years in some cases) and required substantial repairs and downtime. Early natural, polychloroprene and chlorobutyl rubbers have been replaced with bromobutyl rubber, By comparison, FGV coated steel has generally only required local repair. GRP is regarded as being a lifetime if more expensive alternative to FGV or rubber coated steel.

Failures of rubber linings and FGV coatings have led to perforation of ducts and support steelwork in FGD plants. Whilst non-metallic coatings are reported to have given good experience in about 40% of cases, in the rest it has been necessary to carry out repairs on a two-yearly cycle, and in a few cases complete replacement of the lining has been made, usually with metallic wallpapering.

Where concrete is the structural material the selection of the concrete formulations should consider the option of acid-resistant grades for exposed surfaces with additional tiling protection against the environment.

7.3 Material Selection for Amine Environments

Amine units are widely used in upstream oil and gas applications and in refineries for removing CO_2, H_2S and related species such as mercaptans, from hydrocarbon gas streams; there is extensive materials performance experience in these applications [59, 60, 61, 62, 63].

Dilute amine mixtures themselves are not corrosive to carbon steel and carbon steels are often used, particularly for lower temperature areas of the systems. If H_2S is present at a CO_2 : H_2S ratio of about 20:1, or preferably less, sulphide films can provide additional corrosion protection to carbon steel. Higher acid gas loadings can be tolerated in the rich amine in this case. Carbon steels can suffer alkaline stress-corrosion cracking in amine solutions. Post-weld heat treatment of welds is necessary to prevent this, depending on the service temperature and particular amine type. Requirements for PWHT are covered by API 945 “Avoiding Environmental Cracking in Amine Units” [64].

In refinery service, carbon steel is generally the main material of construction for the lean amine piping, and absorber, stripper and reboiler vessels. Austenitic stainless steels are typically used for higher temperature equipment such as the reboiler tube-sheet and tubes, stripper overheads, hot rich amine piping and lean/rich heat exchangers, and often more widely in the reboiler. Stainless steels are often also used for vessel internals and pumps. The main grades used are 304/304L and 316/316L: higher alloy stainless steels or other CRAs are used relatively rarely in refinery applications.

Materials which are not suitable for amine service include martensitic stainless steels (12Cr, AISI 410 etc), aluminium and copper-based alloys.

Several factors can limit the use of carbon steel, including: the formation of organic acids; high acid gas loadings; corrosive contaminants; erosion and / or high velocities; and high temperatures. Process control is critical in avoiding corrosion problems in amine systems, including limiting heat-stable salt loadings, filtering out solids and controlling temperatures and pH.

Oxygen degrades amines, forming a variety of products including organic acids and heat-stable salts which increases the corrosivity of the environment as well as increasing the consumption of amine and reducing the efficiency of operation. As well as being corrosive to carbon steel, these acids can cause damage to stainless steels at the temperatures in the reboiler etc.[65, 66]. Adding caustic to neutralise the organic acids can mitigate corrosion problems to some extent. Other undesirable contaminants include sulphur-containing species (SO_2, sulphates etc), chlorides, ammonia and cyanides. Note that austenitic stainless steels are potentially at risk of chloride stress cracking if both trace oxygen and chlorides are present.

Refinery amine systems normally aim to operate in oxygen-free conditions, and stringent measures are taken to minimise oxygen ingress, for example in make-up chemicals. In contrast, the Post-combustion CCS process stream contains high levels of oxygen as well as trace SO_2, which would create severe problems in conventional amine systems [67 ,68]. The development of particular amine blends and of proprietary additives for CCS applications may help to alleviate the problem of oxidation [69, 70]. Because reducing oxidation is in any case necessary for effective and economic operation, it is assumed for the purpose of this materials selection report that the formation of acids and heat stable salts will be controlled in any future CCS amine system. Chlorides can be assumed to be minimal in the CCS process streams, but should always be minimised in make-up water and chemicals.

Many organic coatings are unsuitable for use with amines, which are strong solvents. A small number of specific siloxane, FGV or filled phenolic-epoxy coatings have been used with success [71] in steel amine CO_2 absorbers or amine containers.

8 MATERIAL SELECTION FOR POST-COMBUSTION CAPTURE PROCESS

The material selection for individual plant streams and equipment items is tabulated in Tables 11.1-11.4 and summarised in Figs 11.1-11.4 in Chapter 11. The following text discusses some specific aspects in more detail.

8.1 Flue gas

The flue gas generated by the coal- and gas-fired combustion contains CO_2, water, N_2, O_2 and other impurities are produced in the coal-fired process only such as Hg, Cl, and SO_2. In the coal-fired case, the flue gases are passed though a FGD system, which will reduce the levels of soluble impurities such as chlorides and SO_2. The corrosion rates of unprotected carbon steel would be high throughout the entire loop, due to the wet conditions and presence of CO_2 and O_2. In general, the options are coated or clad carbon steel, solid CRAs and non-metallic materials.

Figure 8.1 shows the schematic diagram of the flue gas loop, the main process stream in this loop is high volume flow at near ambient pressure and temperature and will be handled in ducting. Section 12.2 contains a detailed discussion of materials options for ducting: essentially the choice is between coated carbon steel (with the need for regular maintenance), or wound GRP ducts (higher cost, but expected to be largely maintenance-free).

Similarly, the DCC and SO_2 polisher vessels are likely to be large cross-section towers with panel-construction, rather than conventional pressure vessels. Note that, in the coal-fired case, the SO_2 polisher liquid contains dilute sodium sulphite after reaction of the gas stream with alkali, not SO_2 or sulphur acids, and is therefore relatively less aggressive. A lining is still required because the flue gas is acidic due to the high CO_2 content.

The booster fan may be situated at different positions in this loop. Materials selection for fans is discussed in Section 12.1.

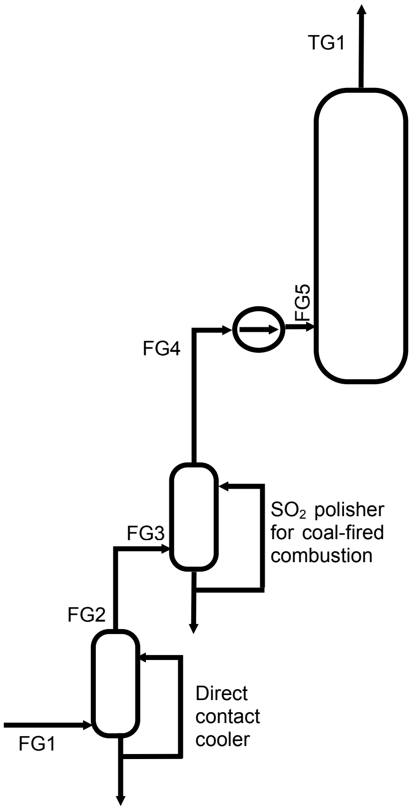

Figure 8.1 : Flue gas loop

8.2 Absorber Vessel

The Absorber Vessel requires special consideration because of its size, estimated at 15 - 20 m diameter and 50 m height [iv].

The top of the absorber carries wet gas with a relatively low CO_2 content to the outlet. Wash water and lean amine is sprayed in towards the top of the vessel and trickles down, becoming richer in CO_2 content as it absorbs CO_2 from the gas stream. The pH at any point will depend on the CO_2 loading, the amine breakdown rate and the amount of carboxylic acid and organic heat stable salts (HSS) formed by reaction of the amine with oxygen. Although lean amine is not particularly corrosive to carbon steel, general conditions in the absorber are not suitable for using unprotected carbon steel. There will be free oxygen present through the vessel, with implications for selection of CRAs: the H&MB for both gas and coal fired cases indicate significant oxygen content in the vent gas and trace levels in the Rich Amine.

The Absorber runs at just over atmospheric pressure and is not a pressure vessel (as below the PED and ASME pressure limits [72]). Since it will be very large (15 – 20 m diameter and 40 – 50 m high), it cannot be built as an unstiffened column without having excessively thick and heavy walls (like blast furnaces). More probably it will be built like

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[iv] EON report, section 4.1.1 p10

FGD units, either a rectangular section tower with flat steel plates with external stiffening and steel structure (as in the majority of existing FGD units), or, as in some more recent FGD units, as a circular reinforced concrete structure. Steel lends itself to prefabricated flat stiffened panels, while concrete lends itself to in-situ slip-casting of circular structures. Some steel towers, however, are built of ring stiffened prefabricated curved sections, much like LNG tanks. Some 33 of 42 units studied by one authority have been built of steel [73] with 7 in concrete and 2 in GRP (record diameter for in-situ filament winding of 23m [74]). At least one FGD unit has been built out of solid 317LMN stainless steel [75]. Concrete with tile lining is arguably becoming the material of choice for new build for cost and ease of maintenance [76].

Both carbon steel and concrete must be lined for protection against the environment. FGV coating has generally proved more reliable than rubber lining of steel in similar applications, as it also has in ducting applications. Few organic coatings are suitable for use with amines, which are strong solvents for many coatings. Whilst a small number of specific siloxane, FGV or ceramic filled phenolic-epoxy coatings have been used on steel with success in amine CO_2 absorbers or amine containers [77], their adhesion to concrete has not been tested for such applications - although such coating may be a successful competitor to tiling if long-term adhesion can be verified. Tiling provides both useful low-friction qualities (for self-cleaning and ease of maintenance) and is more applicable to concrete where the material modulus matches the concrete (tiling steel is a problem because of the comparative elasticity of steel). The leading candidates for absorber columns are therefore: concrete with acid resistant tilling; and sheet steel with FGV or epoxy – phenolic coatings.

It should be noted that welded carbon steel can suffer stress corrosion cracking in amine service in the presence of dissolved CO_2, so PWHT is necessary for coated or lined steel constructions [78].

Inlet and outlet ducts may be FGV coated carbon steel (more suitable for carbon steel rectangular tower) or GRP (more suitable for circular concrete tower). The spray header and nozzle piping which carries the Lean Amine solution to the spray nozzles is exposed to high flow rates and liquid droplets from the top of the absorber vessel. Mist eliminators are exposed to similar conditions. Internal spray pipework and trim should be in non-metallic materials, such as poly-propylene, or in duplex stainless steel.

8.3 Amine System

Figure 8.2 shows the corrosion loop of the amine system, which consists of two main parts, handling either rich amine (denoted as RA) or lean amine (denoted as LA). The issue of oxygen in the amine system has been considered in Section 7.3: it is assumed that the solvent chemistry will be controlled to avoid excessive amine oxidation and formation of acids. However, the H&MB does indicates oxygen is present in the Rich Amine loop and in off-gases from the Stripper. On the plus side, even in the coal-fired case, the incoming process stream is essentially chloride-free as the flue gas has been washed several times in the FGD plant and by the DCC before reaching the Absorber. Providing close control is exercised on make-up chemicals to avoid introducing chlorides, lower alloy stainless steels will be adequate. Hence a conventional materials selection has been made: predominately carbon steel in the lean amine sections and mostly 316L for the rich amine section and for high temperature sections.

This selection should be reviewed considering the chemistry of the specific solvent package adopted.

The chemistry of the amine system should be regularly monitored for both process efficiency and for corrosion control. Chemical supplier recommendations should be followed, but, for example, monitoring may include regular checks on pH, presence of solids and overall fluid chemical composition. Temperature monitoring and control in the reboiler and high temperature parts of the system is critical to avoid over-heating and excessive amine degradation with resultant formation of acid species.

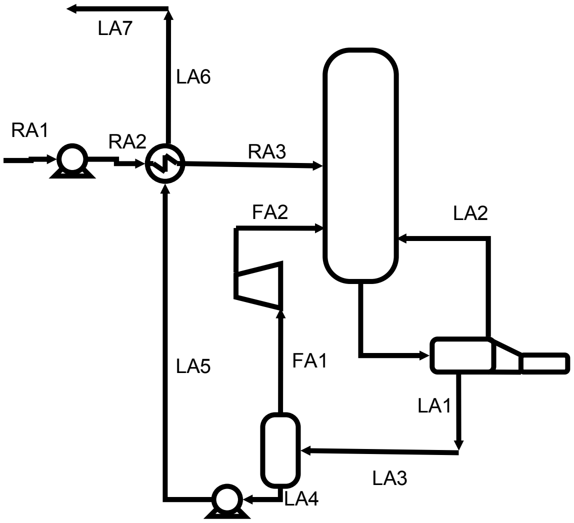

Figure 8.2 : Amine loop

8.4 Absorber Side Streams

Side streams remove heat from the Absorber and introduce wash water in the upper section of the vessel. The streams are similar to the Rich Amine in composition, and similar materials are selected. It is assumed that demineralised water (i.e. chloride-free) is used for make-up of the wash water.

8.5 CO_2 Stripper and Reboiler

Unlike the Post-combustion capture CO_2 Absorber vessel, the CO_2 Strippers are pressure-vessels as defined by the PED (0.5 barg) and ASME VIII (15 psig). With an operating pressure of 0.9 barg at the flash gas inlet and 0.8 barg at the lean amine liquid outlet the design pressure will exceed both these limits. For coal fired cases in this study, the approximate diameter of the stripper will be 10.6 m. For the natural gas case, the diameter will be about 13.4 m. This will make construction using stiffened flat steel panels unlikely as they would not meet pressure vessel code requirements. Concrete and tile construction, as for the Absorber, is impractical because of the higher operating temperatures. Like some FGD units, therefore, the Post-combustion CO_2 stripper towers will probably be of circular ring-stiffened steel construction.

The reboiler gas inlet and liquid (lean amine) outlet operating temperature is 120°C and the Flash (steam) inlet temperature, 168°C. In normal hydrocarbon (refinery) amine strippers the bottoms of the vessels are often in unprotected carbon steel, since the amine is alkaline and protective. However, in this case the continuous flow of oxygen risks formation of carboxylic acids particularly in this area which may cause uncontrolled bottom end corrosion [79]. A few phenolic-epoxy or vinylester coating systems have proven capable of resistance to 120°C but none at a continuous 168°C in spray or immersion conditions. It is therefore necessary to clad the bottom of the stripper with CRA, at least within the area heated to over 120°C. The use of CRA cladding would also avoid the requirement for difficult PWHT of this large site-erected vessel, so there is an economic benefit in using CRA cladding throughout, rather than coating. At this stage there should be no halides present in the vapour or liquids, provided proper control of make-up water is exercised, so a lower-cost CRA such as 316L stainless steel can be used for the amine wetted section up to the upper spray nozzles. However, if chloride levels are greater than 50 ppm more expensive CRA cladding materials with higher Mo content would be necessary.

The top end of the stripper is not necessarily protected by the alkaline amine solution and may suffer from overhead corrosion caused by acid condensation. There is still some trace SO_2 present in the exit gases in the coal-fired cases and a higher alloy CRA lining / cladding is needed: 904L is proposed.

Similar considerations apply to the Reboiler. A carbon steel shell with CRA tubes and tube-sheet is a common selection for O&G or refinery applications. For the potentially more aggressive conditions expected in the CCS system, a CRA clad shell is proposed.

8.6 Wet CO_2

The initial CO_2 gas stream from the stripper (CD1) is a high volume flow at low pressure and will be carried by ducting. CRA wallpapering is preferred here over GRP, organic coating or lining because of the high temperature exiting from the Stripper. There is a risk of acid dew-point corrosion in the coal-fired case, so a higher alloy CRA is indicated there. The liquid streams in equilibrium with the wet CO_2 stream are also very corrosive to carbon steel and CRAs are necessary.

8.7 Compression Train

Figure 8.3 shows the corrosion loop of the compression train. A separate H&MB was not produced for the compression train in the gas-fired case. the stream composition entering the compression train (CO1) is very similar to the equivalent stream in the coal-fired case, but without any SO_2 present.

Conditions in wetted sections down the compression train become progressively more severe as the CO_2 pressure increases. After the dehydrator, the stream is dry and carbon steel can be used.

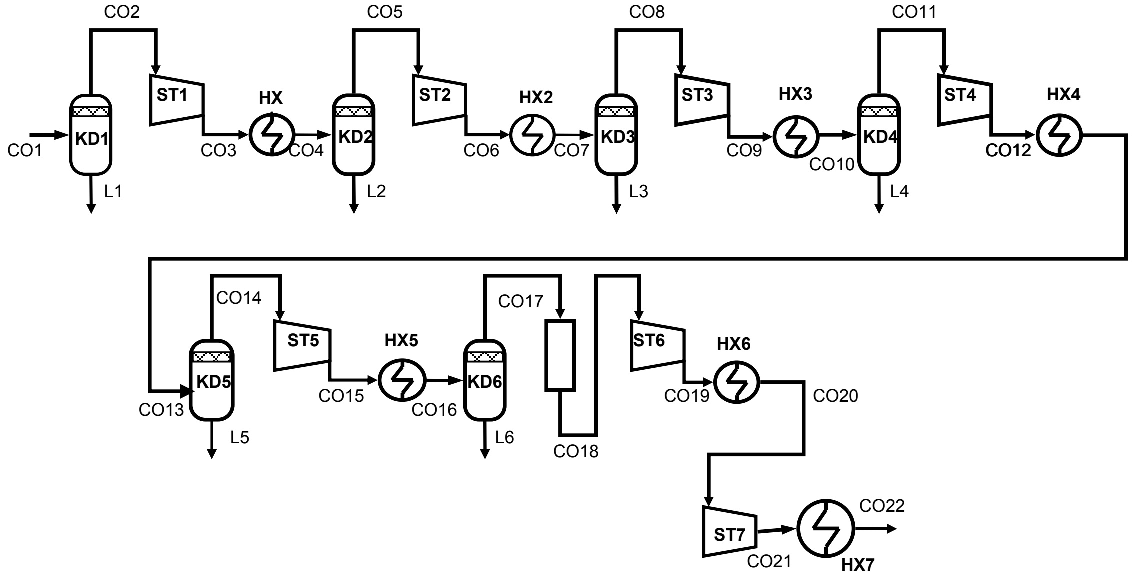

Figure 8.3 : Compression Train

The EON study has only modelled compression for the coal-fired case. The gas-fired case would be very similar, but there is no SO_2 present – see the inlet stream to compression, CO1.

9 MATERIAL SELECTION FOR PRE-COMBUSTION CAPTURE PROCESS

The material selection for individual plant streams and equipment items is tabulated in Tables 11.5-11.10 and summarised in Figs 11.5-11.10 in Chapter 11. The following text discusses some specific aspects in more detail.

9.1 General

Table 9.1 summarises the compositions of the syngas streams. Chlorides and other water soluble species are washed out of the coal syngas in water washes after gasification, while the gas-based syngas is inherently cleaner. Minimal chlorides are assumed on entry to the carbon capture plant. Some trace mercury is possible in the coal-fired cases. The H_2S present from coal-firing will require ISO 15156 / NACE MR0175 compliant materials in parts of the plant where H_2S is present and where wet conditions are possible in normal operation or upsets.

Table 9.1 : Comparison between compositions of the Syngas generated by coal and gas

Component	Bailey Coal		Gas	
	Incoming Syngas	Syngas after shift reactors	Incoming Syngas	Syngas after shift reactors
Water	49.88	24.27	34.56	20.66
Hydrogen	14.0	39.65	49.48	63.38
Carbon Dioxide	1.69	27.3	1.60	15.50
Carbon Monoxide	28.4	2.84	14.36	0.46
Nitrogen	5.56	5.56	0.0000	0.0000
Argon	0.025	0.025	0.0000	0.0000
Oxygen	0.0000	0.0000	0.0000	0.0000
Hydrogen Sulphide	0.33	0.34	0.0000	0.0000
Carbonyl Sulphide	0.0082	0.0000	0.0000	0.0000

The inlet streams do not contain the acid flue gases present in the post-combustion capture and oxy-fuel combustion processes, and as such are comparatively mild.

Carbon monoxide can have an inhibitive effect on the corrosion of carbon steel in wet CO_2 –CO environments. There is a risk of stress-corrosion cracking when conditions are neither very corrosive nor fully inhibited by CO, and stress corrosion failures have been reported in these environments [80, 81]. The exact behaviour is sensitive to other species present including hydrogen and oxygen, and the safe limits in terms of CO, CO_2 and other species are not well understood. Stainless steels have been specified for most of the relevant streams to avoid either the corrosion or the stress-corrosion risks.

9.2 Shift reactors and High Temperature Syngas

In the gas fired case, the materials of construction for shift reactors require resistance to high temperature hydrogen attack. With a total pressure of around 37 bara, the hydrogen partial pressures are relatively low compared with some refinery environments. Based on the recommended temperature and pressure limits in API 941, 1Cr-0.5Mo steel has adequate resistance to hydrogen attack for Shift Reactor 1 conditions and carbon steel for Shift Reactor 2 conditions. Similar materials are used for shift reactors in refinery steam hydrocarbon reforming [82]. Conditions are not expected to present a significant metal dusting risk.

The main differences in the coal-fired cases are that sulphur species are present and that a higher temperature is used in Shift Reactor 2. This introduces the risk of sulphidation attack. H_2S does however provide some further protection against metal dusting. The Couper – Gorman curves for sulphidation attack suggest carbon and Cr-alloy steels are unsuitable for both the Shift Reactors, and that 18-10 stainless steel (such as grade 304 or 347) is the minimum requirement. Stabilised grades such as 321 or 347 are necessary for extended service above approximately 420°C to avoid Cr carbide formation and depletion of Cr in the steel matrix. Even so, 18-10 stainless steel may suffer corrosion at a significant rate in the higher temperature Shift Reactor 1 conditions, of the order of 0.1 mm/yr [83]. Where lower corrosion rates are desirable for specific components, then higher chromium stainless steels, such as grades 309, 310, or specialised Cr-Ni-Co alloys may need to be considered.

Similar considerations apply to high temperature pipework and to the gas coolers / heat exchangers, where the requirement to have minimum wall thickness to optimise heat exchange makes the choice of higher grade materials like 310 stainless steel or Cr-Ni-Co alloys more likely.

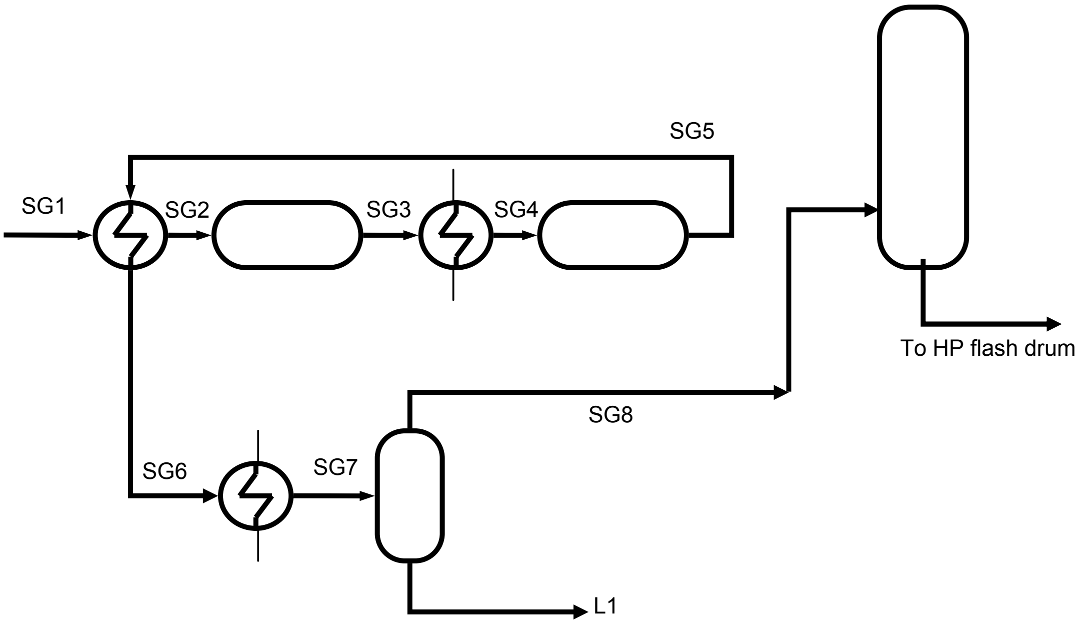

Figure 9.1 : Syngas corrosion loop (coal case, gas case omits SG1/SG2 heat exchanger)

9.3 Wet Syngas

When the syngas is cooled below dewpoint in the final heat exchanger, there is a risk of wet CO_2 corrosion (stream SG7). Stainless steel 316/316L is adequate for wetted areas. The free water is then removed in a knockout drum as stream L1, but the gas stream from the knock-out drum is assumed to be wet to cater for possible water carryover or process upsets. Sour service resistant materials are necessary for the coal-fired cases: 316L is still adequate due to the moderate temperature and H_2S partial pressure and low chloride conditions.

9.4 Fuel and emission

Figure 9.2 shows the fuel loop consisting of the fuel streams (Fuel 1 & Fuel 2) and the combustion product streams (EX1 & EX2). Fuel 1 is CO_2 -free syngas with trace water; the normal operating temperature of 31 °C exceeds the dew point significantly. Fuel 2 is diluted syngas after mixing with N_2 (for coal case) at 20 °C or steam (for gas case) at 250 °C. The emission streams exiting from the gas turbine are dry due to high operating temperatures.

Carbon steel will suffer some loss of wall thickness due to oxidation at EX1 temperature (520°C), of the order of 0.1 mm/year: a low Cr-alloyed steel is preferred.

EX2 is above the dew-point initially, but at some point downstream condensation will occur and a CRA or non-metallic lining will be necessary. As there is no SO_2 and little CO_2 present in the exhaust stream, dew-point conditions will not be severe and 304L stainless steel would be adequate.

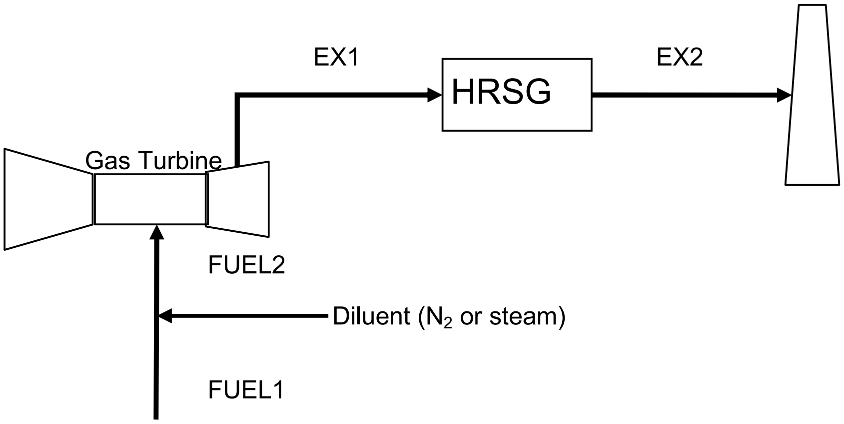

Figure 9.2 : Fuel and emission loop

9.4.1 Turbine

Turbine manufacture is a specialist area, and the turbine system will probably be supplied as a separate package designed (including the material selection) by the manufacturer.

Because of the shift reactions, the fuel gas mixture with the CCS Pre-combustion capture process is higher in hydrogen than with a conventional IGCC system. Other factors being equal, this leads to higher water contents in hot combustion gases, and increased heat transfer to the materials. Lower gas temperatures at the turbine inlet are then necessary to protect the turbine materials [84]. High temperatures are desirable for efficiency, and turbine manufacturers are continuously trying to develop materials and design to achieve this. Gas turbine manufacturers already offer units designed for high hydrogen-content fuels and there is experience operating with high hydrogen contents, for example using process and refinery gases.

The fuel gas streams after the CCS plant are expected to have very low levels of soluble impurities such as halides and sodium, potassium and vanadium salts etc which are significant in high temperature corrosion.

The turbine materials will require specific evaluation by the supplier depending upon the precise fuel and air quality used in any particular project, but no new corrosion issues are expected unique to the CCS application.

9.5 Solvent System

Conventional IGCC plants generally have an acid gas removal system to capture the H_2S from the syngas in order to minimise levels of SO_2 emissions [3]. In existing plant, this is often an amine-based process, although some plants use physical solvents to achieve better H_2S removal. Without the shift reactions, the syngas in conventional plants is very much lower in CO_2 than in the CCS process, as shown in Table 9.1 above. As CO_2 capture is not critical in conventional plant, the acid gas removal system can be optimised for H_2S removal. The ratio of H_2S to CO_2 in the solvent is therefore much higher than for the equivalent process with carbon capture. In the CCS situation, it is desired to remove the maximum percentage of CO_2. In the coal-fired cases, there is also the need to remove H_2S. Two schemes have been studied. Co-capture removes CO_2 and H_2S as a single export stream for storage. Alternatively, separate capture produces a higher purity CO_2 stream, with separate removal of H_2S through a sulphur recovery unit. This second option may be preferred if high levels of H_2S are not acceptable in the export stream for storage.

In similar solvent systems in conventional plants, carbon steel is widely used in lean and semi-lean solvent service, with stainless steel (304L or 316L) for rich solvent and high temperature or turbulent conditions [85].

9.5.1 Co-Capture, Coal

Figure 9.3 shows the solvent loop containing the absorber column, a series of flash drum with rich/lean acid gas streams. The acid gas-loaded streams enter the flash drums, release CO2 at different pressures, then yield the lean and semi-lean solvent streams (SOLV2, 3 and 4) which are recirculated to the absorber column.

Carbon steel can be used for some of the streams where the presence of H_2S has a beneficial effect in reducing the corrosion rate. An exception is the stripper vessel, where there is evolution of gases and possible turbulent conditions, and stainless steel is chosen in preference to carbon steel. Where CRAs are necessary, the reducing conditions and absence of chlorides means that 316L is adequate.

Stainless steel is necessary for the incoming wet syngas entering the Absorber and for the rich solvent. It may be possible to specify carbon steel for parts of the Absorber exposed only to lean solvent or cleaned fuel gas: the extent would depend on detailed design of the absorber vessel.

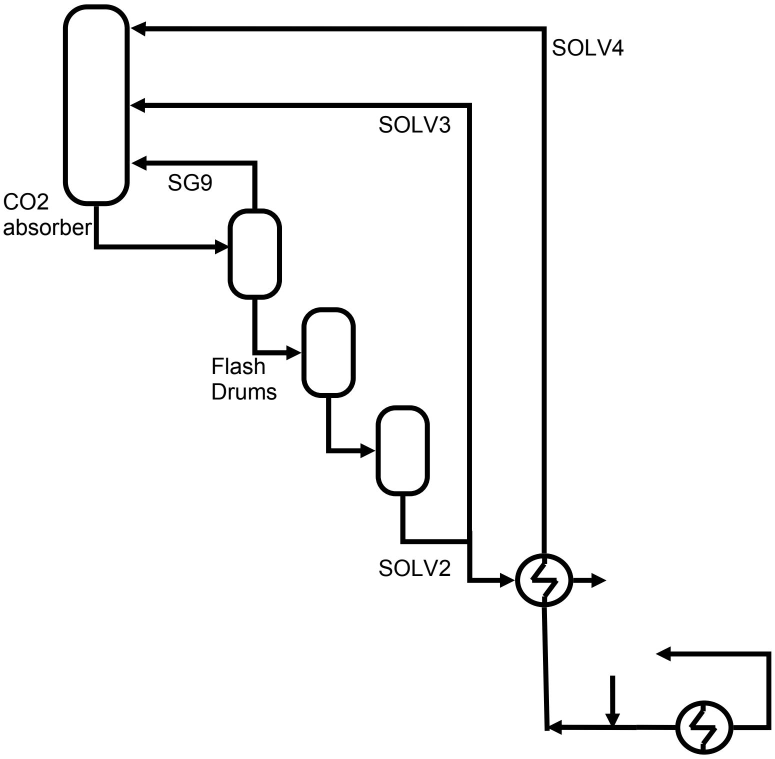

Figure 9.3 : Solvent loop, co-capture

9.5.2 Gas-fired

The process scheme is similar to the co-capture case. There is no H_2S present to protect carbon steel, so there is slightly wider use of stainless steel than in the coal co-capture case.

9.5.3 Separate capture, Coal

In the separate-capture configuration (Figure 9.4), two absorber vessels are used, although the same solvent is used in both absorbers. The first absorber preferentially removes H_2S. The second absorber removes CO_2, which is then flashed off from the rich CO_2–loaded solvent at lower pressures in a series of flash drums and fed to the compression train.

The acid gas that is recovered from the top of the H_2S stripper must contain a minimum H_2S concentration in order for the downstream sulphur recovery unit to operate properly. The H_2S absorber also captures CO_2 and when the loaded solvent is regenerated, both the CO_2 and the H_2S will be released. In the carbon capture case, this gas would be too dilute in H_2S to be used in the sulphur recovery unit. Therefore, separate capture of the H_2S requires the H_2S concentration step; a gas stream is used to strip CO_2 from the solvent in the concentrator vessel, thus increasing the H_2S to CO_2 ratio in the solvent.

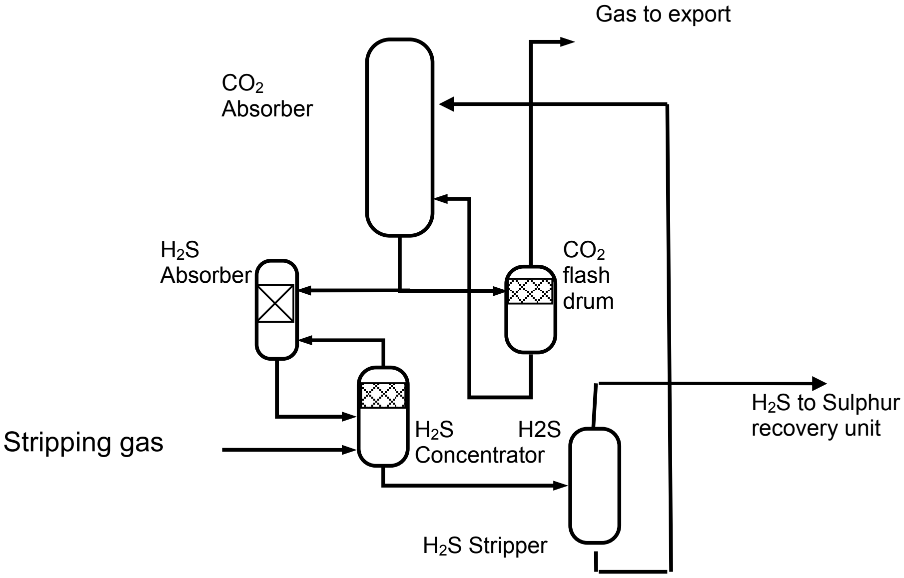

Fig. 9.4: Solvent loop, separate capture

There are two obvious sources of stripping gas for the H_2S concentrator, namely nitrogen from the air separation unit, or a side stream from the clean fuel gas (FUEL 1). Introducing significant concentrations of air into the system with the stripping gas creates a risk of producing extremely corrosive conditions for both carbon steel and CRAs. Oxygen and H_2S dissolved in water will react together producing solid sulphur and potentially other oxidised sulphur species. Sulphur, SO_2, H_2S, and other sulphur species are very powerful agents in promoting both pitting and general corrosion of carbon steels and pitting corrosion of CRAs. Only the very highest alloy CRAs would be resistant to these conditions, which would have substantial cost impacts. In the current case, nitrogen from the air separation unit has been selected as the stripping gas, with a maximum oxygen limit of 5 ppm [85]. This is achievable with current separation technology. The controlled oxygen content allows the use of carbon steel and low-alloy CRAs in the solvent system. It is critical that this oxygen limit is not exceeded in operation, since rates of corrosion attack and pitting on CRAs can be extremely fast in adverse conditions. If this level of control cannot be guaranteed, then clean fuel gas could be used as stripping gas. Continuous monitoring of the oxygen content in the stripping gas stream is essential if the materials selection is based on the lower cost materials suitable for low oxygen conditions.

As in the co-capture case, it may be possible to specify carbon steel for parts of the H_2S and CO_2 Absorbers exposed only to lean solvent or cleaned fuel gas.

9.6 Compression Train

Figure 9.5 shows the schematic diagram of the compression train of the pre-combustion process (separate capture). The compression train has to be regarded as dry in normal operation as the compressors would otherwise have a short life, and carbon steel can be used. Sour service resistance is required for possible short upset conditions. The only normally wetted section is the cooler and the dehydrator or knock-out drum part-way down the train, for instance, stream 11-1 in separate capture case (Figure 11.6), stream 14-1 in co-capture (Figure 11.8) & gas-fired cases (Figure 11.10). Suitable CRAs are selected here.

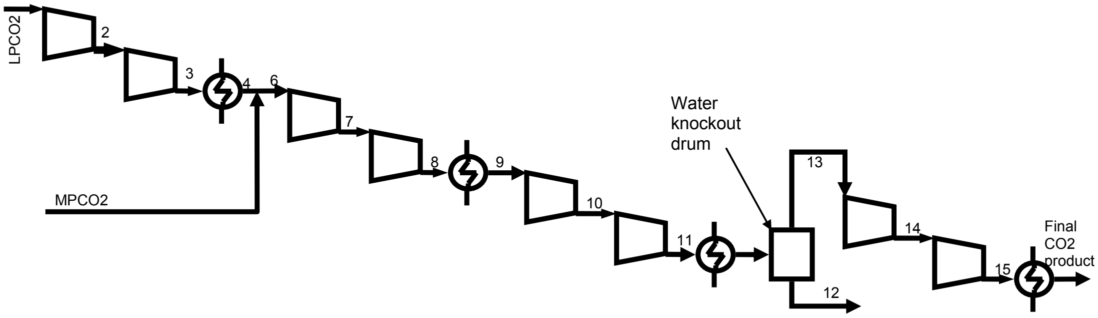

Figure 9.5 : Compression Train (separate capture)

9.7 Sulphur unit

The SRU is present only in the coal-fired separate capture case, this loop consists of the stripper, condenser and the SRU (Figure 9.6).

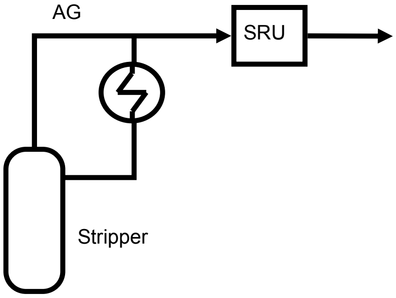

Figure 9.6 : Sulphur unit loop

Claus process sulphur recovery units are widely used in other applications and are not specific to carbon capture.

10 MATERIALS SELECTION FOR OXY-FUEL COMBUSTION PROCESS

The material selection for individual plant streams and equipment items is tabulated in Tables 11.11-11.12 and summarised in Figs 11.11-11.14 in Chapter 11. The following text discusses some specific aspects in more detail.

10.1 Wet Flue Gas

The flue gases entering the CCS plant from the FGD plant contain high levels of CO_2 with water, oxygen and some SOx and NOx. On the basis of the CO_2 content alone, this stream is extremely corrosive to carbon steel wherever free water is present. The reactions involving NOx and SOx are complex and so is prediction of which species are present at which points in the process, including possible upsets and start-up / shut-down states. A conservative materials selection is therefore advisable. Although the average content of SO_2 is low, it is very soluble in water and there is a risk of dew-point corrosion from small volumes of acid mist or condensation in the inlet ducting and pipework (RCO1, RCO2 in Figure 10.1).

Relatively high alloy materials are proposed for the inlet compressor (RCO1/02) as there is a higher risk from particulates and from acid condensation on shut-down in this stream than in the downstream compressor trains. GRE piping is a possible alternative to CRAs for RCO2 and RCO3, although the temperatures (70 & 82°C) are near the limit for the material.

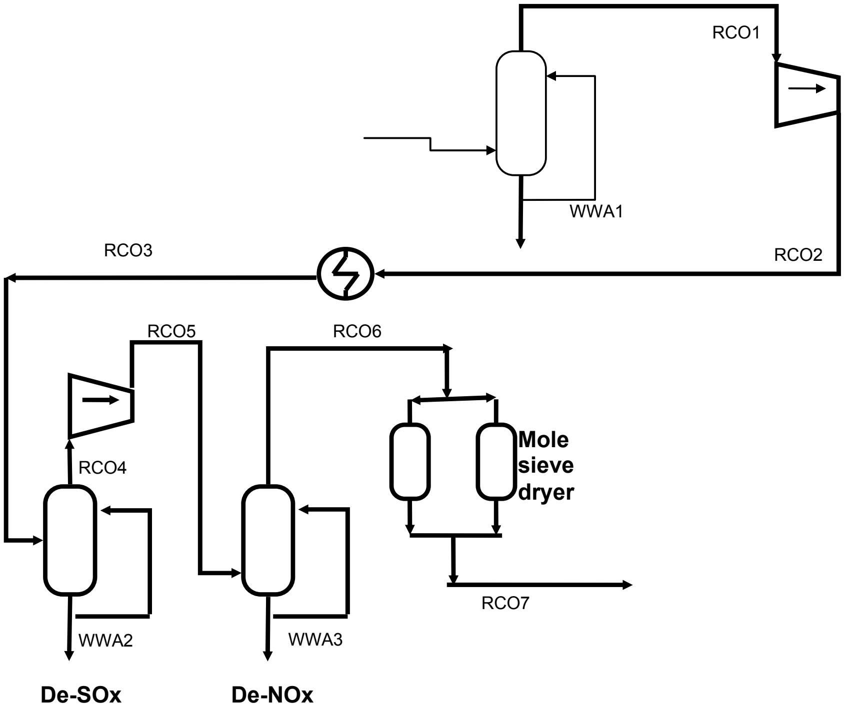

Figure 10.1 : Untreated flue gas loop

Options for the De-SOx vessel are carbon steel clad with CRA, or carbon steel with a high-quality organic coating. The De-SOx wash water and drain is dilute acid and preferably handled with non-metallic piping, and a lined or non-metallic pump. Conditions after the De-SOx reactor are more benign and lower alloy CRAs such as 316/316L can be used for wet areas.

Stream RC07 and all streams downstream of the molecular sieves are dry. As removal of water is critical for integrity of the system downstream, continuous monitoring of water content, for example dew-point monitoring, is necessary after the molecular sieves.

10.2 CO_2 purification

Figure 10.2 shows the low temperature CO_2 purification process modelled for the low CO_2 case. Various different process arrangements are possible depending on the purity and recovery of CO_2 required. Gas purification is a specialist area, and the sub-system will probably be supplied as a separate package and designed by the supplier, including material selection.

In the present design cases, the only inlet to the system, stream RCO7, has been dried in the previous molecular sieve dryer and contains only 5 ppm of water. Therefore, the entire purification process can be regarded as dry and corrosion free. Some of the streams are at temperatures suitable for low temperature carbon steel (LTCS), for example to ASTM A333 with a specified Charpy impact transition temperature of -46°C. For operating temperatures below this range, austenitic stainless steels, such as 316L or 304L are suitable. Carbon steel is suitable for exit streams at near ambient temperature.

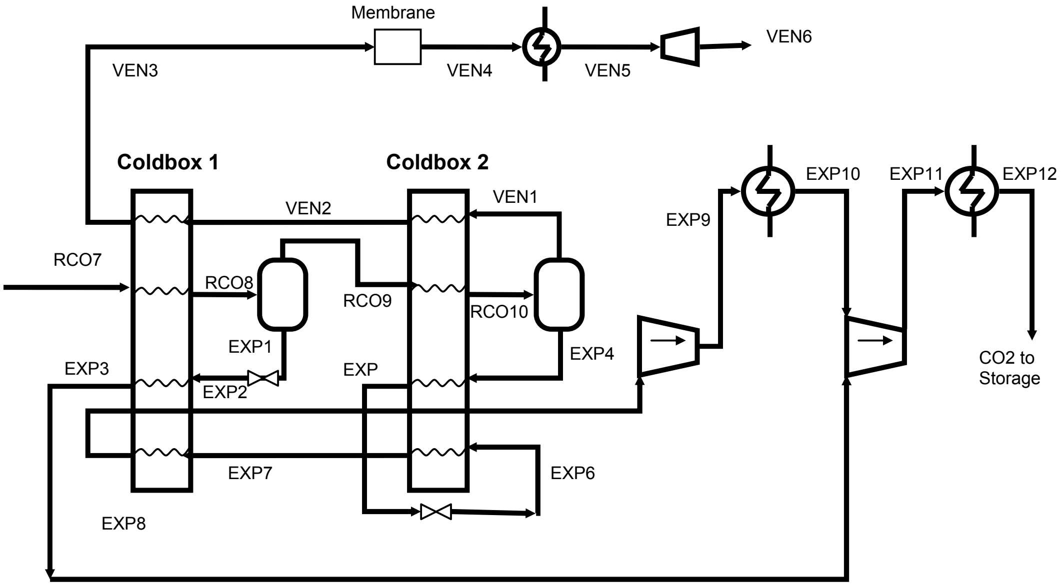

Figure 10.2 : CO_2 purification loop

Since the inlet pressure will be about 30 bara, standard bolted plate heat exchangers are not a practical solution, since few, if any, have capability beyond 20 bar [86]. However brazed or welded compact heat exchangers are offered for service up to 100 bar, and diffusion bonded printed circuit heat exchangers up to 500 bar and above. The temperature differences are not too extreme, compared for example with air separation, somewhat similar conditions exist in LNG plant where brazed aluminium heat exchangers are used [87]. These may be manufactured as banks connected by pipework in cold-boxes mounted on skids. In this case the volume to be handled - 660,000 Sm^3/hr (22,000 m^3/hr at 30 bar) would require such a solution.

316L stainless steel is a possible heat exchanger material, and is widely available in the form of brazed, welded or diffusion bonded plate or fin-plate heat exchangers. At least one manufacturer offers standard spiral heat exchangers in aluminium alloy as well as in stainless steel. However, the advantages of aluminium fin-plate heat exchangers - high heat transfer surface area per unit volume, multi-stream capability, low weight and the excellent heat transfer properties of aluminium - gives them a high efficiency / cost when the temperature differential is small. Current packages proposed by gas purification suppliers seem to favour aluminium. It is possible that the raw flue gas will contain some mercury, and there is concern about the use of aluminium as it is subject to liquid metal embrittlement, corrosion and stress corrosion by mercury. Some manufacturers offer fin-plate brazed aluminium compact heat exchangers whose design is claimed to be less susceptible to mercury attack [88], but it is nevertheless proposed that a mercury removal unit be installed in the plant upstream of the heat exchangers if aluminium is used, and this additional expense needs taking into account.

11 MATERIAL SELECTION DIAGRAMS AND MATERIAL SELECTION TABLES

The summarised material selections for all CCS processes are presented in the following material selection diagrams (MSD); each stream and equipment item in the MSDs are colour coded and annotated. Each set of MSDs is followed by the material selection tables. Stream compositions are taken from the EON H&MB tables. In some case, extra streams are identified for which H&MB data was not generated and the composition fields are empty. Where wet sour conditions apply, reference is made to the appropriate section of ISO15156 in the notes. The text in the previous Chapters 8-10 should be consulted for more details on the rationale for materials selection and discussion of alternative options.

In general, wherever carbon steel clad with CRA is indicated, solid CRA is equally acceptable as regards corrosion (and vice versa): the more cost-effective alternative can be chosen.

The legend of the colour coding for different materials is presented below.

LEGEND

▬ (black) Carbon and low alloy steels without corrosion allowance

▬ (green) Carbon and low alloy steels with corrosion allowance

▬ (blue) Duplex stainless steel

▬ (pink) Austenitic stainless steel

▬ (yellow) Special austenitic stainless steel

▬ (red) Martensitic stainless steel

▬ (gray) Non metallic (flake glass/GRP/FRP/PP) materials

▬ (dark green) Nickel alloys

▬ (brown) Cement and tiling

┅ (dash line with CS color code) Low temperature carbon steel

▨ (black with non-metallic color strap) Non metallic lined carbon steel

▨ (black with CRA color strap) CS with CRA clad

▬ (purple) Other specified materials

Strap colours vary according to the lining material selected.

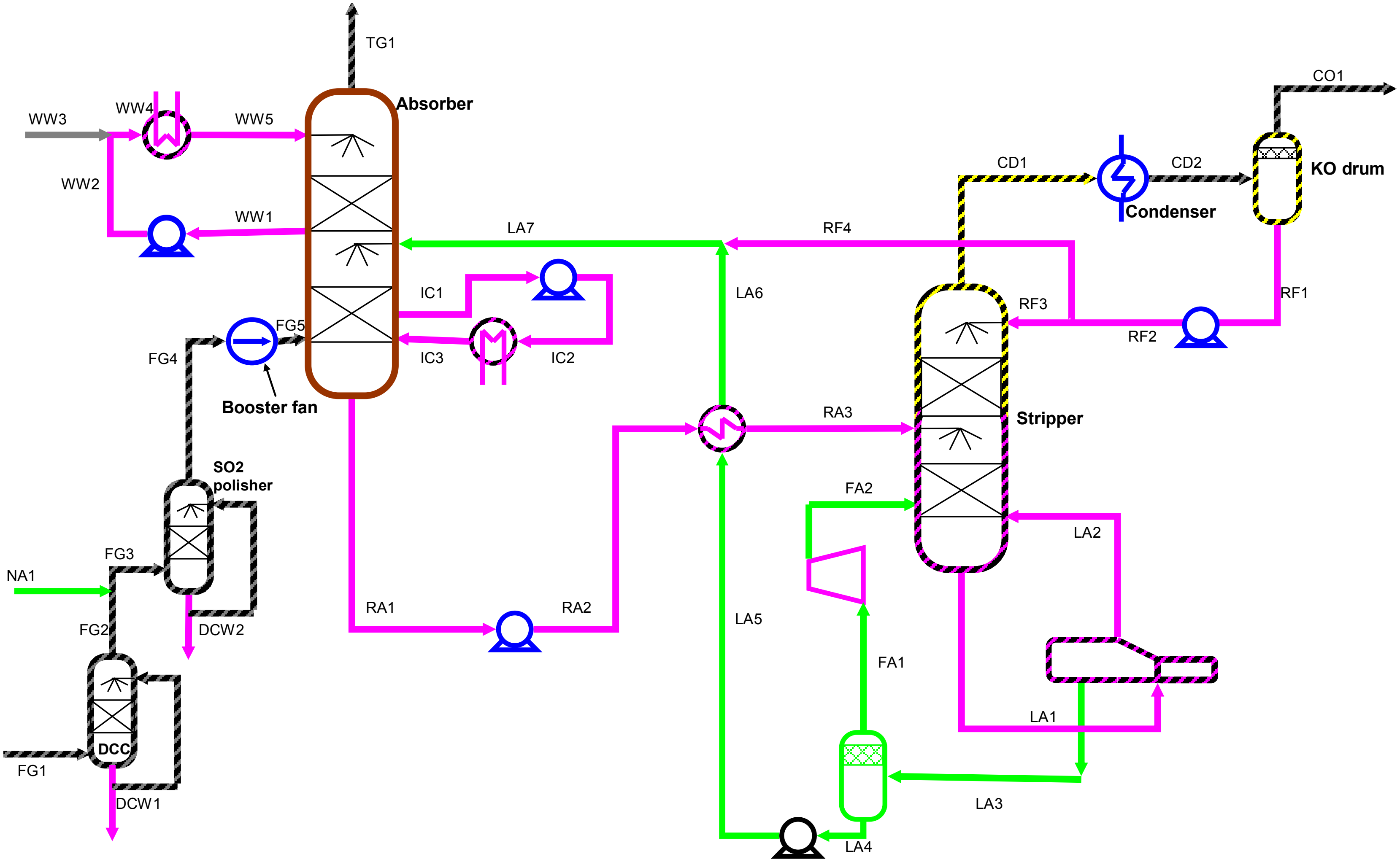

Figure 11.1 : Material selection diagram for Post-combustion capture with coal

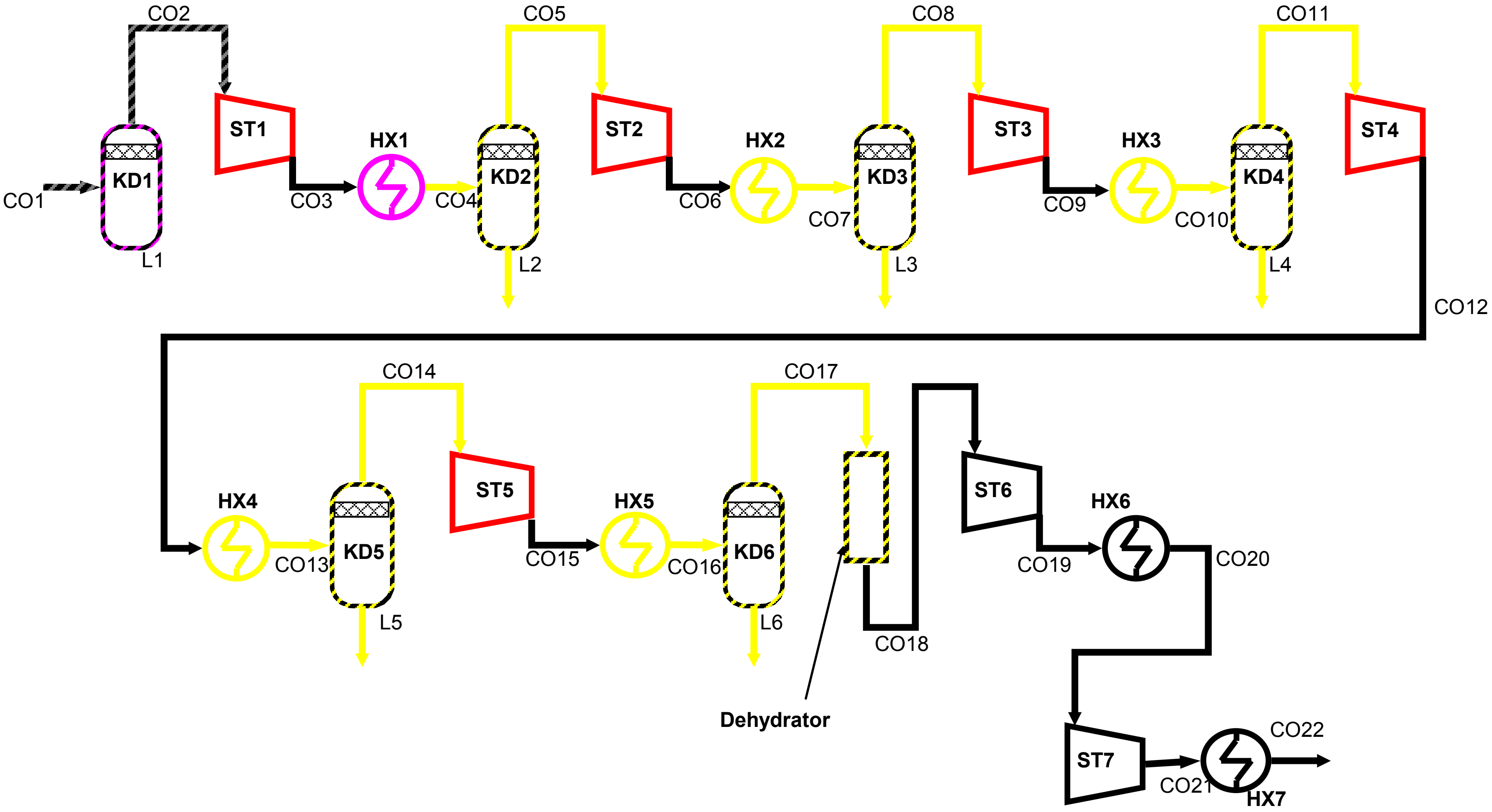

Figure 11.2 : Material selection diagram for compression train of Post-combustion capture with coal

Table 11.1 : Material selection table for Post-combustion capture streams (coal)

Corrosion Loops	**Flue gas**							
Process Streams	**FG1**	**FG2**	**DCW1**	**DCW2**	**FG3**	**FG4**	**FG5**	**TG1**
Component (Mol %)								
Carbon Dioxide	13.83	14.652	0.0076	0	14.6453	14.6786	14.6786	1.67
Water	9.6224	4.2796	99.99	95.2232	4.3166	4.1101	4.1101	6.018
Oxygen	3.6155	3.8293	8.18E-5	0	3.8274	3.8361	3.8361	4.360
Nitrogen	72.069	76.330	0.0008	0	76.2945	76.468	76.468	86.92
Sulphur Dioxide	0.0035	0.0037	7.59E-05	1.4561[v]	0.0037	0.0004	0.0004	0.0004
Argon	0.8547	0.9052	2.09E-05	0	0.9048	0.9069	0.9069	1.030
Monoethanolamine	0	0	0	0	0	0	0	2.60E-05
Sodium Hydroxide	0	0	0	3.3207	0.0075	0	0	0
Temperature (°C)	45	30	30	31	31	31	39	36
Pressure (bara)	1.02	1.00	1.00	0.98	1.00	0.98	1.06	0.99
Material	CS + FGV	CS + FGV	316L	316L	CS + FGV	CS + FGV or wound GRP	CS + FGV or wound GRP	CS + FGV or wound GRP
NOTES	Duct	Duct			Duct	Duct	Duct	Duct

---

[v] As sodium sulphite

Corrosion Loops	**Wet CO_2**						
Process Streams	**CD1**	**CD2**	**RF1**	**RF2**	**RF3**	**RF4**	**CO1**
Component (Mol %)							
Carbon Dioxide	64.2013	64.2013	0.0564	0.0564	0.0564	0.0564	94.87
Water	35.7848	35.7848	99.9432	99.943	99.943	99.9432	5.109
Oxygen	0.0012	0.0012	4.65E-8	4.655E-8	4.655E-08	4.655E-08	0.0017
Nitrogen	0.0121	0.0121	2.50E-07	2.50E-07	2.50E-07	2.50E-07	0.0180
Sulphur Dioxide	9.65E-05	9.65E-05	3.13E-06	3.13E-06	3.125E-06	3.125E-06	0.0001
Argon	0.0003	0.0003	1.27E-08	1.27E-08	1.269E-08	1.269E-08	0.0004
Monoethanolamine	0.0001	0.0001	0.0004	0.0004	0.0004	0.0004	1.25E-11
Sodium Hydroxide	0	0	0	0	0	0	0
Temperature (°C)	85	40	39	39	39	39	39
Pressure (bara)	1.6	1.5	1.4	6.4	5.4	5.4	1.4
Material	CS + 904L wall-papered	CS + FGV	316L	316L	316L	316L	CS + FGV
NOTES	Duct; Dew-point corrosion risk	Duct	pipe	pipe	pipe	pipe	Duct

Corrosion Loops	**Rich Amine System**			**Lean Amine**								
Process Streams	**RA1**	**RA2**	**RA3**	**FA1**	**FA2**	**LA1**	**LA2**	**LA3**	**LA4**	**LA5**	**LA6**	**LA7**
Component (Mol %)												
Carbon Dioxide	6.0740	6.0740	6.0740	2.0039	2.0039	2.5489	4.1052	2.3795	2.3935	2.3935	2.3935	2.3702
Water	82.212	82.212	82.212	97.539	97.539	86.672	95.391	85.723	85.282	85.282	85.282	85.429
Oxygen	6.9E-05	6.9E-05	6.9E-05	0	0	0	0	0	0	0	0	0
Nitrogen	0.0007	0.0007	0.0007	0	0	0	0	0	0	0	0	0
Sulphur Dioxide	5.7E-06	5.7E-06	5.7E-06	0	0	0	0	0	0	0	0	0
Argon	1.8E-05	1.8E-05	1.8E-05	0	0	0	0	0	0	0	0	0
Monoethanolamine	11.7128	11.7128	11.7128	0.4573	0.4573	10.780	0.5033	11.898	12.324	12.324	12.324	12.201
Sodium Hydroxide	0	0	0	0	0	0	0	0	0	0	0	0
Temperature (°C)	30	30	92	104	168	119	120	120	104	104	41	41
Pressure (bara)	1.06	7.06	6.06	1.06	1.85	1.85	1.84	1.84	1.06	7.06	6.06	1.4
Material selection	316L	316L	316L	CS + 6mm	CS + 6mm	316L	316L	CS + 6mm	CS + 6mm	CS + 6mm	CS + 6mm	CS + 6mm
Notes				PWHT for stress cracking control on carbon steel; pH control								

Corrosion Loops	**Absorber side streams**							**Chemicals**	
Process Streams	**IC1**	**IC2**	**IC3**	**WW1**	**WW2**	**WW4**	**WW5**	**WW3**	**NA1**
Component (Mol %)									
Carbon Dioxide	6.0353	6.0353	6.0353	3.6304	3.6304	3.6214	3.6214	0	0
Water	82.2269	82.2269	82.2269	85.1530	85.1530	85.1898	85.1898	100	83.8199
Oxygen	6.475E-05	6.475E-05	6.475E-05	1.66E-05	1.66E-05	1.65E-05	1.65E-05	0	0
Nitrogen	0.0007	0.0007	0.0007	0.0002	0.0002	0.0002	0.0002	0	0
Sulphur Dioxide	4.944E-06	4.944E-06	4.944E-06	8.352E-07	8.352E-07	8.33E-07	8.33E-07	0	0
Argon	1.637E-05	1.637E-05	1.637E-05	4.07E-06	4.07E-06	4.06E-06	4.06E-06	0	0
Monoethanolamine	11.7370	11.7370	11.7370	11.2164	11.2164	11.1886	11.1886	0	0
Sodium Hydroxide	0	0	0	0	0	0	0	0	16.1801
Temperature (°C)	42	42	26	64	64	64	38	20	15
Pressure (bara)	1.05	3.05	2.55	1.01	5	5	4	5	1.5
Material selection	316L	316L	316L	316L	316L	316L	316L	PVC	CS + 3mm
Notes								Demin water	

Corrosion Loops	**Compression Train**										
Process Streams	**CO2**	**CO3**	**CO4**	**CO5**	**CO6**	**CO7**	**CO8**	**CO9**	**CO10**	**CO11**	**CO12**
Component, mol%											
Carbon Dioxide	94.8707	94.8707	94.8707	97.2388	97.2388	97.2388	98.5557	98.5557	98.5557	99.2223	99.2223
Water	5.1090	5.1090	5.1090	2.7404	2.7404	2.7404	1.4233	1.4233	1.4233	0.7565	0.7565
Oxygen	0.0017	0.0017	0.0017	0.0018	0.0018	0.0018	0.0018	0.0018	0.0018	0.0018	0.0018
Nitrogen	0.0180	0.0180	0.0180	0.0184	0.0184	0.0184	0.0187	0.0187	0.0187	0.0188	0.0188
Sulphur Dioxide	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001
Argon	0.0004	0.0004	0.0004	0.0004	0.0004	0.0004	0.0004	0.0004	0.0004	0.0005	0.0005
MEA	1.3E-11	1.3E-11	1.3E-11	2.2E-18	2.2E-18	2.2E-18	0	0	0	0	0
Temperature (°C)	39	102	40	40	103	40	40	103	40	40	104
Pressure (bara)	1.4	2.8	2.76	2.76	5.52	5.43	5.43	10.9	10.7	10.7	21.4
Material selection	CS + FGV	CS	317LMN	317LMN	CS	317LMN	317LMN	CS	317LMN	317LMN	CS
Notes											

Corrosion Loops	**Compression Train**									
Process Streams	**CO13**	**CO14**	**CO15**	**CO16**	**CO17**	**CO18**	**CO19**	**CO20**	**CO21**	**CO22**
Component, Mol%										
Carbon Dioxide	99.2223	99.5564	99.5564	99.5564	99.7142	99.9687	99.9687	99.9687	99.9687	99.9687
Water	0.7565	0.4223	0.4223	0.4223	0.2644	0.0100	0.0100	0.0100	0.0100	0.0100
Oxygen	0.0018	0.0018	0.0018	0.0018	0.0018	0.0018	0.0018	0.0018	0.0018	0.0018
Nitrogen	0.0188	0.0188	0.0188	0.0188	0.0189	0.0189	0.0189	0.0189	0.0189	0.0189
Sulphur Dioxide	0.0001	0.0001	0.0001	0.0001	0.0001	1.48E-06	1.48E-06	1.48E-06	1.48E-06	1.48E-06
Argon	0.0005	0.0005	0.0005	0.0005	0.0005	0.0005	0.0005	0.0005	0.0005	0.0005
MEA	0	0	0	0	0	0	0	0	0	0
Temperature (°C)	40	40	105	40	40	40	107	40	93	40
Pressure (bara)	21.1	21.1	42.2	41.5	41.5	39.5	79.1	77.9	152.3	150
Material selection	317LMN	317LMN	CS	317LMN	317LMN	CS	CS	CS	CS	CS
Notes						dry	dry	dry	dry	dry

Corrosion Loops	**Liquid from knock out**				
Process Streams	**L2**	**L3**	**L4**	**L5**	**L6**
Component (Mol %)					
Carbon Dioxide	0.1103	0.2165	0.4156	0.7698	1.3311
Water	99.8897	99.7834	99.5844	99.2302	98.6689
Oxygen	9.3171E-08	1.8616E-07	3.6998E-07	7.3676E-07	1.5026E-06
Nitrogen	5.0135E-07	1.0017E-06	1.9909E-06	3.9665E-06	8.1173E-06
Sulphur Dioxide	6.0616E-06	1.1699E-05	2.1703E-05	3.7463E-05	5.5244E-05
Argon	2.5371E-08	5.0682E-08	1.0069E-07	2.0035E-07	4.0794E-07
Monoethanolamine	5.1446E-10	0	0	0	0
Material selection	317LMN	317LMN	317LMN	317LMN	317LMN
Notes	Small dia pipe	Small dia pipe	Small dia pipe	Small dia pipe	Small dia pipe

Table 11.2 : Material selection table for Post-combustion capture equipment (coal)

Corrosion Loops	**Flue Gas**					**Absorber side streams**				
Equipment	**DCC**	**DCC pump & cooler**	**SO_2 polisher**	**Polisher pump & cooler**	**Booster fan**	**Absorber**	**Intercooler pump**	**Intercooler**	**Washer cooler**	**Wash Pump**
Material type	CS + FGV Internals: PP, GRP	DSS pump and heat exchanger	CS+ FGV Internals: PP, GRP or 316L	316L pump and heat exchanger	25Cr SDSS	Concrete + acid resistant tiling	Case and impeller: DSS	Shell: CS + 316L clad Tubes: 316L	Shell: CS + 316L clad Tubes: 316L	Case and impeller: DSS
Notes	Panel tower		Panel tower			See text for alternate materials				

Corrosion Loops	**Amine System**							**CO_2**		
	Rich Amine Pump	**Lean/Rich Exchanger**	**Stripper**	**Reboiler**	**Flash drum**	**Lean Amine Pump**	**FA1/2 compressor**	**Condenser**	**KO Drum**	**RF1/2 pump**
Material type	DSS case and impeller	Shell : CS + 316L clad Tube : 316L	CS + CRA lining / cladding; CRA internals	Shell, CS+ 316L clad; Tubes, 316L	CS + 3mm	CS case, 316L impeller	316L & 13Cr-4Ni	Shell : 22Cr Tube : 22Cr	CS + 316L clad or 22Cr wall paper	DSS case & impeller
Notes			316L clad below spray nozzles; 904L clad in head space							

Corrosion Loops	**COMPRESSION TRAIN**							
	Compressors ST-1 ST-2 ST-3 ST-4 ST-5	**Knockout drums KD-1**	**Gas coolers HX-1**	**Knockout drums KD-2 KD-3 KD-4 KD-5 KD-6**	**Gas coolers HX-2 HX-3 HX-4 HX-5**	**Dehydrator**	**Compressors ST-6 ST-7**	**Gas Coolers HX-6 HX-7**
Material	13Cr-4Ni; 316L casing	CS + 316 clad	Shell & tubes 316L	CS + 317LMN clad	317LMN and/ or 22Cr	CS +317LMN clad; 317LMN & 22Cr internals	CS & low alloy steels	Shell and tubes: CS
Notes			Assumes coolant is non-corrosive		Assumes coolant is non-corrosive		dry	Dry; assumes coolant is non-corrosive

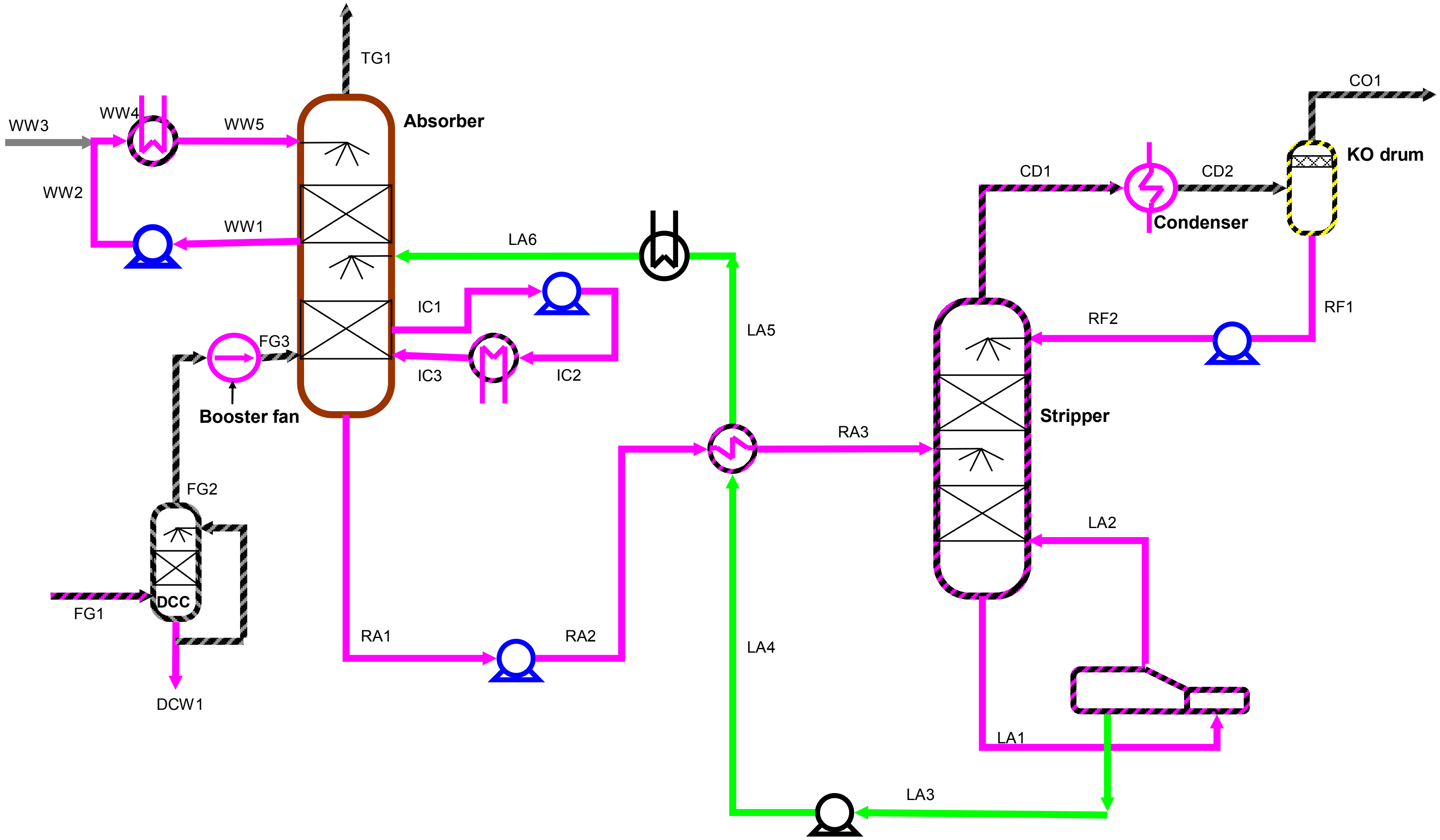

Figure 11.3 : Material selection diagram for Post-combustion capture with gas

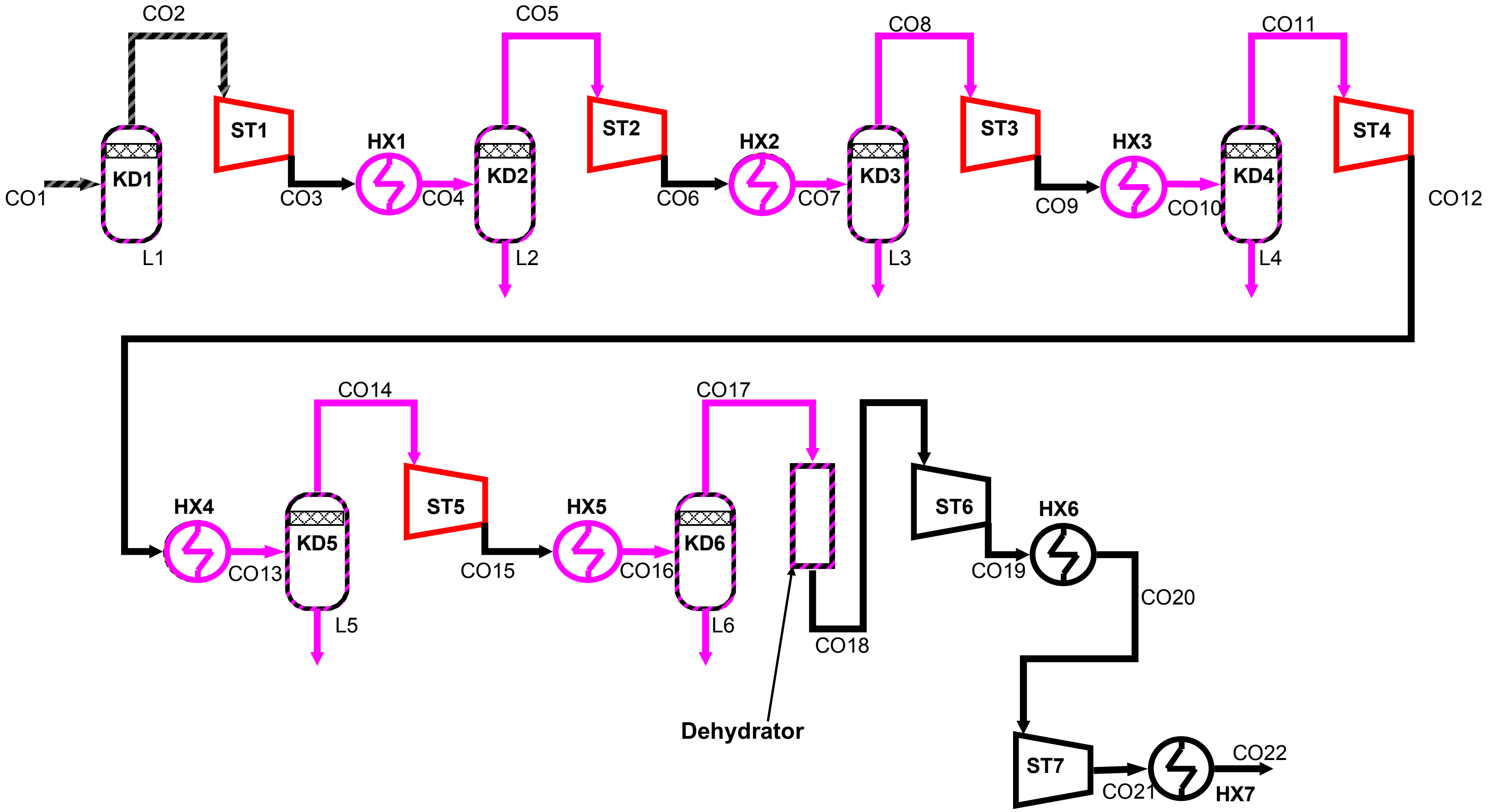

Figure 11.4 : Material selection diagram for compression train of Post-combustion capture with gas

Table 11.3 : Material selection table for Post-combustion capture streams (gas)

Corrosion Loops	**Flue gas**				
Process Streams	**FG1**	**FG2**	**DCW1**	**FG3**	**TG1**
Component (Mol %)					
Carbon Dioxide	3.7851	3.8364	0.0017	3.8364	0.3927
Water	7.2358	5.9775	99.9972	5.9775	7.2465
Oxygen	13.0056	13.1820	0.0003	13.1820	13.4998
Nitrogen	75.0738	76.0921	0.0007	76.0921	77.9271
Argon	0.8996	0.9119	1.9481E-05	0.9119	0.9338
Monoethanolamine	0	0	0	0	1.6613E-05
Temperature (°C)	110	36	36	40	40
Pressure (bara)	1.02	1	1	1.04	1.01
Material	CS+ 316L lined	CS + FGV or wound GRP	316L	CS + FGV or wound GRP	CS + FGV or wound GRP
NOTES	Duct	Duct		Duct	Duct

Corrosion Loops	**CO_2**				
Process Streams	**CD1**	**CD2**	**RF1**	**RF2**	**CO1**
Component (Mol %)					
Carbon Dioxide	37.9165	37.9165	0.0659	0.0659	95.3520
Water	62.0714	62.0714	99.9319	99.9319	4.6206
Oxygen	0.0026	0.0026	2.0664E-07	2.0664E-07	0.0067
Nitrogen	0.0080	0.0080	3.2281E-07	3.2281E-07	0.0202
Argon	0.0002	0.0002	1.6430E-08	1.6430E-08	0.0005
Monoethanolamine	0.0013	0.0013	0.0021	0.0021	1.9577E-10
Temperature (°C)	85	40	39	39	39
Pressure (bara)	1.6	1.5	1.4	6.4	1.4
Material	CS + 316L clad / 22Cr wall papered	CS +FGV	316L	316L	CS + FGV
NOTES	Duct	Duct	Pipe	Pipe	Duct

Corrosion Loops	**Amine System**								
Process Streams	**RA1**	**RA2**	**RA3**	**LA1**	**LA2 Reboiler OH**	**LA3**	**LA4**	**LA5**	**LA6**
Component (Mol %)									
Carbon Dioxide	5.7785	5.7785	5.7785	2.6314	3.6700	2.4817	2.4817	2.4817	2.4817
Water	81.7161	81.7161	81.7161	85.9649	95.7546	84.5537	84.5537	84.5537	84.5537
Oxygen	0.0002	0.0002	0.0002	0	0	0	0	0	0
Nitrogen	0.0007	0.0007	0.0007	0	0	0	0	0	0
Argon	1.769E-05	1.769E-05	1.769E-05	0	0	0	0	0	0
Monoethanolamine	12.5044	12.5044	12.5044	11.4037	0.5754	12.9646	12.9646	12.9646	12.9646
Temperature (°C)	40	40	110	119	120	120	120	50	40
Pressure (bara)	1.04	14.3	13.3	1.83	1.83	1.83	10.4	9.4	1.02
Material selection	316L	316L	316L	316L	316L	CS + 6 mm	CS + 6 mm	CS + 6 mm	CS + 6 mm
Notes						PWHT	PWHT	PWHT	PWHT

Corrosion Loops	**Absorber side streams**							**Chemical**
Process Streams	**IC1**	**IC2**	**IC3**	**WW1**	**WW2**	**WW4**	**WW5**	**WW3**
Component (Mol %)								
Carbon Dioxide	5.3272	5.3272	5.3272	0.9276	0.9276	0.9118	0.9118	0
Water	82.2074	82.2074	82.2074	98.1417	98.1417	98.1733	98.1733	100
Oxygen	0.0002	0.0002	0.0002	0.0002	0.0002	0.0002	0.0002	0
Nitrogen	0.0007	0.0007	0.0007	0.0007	0.0007	0.0007	0.0007	0
Argon	1.76E-05	1.76E-05	1.76E-05	1.76E-05	1.76E-05	1.76E-05	1.76E-05	0
Monoethanolamine	12.4644	12.4644	12.4644	0.9297	0.9297	0.9139	0.9139	0
Temperature (°C)	46	46	36	45	45	45	20	20
Pressure (bara)	1.03	3	2.5	1.01	3.95	3.95	3.45	3.95
Material selection	316L	316L	316L	316L	316L	316L	316L	PVC
Notes								Demin water

Corrosion Loops	**Compression Train**										
Process Streams	**CO2**	**CO3**	**CO4**	**CO5**	**CO6**	**CO7**	**CO8**	**CO9**	**CO10**	**CO11**	**CO12**
Component, Mol %											
Carbon Dioxide											
Water											
Oxygen											
Nitrogen											
Sulphur Dioxide	nil	nil	nil	nil	nil	nil	nil	nil	nil	nil	nil
Argon											
Monoethanolamine											
Temperature (°C)											
Pressure (bara)											
Material selection	CS + FGV	CS	316L	316L	CS	316L	316L	CS	316L	316L	CS
Notes	Duct	See text									

Corrosion Loops	**Compression Train**									
Process Streams	**CO13**	**CO14**	**CO15**	**CO16**	**CO17**	**CO18**	**CO19**	**CO20**	**CO21**	**CO22**
Component, Mol %										
Carbon Dioxide										
Water										
Oxygen										
Nitrogen										
Sulphur Dioxide	nil	nil	nil	nil	nil	nil	nil	nil	nil	nil
Argon										
Monoethanolamine										
Temperature (°C)										
Pressure (bara)										
Material selection	316L	316L	CS	316L	316L	CS	CS	CS	CS	CS
Notes	See text					Dry	Dry	Dry	Dry	Dry

Corrosion Loops	**Liquid from knock out**					
Process Streams		**L2**	**L3**	**L4**	**L5**	**L6**
Component (Mol %)						
Carbon Dioxide		0.1103	0.2165	0.4156	0.7698	1.3311
Water		99.8897	99.7834	99.5844	99.2302	98.6689
Oxygen		9.3171E-08	1.8616E-07	3.6998E-07	7.3676E-07	1.5026E-06
Nitrogen		5.0135E-07	1.0017E-06	1.9909E-06	3.9665E-06	8.1173E-06
Sulphur Dioxide		6.0616E-06	1.1699E-05	2.1703E-05	3.7463E-05	5.5244E-05
Argon		2.5371E-08	5.0682E-08	1.0069E-07	2.0035E-07	4.0794E-07
Monoethanolamine		5.1446E-10	0	0	0	0
Material selection		316L	316L	316L	316L	316L
Notes		Small dia pipe	Small dia pipe	Small dia pipe	Small dia pipe	Small dia pipe

Table 11.4 : Material selection table for Post-combustion capture equipment (gas)

Corrosion Loops	**Flue Gas**				**Absorber side streams**			
Equipment	**DCC**	**DCC pump & cooler**	**Booster fan**	**Absorber**	**Intercooler pump**	**Intercooler**	**Washer cooler**	**Wash Pump**
Material selection	Carbon steel FGV or GRP lined Internals: PP, GRP or 316L	316L	316L	Concrete + acid resistant tiling	Case and impeller : DSS	Shell: CS + 316L clad Tubes: 316L	Shell: CS + 316L clad Tubes: 316L	Shell & Impeller: DSS
NOTES				See text for alternate materials				

Corrosion Loops	**AMINE SYSTEM**						**CO_2**		
Equipment	**Rich Amine Pump**	**Lean/Rich Exchanger**	**Stripper**	**Reboiler**	**Lean Amine Pump**	**Trim cooler**	**Condenser**	**Reflux Drum**	**Reflux Pump**
Material selection	DSS case and impeller	Shell CS+ 316L clad; tubes:316L	CS+316L clad; 316L internals	Tube : 316L Shell side : CS+316L clad	CS case, impeller: 316L	Shell : CS Tubes: CS	Shell: 316L Tube : 316L	CS + 316L clad or 22Cr wall paper	DSS case and impeller
NOTES			See text						

Corrosion Loops	**COMPRESSION TRAIN**					
Equipment	**Compressors ST-1 ST-2 ST-3 ST-4 ST-5**	**Knockout drums KD-1 KD-2 KD-3 KD-4 KD-5 KD-6**	**Gas coolers HX-1 HX-2 HX-3 HX-4 HX-5**	**Dehydrator**	**Compressors ST-6 ST-7**	**Gas coolers HX-6 HX-7**
Material	13Cr – 4Ni martensitic stainless; 316L casing etc	CS + 316L clad	316L and/or 22Cr DSS	CS + 316L clad, 316L internals	CS & low alloy steel	CS
Notes					Dry	Dry; assumes coolant side is non-corrosive

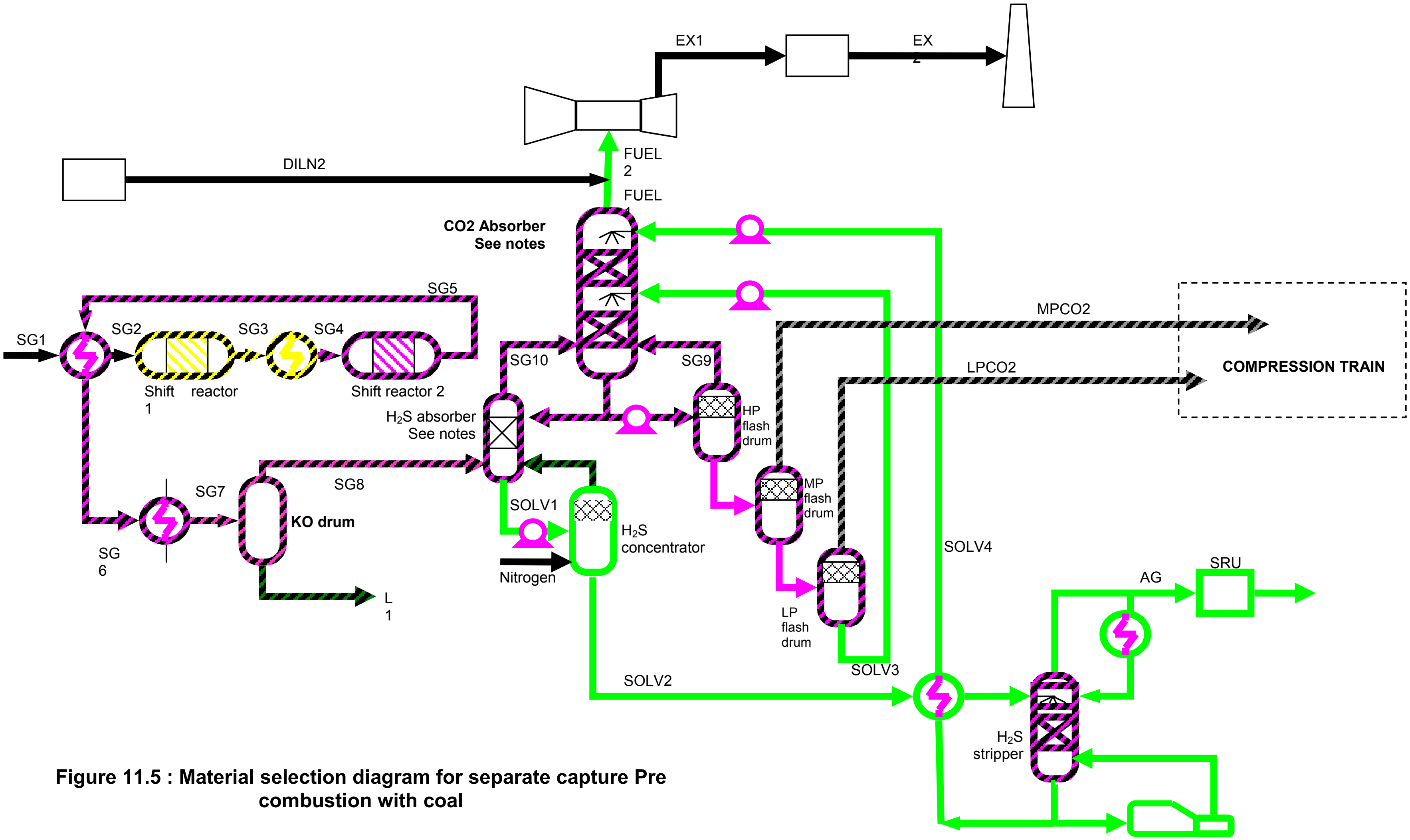

Figure 11.5 : Material selection diagram for separate capture Pre combustion with coal

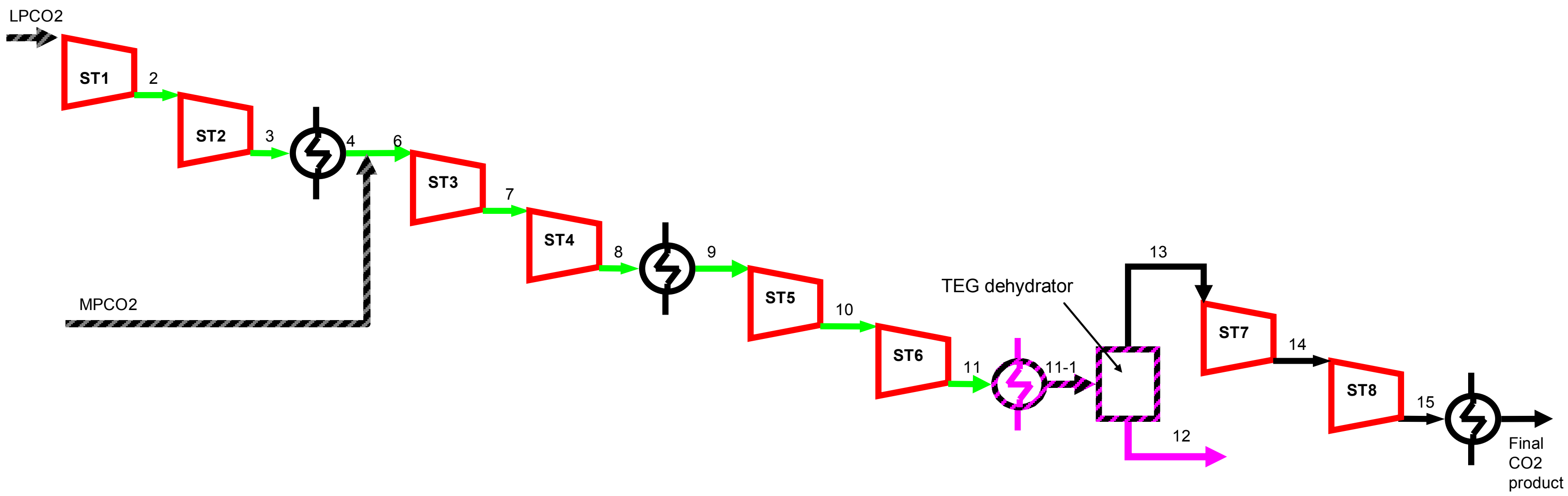

Figure 11.6 : Material selection diagram for compression train of separate capture Pre-combustion capture with coal

Table 11.5 : Material selection table for separate capture Pre-combustion capture streams (coal)

Corrosion Circuit	**Syngas**								**Solvent System**		
Process Streams	**SG1**	**SG2**	**SG3**	**SG4**	**SG5**	**SG6**	**SG7**	**SG8**	**SG9**	**SG10**	**Bottom outlet of absorber**
Component, mol %											
Water	49.8787	49.8787	27.8742	27.8742	24.2652	24.2652	24.2652	0.2571	0.0106	0.0052	
Hydrogen	14.0425	14.0425	36.0388	36.0388	39.6478	39.6478	39.6478	52.2829	41.0293	48.4558	
Carbon Dioxide	1.6974	1.6974	23.7019	23.7019	27.3109	27.3109	27.3109	35.8914	43.7883	38.2528	
Carbon Monoxide	28.4521	28.4521	6.4558	6.4558	2.8468	2.8468	2.8468	3.7540	4.1558	3.4819	
Nitrogen	5.5648	5.5648	5.5648	5.5648	5.5648	5.5648	5.5648	7.3386	10.9896	9.7738	
Argon	0.0246	0.0246	0.0246	0.0246	0.0246	0.0246	0.0246	0.0324	0.0261	0.0300	
Oxygen	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	
Hydrogen Sulphide	0.3317	0.3317	0.3399	0.3399	0.3399	0.3399	0.3399	0.4437	0.0003	0.0005	
Carbonyl Sulphide	0.0082	0.0082	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	
Temperature (°C)	210	260	490	290	328	280	40	40	17	10	17
Pressure	37.0	36.8	36.3	36.1	35.6	35.4	34.4	34.4	25	33.7	
Material selection	CS	CS	CS+ 347SS clad	CS+ 304LSS clad	CS+ 304LSS clad	CS+ 304LSS clad	CS + 316L clad	CS + 316L clad	CS + 316L clad	CS + 316L clad	CS + 316L clad
Notes							ISO15156-3 Table A2				

Corrosion Circuit	**Solvent System**					
Process Streams	**Solv1**	**Solv2**	**Bottom outlet of HP CO_2 flash**	**Bottom outlet of MP CO_2 flash**	**Solv3**	**Solv4**
Component (mol %)						
Water	12.3335	23.3274			23.1939	24.8999
Hydrogen	0.2700	0.0000			0.0000	0.0000
Carbon Dioxide	29.8996	0.0604			7.2757	0.0000
Carbon Monoxide	0.0618	0.0000			0.0000	0.0000
Nitrogen	0.1297	2.886			0.0000	0.0000
Oxygen	0.0000	< 1 ppm (mol)			0.0000	0.0000
Hydrogen Sulphide	9.4521	7.8778			0.0025	0.0000
Sulphur Dioxide	0.0012	0.0015			0.0016	0.0000
Dimethyl Ethers of Polyethylene Glycol	47.8520	66.6442			69.5263	75.100
Temperature (°C)	20	123			4	100
Pressure (bara)	45.0	38.2			1.2	8.5
Material selection	CS +3mm	CS+ 3mm	316L	316L	CS +3mm	CS + 3mm
NOTES	ISO 15156-2		ISO15156-3 Table A2	ISO15156-3 Table A2	ISO 15156-2	ISO15156-2 (assuming H_2S carry-over may be possible)

Corrosion Circuit	**CO_2**		**Drains**	**Utilities**	**Fuel and Emission**				
Process Streams	**LP CO_2**	**MP CO_2**	**L1**	**Nitrogen**	**AG**	**Fuel 1**	**Fuel2**	**EX1**	**EX2**
Component (mol %)									
Water	0.4000	0.1500	99.5535	0.0000	3.6700	0.0037	0.0023	11.1190	11.1190
Hydrogen	0.0065	1.1618	0.0248	0.0000	0.0000	76.4968	47.2820	0.0000	0.0000
Carbon Dioxide	99.5707	97.4975	0.4030	0.0000	0.7133	2.8058	1.7342	1.1260	1.1260
Carbon Monoxide	0.0085	0.4022	0.0018	0.0000	0.0000	5.3942	3.3341	0.0000	0.0000
Nitrogen	0.0120	0.7867	0.0026	99.9995	20.023	15.2522	47.618	74.9135	74.9135
Argon	0.0000	0.0008	0.0000	0.0000	0.0000	0.0474	0.0293	0.7860	0.7860
Oxygen	0.0000	0.0000	0.0000	0.0005	0.0005	0.0000	0.0002	12.0530	12.0530
Hydrogen Sulphide	0.0023	0.0009	0.0143	0.0000	75.5781	0.0000	0.0000	0.0000	0.0000
Temperature (°C)	4	10	40	20	38	35	28	520	103
Pressure (bara)	1.2	5.0	34.4	35.0	1.8	33.5	33.5	1.0	1.0
Material selection	CS + FGV lined	CS + FGV lined	CS + 316 clad	CS	CS + 6mm	CS + 6mm	CS + 6mm	0.5Cr	CS
NOTES	Duct		ISO15156-3 Table A2		ISO15156-2 Low corrosion rate expected, high $H_2S:CO_2$				See text

Corrosion Circuit	**Compression Train**							
Process Streams	**2**	**3**	**4**	**6**	**7**	**8**	**9**	**10**
Component (mol %)								
Water	0.4000	0.4000	0.4000	0.2633	0.2633	0.2633	0.2633	0.2633
Hydrogen	0.0065	0.0065	0.0065	0.6384	0.6384	0.6384	0.6384	0.6384
Carbon Dioxide	99.5707	99.5707	99.5707	98.4377	98.4377	98.4377	98.4377	98.4377
Carbon Monoxide	0.0085	0.0085	0.0085	0.2238	0.2238	0.2238	0.2238	0.2238
Nitrogen	0.0120	0.0120	0.0120	0.4399	0.4399	0.4399	0.4399	0.4399
Argon	0.0000	0.0000	0.0000	0.0004	0.0004	0.0004	0.0004	0.0004
Oxygen	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Hydrogen Sulphide	0.0023	0.0023	0.0023	0.0015	0.0015	0.0015	0.0015	0.0015
Temperature (°C)	63	129	40	23	85	156	40	106
Pressure (bara)	2.4	4.8	4.3	4.3	8.6	17.2	16.7	33.4
Material selection	CS + 3mm	CS + 3mm	CS + 3mm	CS + 3mm	CS + 3mm	CS + 3mm	CS + 3mm	CS + 3mm
NOTES	normally dry							Normally dry, ISO 15156-2 for wet upset conditions

Corrosion Circuit	**Compression Train**						
Process Streams	**11**	**11-1 (after HE)**	**12 (drain)**	**13**	**14**	**15**	**16**
Component, mol %							
Water	0.2633	0.2633	98.1183	0.0200	0.0200	0.0200	0.0200
Hydrogen	0.6384	0.6384	0.0010	0.6399	0.6399	0.6399	0.6399
Carbon Dioxide	98.4377	98.4377	1.8799	98.6778	98.6778	98.6778	98.6778
Carbon Monoxide	0.2238	0.2238	0.0003	0.2244	0.2244	0.2244	0.2244
Nitrogen	0.4399	0.4399	0.0004	0.4360	0.4360	0.4360	0.4360
Argon	0.0004	0.0004	0.0000	0.0004	0.0004	0.0004	0.0004
Oxygen	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Hydrogen Sulphide	0.0015	0.0015	0.0000	0.0015	0.0015	0.0015	0.0015
Temperature (°C)	181	40	40	40	104	118	40
Pressure (bara)	66.8	64.8	64.8	64.8	129.6	150.5	150
Material selection	CS + 3mm	CS + 316L clad	316L	CS	CS	CS	CS
NOTES	Normally dry, ISO 15156-2 for wet upset conditions	ISO15156-3 Table A2	ISO15156-3 Table A2	Dry	Dry	Dry	Dry

Table 11.6 : Material selection table for separate capture Pre-combustion capture equipment (coal)

Corrosion Loops	**PROCESS GAS**							
Equipment	**SG1-SG2 cooler**	**Shift reactor stg 1**	**SG3-SG4 cooler**	**Shift reactor stg 2**	**SG6-SG7 cooler**	**KO drum**	**H_2S absorber**	**CO_2 absorber**
Material selection	Shell : CS + 304L clad. Tubes: 304	Shell CS+ 347SS clad	Shell : CS + 347SS clad Tubes: 309	Shell CS + 304 clad	Tube : 316L Shell : 316L clad	CS + 316L clad	CS + 316L clad (after detailed design may be able to use CS in sections with lean solvent only)	CS + 316L clad (after detailed design may be able to use CS in sections with lean solvent or clean fuel gas only)
NOTES	Sulphidation risk on hot (shell) side	See text. May need 309, 310 etc for internals		Operate at 328 °C	280 °C --> 40 °C. Wet	ISO15156-3 Table A2	ISO15156-3 Table A2 (ISO 15156-2 for CS)	ISO15156-3 Table A2 (ISO 15156-2 for CS)

Corrosion Loops	**Solvent and Acid Gas**							
Equipment	**H_2S concentrator**	**HP CO_2 flash drum**	**MP CO_2 flash drum**	**LP CO_2 flash drum**	**SOLV2/4 HE**	**H_2S stripper**	**H_2S condenser**	**Stripper reboiler**
Material selection	CS + 3mm	CS + 316L clad	CS + 316L clad	CS + 316L clad	Tube side : 316L Shell side : CS + 3mm	CS + 316L clad	Tube : 316L Shell : CS	Tube: 316L Shell side : CS + 3mm
NOTES	ISO15156-2	ISO15156-3 Table A2	ISO15156-3 Table A2	ISO15156-3 Table A2	ISO15156-3 Table A2 / ISO15156-2	ISO15156-3 Table A2	non-corrosive coolant, tubes ISO15156-3 Table A2	ISO15156-3 Table A2 / ISO15156-2

Corrosion Loops	**Solvent & Acid Gas**			
Equipment	**SOLV 1 Pump**	**SOLV 3 Pump**	**SOLV 4 Pump**	**Absorber outlet pump**
Material selection	316	316	316	316
NOTES	ISO15156-3 Table A2	ISO15156-3 Table A2	ISO15156-3 Table A2	ISO15156-3 Table A2

Corrosion Loops	**COMPRESSION TRAIN**			
Equipment	**Compressors** **ST-1 ST-5** **ST-2 ST-6** **ST-3 ST-7** **ST-4 ST-8**	**Gas Coolers** **HE 3 to 4** **HE 8 to 9** **HE 15 / export**	**TEG Dehydrator**	**Gas coolers** **HE 11**
Material selection	13Cr-4Ni martensitic SS; 316L casing etc	Shell and tube sides: CS	CS + 316L clad	Shell: CS+ 316L clad Tubes: 316
NOTES	ISO15156-3 Table A6 & A22	Process-side dry. Assuming non-corrosive coolant,	Wet	Process side wet

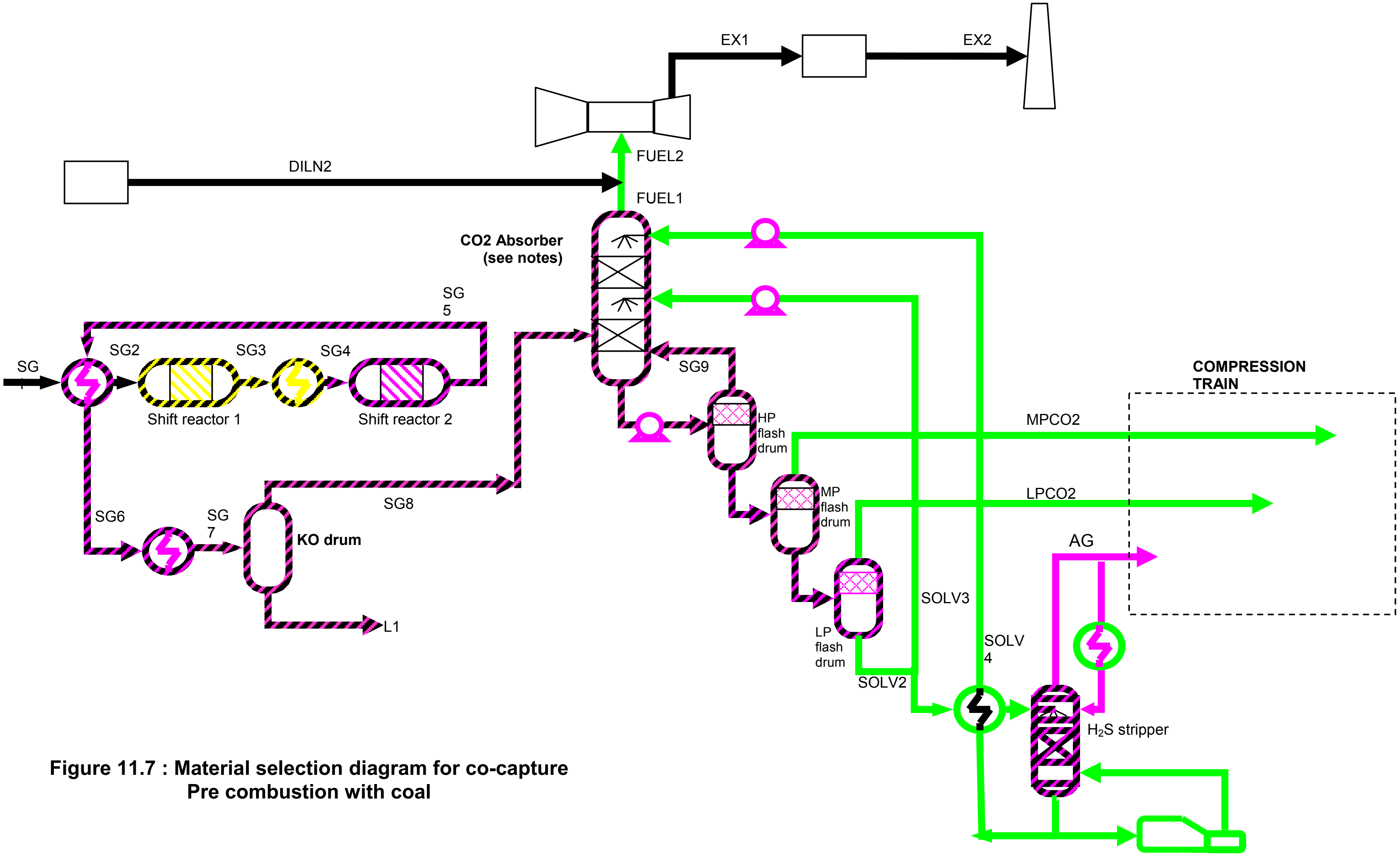

Figure 11.7 : Material selection diagram for co-capture
Pre combustion with coal

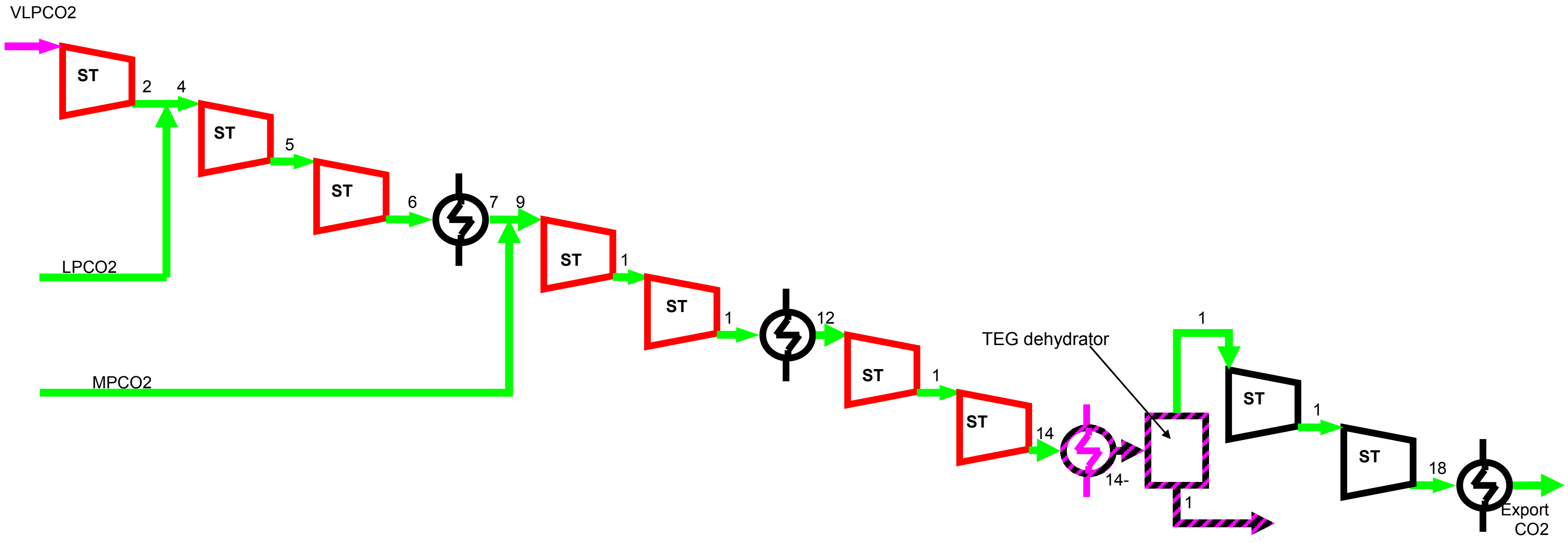

Figure 11.8 : Material selection diagram for compression train of co-capture Pre-combustion capture with coal

Table 11.7 : Material selection table for co-capture Pre-combustion capture streams (coal)

Corrosion Loops	**Syngas**								**Solvent**	
Process Streams	**SG1**	**SG2**	**SG3**	**SG4**	**SG5**	**SG6**	**SG7**	**SG8**	**SG9**	**Bottom outlet of CO_2 absorber**
Component, mol %										
Water	49.8787	49.8787	27.8742	27.8742	24.2652	24.2652	24.2652	0.2571	0.0053	
Hydrogen	14.0425	14.0425	36.0388	36.0388	39.6478	39.6478	39.6478	52.2829	44.9205	
Carbon Dioxide	1.6974	1.6974	23.7019	23.7019	27.3109	27.3109	27.3109	35.8914	39.4380	
Carbon Monoxide	28.4521	28.4521	6.4558	6.4558	2.8468	2.8468	2.8468	3.7540	5.5813	
Nitrogen	5.5648	5.5648	5.5648	5.5648	5.5648	5.5648	5.5648	7.3386	9.8641	
Argon	0.0246	0.0246	0.0246	0.0246	0.0246	0.0246	0.0246	0.0324	0.0276	
Oxygen	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	
Hydrogen Sulphide	0.3317	0.3317	0.3399	0.3399	0.3399	0.3399	0.3399	0.4437	0.1630	
Carbonyl Sulphide	0.0082	0.0082	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	
Temperature (°C)	210	260	490	290	328	280	40	40	18	
Pressure (bara)	37.0	36.8	36.3	36.1	35.6	35.4	34.4	34.4	19.0	
Material selection	CS	CS	CS+ 347SS clad	CS+ 304LSS clad	CS+ 304LSS clad	CS+ 304LSS clad	CS + 316L clad	CS + 316L clad	CS + 316L clad	CS + 316L clad
NOTES							ISO5156-3 Table A.2	ISO5156-3 Table A.2	ISO5156-3 Table A.2	ISO5156-3 Table A.2

Corrosion Loops	**SOLVENT**				
Process Streams	**Bottom outlet of HP CO_2 flash**	**Bottom outlet of MP CO_2 flash**	**Solv2**	**Solv3**	**Solv4**
Component, mol %					
Water			22.6142	22.6142	25.1000
Hydrogen			0.0000	0.0000	0.0000
Carbon Dioxide			7.6897	7.6897	0.0000
Carbon Monoxide			0.0000	0.0000	0.0000
Nitrogen			0.0000	0.0000	0.0000
Argon			0.0000	0.0000	0.0000
Oxygen			0.0000	0.0000	0.0000
Hydrogen Sulphide			1.1727	1.1727	0.0000
Dimethyl Ethers of Polyethylene Glycol			68.5234	68.5234	74.9
Temperature (°C)			11	11	84
Pressure (bara)			1.5	1.5	8.5
Material selection	CS + 316L clad	CS + 316L clad	CS + 3mm	CS + 3mm	CS + 3mm
NOTES	ISO5156-3 Table A.2	ISO5156-3 Table A.2	Carbon steel materials & construction to comply with ISO15156-2	Carbon steel materials & construction to comply with ISO15156-2	Lean solvent, H_2S & CO_2 free

Corrosion Loops	**Utilities**		**CO_2**		**Fuel and Emission**			
Process Streams	**L1**	**Dil N_2**	**LP CO_2**	**MP CO_2**	**FUEL1**	**FUEL2**	**EX1**	**EX2**
Component, mol %								
Water	99.5535	0.0000	0.4000	0.1500	0.0011	0.0006	11.1190	11.1190
Hydrogen	0.0248	0.0000	0.0139	1.9807	80.1696	47.2506	0.0000	0.0000
Carbon Dioxide	0.4030	0.0000	98.4722	95.4552	3.0898	1.8211	1.1260	1.1260
Carbon Monoxide	0.0018	0.0000	0.0210	0.8307	5.6097	3.3062	0.0000	0.0000
Nitrogen	0.0026	98	0.0204	1.0977	11.0801	46.7709	74.9135	74.9135
Argon	0.0000	0.0000	0.0000	0.0012	0.0497	0.0293	0.7860	0.7860
Oxygen	0.0000	2.00	0.0000	0.0000	0.0000	0.8212	12.0530	12.0530
Hydrogen Sulphide	0.0143	0.0000	1.0725	0.4845	0.0000	0.0000	0.0000	0.0000
Temperature (°C)	40	20	11	15	36	29	520	103
Pressure (bara)	34.4	35	1.5	5.0	33.5	33.5	1.0	1.0
Material selection	CS + 316L clad	CS	CS + 6mm	CS + 6mm	CS + 3mm	CS + 3mm	0.5Cr	CS
NOTES	ISO 15156-3 Table A.2		Duct Carbon steel materials & construction to ISO15156-2	Carbon steel materials & construction to ISO15156-2	Normally dry stream	Normally dry stream		See section 9.4

Corrosion Loops	**Compression Train**								
Process Streams	**VLPCO$_2$ / AG**	**2**	**4**	**5**	**6**	**7**	**9**	**10**	**11**
Component, mol %									
Water	1.4852	1.4852	0.4620	0.4620	0.4620	0.4620	0.3433	0.3433	0.3433
Hydrogen	0.0000	0.0000	0.0131	0.0131	0.0131	0.0131	0.7617	0.7617	0.7617
Carbon Dioxide	85.483	85.483	97.7301	97.7301	97.7301	97.7301	96.8646	96.8646	96.8646
Carbon Monoxide	0.0002	0.0002	0.0198	0.0198	0.0198	0.0198	0.3283	0.3283	0.3283
Nitrogen	0.0002	0.0002	0.0192	0.0192	0.0192	0.0192	0.4296	0.4296	0.4296
Argon	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0004	0.0004	0.0004
Oxygen	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Hydrogen Sulphide	13.0314	13.0314	1.7557	1.7557	1.7557	1.7557	1.2721	1.2721	1.2721
Temperature (°C)	10	64	14	75	143	40	30	93	165
Pressure (bara)	0.8	1.5	1.5	3.0	6.0	5.5	5.0	10	20
Material selection	316L	CS + 3mm	CS + 3mm	CS + 3mm	CS + 3mm	CS + 3mm	CS + 3mm	CS + 3mm	CS + 3mm
NOTES	Stripper overheads may be wet ISO 15156-3 Table A.2	Normally dry. Carbon steel materials & construction to ISO15156-2.							

Corrosion Loops	**Compression Train**								
Process Streams	**12**	**13**	**14**	**14-1 (AFTER HE)**	**15 (drain)**	**16**	**17**	**18**	**Export CO_2**
Component, mol %									
Water	0.3433	0.3433	0.3433	0.3433	100	0.0200	0.0200	0.0200	0.0200
Hydrogen	0.7617	0.7617	0.7617	0.7617	0.0000	0.7642	0.7642	0.7642	0.7642
Carbon Dioxide	96.8646	96.8646	96.8646	96.8646	0.0000	97.1788	97.1788	97.1788	97.1788
Carbon Monoxide	0.3283	0.3283	0.3283	0.3283	0.0000	0.3294	0.3294	0.3294	0.3294
Nitrogen	0.4296	0.4296	0.4296	0.4296	0.0000	0.4309	0.4309	0.4309	0.4309
Argon	0.0004	0.0004	0.0004	0.0004	0.0000	0.0005	0.0005	0.0005	0.0005
Oxygen	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Hydrogen Sulphide	1.2721	1.2721	1.2721	1.2721	0.0000	1.2762	1.2762	1.2762	1.2762
Temperature (°C)	40	106	161	40	40	40	105	122	40
Pressure (bara)	19.5	39	65	63	63	63	126	150.5	150
Material selection	CS + 3mm	CS + 3mm	CS + 3mm	CS + 316L	CS + 316L	CS + 3mm	CS + 3mm	CS + 3mm	CS + 3mm
NOTES	Normally dry. Carbon steel materials & construction to ISO15156-2.			Wet ISO15156-3 Table A.2	Wet ISO15156-3 Table A.2	Normally dry. Carbon steel materials & construction to ISO15156-2.			

Table 11.8 : Material selection table for co-capture Pre-combustion capture equipment (coal)

Corrosion Loops	**PROCESS GAS**					
Equipment	**SG1-SG2 cooler**	**Shift reactor stg 1**	**SG3-SG4 cooler**	**Shift reactor stg 2**	**SG6-SG7 cooler**	**KO drum**
Material selection	Shell : CS + 304L clad Tubes: 304	Shell CS+ 347SS clad	Shell : CS + 347SS clad Tubes: 309	Shell CS + 304 clad	Tube : 316L Shell : 316L clad	CS + 316L
NOTES						Wet ISO15156-3 Table A.2

Corrosion Loops	**Solvent & Acid Gas**							
Equipment	**CO_2 Absorber**	**HP CO_2 flash drum**	**MP CO_2 flash drum**	**LP CO_2 flash drum**	**SOLV2/4 HEX**	**H_2S stripper**	**AG Cooler**	**H_2S Stripper reboiler**
Material selection	CS + 316L clad; 316L internals (after detailed design may be able to use CS in lean solvent sections)	CS + 316L clad	CS + 316L clad	CS + 316L clad	Tubes Shell side : CS + 3mm	CS + 316L clad	Tube side (process) : 316L Shell side : CS+3mm	Tube side : CS Shell side : CS+3mm Tubes 316L
NOTES	ISO15156-3 Table A.2 (ISO 15156-2 for CS)	ISO15156-3 Table A.2	ISO15156-3 Table A.2	ISO15156-3 Table A.2	ISO15156-3 Table A.2 & ISO15156-2.	ISO15156-3 Table A.2	Process gas (VLP CO2 / AG) assumed wet ISO15156-3 Table A.2	ISO15156-3 Table A2 / ISO15156-2

Corrosion Loops	**Solvent & Acid Gas**		
Equipment	**SOLV 3 Pump**	**SOLV 4 Pump**	**Absorber outlet pump**
Material selection	316L	316L	316L
NOTES	ISO15156-3 Table A.2	ISO15156-3 Table A.2	ISO15156-3 Table A.2

Corrosion Loops	**COMPRESSION TRAIN**				
Equipment	**Compressors** **ST-1 ST-5** **ST-2 ST-6** **ST-3 ST-7** **ST-4**	**Compressors** **ST-8** **ST-9**	**Gas coolers** **HE 6 / 7** **HE 11/12** **HE 18 / export**	**Gas coolers** **HE 14 / 14-1**	**TEG Dehydrator**
Material	13Cr-4Ni martensitic SS and 316L	CS	Shell side: CS Tube side : CS	Shell : CS +316L clad Tubes: 316L	CS +316L clad
Notes	ISO 15156-3 Tables A.22 & A.2	Downstream of dehydrator	Normally dry ISO 15156	ISO 15156 Table A.2	CRA to avoid any solid corrosion products ISO15156-3 Table A.2

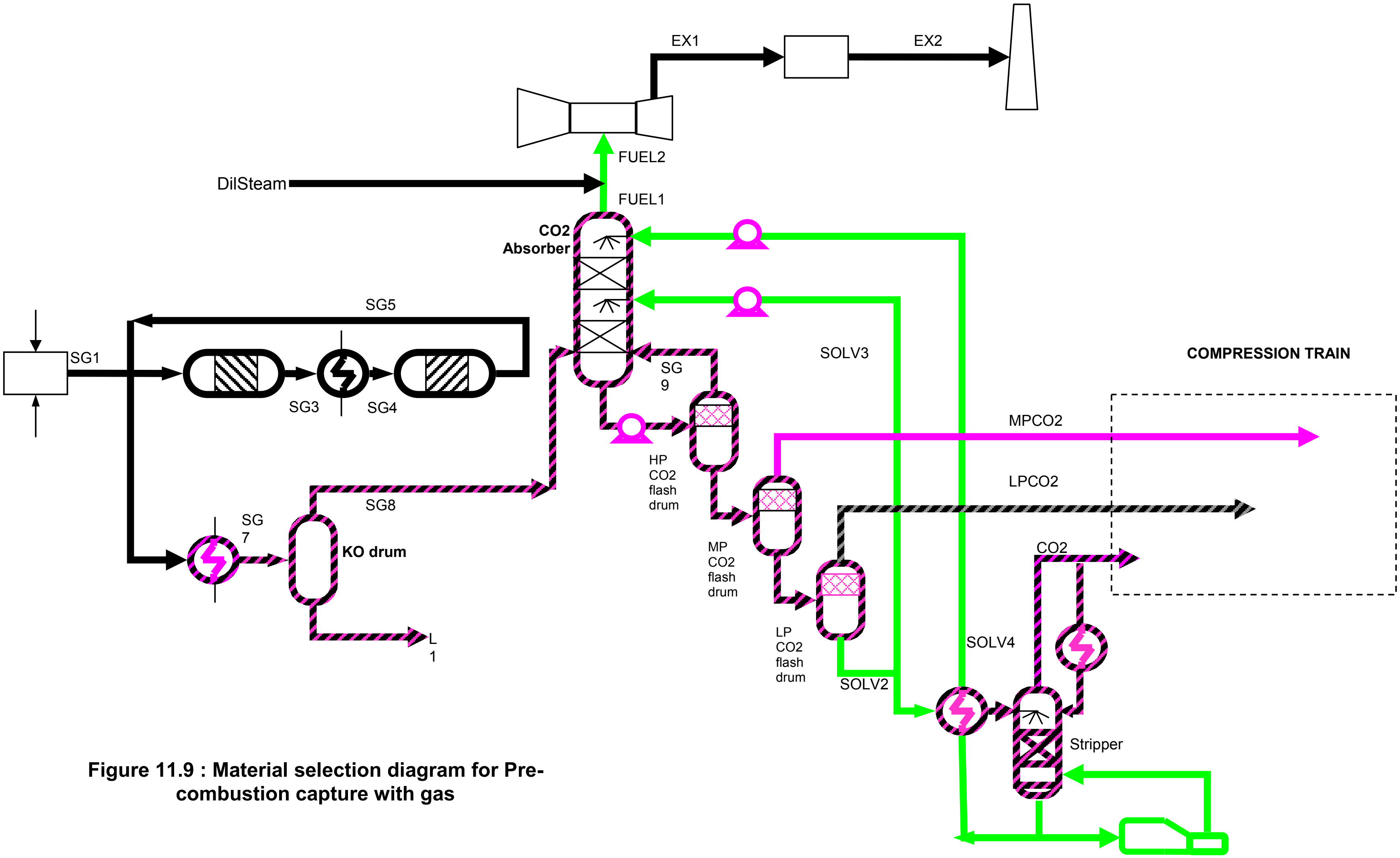

Figure 11.9 : Material selection diagram for Pre-combustion capture with gas

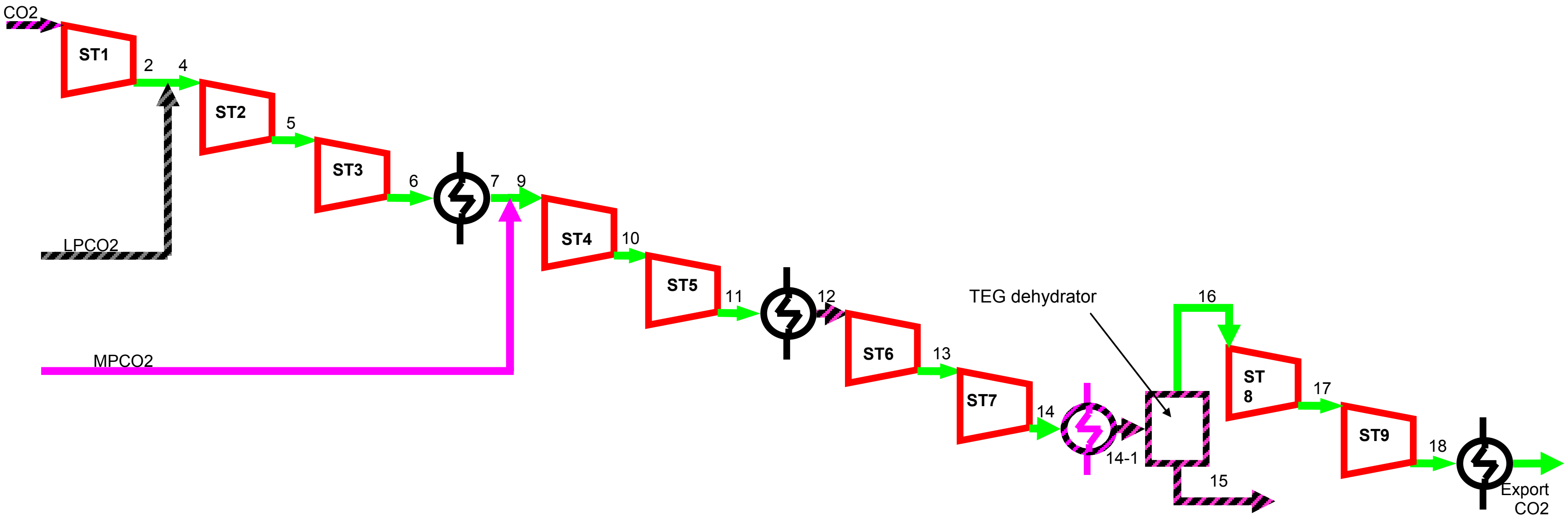

Figure 11.10 : Material selection diagram for compression train of Pre-combustion capture with gas

Table 11.9 : Material selection table for Pre-combustion capture streams (gas)

Corrosion Loops	**Syngas**						
Process Streams	**SG1**	**SG3**	**SG4**	**SG5**	**SG7**	**SG8**	**SG9**
Component, mol %							
Water	34.5640	24.2995	24.2995	20.6648	20.6648	0.2353	0.0303
Hydrogen	49.4760	59.7405	59.7405	63.3752	63.3752	79.7408	68.5925
Carbon Dioxide	1.5960	11.8605	11.8605	15.4952	15.4952	19.4391	30.5767
Carbon Monoxide	14.3640	4.0995	4.0995	0.4648	0.4648	0.5849	0.8006
Temperature (°C)	350	465	200	242	40	40	11
Pressure (bara)	38	37.5	37.3	36.8	35.8	35.8	19.0
Material selection	1Cr ½ Mo	1Cr ½ Mo	CS	CS	CS + 316L clad	CS + 316L clad	CS + 316L clad
NOTES							

Corrosion Loops	**Solvent**					
Process Streams	**Bottom outlet of HP CO_2 flash**	**Bottom outlet of MP CO_2 flash**	**Solv2**	**Solv3**	**Solv4**	**Bottom outlet of CO_2 absorber**
Component, mol %						
Water			23.2874	23.2874	25.9218	
Hydrogen			0.0000	0.0000	0.0000	
Carbon Dioxide			6.8788	6.8788	0.0000	
Dimethyl Ethers of Polyethylene Glycol			69.8337	69.8337	74.0782	
Temperature (°C)			6	6	24	
Pressure (bara)			1.5	1.5	8.5	
Material selection	CS + 316L clad	CS + 316L clad	CS + 6mm	CS + 6mm	CS + 6mm	CS + 316L clad
Notes	Liquid stream, rich solvent	Liquid stream, rich solvent	Semi-lean solvent	Semi-lean solvent	Lean solvent	Rich solvent

Corrosion Loops	**Drain**	**Utilities**	**CO_2**			**Fuel and Emission**			
Process Streams	**L1**	**Dil Steam**	**LP CO_2**	**MP CO_2**	**CO_2 / VLP CO_2**	**FUEL1**	**FUEL2**	**EX1**	**EX2**
Component, mol %									
Water	99.7299	100.0000	0.1500	0.0750	1.5450	0.0151	43.000	21.0100	21.0100
Hydrogen	0.0381	0.0000	0.0139	1.9807	0.0001	95.8845	53.0000	0.0000	0.0000
Carbon Dioxide	0.2317	0.0000	99.8361	97.2316	98.4548	3.4062	2.0000	0.8652	0.8652
Carbon Monoxide	0.0003	0.0000	0.0210	0.8307	0.0000	0.6941	2.0000	0.0000	0.0000
Nitrogen	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	65.5270	65.5270
Argon	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.7892	0.7892
Oxygen	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	11.8100	11.8100
Temperature (°C)	40	250	11	10	10	31	250	520	103
Pressure (bara)	35.8	35	1.5	5.0	0.8	35	33.5	1.0	1.0
Material selection	CS + 316L clad	CS	CS + FGV	CS + 316L clad or solid 316L	CS + 316L clad	CS + 3mm	CS + 3mm	0.5Cr steel	CS
NOTES			Duct	Normally dry	Duct				See text

Table 11.10 : Material selection table for Pre-combustion capture equipment (gas)

Corrosion Loops	**PROCESS GAS**					
Equipment	**Shift reactor stg 1**	**SG3-SG4 cooler**	**Shift reactor stg 2**	**SG5-SG7 cooler**	**KO drum**	**CO_2 absorber**
Material selection	1 Cr-½ Mo steel	1 Cr-½ Mo steel	CS	Tubes: 316L Shell: CS+ 316L	CS + 316L	CS + 316L
NOTES	Operates at 490 °C	465 °C --> 200 °C	Operates at 242 °C			(May be able to use CS after detailed design for parts exposed only to lean solvent or clean fuel gas)

Corrosion Loops	**Solvent & CO_2**						
Equipment	**HP CO_2 flash drum**	**MP CO_2 flash drum**	**LP CO_2 flash drum**	**Stripper**	**SOLV2/4 HE**	**VLP CO_2 HE**	**Stripper reboiler**
Material selection	CS + 316L clad; 316L internals	CS + 316L clad; 316L internals	CS + 316L clad; 316L internals	CS + 316L clad; 316L internals	Tubes : 316L Shell side : CS + 316L clad	Tube side : 316L Shell side : CS + 316L clad	Tube side : CS Shell side : CS + 3 mm Tubes 316L
. **NOTES**						Wet CO_2	

Corrosion Loops	**Solvent & Acid Gas**		
Equipment	**SOLV 3 Pump**	**SOLV 4 Pump**	**Absorber outlet pump**
Material selection	316L	316L	316L
NOTES			

Corrosion Loops	**COMPRESSION TRAIN**				
Equipment	**Compressors ST-1**	**Compressors** **ST-2 ST-6** **ST-3 ST-7** **ST-4 ST-8** **ST-5 ST-9**	**Gas coolers** **HE 6 to 7** **HE 11 to 12** **HE 18 to export**	**Gas coolers HE after 14**	**TEG Dehydrator**
Material selection	17-4PH or A286 & 316L	13Cr-4Ni martensitic stainless steel & 316L	CS	Shell: CS+ 316L clad Tubes: 316L	CS +316L clad
NOTES	Entry stream VLPCO$_2$ is near dew-point		Assumed coolant is non-corrosive	Assumed coolant is non-corrosive	CRA to avoid any corrosion products

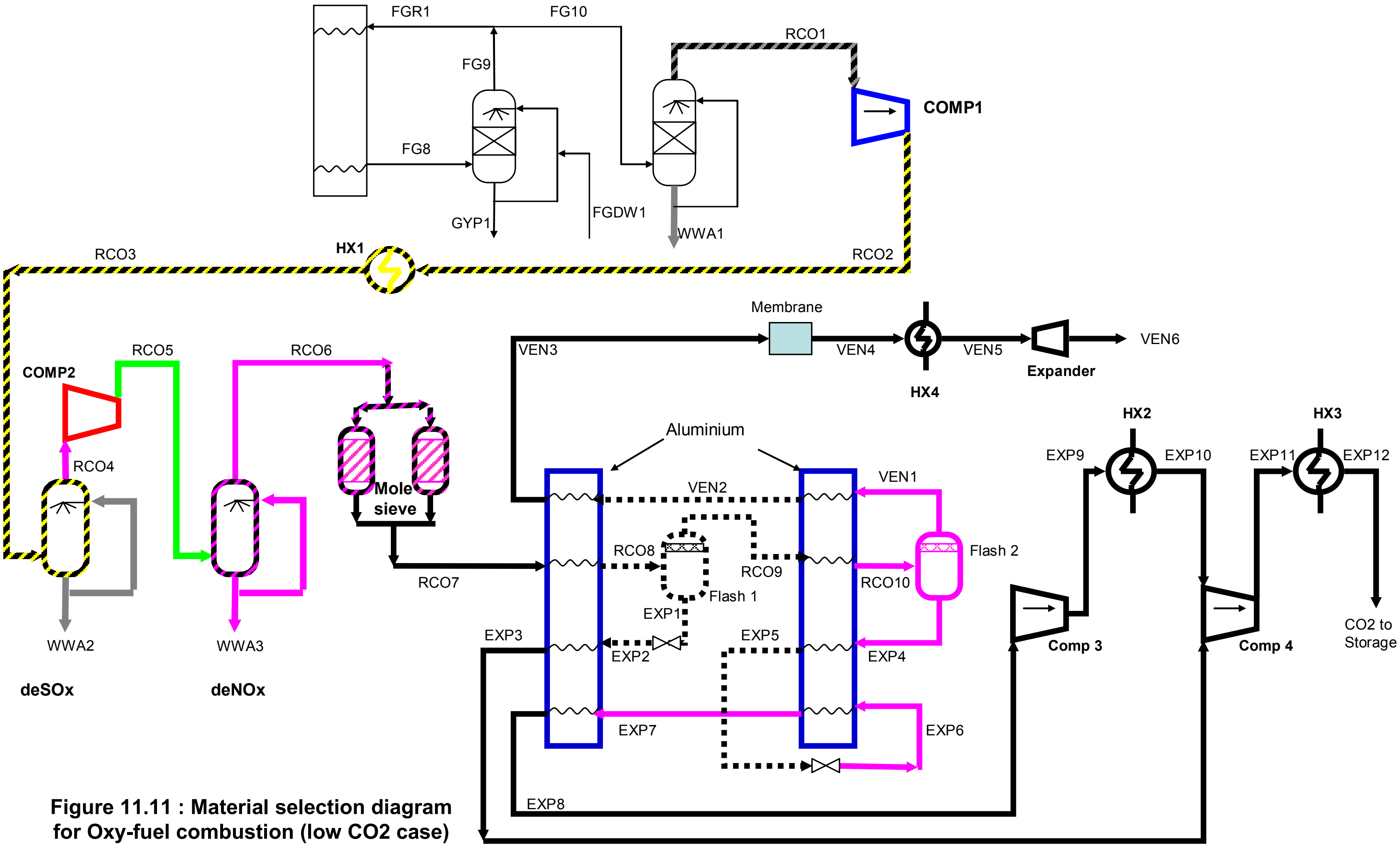

Figure 11.11 : Material selection diagram for Oxy-fuel combustion (low CO2 case)

Table 11.11 : Material selection table for Oxy-fuel combustion streams (low CO_2 case)

Corrosion Circuit	**RAW CO_2**									
Process Streams	**RCO1**	**RCO2**	**RCO3**	**RCO4**	**RCO5**	**RCO6**	**RCO7**	**RCO8**	**RCO9**	**RCO10**
Component (mol %)										
Water	4.2003	4.2003	4.2003	0.3205	0.3205	0.1814	0.0005	0.0005	0.0000	0.0000
Carbon Dioxide	72.6315	72.6315	72.6315	75.5329	75.5329	75.6857	75.8228	75.8228	50.4531	50.4531
Nitrogen	16.5922	16.5922	16.5922	17.3417	17.3417	17.3767	17.4082	17.4082	35.9177	35.9177
Argon	2.2447	2.2447	2.2447	2.3461	2.3461	2.3508	2.3551	2.3551	4.7464	4.7464
Oxygen	4.2005	4.2005	4.2005	4.3903	4.3903	4.3992	4.4071	4.4071	8.8708	8.8708
Sulphur Dioxide	0.0652	0.0652	0.0652	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Nitrogen Oxide	0.0656	0.0656	0.0656	0.0686	0.0686	0.0062	0.0062	0.0062	0.0120	0.0120
Temperature (°C)	30.00	82.31	70.00	30.00	102.69	24.29	24.29	-33.43	-33.43	-50.00
Pressure (bara)	1.02	15.20	15.00	14.60	30.50	30.00	30.00	29.80	29.80	29.70
Material selection	CS + FGV lining	CS + 904L clad or GRE	CS + 904L clad or GRE	CS + 316L clad or 316L	CS + 3mm	CS + 316L clad or 316L	CS	LCTS	LCTS	304L
NOTES	Duct									

Corrosion Circuit	**VENT**						**OTHERS**			
Process Streams	**VEN1**	**VEN2**	**VEN3**	**VEN4**	**VEN5**	**VEN6**	**Recirc Loop DeSOx**	**WWA2**	**Recirc loop De-Nox**	**WWA3**
Component (mol %)										
Water	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	90.0646	90.0646	69.0574	69.0574
Carbon Dioxide	29.4672	29.4672	29.4672	7.2558	7.2558	7.2558	8.4206	8.4206	0.0149	0.0149
Nitrogen	51.2751	51.2751	51.2751	73.2116	73.2116	73.2116	0.0047	0.0047	0.0034	0.0034
Argon	6.7110	6.7110	6.7110	9.1917	9.1917	9.1917	0.0006	0.0006	0.0005	0.0005
Oxygen	12.5302	12.5302	12.5302	10.3135	10.3135	10.3135	0.0012	0.0012	0.0009	0.0009
Sulphur Dioxide	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	1.5082	1.5082	0.0000	0.0000
Nitrogen Oxide	0.0165	0.0165	0.0165	0.0274	0.0274	0.0274	0.0000	0.0000	30.9229	30.9229
Temperature (°C)	-50.00	-40.00	14.20	14.20	300.00	4.91	30.00	30.00	102.69	102.69
Pressure (bara)	29.70	29.68	29.65	29.65	29.00	1.10	15	15	30	30
Material selection	304L	LTCS	CS	CS	CS	CS	GRP	GRP	316L	316L
NOTES							Small diameter	Small diameter	Small diameter	Small diameter

Corrosion Loops	**CO_2 EXPORT**											
Process Streams	**EXP1**	**EXP2**	**EXP3**	**EXP4**	**EXP5**	**EXP6**	**EXP7**	**EXP8**	**EXP9**	**EXP10**	**EXP11**	**EXP12**
Component (mol %)												
Water	0.0010	0.0010	0.0010	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	0.0008	0.0008
Carbon Dioxide	96.7361	96.7361	96.7361	95.5657	95.5657	95.5657	95.5657	95.5657	95.5657	95.5657	96.4933	96.4933
Nitrogen	2.1502	2.1502	2.1502	2.9045	2.9045	2.9045	2.9045	2.9045	2.9045	2.9045	2.3066	2.3066
Argon	0.3838	0.3838	0.3838	0.5232	0.5232	0.5232	0.5232	0.5232	0.5232	0.5232	0.4127	0.4127
Oxygen	0.7276	0.7276	0.7276	1.0042	1.0042	1.0042	1.0042	1.0042	1.0042	1.0042	0.7850	0.7850
Sulphur Dioxide	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Nitrogen Oxide	0.0014	0.0014	0.0014	0.0023	0.0023	0.0023	0.0023	0.0023	0.0023	0.0023	0.0016	0.0016
Temperature (°C)	-33.40	-38.76	13.23	-50.00	-42.97	-55.50	-45.88	14.20	80.46	40.00	32.78	40.00
Pressure (bara)	29.80	17.45	17.25	29.70	29.50	8.65	8.45	8.35	17.45	17.28	150.50	150.00
Material selection	LTCS	LTCS	CS	304L	LTCS	304L	304L	CS	CS	CS	CS	CS
NOTES												

Table 11.12 : Material selection table for Oxy-fuel combustion equipment (low CO_2 case)

Corrosion Loops	**RAW CO_2**											
Equipment	Comp 1 (RCO1/02)	HX 1 (RCO2/RCO3)	De-SOX Reactor	Comp 2 (RCO4/5)	De-NOX Reactor	Mole-sieve driers	Cryogenic 1	Cryogenic 2	Flash separator 1	Flash separator 2	Expander (VEN5/6)	HX 4 (VEN 4/5)
Material selection	25Cr SDSS (F55) & 6Mo super-austenitic	6Mo super-austenitic clad shell & tube-sheet & 6Mo or 25Cr SDSS tubes	CS + 904L clad Or CS + FGV coating	13-4 CrNi martensitic stainless 316L casing	CS + 316L clad	CS + 316L clad	Al heat exchanger	Al heat exchanger	LTCS	304L	CS	CS
NOTES												

Corrosion Loops	**Recirculation Water**		**CO_2 EXPORT**			
Equipment	De SOx recirc. pump	De NOx recirc. pump	Comp 3 (Exp 8 - 9)	HX 2 (EXP9/10)	Comp 4 (EXP3 &10-11)	HX 3 (EXP11/12)
Material selection	Non-metallic (eg PP), or lined.	316L	CS	CS shell, plate & tubes	CS	CS shell, plate & tubes
NOTES			Dry stream	Assumed coolant side is non-corrosive	Dry stream	Assumed coolant side is non-corrosive

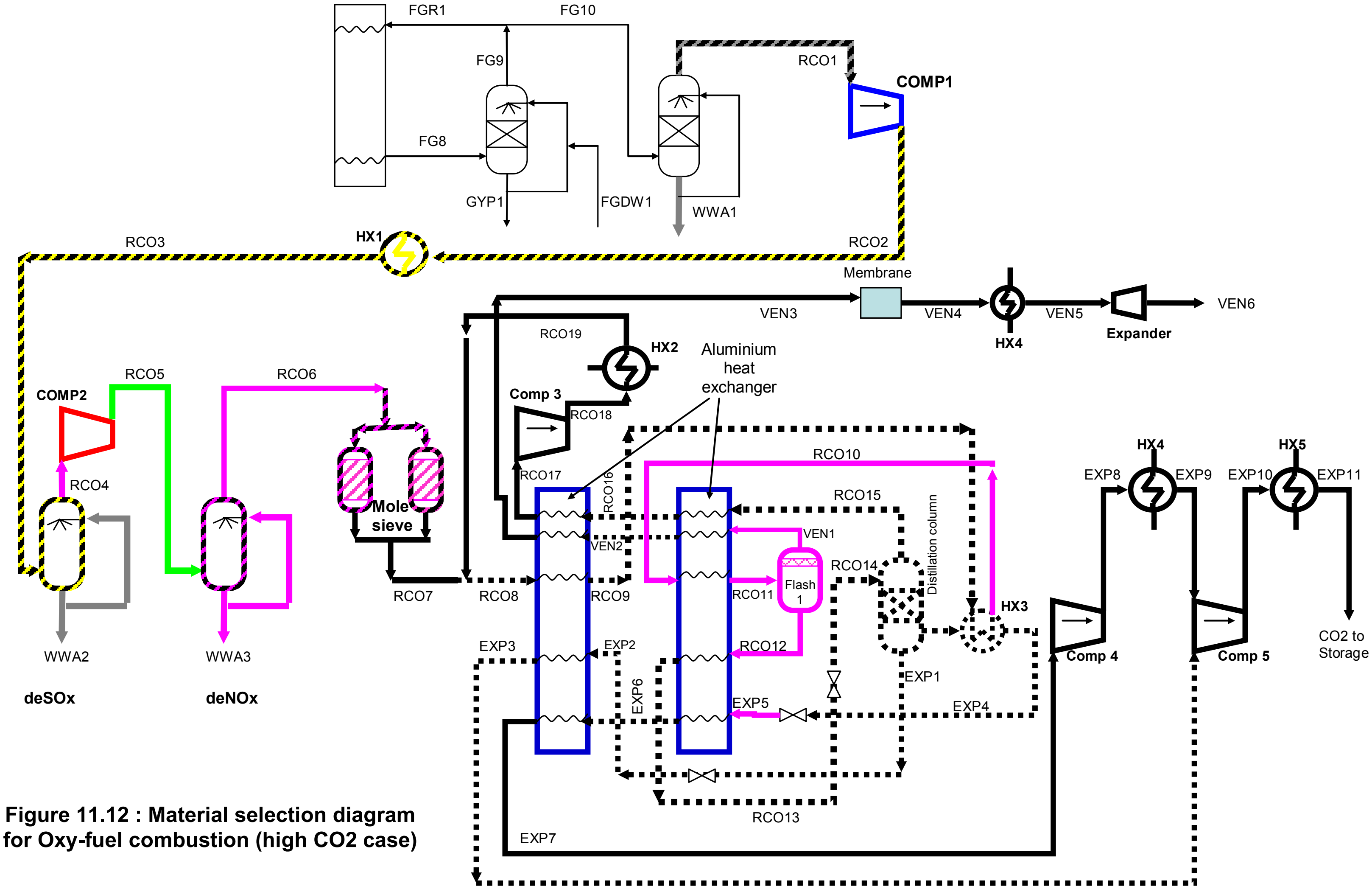

Figure 11.12 : Material selection diagram for Oxy-fuel combustion (high CO2 case)

Table 11.13 : Material selection table for Oxy-fuel combustion streams (high CO_2 case)

Corrosion Loops					**RAW CO_2**					
Process Streams	**RCO1**	**RCO2**	**RCO3**	**RCO4**	**RCO5**	**RCO6**	**RCO7**	**RCO8**	**RCO9**	**RCO10**
Component, mol %										
Water	4.1951	4.1951	4.1951	0.3201	0.3201	0.1812	0.0005	0.0003	0.0003	0.0003
Carbon Dioxide	72.6359	72.6359	72.6359	75.5337	75.5337	75.6863	75.8233	82.5562	82.5562	82.5562
Nitrogen	16.5927	16.5927	16.5927	17.3414	17.3414	17.3764	17.4079	12.2772	12.2772	12.2772
Argon	2.2447	2.2447	2.2447	2.3460	2.3460	2.3508	2.3550	1.7877	1.7877	1.7877
Oxygen	4.2007	4.2007	4.2007	4.3902	4.3902	4.3991	4.4070	3.3728	3.3728	3.3728
Sulphur Dioxide	0.0653	0.0653	0.0653	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Nitrogen Oxide	0.0656	0.0656	0.0656	0.0686	0.0686	0.0062	0.0062	0.0058	0.0058	0.0058
Temperature ,°C	30.00	82.29	70.00	30.00	104.42	24.31	24.29	26.77	-5.16	-19.96
Pressure (bara)	1.02	15.20	15.00	14.60	31.00	30.00	30.00	30.00	30.00	30.00
Material selection	CS + FGV lining	CS + 904L clad or GRE	CS + 904L clad or GRE	CS + 316L clad or 316L	CS + 3mm	CS + 316L clad or 316L	CS	LCTS	LCTS	304L
NOTES	Duct						Dry stream	Dry stream	Dry stream	Dry stream

Corrosion Loops	**RAW CO_2**								
Process Streams	**RCO11**	**RCO12**	**RCO13**	**RCO14**	**RCO15**	**RCO16**	**RCO17**	**RCO18**	**RCO19**
Component, mol %									
Water	0.0003	0.0004	0.0004	0.0004	0.0004	0.0004	0.0004	0.0004	0.0004
Carbon Dioxide	82.5562	95.3324	95.3324	95.3324	95.3324	95.3324	95.3324	95.3324	95.3324
Nitrogen	12.2772	3.0140	3.0140	3.0140	3.0140	3.0140	3.0140	3.0140	3.0140
Argon	1.7877	0.5631	0.5631	0.5631	0.5631	0.5631	0.5631	0.5631	0.5631
Oxygen	3.3728	1.0872	1.0872	1.0872	1.0872	1.0872	1.0872	1.0872	1.0872
Sulphur Dioxide	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Nitrogen Oxide	0.0058	0.0028	0.0028	0.0028	0.0028	0.0028	0.0028	0.0028	0.0028
Temperature, °C	-53.71	-53.71	-29.09	-37.55	-28.05	-24.00	11.22	65.17	25.00
Pressure (bara)	29.70	29.70	30.00	16.99	16.99	16.89	16.79	30.00	30.00
Material selection	304L	304L	LTCS	LTCS	LTCS	LTCS	CS	CS	CS
NOTES									

Corrosion Loops	**VENT**						**OTHERS**			
Process Streams	**VEN1**	**VEN2**	**VEN3**	**VEN4**	**VEN5**	**VEN6**	**Recirc Loop DeSOx**	**WWA2**	**Recirc loop De-Nox**	**WWA3**
Component, mol %										
Water	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	90.0515	90.0515	69.0300	69.0300
Carbon Dioxide	25.7442	25.7442	25.7442	6.0514	6.0514	6.0514	8.4304	8.4304	0.0149	0.0149
Nitrogen	53.4674	53.4674	53.4674	73.7291	73.7291	73.7291	0.0047	0.0047	0.0034	0.0034
Argon	7.2333	7.2333	7.2333	9.8255	9.8255	9.8255	0.0006	0.0006	0.0005	0.0005
Oxygen	13.5360	13.5360	13.5360	10.3636	10.3636	10.3636	0.0012	0.0012	0.0009	0.0009
Sulphur Dioxide	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	1.5116	1.5116	0.0000	0.0000
Nitrogen Oxide	0.0190	0.0190	0.0190	0.0304	0.0304	0.0304	0.0000	0.0000	30.9503	30.9503
Temperature (°C)	-53.71	-24.61	11.22	11.22	300.00	4.91	30.00	30.00	102.69	102.69
Pressure (bara)	29.70	29.68	30.00	30.00	29.50	1.10	0.00	0.00	0.00	0.00
Material selection	304L	LTCS	CS	CS	CS	CS	GRP	GRP	316L	316L
NOTES										

Corrosion Loops	**CO_2 EXPORT**										
Process Streams	**EXP1**	**EXP2**	**EXP3**	**EXP4**	**EXP5**	**EXP6**	**EXP7**	**EXP8**	**EXP9**	**EXP10**	**EXP11**
Component, mol %											
Water	0.0008	0.0008	0.0008	0.0008	0.0008	0.0008	0.0008	0.0008	0.0008	0.0008	0.0008
Carbon Dioxide	99.9992	99.9992	99.9992	99.9992	99.9992	99.9992	99.9992	99.9992	99.9992	99.9992	99.9992
Nitrogen	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Argon	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Oxygen	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Sulphur Dioxide	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Nitrogen Oxide	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Temperature (°C)	-24.67	-24.67	-29.41	-24.67	-56.00	-25.00	11.20	125.72	40.00	35.63	40.00
Pressure (bara)	16.99	16.99	14.54	16.99	5.30	5.10	5.00	17.45	17.25	150.50	150.00
Material selection	LTCS	LTCS	LTCS	LTCS	304L	LTCS	CS	CS	CS	CS	CS
NOTES											

Table 11.14 : Material selection table for Oxy-fuel combustion equipment (high CO_2 case)

	RAW CO_2							
Equipment	Comp 1 (RCO1/ 02)	HX 1 (RCO2/RCO3)	De-SOX Reactor	Comp 2 (RCO4/5)	De-NOX Reactor	Mole-sieve driers	Cryogenic 1	Cryogenic 2
Material selection	25Cr SDSS (F55 etc); 6Mo super-austenitic	6Mo super-austenitic clad shell & tube-sheet; 6Mo or 25Cr SDSS tubes	CS + 904L clad or CS + FGV coating	13-4 CrNi martensitic stainless 316L casing	CS + 316L clad	CS + 316L clad	Al heat exchanger	Al heat exchanger
NOTES								

	RAW CO_2						
Equipment	Flash separator	Comp 3 (RCO17/RCO18)	HX2 (RCO18/19)	Distillation column	HX 3 (RCO9/RCO10)	HX 4 (VEN4/VEN5)	Expander (VEN5/VEN6)
Material selection	304L	CS	CS	LTCS	LTCS shell & tubes	CS	CS
NOTES	Operates < - 50°C	dry	Assume coolant is non-corrosive	Dry streams			Hot and dry stream

Corrosion Loop	**Recirculation water**		**CO_2 EXPORT**			
Equipment	De SOx recirc. pump	De NOx recirc. pump	Comp 4 (EXP7/EXP8)	HX 4 (EXP8/EXP9)	Comp 5 (EXP3,9/EXP10)	HX 5 (EXP10/EXP11)
Material selection	Non-metallic (PP)	316L	CS		CS	CS shell & plate, CS tubes
NOTES			Dry stream	assume coolant is non- corrosive	Dry streams	assume coolant is non- corrosive

12 ASPECTS OF MATERIALS SELECTION COMMON TO SEVERAL PROCESSES

12.1 Blowers and Fans

The induced or forced draft booster fans to be used in the atmospheric pressure, high volume flow regime of the Post-combustion capture gas handling systems require special consideration. These fans need to be capable of handling around 500 m^3/s (~ 1 million scfm) of wet gas with high levels of O_2, CO_2 and possibly some residual SO_2 or particulates depending on the fan location. Although the fans are positioned immediately before the absorber in the present study, it is recognised that a more upstream position may be preferred after detailed design.

Table 12.1: Post-combustion Capture Flue Gas at CCS Plant Entry (mol%)

Case	Flow rate	Temp	O_2	Water	CO_2	SO_2
Gas	86370 kmol/hr	110°C	13.0	7.23	3.79	Nil
Douglas Coal	52821 kmol/hr	45°C	3.62	9.62	13.8	0.0035

Table 12.2 : Gases at Absorber Entry (mol%)

Case	Flow rate	Temp	O_2	Water	CO_2	SO_2
Gas	85214 kmol/hr	40°C	13.2	5.98	3.84	Nil
Douglas Coal	49783 kmol/hr	39°C	3.83	4.10	14.7	0.0004

The detailed design of high volume fans is outside the scope of this report. Typically, variable pitch axial fans provide the best efficiency and range of operation [89], while centrifugal fans have good resistance to dust and liquid droplet erosion and are considerably cheaper (about half the price). Since a 500 m^3/s fan may consume 5MW electrical energy the efficiency is an extremely important consideration, especially for a 'green' project. Intermediate designs of fan such as impulse axial fans (fixed blades welded to conical hub) and aerofoil centrifugal fans may provide a cost-effective, more robust solution compared with axial fans. However from a practical point of view centrifugal fans (since they have rectangular section casing) lend themselves to application with rectangular section lined steel ducting while direct drive integral motor axial fans naturally suit the use of circular section filament wound GRP ducting.

For wet air, steel axial and centrifugal fans are normally provided with internal and external epoxy or phenolic coating, and blades are carbon steel or (for axial blowers) ductile cast iron or low alloy steel for erosion resistance. These materials are not suitable for use with CO_2 laden wet gas. For more aggressive purposes, 316L or 22Cr blades are used with coated steel casings, but in FGD applications (after the de-SOx absorber and when cooled to below 50°C) rotors should be higher chromium stainless steel and the cases and shafts may be lined with rubber or flake glass vinylester (FGV). 25Cr austenitic alloys such as S34565 (WN1.4565) are also used, and at least one manufacturer [90] prefers all duplex 25Cr for good fatigue, corrosion, erosion resistance, robustness and long life, with solid 25Cr welded casing and shaft lining in the same material. 25Cr materials would be more resistant to solids and residual SOx so the placement of such blowers would not be a vital consideration.

The final choice of material will depend on the balance between capital and operational expenditure, since the use of lower chromium stainless steel blades and linings will inevitably cost down-time which may stop production.

12.2 Ductwork

The incoming flue gases from the Oxy-fuel combustion and Post-combustion capture process are low pressure, large volume flows (in excess of 400 kg/s for the Post-combustion capture case) and will be handled by ducting rather than piping. On the exit side, the CO_2 stream from the CO_2 stripper in the Post-combustion capture schemes, and the low-pressure acid gas streams in the Pre-combustion capture schemes may also be handled in ducting.

A typical duct section in FGD plant (e.g. Neurath A/B/C) may be as much as 9.8 m x 6.4 m [58] for each 300MW unit (most power stations have a separate FGD unit for each generator block so that maintenance can be scheduled). Mild steel is the usual structural material with external stiffening and support structure, except for necessary internals such as demisters, deflectors or spray-nozzle supports, with internal surfaces kept as flat and smooth as possible to allow for rubber lining, flake-glass vinylester coating (FGV) or CRA wallpapering.

The choice of ducting protection depends on several factors, but the prime factor is usually cost, as the corrosion protection is an expensive item. Where maintenance (scheduled or unscheduled) can be tolerated the selection of non-metallic lining is more acceptable and FGV is considered to be the preferred lining option for moderate temperature use, with an expected service life of about 10 years. As noted in section 7.2.2 above, inferior or badly applied coatings have sometimes required much shorter intervals before repair or replacement.

Metallic lining has higher initial cost, but if correctly fabricated would cover the full design life (25 years). Large diameter filament wound glass reinforced plastic (GRP) pipe also has initially larger capital outlay than FGV-lined ducting but is expected to last the 25 year design life without major maintenance. GRP duct is currently only available as standard up to around 4m diameter but larger sections may be filament wound in-situ.

Metallic lining is necessary for high temperature ducts exiting the CO_2 stripper in the Post-combustion capture processes (stream CD1). The presence of trace amine makes metallic lining advisable for this stream after cooling (CD2).

12.3 Compressors

Compressors are typically provided by specialist suppliers, who are responsible for design, materials selection and the equipment performance. There is extensive experience in compression of CO_2 in fertiliser plants and other applications, in oil and gas service [91], and also in a limited number of CO_2 injection projects, including the Weyburn and Statoil operations [92]. ISO 10439 (formerly API 617) [93], Annex B lists well-established materials from oil and gas experience. Based on the flow rates to be handled, multi-stage centrifugal compressors are expected to be the leading technology for full-scale CCS projects.

Compression depends on microns clearance between impeller and casing diaphragm so the design basis requires minimal wear or corrosive damage. Compressor operating conditions are intended to be dry, the presence of droplets risks serious erosion damage to the high-velocity moving parts, but CRA materials are usually selected for conditions which are potentially corrosive, for example to cover downtime conditions when condensation may occur. Martensitic stainless steels are often the materials of choice for impellers and shafts where practical due to their combination of moderate cost, some corrosion resistance and the ability to achieve high strengths by heat-treatment.

The CO_2 export streams are expected to be relatively clean, with minimal levels of salts, solids or sulphur oxides. In particular, the low chloride conditions greatly reduce the risk of pitting or stress-corrosion in martensitic stainless steels. Despite the high CO_2 contents, the conditions are therefore not particularly aggressive. The oxy-fuel CO_2 export stream is dried before entering the compressor train, so low alloy steels can be used throughout. In the other two processes, the export CO_2 stream contains significant amounts of water at the entry of the compressor train, so CRAs are necessary for start-up / shut-down conditions. Low alloy steels can be used for the final stages after the dehydrators.

Martensitic stainless steels, for example 13Cr-4Ni grades, are suitable for rotors, impellers and shafts where high strength and wear resistance is necessary. More highly alloyed precipitation-hardening stainless steels, such as 17-4 PH and A286, or precipitation-hardening nickel alloys may also be used. Austenitic or duplex stainless steels are suitable for interconnecting piping, casings and liners. High Ni alloys are not expected to be necessary for the CCS export stream compressors.

Conditions are potentially more severe for the two upstream compressors in the oxy-fuel combustion process, which operate with FGD flue gas before and after the de-SOx reactor.

Materials compliant with ISO15156 / NACE MR0175 will be necessary for the Pre-combustion capture coal case due to the levels of H_2S present.

13 PIPELINE TRANSPORT

13.1 Experience with CO_2 Trunk Pipelines

Pipelines are expected to be the most practical and cost-effective means of CO_2 transport for full-scale CCS.

The accepted basis of design for long-distance trunk pipelines is to use carbon and low alloy steels, and operate the pipeline system with dry, water-free internal conditions.

There are over 3,100 miles of long-distance CO_2 pipelines in the USA, transporting over 44 million tonnes of CO_2 per year. The earliest significant CO_2 pipeline system was the Canyon Reef (SACROC) system which started up in 1972. This takes CO_2 from gas processing plants for injection into oil reservoirs to increase oil production, Enhanced Oil Recovery (EOR). Starting in the 1980's, CO_2 from geological CO_2 reservoirs in Colorado, New Mexico, Wyoming and Mississippi began to be used for EOR projects. More recently, the EnCana Weyburn project delivers CO_2 from a coal gasification plant in North Dakota to the Weyburn field in Canada.

Current US and Canadian regulations do have specific requirements for CO_2 pipelines and both classify CO_2 with "hazardous materials". However, many of the older CO_2 pipelines in North America were designed before these current regulations were introduced. Typically, standard API 5L linepipe materials have been used [94]. In recent years the issue of resistance to propagation of long running ductile fractures in CO_2 pipelines has received more attention (see section below). Some older CO_2 pipelines in the US have been retro-fitted with mechanical crack arrestors due to the lower Charpy energies typical of pipeline steels used at the time of their construction. Note that there are no reported service instances of long-running ductile fractures in CO_2 pipelines. Table 13.1 lists some of the most significant onshore CO_2 pipeline systems.

Table 13.1 : Some Major Onshore CO_2 Pipelines [95,96]

Name	Operator	Length & size	Year of first operation	CO_2 Origin
Canyon Reef	Kinder Morgan	140 km x 16" 133 km x 10"	1972	Gas processing plants
Bati Raman (Turkey)	Turkish Petroleum	90 km	1983	Natural CO_2
Cortez	Kinder Morgan	808 km x 30"	1984	Natural CO_2
Sheep Mt	Oxy Permian	195 km x 20" 360 km x 24"	-	Natural CO_2
Bravo	BP	350 km x 20"	1984	Natural CO_2
Bravo - Postle	Transpetco	195 km x 12.75"	1996	Natural CO_2
Val Verde	Petrosource	130 km x 10"	1998	Gas processing
Weyburn	North Dakota Gasification Co	320 km, 14" & 12 "	2000	Gasification plant
Central Basin	Kinder Morgan	224km x 16"-26"	-	Natural CO_2

Other projects handling large quantities of nearly pure CO_2 include BP Salah project (Algeria) and Statoil Snovit (offshore, North Sea).

Operational experience of the US CO_2 trunk pipelines has been generally good. From 1986 to 04/2009 the US Office of Pipeline Safety recorded only 15 "significant" incidents related to CO_2 pipelines, none of which resulted in fatalities or injuries, Table 13.2, according to the OPS definitions, these incidents were classed as "significant" due to the quantity of CO_2 released. The majority of incidents were related to ancillary equipment rather than the pipeline itself [97].

Table 13.2 : Significant Incidents on US CO_2 transmission pipelines 1986-2009

Classification	Number	Comments
Control & relief equipment malfunction	6	Mostly related to relief valves
Welds	3	butt weld on pump, construction defect girth weld in pipeline, construction defect ERW seam weld in pipeline, 1" rupture, material defect
Valve seal / packing	2	
Other	2	Pipe nipple broken Pipe coupling at valve
External corrosion	1	Corrosion of bolts on relief valve equipment
External damage	1	

No instances of leaks due to internal corrosion are recorded. Corrosion problems have been reported in metering and ancillary equipment due to hydrotest water not being fully removed.

13.2 Pipeline Design

Table 13.3 lists the compositions of the fluids entering the pipeline for the different cases modelled. The nominal operating conditions are 150 bar and 40 °C at the pipeline inlet.

Table 13.3 : Pipeline Entry Stream Compositions, mol%

	Past Combustion (Douglas)	Oxy-Fuel (High CO_2)	Oxy-Fuel (Low CO_2)	IGCC (Coal co-capture)	IGCC (coal separate capture)
Carbon Dioxide	99.9687	99.9992	96.4933	97.1788	98.6778
Water	0.01	0.0008	0.0008	0.02	0.02
Oxygen	0.0018	0	0.785	0	0
Nitrogen	0.0189	0	2.3066	0.4309	0.436
Sulphur Dioxide	1.48E-06	0	0	-	-
Argon	0.0005	0	0.4127	0.0005	0.0004
Carbon Monoxide	-	-	-	0.3294	0.2244
Hydrogen	-	-	-	0.7642	0.6399
Nitrogen Oxide	-	0	0.0016	-	-
Hydrogen sulphide	-	-	-	1.2762	0.0015
Temperature (°C)	40	40	40	40	40
Pressure (bara)	150	150	150	150	150

The gas-fired Post Combustion stream will be similar to the Post Combustion coal-fired case but without trace SO_2.

The recommended basis of design is to use carbon and low alloy steels, and operate the pipeline system in dry, water-free internal conditions.

Pipeline design for carrying hydrocarbon liquid and gas is well established, but the properties of CO_2 compared with hydrocarbons mean there are some significant differences in the requirements for CO_2 pipelines. The main issue is the greater requirement for material toughness to prevent long-running ductile fracture in CO_2 pipelines compared with natural gas pipelines.

There are also specific materials requirements depending on the details of the fluids being carried in the different Design Cases.

13.2.1 Internal corrosion risk

The background to the corrosion risks to carbon steel from CO_2 and the various contaminants in the gas streams are discussed in detail in Chapter 6.

Provided that the gas stream is dried adequately before entering the pipeline so that there is no free water phase, there will be no general or localised corrosion of carbon steel. The lack of corrosion of carbon steel by dry CO_2 is well established in practice. As an example, export gas flowlines typically transport natural gas with CO_2. Corrosion risk is mitigated by reducing the gas water content to a dewpoint typically 10ºC lower than the lowest temperature reached by the pipeline in service. Pipelines have given service lives in excess of 40 years if well managed to prevent unplanned water ingress [98]. This approach has also been proved effective in eliminating corrosion in existing CO_2 trunk pipelines and there are no reports of internal corrosion failures in these lines.

Similarly, without a free water phase, there is no risk from other failure mechanisms involving internal corrosion including stress-cracking, hydrogen embrittlement, hydrogen induced cracking (HIC) or sulphide stress corrosion (SSC).

The degree of dehydration should be sufficient to prevent free water and hydrates from forming in the pipeline under all operating conditions including shut-ins and decompression events: see section (6.3). Water content limits adopted for existing CO_2 pipelines vary and to some extent reflect the CO_2 source, but are generally somewhat higher than the maximum water content of 0.02 mol% in the present CCS design cases. Major US CO_2 pipeline operators specify maximum water limits of around 25-30 lb / MMscf, corresponding to approximately 0.05 – 0.06 mol%. Initial dewatering and drying operations and continuous monitoring are essential to ensure dry conditions are achieved and maintained. These issues are covered in section 13.2.6 below.

It is prudent to include a minimal corrosion allowance of, say, 1.5 mm to allow for any short-term upset conditions that may arise over the lifetime.

In dry conditions, there is no issue with hydrogen sulphide in the fluid causing sulphide stress corrosion cracking or HIC (regardless of the actual H_2S level) as both mechanisms require some corrosion attack to generate hydrogen. In the event of free water being present, the level of H_2S becomes relevant. SSC cracking can be rapid in susceptible material (cracking may occur within hours to a few days), so short-term events are potentially hazardous. ISO 15156-2 / NACE MR0175 requires special sour service resistant carbon steels to avoid sulphide stress cracking at H_2S partial pressures of 0.05 psi and above.

13.2.2 Non-metallic Components

Depending on the valve designs selected, polymer seals may be required. Many polymers are susceptible to swelling and changes in physical properties due to absorption of CO_2. There may also be short-term exposure to methanol or glycol during pipeline dewatering operations at start-up.

Chemical aging is not considered a significant risk due to the moderate temperatures and low levels of species which can cause chemical aging in the pipeline fluid, such as H_2S, except in the IGCC Co-capture case. There may be short term exposure to low levels of biocide and oxygen scavenger during hydrotesting, again this is not considered to present a serious problem.

Polymers from various classes have been reported as suitable for liquid CO_2 service including EPDM, HNBR, PTFE and FKM (Viton®). There can be great differences between in the performance of different elastomer formulations in the same general class and it is recommended that advice is taken from suppliers before selecting specific elastomer compounds.

13.2.3 Fracture Control

Design against long-running fracture in pipelines is based on the ability to arrest running cracks, rather than avoiding crack initiation.

Brittle fractures propagate at extremely high speed, and much faster than decompression of the pipeline contents. Hence, the driving force for brittle fracture is essentially the initial pressure in the pipeline and brittle fracture propagation is basically independent of the properties of the fluid in the pipeline. Brittle fracture has been extensively studied by the industry, leading to the development of the drop-weight tear test (DWTT) as a quality control and specification requirement. This design approach is considered to be adequate to avoid brittle fracture in CO_2 pipelines and is incorporated in pipeline codes such as API 5L / ISO 3183:2007.

The second possible type of fracture is a ductile fracture (also referred to as shear fracture). If a defect exceeds the critical size for the material and stress level, a crack may propagate along the pipeline driven by the hoop stress and internal pressure. Ductile crack propagation is slower than that of brittle cracks, and the driving force for cracking may be reduced by decompression of the fluid and resulting reduction in hoop stress at the crack tip. The properties of CO_2 are such that the internal pressure during decompression remains at a higher level for longer than (for example) with methane. This results in greater forces being exerted at the crack tip and a greater risk of ductile crack propagation [99].

13.2.3.1 Effect of Fluid Composition

In the normal operating conditions of CCS pipelines, CO_2 will be a liquid or a supercritical fluid, depending on the temperature. On decompression, it will initially behave as a single phase, until the state reaches the gas / liquid phase boundary. At this point a nearly constant pressure is maintained until the liquid phase is finally exhausted: this is called the "*saturation pressure*". It is this pressure which provides the sustained driving force in ductile crack propagation. In the final stages of decompression there is only gas present and the pressure drops to zero.

In the worst case, the saturation pressure can not be greater then the critical pressure, 73.8 bar and 30.9°C for pure CO_2. Because CO_2 pipelines operate near the critical temperature and above the critical pressure, it is likely that some possible conditions within the design envelope will in fact result in crossing the phase boundary at or very close to the critical pressure. As a simplification, therefore the critical pressure can be used as an upper bound estimate of the saturation pressure.

The position of the phase boundaries and critical point will be affected by minor components of the gas mixture. Impurities generally open up a two phase region between the gas and liquid fields and increase the pressure at the phase boundaries compared with the pure CO_2 case. Nitrogen, methane and hydrogen have particularly adverse effects by increasing the phase boundary pressure and therefore the saturation pressure. H_2S is reported to have little effect in quantities expected in the pipeline fluids.

13.2.3.2 Toughness Requirements

Ductile crack propagation has been studied extensively for pipes containing methane and also "rich" natural gas mixtures, which have some similarity with CO_2 in their decompression behaviour. The standard means of mitigating the risk is too specify an adequate toughness, in terms of Charpy V-notch test values. If this is impractical, then various forms of mechanical crack arrestors may be used.

The required level of toughness to arrest ductile fracture can be calculated using the Battelle Two Curve model (BTC) [100]. This model is based on and has been validated against, full scale testing data from a range of linepipe steels. The BTC correlation between Charpy energy and arrest stress is recognised to become unreliable for very high toughness pipeline steels and for very high strength (X80, X100) grades [101]. One factor is undoubtedly the short-comings of the Charpy impact test method as a simulation of full-scale fracture behaviour. Unfortunately, no alternative prediction method and has yet been proved reliable and accepted. The BTC approach is included as an option in the current API 5L / ISO 3183:2007 linepipe specifications.

Note that UK and European regulatory authorities have indicated that they will require some full-scale burst testing data with liquid CO_2 in order to confirm the validity of the design approach before CCS pipelines are built.

13.2.3.3 Example Calculations

The exact pipeline dimensions will have to be calculated depending on the length, route profile, whether intermediate compression stations are possible etc. The examples of existing CO_2 pipelines suggest that the flowrates of 93–138 kg/s for the modelled CCS cases would be handled by a pipeline of around 16" diameter. Larger lines, say 30-40" diameter could handle output from several CCS units.

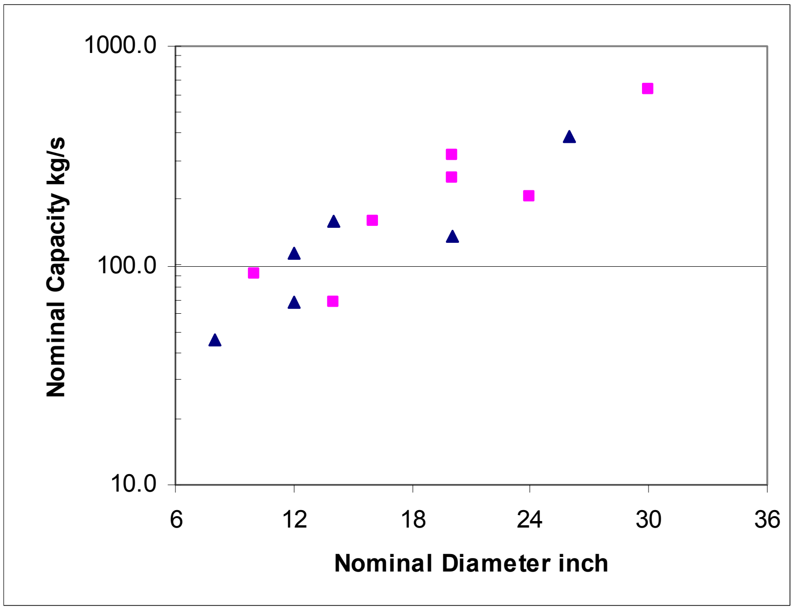

Figure 13.1 : Pipeline Capacity vs Diameter for existing CO_2 trunklines, based on carrying pure CO_2

Results of example calculations in the table below are based on containing a maximum design pressure of 180 bar with a 0.72 design factor. Charpy impact values have been calculated using the BTC model for different saturation pressures with a design factor of 0.72 applied. For a pipeline containing pure CO_2, in the worst case, the driving force for ductile fracture (the saturation pressure) is the same as the critical pressure, 73.8 bar.

Table 13.4 : Calculated Minimum Charpy Energies (0.72 design factor) for X60 linepipe, BTC method

Pipe Dimensions	**16" x 12.7mm**	**30" x 25.4mm**
Fluid Saturation Pressure, bar		
70	63	100
73.8	75	118
80	101	153

Modern pipeline steels produced from controlled-rolled plate or coil can typically achieve average upper-shelf Charpy toughness values in excess of 100 J (and often in excess of 200 J) in the parent material. Resistance to ductile fracture in CO_2 pipelines, therefore, can be achieved with realistic values of pipe properties and dimensions. The examples above show that, according to the BTC model, it is more difficult to achieve ductile fracture resistance in larger diameter pipe (i.e. a higher Charpy toughness is needed). In some cases it may be necessary to have a slightly greater wall thickness to ensure adequate resistance to fracture than would otherwise be necessary based on the hoop stress or other design requirements. High resistance to ductile fracture is favoured by high thickness: diameter ratio, and other factors which have the effect of requiring a larger wall thickness (such as low design factors, high operating pressures, low material strength)

There is not much benefit in specifying Charpy values above around 100 - 150J, as the resistance to fracture predicted by the BTC formula approaches a limiting value, and the method itself also becomes less reliable. In the case of CO_2 pipelines, the minimum wall thickness is eventually limited by crack arrest requirements rather than static hoop strength, so that beyond a certain point, high strength steels do not allow any material savings. Based on present design codes, there is unlikely to be any benefit in using strength grades beyond X60 - X65 for CO_2 pipelines in most cases.

Note that, the pipeline operating pressure does not directly affect the toughness requirements for resistance to ductile fracture: the requirement is determined by the phase boundary or saturation pressure. This implies there is no penalty in this respect to increasing the operating pressure of a pipeline.

13.2.4 Material selection

The main standards for pipeline steel are ISO 3183:2007 / API 5L and EN 10208 [102]. ISO 3183 / API 5L includes optional requirements for enhanced toughness and for sour service resistance not present in EN 10208, and is therefore considered to be the more appropriate for CO_2 transmission pipelines. Pipeline steel should be in accordance with ISO 3183:2007 / API 5L to product specification level (PSL) 2. The following optional requirements should be specified:

- Qualified Manufacturing Procedure (Annex B);
- Resistance to Ductile Fracture Propagation (Annex G), using approach 3 (the BTC model);
- and, if applicable, Offshore Service (Annex J).

If the H_2S content in the pipeline fluids is high enough to exceed the ISO 15156 limit of 0.05psia, then Sour Service (Annex H) should also be specified: this applies to the Pre-combustion co-capture case. The pipe material will therefore be a high quality linepipe, similar to those currently used for demanding off-shore and sour-service applications.

Depending on the pipeline dimensions, submerged-arc welded (SAW), high-frequency induction (HFI) welded or seamless pipe may be considered. Most trunk lines are likely to be too large for seamless pipe. Where high Charpy impact energies are necessary, this is most easily achieved in welded pipe made from thermo-mechanically controlled-rolled coil or plate. Electric resistance welded (ERW) pipe and spiral weld pipe are not accepted under PSL2 and are not recommended.

Pipeline bends may be hot bent, induction bent or cold bent. In all cases, it should be demonstrated that the bend properties are compatible with the pipeline requirements including sour service properties and toughness requirements for resistance to ductile fracture propagation. It may be necessary for bends to be thicker than straight pipe to achieve an adequate arrest pressure.

The demands on CO_2 pipelines as regards girth weld toughness and allowable weld defect sizes are in principle no different than those for hydrocarbon gas pipelines. Pipeline welding should be in accordance with appropriate standards such as BS4515-1:2009 and EN14163: 2001 [103].

Extreme low temperatures may result locally where rapid expansion of CO_2 occurs. Materials in relief valves and flaring equipment should be resistant to low temperatures, for example high-nickel carbon steel or austenitic stainless steels. Flare pre-heaters should be fitted. Bolting in these locations should also be suitable for low temperatures, for example to ASTM A320. Similar considerations apply to ancillary equipment which may be isolated and depressurised.

13.2.5 External corrosion protection

There are no special requirements for protection against external corrosion arising from carrying liquid CO_2. Standard industry practice is to ensure external protection of buried and immersed pipelines by application of pipe and field-joint coatings supplemented by cathodic protection (CP). Typical pipe coatings are either fusion bonded epoxy (FBE), single and dual layer depending on service temperature, or three layer systems consisting of a single layer FBE primer, an adhesive layer and an outer polyolefin layer (polypropylene or polyethylene). For offshore lines, it is normal to use sacrificial anode CP of the close fitted bracelet type; while onshore it is usual to employ a temporary sacrificial system to provide protection during construction and to install a permanent impressed current CP system for through life protection. Applicable standards include ISO 15589 and DNV F103 [104 105]

In the absence of internal corrosion , external degradation is likely to be life-limiting in practice.

13.2.6 General Design and Operational Issues

Particular operational safety considerations with CO_2 pipelines are:

- The asphyxiation risk from leaks or releases, due to CO_2 gathering and displacing oxygen, especially in confined or low-lying areas.
- The potential for violent expansion as CO_2 changes phase (several hundred times expansion on going from liquid to gas phase) and severe local cooling.

CO_2 is heavier than air, so leaks and releases will tend to stay at ground level, and collect in depressions and confined areas. The site of the pipeline and especially locations where personnel may work near the pipeline should be designed to avoid this risk, bearing in mind that the majority of reported leaks have been associated with metering and control equipment. CO_2 itself is odourless and not readily detectable by humans, however some of the possible impurities, in particular H_2S, do have strong odours. If impurities are not at a high enough level to be readily detected, consideration should be given to dosing an odorant marker, as is done with natural gas. Use of sensors for leak detection of CO_2 is made more difficult by the fact that CO_2 is naturally present in air at trace levels.

Release of high pressure CO_2 can be powerful and can result in extreme low temperatures down to around -90°C. CO_2 ice can form in these conditions, creating a dangerous stream of solid particles in the exhaust gas or blocking piping. Deliberate blow-downs should be over longer times than normal for natural gas lines to control temperature drops. Vent pre-heaters are recommended and the use of materials resistant to low temperatures in vent equipment, such as high nickel carbon steel or austenitic stainless steel. Vent points should be positioned to avoid impingement of cold gas on nearby equipment or structures and to enable adequate dispersion of the gas.

Levels of H_2S in particular may present additional environmental and safety issues: this is discussed in more detail in section 13.2.7.1 below.

13.2.6.1 Start-up

The principal activities in preparing a pipeline for operation include cleaning and gauging; hydrotesting; dewatering and drying. Cleaning, gauging and hydrotesting should follow standard industry practices.

Because of the high corrosion rates expected with free water present, the pipeline should be very thoroughly dewatered and dried prior to introducing CO_2. Typically, methods will involve a combination of running foam swabs, followed by slugs of methanol or glycol, and purging with dry air or nitrogen. Care should be taken to avoid leaving water in any valve cavities, side branches, attached instrumentation etc.. The quality of this initial dewatering and drying is safety critical.

Feeding high pressure CO_2 into a section of line at lower pressure could potentially lead to severe cooling on expansion of the fluid through the valve etc. Start-up procedures should be designed to avoid rapid gas expansion so far as possible and gas injection rates when starting up should be controlled to ensure the gas temperature does not drop below the allowable limits for the materials of the pipeline and fittings.

13.2.6.2 Pigging operations

Running pigs in CO_2 pipelines has been problematic: CO_2 has poor lubricating properties so it may be necessary to add a lubricant such as diesel oil; also CO_2 is readily absorbed by many polymers causing expansion and/or change of properties of materials in the pig. However, with no free water present and no corrosion, running cleaning pigs in normal operation is unnecessary.

In the absence of progressive corrosion attack, intelligent pigging to monitor internal corrosion is also arguably superfluous. However, regulatory authorities are likely to require pigging capability to be available and measurement pigs to be run at intervals to confirm the lack of corrosion (for example, Canadian authorities have required intelligent pigging of CO_2 pipelines every five years). In the case of accidental water ingress, measurement pigging may be part of an assessment of fitness for continuing operation. Intelligent pigging can also have a role in monitoring external corrosion protection, especially in hard to access locations. Suitable pig launchers and receivers should be installed.

13.2.6.3 Monitoring

As internal corrosion would be rapid in the event of water ingress, continuous monitoring is necessary to confirm dry conditions are maintained. This should start with dew-point monitoring of the inlet fluid. In the pipeline, sensitive electrical resistance (ER) probes are suitable for detecting the presence of water and corrosive conditions. Electrochemical methods are also possible, but as most of the time the expectation is for dry conditions, and therefore an open circuit state, there is an issue with distinguishing this from an equipment fault. Resistance probes do provide a positive measurement response (the wire resistance) in dry conditions. CO_2 is generally less dense than water in the range of pipeline operating conditions, but may be denser at high pressure and low temperature, so probes at both top and bottom of line are recommended. Monitoring positions should include the coldest section of the pipeline, probably the delivery end or an exposed, above ground section.

The requirements for monitoring and control of external corrosion are in principle no different than those for pipelines carrying hydrocarbon gas or other hazardous contents. Coating breakdown or damage will result in changes on the demand on the CP system for current, and changes in the current and potential fields around the defect location. This provides the basis for various monitoring and indirect inspection or survey techniques used by the industry to assess coating integrity. An integrity management system will combine background pipeline data, operational and monitoring data and indirect inspection and survey data together with direct inspection of pipeline at a small number of locations. NACE RP0502-2002 [106] details guidance on systems for monitoring, indirect inspection and direct inspections, together with guidance on some inspection techniques.

13.2.7 Specific Design Cases

13.2.7.1 IGCC Coal Co-Capture

The pipeline fluid in this case has a H_2S content of 1.2762 %, equivalent to 1.91 bar partial pressure at 150 bar operating pressure. This is well above the limit of 0.05 psi which defines sour service conditions for carbon steels in ISO15156-2:2003, and sufficient to present a serious risk of both SSC and HIC in susceptible carbon steels. Although normal operating conditions are dry, sour service materials should be specified throughout the pipeline in case of short-term water ingress.

Given that a high specification linepipe steel will be required in any case for fracture resistance, the additional cost for HIC resistant, sour service pipe is expected to be no more than 10 - 20%. Welding procedures should comply with the hardness requirements for sour service in ISO 15156-2 and/or other applicable codes such as BS 4515-1 [107]. Typically, no major changes are needed to normal good welding practices to ensure this. Flanges and other carbon steel fittings should also be in accordance with ISO15156-2. For forgings and seamless fittings this is not onerous, typically being achieved by control of chemical composition.

Where CRAs are used, for example valve trim or control and measurement equipment, they must also comply with ISO15156-3. The most likely sources of water are hydro-test water and condensed water from the gas. It can therefore be assumed that chloride content of any water will be minimal. Temperatures are also moderate. Sour service requirements are therefore not severe for CRAs and exotic alloys will not be necessary: 316/316L stainless steel will be suitable for many ancillary items as chloride levels will be well below the 50 mg/l limit in ISO 15156-3 Table A.2.

The H_2S content presents some risk of chemical aging of polymers, particularly elastomers; these should be specified as H_2S compatible. However, a level of 1.28% H_2S is not particularly high in this regard and it is expected that suitable grades will be readily available.

As regards operations, the H_2S content in this case means that releases are potentially more dangerous than with pure CO_2. There is a significant risk of death from short exposure term to H_2S concentrations of around 500 ppm upwards, meaning that in this case a leakage would be extremely dangerous even if heavily diluted [108]. H_2S has an obnoxious smell which is easily detectable by humans in very low concentrations, well below 1 ppm However, high concentrations can rapidly cause loss of the sense of smell, thus increasing the danger of H_2S releases. Release of significant amounts of H_2S – containing gases is generally not allowed by regulatory authorities.

13.2.7.2 IGCC Coal - Separate Capture

The trace H_2S content present in this case is below the ISO15156-2 limit of 0.05 psia. Sour service carbon steels are not required and there are no special material implications. The level of H_2S is still high enough to be detectable in diluted releases.

13.2.7.3 Oxy-fuel Combustion (Low CO_2)

The high nitrogen content of 2.3% will increase the critical pressure compared with pure CO_2 and raise the phase boundary pressure. This will result in an increase in the fracture arrest capacity needed in the pipeline, and hence either a higher material toughness requirement and/or increased wall thickness. There will also be some reduction in transport efficiency of the fluid compared with pure CO_2 which may require larger pipe sizes or additional / more powerful compression equipment.

13.2.8 Summary

Trunk pipelines carrying liquid CO_2 are in a high risk category because of the possible consequences of a major release of CO_2. This is particularly so for the cases where H_2S is present as a minor component. However, operational experience of a limited number of CO_2 pipelines over nearly 40 years gives confidence that CO_2 trunk pipelines can be designed and operated safely.

The recommended basis of design is to use carbon and low alloy steels, and operate the pipeline system in dry, water-free internal conditions. Achieving a long service life is critically dependent on maintaining dry internal conditions, and on good external maintenance: a 30, or even 50 year life, is entirely possible with best practice. Table 13.5 summarises key materials and operating issues for the pipeline.

Table 13.5 : Key Materials and Related Operating Issues for Pipeline

Issue	Summary of recommendations
Pipeline Steel	Pipe steel to ISO 3183:2007 / API 5L to PSL2 and Annex G. Charpy toughness beyond normal specification values, but within manufacturing capability, will probably be necessary; and possibly extra wall thickness and/or crack arrestors for ductile fracture arrest. Regulatory authorities may require full-scale validation tests for crack arrest.
Compatibility of non-metallic materials with CO_2	Some standard polymer grades may not be suitable. Careful selection of specific grades is necessary.
Sour Service	Sour service carbon steel and CRA materials to ISO 15156 are required for the IGCC Coal Co-capture case.
Low temperatures	Low temperature materials in specific locations where bleeding or flaring of gas is anticipated.
Internal corrosion	Thorough drying before introducing CO_2 Maintain dry internal conditions throughout operation Continuous monitoring of pipeline and inlet fluid Facilities for intelligent pigging
External corrosion	Coating, cathodic protection and integrity management to industry best practices
Other design and operating issues	Site avoiding opportunity for leaks of CO_2 to collect, in so far as possible Odorant marking of fluids Handling release of gases containing H_2S in IGCC Coal cases

14 INJECTION WELLS

14.1 International Experience

There are various ways in which CO_2 can be sequestered and each is associated with different environmental conditions, particularly temperature, pressure, injected gas composition and water composition. This means that care is needed when considering the materials choices which have been made in previous projects, as they may not be relevant to the specific conditions of the present study. As an example, the use of fibreglass and fibreglass-lined tubing has been frequently selected for water-alternating-gas (WAG) injection wells for shallow CO_2 enhanced oil recovery (EOR) projects in the USA. However fibreglass is not suitable above 90 °C and 34 MPa and so this experience could not be generalised to every scenario of injection.

Data has been gathered on the injecting well experience for various CO_2 injection projects, mostly in the USA and from the Norwegian sector. The precise CO_2 -stream composition is not always known, but these projects have generally utilised CO_2 derived either from CO_2 source wells, or extracted from produced natural gas. In either case, the composition would be expected to be of a reducing composition, possibly containing traces of sulphur compounds (H_2S and some mercaptans) rather than any traces of oxidising contaminants. The materials choices used and the experience gained is of interest, but not necessarily of direct applicability to every CCS case.

14.1.1 USA Experience

The summary of the most widely used materials in CO_2-EOR well design and construction in the USA projects is given in the Table 14.1 [109]. It must be borne in mind that the majority of the US experience is in shallower (lower pressure and temperature) conditions and most of the service is WAG, with water of unknown (and possibly varying) quality alternating with periods of dry CO_2 injection. The purpose of the majority of USA CO_2 injection projects is for miscible flood (i.e. tertiary oil production) rather than CO_2 sequestration. Relatively short service lifetimes or frequent component replacement is tolerated in some of these applications.

Table 14.1 : The commonly used materials in CO_2 injection well design and construction - USA projects (mostly WAG service)

Component	Materials
Xmas Tree (Trim)	316 SS, Electroless Nickel plate, Monel
Valve Packing and Seals	Teflon, Nylon
Wellhead (Trim)	316 SS, Electroless Nickel plate, Monel
Tubing	Glass Reinforced Epoxy (GRE) – lined carbon steel; internally plastic coated carbon steel, Corrosion Resistant Alloys (CRA)
Tubing Joint Seals	Seal ring (GRE), Coated threads and collars
ON/OFF Tool, Profile Nipple	Nickel plated wetted parts
Packers	Internally coated hardened rubber, etc. Nickel plated wetted parts; corrosion resistant alloys particularly in old wells to improve sealing to worn casings.
Cements and Cement Additives	API cements and/or acid resistant cements

The most complete record of materials of construction and experience for a CO_2-EOR flood was provided by Chevron after 10 years operation at the SACROC (Scurry Area Canyon Reef Operators Committee) Unit [110,111]. The injection tubing was plastic coated but they had varying degrees of success with different coatings. Epoxy-modified phenolic coating was most successful except where applied too thick (>0.17mm thick) as that resulted in blistering; powder applied epoxy was the most resistant. The average service life for coated tubing was 50 months. They also tested 6 tubing strings with polyethylene liners, and they all failed. The mechanism was attributed to CO_2 permeation of the liner, subsequent deterioration of the adhesive and collapse of the liner by pressure build-up.

Unocal used plastic coated injection tubing in their Dollarhide Unit (WAG) but damage during field installation lead to tubing corrosion problems [112], They also reported problems of leaks at connections. They tried various 8-round thread coupling and thread lubricants including modified seal rings and premium nose-seal couplings, Teflon tapes and Teflon thread lubricant, but all developed tubing leaks. They finally established the use of a modified 8-round coupling with Ryton coating on the threads and a seal ring. They also applied low-speed make up of the connections and rigorous helium testing of each connection to solve the leak problem.

In one of the few continuous CO_2 injection programs (no WAG used), Texaco ran bare carbon steel tubing in CO_2 injection wells since the tubing would not be exposed to water and so no corrosion was expected [113].

Shell also used bare steel tubing for CO_2 injection wells in Mississippi but with modified couplings that had resilient seals to minimise CO_2 leakage to the annulus (Welch).

EnCana operates the Weyburn CO_2 flood (WAG) in Canada. They initially used Alloy 625 clad injection Xmas trees but found them too expensive so changed to internal coatings, many of which failed. [114].

It should also be considered that whilst many of these USA CO_2-floods have been in service since the 1970’s, there is not yet long-term experience of the abandonment (storage) phase of the project life to indicate how the well integrity is maintained over time.

14.1.2 Experience Outside USA

StatoilHydro pioneered the longest-running CO_2-storage project after Norway imposed a tax on CO_2 emissions from its offshore gas and oil sector. Since 1996 it has been using amine solvents to remove the 9% CO_2 from the natural gas extracted from the West Sliepner field. This is injected at about 1m tonnes/yr into a saline aquifer about 800m below the seabed at Sliepner. A slightly smaller scale operation, 0.7 m tonnes/yr, started up in 2006 at its Snohvit field in the Barents Sea, injecting at 2,500 m depth.

For Sliepner (illustrated in Figure 14.1), the tubing material selection was 25Cr duplex stainless steel. The injected gas is essentially sweet but may contain up to 150 ppm H_2S and potentially 0.5-2% ppm of organics (mostly CH4) [115].

Estimating from the saline aquifer depth, the conditions are considered to be within the safe operating envelope of 25Cr duplex, bearing in mind that there are no oxidising acid species.

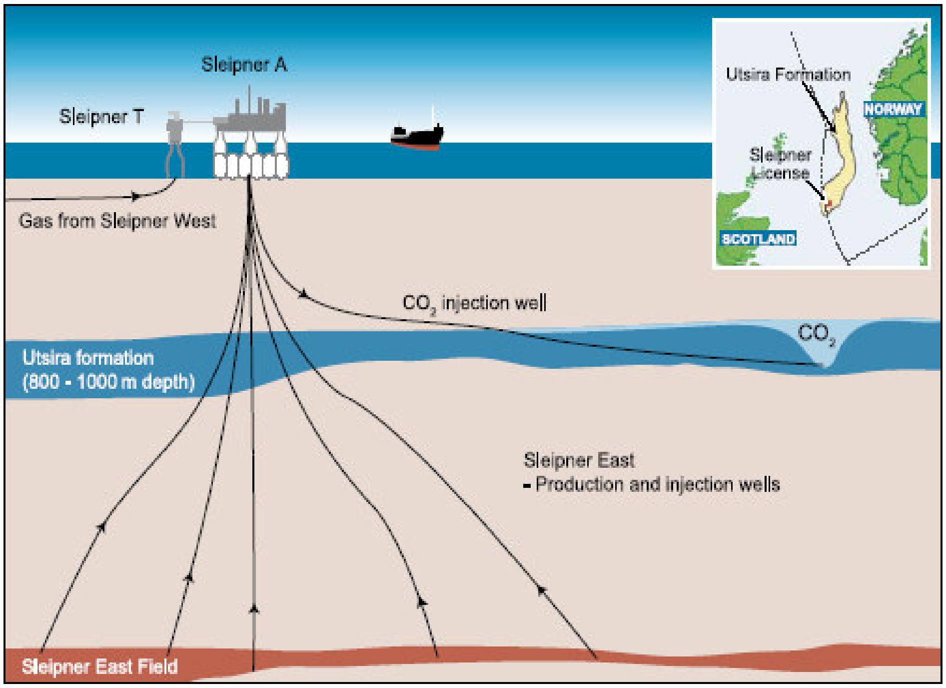

Figure 14.1 : Simplified diagram of the Sleipner CO_2 Storage Project. Inset: location and extent of the Utsira formation.

For Snohvit the tubing was AISI 4140 with all completion components in 25Cr duplex stainless steel. The choice of 4140 is unusual and possibly driven by low temperature fracture considerations, but this is not certain. The deepest well components are all reported to be 13Cr quality [116] but Sumitomo Metals confirmed that they supplied 25Cr duplex stainless steel for the liner for the well. The gas composition and aquifer composition are not known, but, like Sleipner, there would be no oxidising acid components from this offshore source.

14.1.3 Summary

The key conclusions to be drawn from the above CO_2 injection well experience are:

- There is mixed performance of various polymeric linings at high pressure conditions. For deeper wells with >350 bar at bottom hole conditions, linings would not be recommended because of concerns of blistering.
- Whilst the WAG service typical of many USA wells results in particularly aggressive intermittent wet and dry service at the bottom of the well, the experience in several cases of corroded liners and casings is an indication that the conditions *would be* aggressive in CCS service if the aquifer flowed back to the well-bore over time (e.g. during prolonged well shut-in, or at abandonment). Thus, selection of Corrosion Resistant Alloys for the bottom of the well would be advised, following the approach taken by StatoilHydro.
- High performance tubing connections are necessary to minimise the risk of CO_2 leaks to the annulus.
- Materials selection used in existing CO_2 injection projects has often been 25Cr duplex stainless steel, but that may not be applicable where the components in the injected fluid stream are more acidic or oxidising. 25Cr duplex stainless steel will depassivate at pH2.

14.2 Defining the Well Corrosivity

As discussed in Section 6.3 the injected fluid is dry and non-corrosive, so during the injection phase the well is not subject to corrosion and standard low alloy carbon steels could be used for all the well components, considering only the injection phase of the well life. Injection of fluids is assumed, ideally, to push back the aquifer waters during the well life creating a dry, non-corrosive zone around the immediate well bore. However, such an ideal scenario may not exist at all stages of the well life.

It has to be assumed that at the interface of the brine and the injected fluid within the formation, there will be a rapid dissolution of CO_2 and other injected components into the water phase. The reservoir brine (formation water) will change in composition as a consequence, depending upon its initial composition, but undoubtedly becoming more corrosive as its pH drops.

Scenarios that have to be considered are the possibility of corrosive water contact with the bottom of the tubing during any periods of well shut-in or long term abandonment when the lack of injection may allow the reservoir brine to move back towards the well bore. At bottomhole temperature conditions the estimated corrosion rate of carbon steel in contact with an aqueous phase completely saturated with CO_2 would be around 5-8 mm/y assuming slow (0.1 m/s) flow conditions. Given the effectively infinite supply of corroding species (dissolved CO_2) it is expected that this corrosion rate would be sustained (i.e. it would not stifle as it does in a confined volume of fluid), resulting in rapid loss of the exposed section of any carbon steel injection tubing below the packer.

On completion of the injection period when the well is abandoned to long term storage the tubing may be removed and the well capped, and therefore continued resistance to well fluids over the long storage term would not be a necessity in this scenario. If it is intended that the tubing is kept in place during the abandonment phase then it may be necessary to consider CRA material for the whole tubing if it is envisaged to be totally exposed to the aggressive water over the long term. This decision needs a more complete understanding of the long-term well–life scenario on a per project basis.

The material selection of the critical well components in the bottom of the well is driven by the environment composition which is achieved when the injected gas dissolves in the initial fluid present. The corrosivity is driven by the temperature, the chloride content and the pH of the resulting solution.

14.2.1 Injection Fluid Composition

The gas composition is dependent upon the method of CO_2 extraction process with compositions in the compressor outlet streams indicated in Table 14.2 below.

Table 14.2 : Typical export CO_2 composition (mol%) from various combustion processes

	Post-combustion capture (Coal)	**Oxy-Fuel (High CO_2)**	**Oxy-Fuel (Low CO_2)**	**IGCC (Coal co-capture)**	**IGCC (Coal separate capture)**
Carbon Dioxide	99.9687	99.9992	96.4933	97.1788	98.6778
Water	0.01	0.0008	0.0008	0.02	0.02
Oxygen	0.0018	0	0.785	0	0
Nitrogen	0.0189	0	2.3066	0.4309	0.436
Sulphur Dioxide	1.48E-06	0	0	-	-
Argon	0.0005	0	0.4127	.0005	.0004
Carbon Monoxide	-	-	-	0.3294	0.2244
Hydrogen	-	-	-	0.7642	0.6399
Nitrogen Dioxide	-	0	0.0016	-	-
Hydrogen sulphide	-	-	-	1.2762	0.0015
Temperature (°C)	40				
Pressure (bara)	150				

The gas-fired Post Combustion export stream will be similar to the Post Combustion coal-fired case but without trace SO_2.

The components of interest are:

- CO_2–controls the basic material selection
- H_2S shifts the choice of materials significantly because of risk of pitting and/or hydrogen loading
- O_2 introduces a pitting risk
- SO_2 and NO_2 make the environment more acidic

14.2.2 Brine Composition

Injection may be into either a depleted gas reservoir or a saline aquifer. The depleted reservoir rock will be filled with formation water, the composition of which may vary significantly, but is typically 20 – 120 g/l chloride ion content. Typically formation waters in carbonate rocks are close to saturated in bicarbonate ions, usually 1500 - 2500 ppm although some waters (from sandstones) may be very low in bicarbonate ion concentration.

A saline aquifer could be considerably more concentrated in composition. Example compositions have 150 – 200 g/l chloride ions with varying bicarbonate ion content depending upon the rock type from 0 – 2500 ppm.

14.2.3 Wellhead and Bottomhole Conditions

The temperature and pressure conditions at the bottomhole conditions will depend primarily on well depth. Table 14.3 suggests possible ranges.

Table 14.3 : Estimated Wellhead and Bottomhole conditions.

WHT, °C	Ambient
WHP, bar	120–150
BHT, °C	70–120 °C
BHP, bar	400–500

It is not considered likely that bottomhole temperatures will exceed 120 °C.

14.3 Matrix of Conditions and Corresponding Tubing Material Selection

Depending upon the compressor outlet gas composition, and the type of brine (chloride concentration) that is present in the reservoir, the materials choice is indicated in Table 14.4. For materials for downhole well components, relatively high strength materials are needed. The alloys proposed below are all available in high strength forms, either through heat treatment (13Cr, S13Cr) or by cold working, to yield strength typically 80ksi–120ksi.

Table 14.4 : Materials Selection Matrix for Different Downhole Environments

	Mol%	**Post Combustion (Douglas)**	**Oxy-Fuel (High CO_2)**	**Oxy-Fuel (Low CO_2)**	**IGCC (Coal co-capture)**	**IGCC (Coal separate capture)**
	Carbon Dioxide	99.9687	99.9992	96.4933	97.1788	98.6778
Contaminants present	Oxygen	0.0018	0	0.785	0	0
	Sulphur Dioxide	1.48E-06	0	0	-	-
	Hydrogen	-	-	-	0.7642	0.6399
	Nitrogen Dioxide	-	0	16 ppm	-	-
	Hydrogen sulphide	-	-	-	1.2762	0.0015
Chloride <50,000 ppm		Alloy 625	13Cr	Alloy 625	Alloy 28/ Alloy 825	22Cr
Chloride > 50,000 ppm		Alloy C276	S13Cr/ 22Cr	Alloy C276	Alloy 28/ Alloy 825	22Cr

The CO_2 stream with the least contaminants, oxy-fuel, can be handled using the standard API 13Cr grade in most formation waters (chloride content <50,000 ppm). This selection assumes that the oxygen content is actually zero as indicated in Table 14.4. In the higher concentration saline aquifers the higher alloyed proprietary Super-13Cr material is needed, or 22Cr duplex stainless steel.

If there is also some trace hydrogen sulphide present (e.g. IGCC Coal Separate Capture), then this strongly encourages pitting and the 13Cr/S13Cr options are no longer suitable; 22Cr duplex stainless steel is needed.

At higher levels of H_2S the pitting risk is increased and the high alloy stainless steel, Alloy 28 or the nickel Alloy 825 are needed.

In the most severe conditions with oxygen present or oxidising acid gases (SO_2, NO_2) it is necessary to change to the highly pitting resistant, high molybdenum content nickel alloys such as Alloy 625 and, at high chloride content, Alloy C276. These would also be needed in the oxy-fuel combustion case if the oxygen content was not actually zero.

Chemical oxygen scavenging could be investigated as a means of removing very low trace levels of oxygen. Traditional scavengers operate in an aqueous phase, but volatile organic oxygen scavengers are also used for dry steam, for example carbo-hydrazine [117]. Some existing scavenger chemicals would be unsuitable as the reaction products include water. Specific chemicals would need to be developed for use with liquid and supercritical CO_2.

14.3.1 Wellhead and Xmas Tree

Corrosion mitigation and monitoring for the wellhead and Xmas tree can be summarised as followed:

- No corrosion risk (dry service)
- AISI 4130 low alloy carbon steel with 27J Charpy impact toughness specified at -60 °C

- AISI 316 stainless steel trim
- Corrosion monitoring by visual (boroscope) inspection of any removed valves, or of removed tree during any maintenance, repair or well workover. Frequency – intermittent, as opportunity arises.

The injection fluid is completely dry at wellhead conditions and so standard low alloy carbon steel (AISI 4130) Xmas tree and wellhead equipment would be completely safe for a CO_2 injection well. The selection of AISI 4130 is made because of the need to specify good toughness to minimise the risk of brittle fracture in the event of a major CO_2 leak or blowout. The more usual AISI 4140 material has higher carbon content and it is harder to achieve the required fracture toughness requirement. AISI 316 stainless steel trim is recommended to provide long term sealing capability on sealing faces.

14.3.2 Injection Completion String

Recommendations for corrosion mitigation and monitoring for the completion string (downhole tubing) can be summarised as followed:

- No corrosion risk in upper section of tubing. Possible risk of attack of tailpipe below packer because of possible intermittent wetting of the lower pipe (on internal and external surfaces) during well shut-in for various time periods.
- Upper section of tubing above packer, L80 grade carbon steel; completion components 13Cr stainless steel.
- Tailpipe below packer and flapper valve, CRA material depending upon environment, table 14.4.
- High performance premium tubing connections to minimise risk of CO_2 leakage to the annulus
- Production annulus fluid to be treated with oxygen scavenger and corrosion inhibitor to prevent any risk of galvanic corrosion between different metals in electrical contact.
- Annulus fluid to be biocide treated to mitigate against any risk of microbial influenced corrosion in the annulus.
- Corrosion monitoring by caliper survey of tubing approximately every five years, or by visual examination of tubing whenever removed during workovers for whatever purpose as opportunity arises.

14.4 Start-up Procedures for CO_2 Injection into a Depleted Reservoir

Because of the variable composition of the resident well fluids, the injection program generally will involve two separate fluid injection processes.

- The first injection is typically conducted using an inexpensive liquid fluid of a light density (for example about 8.75 ppg = 1.05 g/ccm) prior to pumping the CO_2 fluid. This "pre injection" program serves as the means to displace the resident wellbore fluids with a fluid of uniform density.
- The "Pre injection" fluid displacement process provides valuable information for the design and possible modification of the CO_2 injecting program.
- After the "pre injection" fluid displacement program is completed, ***the CO_2 injecting program should be interrupted to allow for static pressure readings to be taken*** in the well annulus and within the completion string.
- The initial shut-in completion string pressure (SITHP should be = 0 bar) and shut-in annulus pressure (SIAP should be = 0 bar) are recorded.

- While building-up the completion string pressure above the fluid column of uniform density, the pump is brought up to the desired pump rate.
- Once the pump rate is established, injection pressure (IP) observed at the CO_2 fluid pump is recorded and serves as the control pressure for this injection procedure.
- The injection pressure (IP) is held constant throughout this displacement of the pre-injection fluid by CO_2 fluid.
- Once the displacement is completed, CO_2 fluid injection must be conducted in a manner that maintains a constant bottomhole pressure (CBP).
- This constant bottomhole pressure (CBP) recorded during the second separate fluid injection phase should confirm the simulated pre-job well hydraulic performance of pumped CO_2 in liquid phase.

15 FURTHER RESEARCH

There is a general shortage of corrosion and materials performance data at the higher CO_2 pressures envisaged in CCS systems, particularly with the presence of impurities. During the course of this study, several specific topics related to materials selection have been identified that require further investigation to optimise material selections.

15.1 Post Combustion Amine System

Amine system chemicals are currently being developed for use in CCS plant where the gas inlet stream contains oxygen, in order to overcome the degradation problems that oxygen causes with conventional amine packages. As yet, there is little materials performance experience with these newer chemistries. It is expected that material performance will depend to some extent on the details of how amine degradation is controlled. For example, whether oxygen is removed by scavenger chemicals, or if inhibitors are used, or more stable, oxidation-resistant, amines. The corrosion and pitting resistance of stainless steels in particular is sensitive to the state in which oxygen is present and the effect on electrochemical potential.

The material selections made in this study are on the basis that effects from oxygen are controlled. This would have to be confirmed for the particular amine package adopted.

15.2 Pipeline Ductile Fracture Resistance

A key issue for the pipeline is the basis of design for ductile fracture resistance, particularly for high-toughness and high-strength linepipe materials where the Battelle model is thought to become less reliable. Full-scale ductile fracture tests with CO_2 fluids would provide a more secure basis for design. Ultimately, a correlation between the properties from small-scale tests and the full-scale behaviour, but with wider range of validity than the current BTC model, is desirable.

15.3 Injection well environments

There is relatively little information directly relevant to long-term material performance in the down-hole conditions of high chlorides, high CO_2 pressure and trace oxygen content possible with some injection fluids. Specifically this applies to the Post Combustion processes, and to the Oxy-fuel process if oxygen removal is not complete. Conditions in existing CO_2 injection operations, for example EOR, are generally not equivalent. Water injection, seawater handling and natural gas storage experience provide some guidance, but again conditions in these cases differ from the CCS cases in important aspects. Materials have been proposed in this study, however, further study and testing in simulated service conditions is advisable to optimise or confirm these selections.

Note that achieving these conditions in a laboratory setting will not be straight-forward, due to the combination of high temperature and pressure and the low levels of the critical components in the CO_2 stream.

15.4 Polymers and Organic Coatings

It is expected that suitable materials can be selected from existing polymer grades for CCS service: this has been the case for existing CO_2 handling and injection processes. However, there is relatively little data on polymers in liquid or supercritical CO_2 compared with hydrocarbon service, for example, and some work to qualify particular grades will be necessary before they can be accepted for use. The same applies to organic coating systems.

16 CONCLUSIONS

The corrosion risks involved in three different CCS technologies and seven different process schemes have been assessed, from the entry to the capture plant to the long-term storage reservoir.

From a corrosion point of view, there is a wide range of environments in the different CCS processes. In general, the high CO_2 levels mean that wet process environments tend to be acidic and unprotected carbon steel cannot be used. There are acid-oxidising conditions in some streams which present particular risks to stainless steels and corrosion resistant alloys.

The halide content in entry streams to the CCS plants have been assumed to be minimal: streams are either washed upstream before the CCS plant or are inherently low in halides in gas-fired processes. The presence of significant halide levels would require significant changes in some material selections, typically to much higher alloy CRAs. Control of water and treatment chemicals introduced to the process streams is critical in this respect.

The presence of oxygen is potentially challenging for
- Amine CO2 removal for Post Combustion capture
- Downhole materials in the injection well (Post-combustion and possibly Oxy-fuel)

In the Pre-combustion (IGCC) schemes, oxygen control is critical for streams containing hydrogen sulphide.

In these cases, high-performance, expensive, materials may have to be used if the environment is not controlled within suitable limits. It is expected that oxygen in amine CO_2 removal can be tolerated, although further study will be necessary with specific amine packages. Oxygen in the injection stream will require the use of high alloy materials for a limited section at the bottom of the well.

Major items where there is a choice of competing material solutions include ducting for the main process streams and the CO_2 absorber vessel in Post-Combustion capture.

Ducting is a major item because of the duct size necessary for the main low pressure process streams, and it is of course critical to plant operation. In general, organic coatings, CRA linings and solid wound GRP compete for ducting applications. Each solution has a different balance of initial cost, service life and expected down-time and maintenance intervals.

The CO_2 absorber vessel in Post-Combustion capture is the largest vessel in the processes in this study. A moderate degree of corrosion resistance is required. Concrete with tile lining was selected, but alternative materials of construction have been used for similar vessels including lined or coated carbon steel and solid GRP.

References

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Appendix A

E.ON Report EEN/09/OMS/CF/656/R

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CORROSION AND SELECTION OF MATERIALS FOR CARBON CAPTURE AND STORAGE - PROVISION OF GENERIC SCHEMES

prepared for
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SUMMARY

As part of their work investigating materials issues for carbon capture plants, Intetech have commissioned E.ON Engineering to produce base case simulations of the three main carbon capture options, namely pre-combustion capture, post-combustion capture, and oxy-fuel.

E.ON Engineering has modelled the following cases:

Fuel	Technology		
	Pre-combustion capture	**Post-combustion capture**	**Oxy-fuel**
Low sulphur coal (South African Douglas)	✓	✓	✓
High sulphur coal (USA Bailey)	✓	✓	✓
Natural gas	✓	✓	

This report includes a description of the three capture technologies, highlighting the sections of the plant that are affected by CO_2 capture (including CO_2 compression).

For each case, a generic flowsheet diagram has been provided, including information on composition and operating conditions. Where applicable, guidance has been provided regarding the fate of trace species in the flue gas from these processes.

A summary of materials issues associated with the hot gas path components of an oxy-fuel plant has been presented.

Finally, based on the compressor outlet pressure selected in this study, a generic pipeline diameter has been provided.

Prepared by	**Approved for publication**
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LIST OF ABBREVIATIONS

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AGR	Acid gas removal
ASU	Air separation unit
CCGT	Combined cycle gas turbine
CCS	Carbon capture and storage
DCC	Direct contact cooler
ESP	Electrostatic precipitator
FGD	Flue gas desulphurisation
FGVE	Flake glass vinyl ester
GGH	Gas–gas heater
GT	Gas turbine
HNA	High nickel alloys
HP	High pressure
HRSG	Heat recovery steam generator
IGCC	Integrated gasification combined cycle
LP	Low pressure
MDEA	Methyldiethanolamine
MEA	Monoethanolamine
MP	Medium pressure
QA/QC	Quality assurance/quality control
SCR	Selective catalytic reduction
SRU	Sulphur recovery unit
Syngas	Synthesis gas

1 INTRODUCTION

As part of their work investigating materials issues for carbon capture plants, Intetech have commissioned E.ON Engineering to produce base case simulations of the three main carbon capture options, namely pre-combustion capture, post-combustion capture, and oxy-fuel.

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For each case, a generic flowsheet diagram is provided, including information on composition and operating conditions. Where applicable, guidance is provided regarding the fate of trace species in the flue gas from these processes.

A summary of materials issues associated with the hot gas path components of an oxy-fuel plant is presented.

Finally, based on the compressor outlet pressure selected in this study, a generic pipeline diameter is provided.

2 FUEL SPECIFICATIONS

Two coals have been selected in this study: South African Douglas and USA Bailey. The former is a low sulphur coal and the latter is a high sulphur coal. The properties of these fuels are shown in Table 1.

Table 2 illustrates a typical composition for natural gas.

3 PRE-COMBUSTION CAPTURE

The scope of E.ON Engineering's work was to cover aspects that were specific to an integrated gasification combined cycle (IGCC) plant which had carbon capture applied. Specifically, the scope was stated as being from after the gas clean-up, to include the changed conditions of the shift reactor, the CO_2/H_2 separation, and the impacts of hydrogen fuel instead of syngas on the gas turbine. Additionally, E.ON Engineering was required to perform the same task for a pre-combustion capture system fuelled by natural gas. There is less experience in this area, although many of the carbon capture aspects can be transferred from the coal-fired case.

3.1 Pre-Combustion Capture from Coal Plant

The capacity of the IGCC plant considered in this study was $400MW_e$. This value already includes the penalty associated with CO_2 capture and compression.

It is not straightforward, in the case of an IGCC plant, to distinguish between the items which are due to the carbon capture plant. However, in order to clarify this point, the plant areas described in Section 3.1.1 are considered.

3.1.1 Overview of Plant Areas

1) Gasifier (and Associated Gas Clean-Up)

This plant area is not specific to CCS plant, and there are a number of gasifiers operating around the world with varying degrees of success. The majority of the gasifiers are in the chemicals production industry, but there are a small number that are part of IGCC plants, whose main purpose is power generation. Therefore, the gasifier was not included within the scope of this report.

In the context of this report, the gasifier is taken to include the associated gas clean-up. Such gas clean-up typically includes particulate removal, scrubbing to remove water soluble species (such as chlorides and fluorides), and cooling to around 250ºC. Also included are grey water systems and, where applicable, black water systems. Therefore, the addition of a CCS capability does not alter the performance or operation of these plant items.

2) Shift Reactor

Conventional, non-capture, IGCC plants do not require shift reactors, the purpose of which are to convert CO to CO_2 through the reaction below:

$$CO + H_2O \Leftrightarrow CO_2 + H_2$$

Instead, it is common for them to have COS hydrolysis reactors, in order to convert the sulphur species in the syngas from COS to H_2S, which is more readily captured by acid gas removal (AGR) processes, such as amines or Selexol.

In the case of IGCC plants with carbon capture, the majority of the CO must be converted to CO_2 in order for it to be captured; any CO remaining unconverted will ultimately end up being converted to CO_2 in the gas turbine and emitted to atmosphere. Therefore, such plants must have a shift reactor. In practice, in order to achieve 90% carbon capture, two shift reactors, with an intercooler, must be used.

The use of shift reactors has additional benefits in that they promote the COS hydrolysis reaction, as well as converting HCN to ammonia. These reactions are shown below:

$$COS + H_2O \Leftrightarrow H_2S + CO_2$$
$$HCN + H_2O \Leftrightarrow NH_3 + CO$$

A further advantage is that the cobalt-molybdenum catalyst typically used in the shift reactor will tend to absorb any arsenic that is present in the syngas in the form of AsH_3.

In the modelling carried out as part of this study, the size of each of the shift reactors was estimated to be around 5.75 m diameter, with a height of 6 m. The syngas pressure within them was up to 37 bara, and the temperature was up to 500°C.

Within the scope of the shift reactor area are two heat exchangers. The first is a gas–gas heat exchanger, which increases the temperature of the incoming syngas by cooling the exiting (shifted) syngas. The duty of this heat exchanger is $15.3MW_{th}$. The second heat exchanger is typically used to raise saturated HP steam (at around 130 bara) by cooling the syngas between the shift reactors. The duty of this heat exchanger is around $66MW_{th}$.

3) Syngas Cooling

Following the shift reactors, there is a requirement to cool the syngas down to near ambient temperature in order to be suitable for the AGR process. Physical AGR processes, such as that assumed within this report, require the syngas and solvent to be as cold as possible in order to promote better capture of the H_2S and CO_2. However, there is a cost associated with cooling too much below ambient. In practice, the Selexol process assumed here operates with slight chilling, but the majority of the syngas heat is taken out through preheating boiler feedwater and, when there is nowhere else for the heat to be rejected to, it is rejected to the site's cooling water system. The exact configuration of this area of syngas cooling is very site-specific, and will depend on the level of integration between the boiler feedwater and the gasification plant.

In practice, IGCC plants without carbon capture also need to cool the syngas to near ambient temperatures in order for the sulphur capturing aspect of the AGR to function; therefore there is nothing novel about this area of the plant. The only notable difference is the composition of the syngas. In a non carbon capture plant, the dry syngas principally comprises 56% CO, 28% H_2 and 4% CO_2; however, in the case of a capture plant, it will comprise around 4% CO, 52% H_2 and 36% CO_2.

4) Acid Gas Removal (AGR)

In this study, a Selexol-type physical solvent AGR process was assumed. It is debateable whether this is considered to be 'novel' for a capture plant. Existing IGCC plants generally use a chemical solvent such as an amine (typically MDEA) to capture the H_2S from the syngas in order to minimise levels of SO_2 emissions to atmosphere from the gas turbine exhaust. These have generally been chosen as they are lower cost than physical solvents, but are able to reduce H_2S to acceptable levels. It is an area of debate within the industry whether a future IGCC plant *without* carbon capture would require a physical solvent, or whether a chemical solvent would suffice. More stringent sulphur emission limits, and the possibility of selective catalytic reduction (SCR) being required for NO_x control, could drive the plant designer towards requiring a physical solvent. In this sense the use of a physical solvent would not be unique to carbon capture plants. Furthermore, such processes are already in use on a number of gasification plants for chemicals production, where removal of both H_2S and CO_2 is required. Discussion with AGR vendors suggests that, in order for them to guarantee their process, the equipment would need to be built to their specification, including sizing and materials of construction. However, for completeness, it has been assumed that the AGR process is sufficiently novel to warrant inclusion in this report.

An overview of the AGR process follows. The sour syngas first enters the H_2S absorber, where it is contacted with the solvent (a mixture of dimethyl ethers of polyethylene glycol). This solvent comes from the CO_2 absorber and therefore is loaded with CO_2. The solvent has a higher selectivity for H_2S over CO_2, and so CO_2 is released from the solvent as the H_2S is absorbed. Syngas leaving the top of the H_2S absorber has the majority of the sulphur removed, such that the H_2S level in the syngas at this point is around 20 ppm.

The syngas next passes through a second column (the CO_2 absorber), where it is contacted with lean solvent. The amount of solvent passing through this column is much greater than that passing through the H_2S absorber, due to the much greater quantities of CO_2 compared with H_2S. The CO_2 is removed from the syngas as it passes up the column, and the syngas that exits the top of this column is predominantly hydrogen, with some nitrogen being introduced from the AGR process.

The loaded solvent from the bottom of the H_2S absorber is sent to a H_2S stripper in order to recover the H_2S and to regenerate the solvent. However, the acid gas that is recovered from the top of the H_2S stripper must contain a minimum of 25% (vol) H_2S in order for the downstream sulphur recovery unit to operate. With no other process steps, this would not be achieved. As well as capturing H_2S, the H_2S absorber will also capture CO_2. When this loaded solvent is regenerated, both the CO_2 and the H_2S will be released, and the acid gas will be too dilute to be used in the sulphur recovery unit. Therefore, an additional process step – H_2S concentrator – is used. Here, the solvent is stripped with nitrogen in order to drive off some of the CO_2 from the solvent. This increases the H_2S:CO_2 ratio in the solvent, which results in an acid gas more concentrated in H_2S. The gases driven off from the solvent in the H_2S concentrator are compressed and recycled back to the H_2S absorber.

The regenerated lean solvent from the H_2S stripper is sent back to the top of the CO_2 absorber.

The CO_2-loaded solvent which is drawn off from the bottom of the CO_2 absorber is regenerated through a series of flash vessels. The ability of a physical solvent to absorb CO_2 (or any other acid gases) decreases with decreasing pressure. Therefore, by reducing the pressure of the solvent, CO_2 can be flashed off. This is done over a series of steps. The flash gas from the first vessel is recycled back to the CO_2 absorber column, since it contains large quantities of hydrogen which has been co-absorbed by the solvent. A medium pressure flash, at around 5 bara, releases most of the CO_2. In order to get even more CO_2 released, a final, low-pressure, flash is used. The disadvantage of flashing at lower pressures is the additional duty this puts on the CO_2 compression system. Careful design of the system is required in order to balance the yield of CO_2 against the increased cost of compression.

The solvent after the low pressure flash still contains some CO_2, and so is considered to be 'semi-lean'. This semi-lean solvent is pumped back to the pressure of the CO_2 absorber, and enters part way up the column. It does not enter at the top, since this would introduce large amounts of CO_2 at a point near the syngas exit of the column, which would result in increased amounts of CO_2 in the final syngas.

Indicative stream compositions for the AGR process are included within this report, although the actual compositions would be proprietary to the AGR vendor.

Indicative sizing for the main vessels in the AGR processes have been estimated (Table 3), but are likely to be determined by the AGR vendor.

5) Sulphur Recovery Unit (SRU)

The SRU uses the Claus process to convert H_2S into elemental sulphur through the use of a furnace which converts part of the H_2S to SO_2, and then by passing this mixture over a number of catalyst beds to produce liquid sulphur, which can be sold as a by-product. This plant operates in exactly the same way whether carbon capture is included or not, and so is not considered any further here.

6) Gas Turbine (GT)

The gas turbines used in IGCC plants with carbon capture are likely to be based on those used in IGCC plants without carbon capture. The main difference will centre on the combustion system, and on the composition of the fuel used.

The GT fuel for non-capture IGCC plants is mainly CO and H_2. No major GT vendors offer lean premixed combustion systems when the fuel contains more than a few percent H_2, so GTs on IGCC plants all utilise diffusion combustion. This would result in unacceptably high NO_x levels due to the high peak flame temperatures that are reached in such systems, and so it is necessary to dilute the fuel with an inert, typically nitrogen or steam. The same approach would apply to an IGCC plant with carbon capture. Due to the availability of nitrogen from the air separation unit (ASU), it would be sensible to use this as the inert unless there were a strong reason not to use it.

Sufficient nitrogen is added to reduce the H_2 content of the fuel to around 50% (vol.). This reduces the peak flame temperature within the GT combustor, and so reduces the amount of NO_x produced via the thermal route. The exact amount of nitrogen dilution required will vary depending on the GT vendor, but will generally be around 50%.

The combustion products will contain much higher levels of steam than a conventional GT combustor using natural gas as the fuel, due to the fact that hydrogen, rather than methane, is the main component of the fuel. This increases the amount of heat transfer to the hot gas path components. Many GT vendors have countered this by reducing the turbine inlet temperatures in order to maintain the life of these components, although this does reduce the thermal efficiency of the cycle.

3.1.2 Trace Species

It is difficult to fully account for the fate of trace species within the coal. Levels are so small that it is difficult to measure these species with any degree of confidence, as has been discovered by many existing IGCC plants. In most cases the trace species will follow the same route as for an IGCC plant without carbon capture. The following highlights the expected fate of the trace species.

a) Mercury

It is assumed that the amount of mercury in the coal is 0.1 mg per kg of dry coal. In the case of the South African Douglas coal, this equates to 14 g of mercury per hour. A significant proportion of the mercury will remain in the slag, and will therefore not pass through the system. This is no different to the case where carbon capture is not included. If no mercury removal system is installed, such as activated carbon beds, then the remaining mercury (around half of that originally in the coal) will pass through the system, and mostly be emitted from the heat recovery steam generator (HRSG) stack. Therefore, a conservative estimate is that 7.0 g/h of mercury will be passing through the entire system. If a mercury removal bed is included, which is typically included upstream of the AGR, then this figure will drop to around 1.4 g/h. Note that there is not currently a requirement in the UK to fit such mercury abatement equipment, although it is mandatory in the US. For the purposes of this study, it is recommended that no mercury abatement is assumed, and that there is 7.0 g/h of mercury passing through the system. Due to the reducing atmosphere, the mercury can be considered to be in the elemental form.

b) Arsenic

On an IGCC plant with no carbon capture and no specific arsenic capturing stage, it is possible for the arsenic to pass through the system and be deposited in the gas turbine. However, a cobalt-molybdenum catalyst, such as that used in the shift reactor, removes arsenic very efficiently. Therefore, there is unlikely to be any arsenic in the syngas downstream of the shift reactor, although a build-up on the shift reactor catalyst can be expected. However, the levels are likely to be very small, and directly proportional to the amount of arsenic in the coal feed.

c) Selenium

Any selenium in the coal which is carried with the syngas will get washed out in the gasifier water washing process, and therefore its fate will be the same as in non carbon capture IGCC plants.

d) Chlorides and Fluorides

These and other water soluble species will be washed out of the syngas in the water washes immediately downstream of the gasifier. In this way, their fate is no different to that of a non carbon capture IGCC plant.

3.1.3 Typical IGCC Layout

A layout for a typical IGCC plant with carbon capture is shown in Figure 1. Two simulations were made using a low sulphur coal (South African Douglas) and a high sulphur coal (USA Bailey) (Tables 4 and 5, respectively).

3.1.4 Expected Variability in Composition

There is potentially a very large variability in the components of each of the streams. Many factors affect the composition including, but not limited to, the coal composition, the type of gasifier selected (dry feed vs slurry feed), the quenching method (water quench vs syngas cooling), the amount of CO that is converted in the shift reactors, the AGR technology chosen, the required purity of the final CO_2 stream and the gas turbine selected. Table 6 reflects this potential variability.

3.1.5 High-Sulphur CO_2 Stream Option

In order to reduce the capital and operating costs of the plant, it is possible to co-capture both the CO_2 and the H_2S in the AGR system. Doing this allows the removal of the sulphur recovery unit, the H_2S absorber and the H_2S concentrator. The revised flow scheme is shown in Figure 2.

This scenario was modelled using the high sulphur USA Bailey coal. The results of this are shown in Table 7.

3.2 Pre-Combustion Capture from Gas Plant

The capacity of the IGCC plant considered in this study was 400 MW_e. This value already includes the penalty associated with CO_2 capture and compression.

As with pre-combustion capture from coal, the aim is to convert the carbon-containing fuel (in this case natural gas) into a non-carbon-containing fuel (i.e. hydrogen). However, when natural gas is used as the feedstock, this process is actually well established throughout the world.

Hydrogen is required in large quantities in order to aid oil refining processes. It is also required for the production of ammonia. The lowest cost method of producing this hydrogen is through steam–methane reforming. In this process, the methane reacts with steam over a catalyst at around 700–1100°C in order to produce a syngas consisting of CO and H_2. The yield of hydrogen is then further increased by passing the syngas over a shift catalyst to promote the water-gas shift reaction described in Section 3.1.1.

The difference between the catalyst in this case is due to the fact that there is no sulphur species in the syngas. This allows use of an iron oxide catalyst. In fact, a cobalt molybdenum catalyst would not work due to the absence of sulphur in the syngas.

The syngas produced from a steam–methane reformer will not contain any of the trace components that are present in a syngas derived from coal, in particular sulphur, mercury, arsenic and ammonia. Therefore, the syngas derived from natural gas is much more benign.

The scope of this report is to detail those syngas streams which are different from a plant that does not have carbon capture. Such a statement is not applicable in this case – a natural gas-fired plant that does not have carbon capture installed would be a conventional CCGT plant. The effect of adding post-combustion capture to such a plant is discussed in Section 4.2

A more appropriate comparison is with the many chemical process plants which use steam–methane reforming for hydrogen production. There are many examples of these around the world, such that it is not considered ‘novel’. In these cases, their aim is to produce a hydrogen stream for use in chemical process operations. In the case of a natural gas plant with pre-combustion capture, exactly the same process is followed. However, in this case the aim is to produce a hydrogen stream to act as a fuel in a gas turbine.

The only area where the two types of plant differ is in the use of the hydrogen. The use of hydrogen in the gas turbine was discussed in Section 3.1.1, and the same principles apply here. The only difference is the diluent that is used. In the case of a gas-fuelled pre-combustion plant, there is no readily available source of nitrogen, so steam is used instead. The amount of steam that is required will be gas turbine specific, but an indication can be given below.

Since steam is a more effective diluent than nitrogen, not as much of it is required. The main point to note here is the increased steam content of the combustion products. This increases the heat transfer to the gas turbine hot gas parts, and so many gas turbine vendors will compensate for this by lowering the firing temperature in order to maintain the life of the hot gas path components.

A layout for a typical gas-fired IGCC plant with carbon capture is shown in Figure 3. The simulation results are shown in Table 8.

3.3 Compression of CO_2 Stream

In general, the CO_2 compression from a pre-combustion carbon capture plant will look very similar, irrespective of the fuel type (low sulphur coal, high sulphur coal, or natural gas). For the purposes of this section, a high sulphur coal has been assumed. The CO_2 from the natural gas case will contain no H_2S, and so can be considered to be a more benign case.

Two cases have been considered. In the first, it is assumed that the CO_2 and H_2S are captured separately. In the second case, it is assumed that the CO_2 and H_2S are captured together. The schematics for both cases are shown in Figures 4 and 5, respectively. The simulation of both compression systems is shown in Tables 9 and 10.

4 POST-COMBUSTION CAPTURE

The scope of E.ON Engineering’s work was to cover post-combustion capture from a coal-fired power plant and a natural gas-fired power plant with a benchmark model using aqueous monoethanolamine (MEA) as the solvent for capturing CO_2.

It is important to mention that other alkanolamine-based solvents are also being used/developed for post-combustion capture applications. At present there is an extensive research effort worldwide to improve the performance of the capture process, in particular in areas such as reduction in the energy requirements of the stripper reboiler, improvement of amine stability in the presence of compounds like SO_2 and O_2, and reduction in corrosion characteristics of the solvent. In many cases, blends of different amines are employed. Many of these solvents developments and formulations are proprietary and therefore it is not possible to even know the components in them.

Below is a list of other alkanolamines that can potentially be used for CO_2 capture (Kohl and Nielsen, 1997):

- Diethanolamine
- Triethanolamine
- Diisopropanolamine
- Methyldiethanolamine
- 2-amino-2-methyl-1-propanol
- Diglycolamine.

4.1 Post-Combustion Capture from Coal Plant

The capacity of the pulverised coal-fired plant considered in this study was 400 MW_e. This value does not include the penalty associated with CO_2 capture and compression.

The equipment included in the coal-fired model is described in this section.

4.1.1 Overview of Plant Areas

1) Direct Contact Cooler (DCC)

The DCC reduces the temperature of the saturated flue gas before it enters the absorber. This primarily helps to keep the absorber temperature low and thus to increase the CO_2 loading of the solvent leaving the absorber. This reduces the parasitic requirement of the stripper reboiler. In addition, highly soluble components (such as SO_3 and HCl), particulates and liquid carryover are also removed from the flue gas.

2) SO_2 Polisher

The SO_2 polisher reduces the SO_2 concentration significantly via an irreversible chemical reaction with a reagent (for example, aqueous NaOH). The level of SO_2 removal required will depend on the performance of the flue gas desulphurisation unit (FGD) and on the tolerance of the solvent to SO_2. Alkanolamine-based solvents react with SO_2 to form heat stable salts, thus representing an increased capital cost for replacing the solvent lost through this reaction.

3) Booster Fan

The booster fan is needed to overcome the pressure drop in the DCC, SO_2 polisher, CO_2 absorber and ductwork. In this study, it was assumed that the booster fan is located immediately upstream of the CO_2 absorber. However, other locations are also possible:

- Fan located between the FGD unit and the DCC: The fan will handle the full flue gas flow entering the capture plant. This flue gas will contain the highest concentrations of SO_3, HCl and particulates leaving the FGD unit. In this location the flue gas will be saturated with water at the highest temperature of all other locations.

- Fan located between the DCC and the SO_2 polisher: In this case the fan will handle a reduced flue gas flow as the water content of the flue gas will be significantly reduced on cooling. Also the concentrations of SO_3, HCl and particulates in the flue gas will be significantly reduced. The flue gas will be saturated with water at a lower temperature than in the previous location.

- Fan located between the SO_2 polisher and the CO_2 absorber: The conditions will be similar to the previous location, although the SO_2 concentration will be significantly lower. It is important to mention that the DCC and SO_2 polisher can be coupled in a single column.

- Fan located after the CO_2 absorber: In this case the fan will handle the lowest flue gas flow rate of all locations as a significant proportion of CO_2 is removed in the absorber. This flue gas will be saturated with water at low temperature. The inlet pressure to the fan will also be the lowest in this location, certainly below atmospheric pressure.

4) CO_2 Absorber

In the absorber, CO_2 is chemically absorbed by MEA via a reversible reaction. Under these conditions, this reaction is exothermic, thus increasing the temperature inside the absorber. The highest temperatures achieved are located at the top of the absorber column. In order to make the capture process more efficient, the absorber is fitted with an intercooler at the bottom section. This intercooler helps increase the CO_2 loading of the solvent leaving the absorber at the bottom, thus reducing the parasitic load of the reboiler in the stripper.

At the top of the absorber, a wash water cooler is installed to significantly reduce the concentration of MEA leaving the absorber with the flue gas. This also helps reduce the concentration of MEA degradation products in the flue gas, such as NH_3.

For the two coals modelled in this study, the approximate diameter of the absorber will be 15 m, with a height of 40–50 m including the wash water section. For the natural gas case (see Section 4.2), this diameter will be 19 m approximately. This difference reflects the different volumetric flow rates entering the absorber.

It is common practice to design the absorber with an 80% approach to flooding.

5) Lean/Rich Heat Exchanger

The lean/rich heat exchanger increases the temperature of the rich solvent leaving the absorber at the bottom before it enters the stripper. The heating stream is the hot lean solvent leaving the stripper reboiler.

6) CO_2 Stripper

A significant portion of the CO_2 absorbed by the solvent is recovered in the stripper via an endothermic reaction. The heat required is provided in the stripper reboiler at the bottom of the column, which boils water off the solvent. The steam generated provides the heat for reaction and also reduces the concentration of CO_2 in the gas, therefore increasing the driving force for regeneration. At the top the stripper is fitted with a conventional condenser and a reflux drum. The CO_2 recovered at the exit of the reflux drum is saturated with water. The reboiler heat load is provided by steam taken from the power plant steam cycle.

For MEA, the typical maximum operating temperature in the reboiler is 120ºC to limit degradation of this compound via thermal and chemical mechanisms.

For the two coals modelled in this study, the approximate diameter of the stripper will be 10.6 m. For the natural gas case (see Section 4.2), this diameter will be 13.4 m approximately.

7) Vapour Compressor

A possibility to further reduce the reboiler load is to use a vapour compressor at the bottom of the stripper. The lean solvent leaving the reboiler is partially flashed and the hot recovered vapour compressed back into the stripper column. A balance must be kept between the reboiler load reduction and the power requirements of the vapour compressor.

8) Reclaimer

MEA reacts with flue gas components such as SO_2 and O_2 forming heat stable salts. MEA can be partially recovered from these salts in a reclaimer. In this vessel the lean solvent is intermittently heated up when the MEA concentration decreases to a certain value (determined by the vendor according to their process specifications). After reclaiming, the sludge remaining after heating is disposed of and the MEA recovered pumped back into the process. Fresh MEA is added as needed to replace the losses. E.ON Engineering does not have the modelling tools required to model the reclaimer unit. Therefore the calculations do not include amine replenishing.

4.1.2 Trace Species

It is difficult to fully account for the fate of trace species within the coal. Levels are so small that it is difficult to measure these species with any degree of confidence. However, with some degree of confidence it can be said that trace species that are soluble in water will be removed in the DCC, while those that are not soluble in water will flow through the CO_2 absorber and therefore released through the stack.

Of the two nitrogen oxides present in combustion flue gases (NO and NO_2), NO is not soluble in water and therefore is released with the treated flue gas at the absorber top. NO_2, by contrast, reacts with the amine solvent and therefore increases its consumption in a way similar to SO_2.

4.1.3 Typical Post-Combustion Capture Plant Layout

A layout for a post-combustion capture plant with carbon capture is shown in Figure 6. Two simulations were made using a low sulphur coal (South African Douglas) and a high sulphur coal (USA Bailey) (Tables 11 and 12, respectively). Both simulations assumed a CO_2 removal efficiency of 90%.

4.1.4 Expected Variability in Composition

Given the complexity of the system, it would be extremely difficult to predict variability in composition from different coal types without modelling each case individually. Nevertheless, from a corrosion point of view, in this plant the most important parameter is the solvent loading, expressed as moles of CO_2 per mole of MEA in each stream. Typically rich loadings can be as high as 0.5 and lean loadings as low as 0.1.

4.2 Post-Combustion Capture from Gas Plant

The capacity of the natural gas-fired CCGT plant considered in this study was 390 MW_e. This value does not include the penalty associated with CO_2 capture and compression.

Conceptually the process is exactly the same as in the coal-fired case. However, there are two important differences in terms of the composition of flue gas entering the capture plant:

- No SO_2 is present in flue gas from natural gas and therefore the SO_2 polisher is not required.

- The oxygen molar concentration is approximately 10 percentage points higher than in the coal-fired case. In practice this can create problems as MEA chemically degrades in the presence of high oxygen concentration. However, the available software package cannot model this reaction.

For this natural gas-fired case, three changes have been considered to the previous coal-fired case:

1. The SO_2 polisher has been removed.

2. The vapour compressor has not been modelled. Instead the lean solvent from the reboiler is pumped to the lean/rich heat exchanger.

3. A trim cooler has been added to reduce the temperature of the lean amine before it enters the absorber.

It is important to note that these modifications are not exclusive to the natural gas-fired case and the aim is to illustrate that this process has different configurations.

A layout for the natural gas-fired post combustion capture plant is shown in Figure 7. The simulation results are shown in Table 13.

4.3 Compression of CO_2 Stream

As seen in Tables 11 to 13, the conditions and composition of the exported CO_2 for the two coal cases and the natural gas case are extremely similar. Therefore the compression system will also be almost identical. For this reason, in this report the compression of the exported CO_2 for the Douglas coal is illustrated. The schematic diagram of the compression system (including the dehydration unit) is shown in Figure 8. The modelling of the interstage compression streams is shown in Table 14.

5 OXY-FUEL

The scope of E.ON Engineering's work was to:

- Provide preliminary flowsheets outlining expected oxy-fuel combustion plant configurations.
- Provide heat and mass balances detailing the conditions and compositions in the areas of the plant which are affected by/result from the introduction of carbon capture.
- Assess the implications of oxy-fuel combustion for corrosion and materials selection in the hot gas path.

A total of eight different configurations were considered, covering two different coals, two different levels of CO_2 purity, and two different locations of the flue gas desulphurisation plant.

At first glance, oxy-fuel combustion for CCS shares many components with conventional coal-fired plant, but also introduces a number of new processes, such as oxygen production and CO_2 purification and compression. It is also important to note that those components that are similar to conventional plant (for example, milling plant, boiler, heat exchangers, emission control equipment, etc.) may be subject to conditions substantially different to those experienced during air-firing.

5.1 Overview of Plant Areas

1) Oxygen Production

It has been assumed that conventional cryogenic air separation will be used for oxygen production. This is a technology which has already been commercially deployed around the world at the scale necessary for full-scale carbon capture. As such, it is excluded from this study.

It is acknowledged that it may be desirable to integrate the air separation unit with other parts of the oxy-fuel plant in order to maximise overall plant efficiency. However, for the purposes of this study, it has been assumed that first-of-kind oxy-fuel plant will not be heavily integrated.

2) Boiler (Including Flue Gas Clean-Up, Flue Gas Recirculation and Mills)

Pulverised coal is pneumatically conveyed from the mills to the burner using recirculated flue gas, which has been de-dusted and has had sufficient oxygen added to promote stable combustion, whilst at the same time minimising the risk of ignition prior to the burner. Additional recirculated flue gas which has also been de-dusted and oxygenated is also fed to the burner, to provide the balance of oxygen required for combustion. This secondary recirculation will have a higher oxygen concentration than the primary coal-conveying recirculation. The ratio of oxygen to recirculated flue gas is controlled to achieve the required heat transfer profile.

The flue gas leaving the boiler will vary depending on coal composition, oxygen purity, excess oxygen and degree of air ingress. As it is a recirculating system, composition will also be a function of downstream parameters, such as flue gas clean-up. The main component will be CO_2. Water vapour, nitrogen and oxygen will also be major gas phase constituents.

It is important to state that the impact of oxy-fuel combustion on the formation and removal of trace species is not at all clear. This is discussed in more detail in Section 5.2. Mercury and SO_3, in particular, are the subject of ongoing studies and prediction of their behaviour is not practical at this stage.

The flue gas is cooled in a gas–gas heat exchanger, and then fly ash is removed in an electrostatic precipitator (ESP). Due to the increased moisture and acid gas concentrations, dew point temperatures are significantly higher than conventional plant. For this reason, and also because sensible heat can be returned to the process via flue gas recirculation, the ESP will be operated above conventional temperatures.

Both recirculated flue gas streams may or may not have passed through a wet limestone flue gas desulphurisation (FGD) scrubber, depending on whether the FGD is located before or after the recirculation take-off point. This affects the concentration of acid gas species such as sulphur dioxide and hydrogen chloride, as well as water vapour; all are higher in the case where the recirculated flue gas has not passed through the FGD.

The cleaned flue gas from the FGD outlet then goes to the CO_2 purification and compression plant.

3) CO_2 Purification and Compression

The flue gas leaving the FGD is saturated with water vapour, whilst the CO_2 concentration is only in the region of 60% mol, which is much too low for transport and storage. It is therefore necessary to dry the flue gas substantially (for corrosion considerations), and remove non-CO_2 components (for energy and storage capacity considerations).

Bulk moisture content is reduced in a direct contact flue gas condenser. The flue gas is then compressed to an intermediate pressure, and then intercooled. At this point, further moisture condenses out. At elevated pressure, reactions of H_2O, NO, NO_2 and SO_2 promote the conversion of SO_2 to H_2SO_4 and of NO to HNO_3. These are removed as dilute acid liquid streams. It is also postulated that mercury is captured in this part of the process through sulphatisation and nitration, although removal efficiency is unknown.

Purification of the CO_2 entails cryogenic phase separation at temperatures close to the triple point, which requires a very dry gas in order to avoid ice and hydrate formation in the process. For this reason, the flue gas passes through a set of molecular sieves. Mercury removal is also important at this stage, due to its negative impact on aluminium heat exchangers used in the cryogenic process.

After the molecular sieves, the flue gas is virtually dry (<10 ppm moisture) and should contain only CO_2 and non-condensable gases (N_2, O_2 and Ar). The significant presence of other components beyond this point is not anticipated. For the low CO_2 purity case, two stages of cryogenic phase separation are used, whilst for the high purity case, a single stage of separation and a distillation column are used.

The CO_2 stream (with some dissolved non-condensable N_2, O_2 and Ar) leaves the phase separators/distillation column as a liquid stream. The remainder (mostly non-condensable components with some CO_2 carryover) leaves as a gas stream.

The CO_2 stream is compressed to high pressure and cooled ready for export.

The non-CO_2 stream is passed through a low temperature polymeric membrane, where a proportion of the O_2 and CO_2 can be recovered and recycled to the boiler, thereby reducing energy consumed for O_2 production and increasing CO_2 recovery. The retentate is vented to atmosphere. This membrane is a commercial technology already widely used in the industrial gas industry, and is therefore not relevant to this study.

Indicative stream compositions for the CO_2 purification process are included within this report, although the actual compositions would be proprietary to the equipment vendor.

5.2 Trace Species

It is difficult to fully account for the fate of trace species within the coal. As discussed above, the characterisation of trace species' behaviour during oxy-fuel combustion is ongoing.

a) Mercury and SO_3

Predictions of maximum possible concentrations of mercury and SO_3 are shown in Table 15. These are highly conservative, as there will be some removal of these components with the ash, in the FGD, in condensate and in the molecular sieves. However, these values are presented in order that the worst-case impacts of their presence can be assessed.

b) Chlorides and Fluorides

It is expected that these and other water soluble species will be washed out in the FGD. In this way, they have no implications for corrosion and materials selection in the CO_2 purification and compression plant. However, their concentration in the boiler and recirculated flue gas path is considered in Section 5.5.

5.3 Typical Oxy-Fuel Plant Layout

The four different layouts considered in this study are shown in Figures 9 to 12. The results of four simulations are shown in Tables 16 to 19. The simulations were made using two different coals, namely a low sulphur coal (South African Douglas) and a high sulphur coal (USA Bailey), with two different levels of CO_2 purity. The simulations do not consider the impact of FGD location, as this has no significant impact on the CO_2 compression and purification plant. The impact of this variable is considered in Section 5.5 as it relates to corrosion and materials selection in the boiler and recirculated flue gas path.

5.4 Expected Variability in Composition

Given the complexity of the system, it would be extremely difficult to predict variability in composition from different coal types without modelling each case individually. At the same time, the current assumptions for oxy-fuel technology do not allow making accurate extrapolations.

5.5 Materials Selection for the Oxy-Fuel Hot Gas Path

The operating conditions within the various hot gas path components in an oxy-fuel fired system are varied and, as such, the materials requirements are also varied. For the current generation of new build supercritical boilers, the economiser, furnace section and superheater tubing could be expected to operate with internal steam pressures of up to 300 bar and metal temperatures ranging from 300°C to 620°C, with the reheater tubing containing 60 bar steam and metal temperatures ranging from 400ºC to 650°C. Such coal-fired boilers might be expected to achieve an efficiency of 46% without CCS. More advanced steam conditions (up to 350 bar and 760°C final steam) have been proposed, which could achieve efficiencies of 50% without CCS. Tubing operating with such water/steam conditions would need to be produced from a range of high strength materials, with high creep strength being required for materials operating with metal temperatures in excess of approximately 450°C. In addition to the strength requirements, both steam side oxidation resistance and fireside corrosion resistance would also be considered important with tubing required to achieve operating lives of 100,000–200,000 hours.

Fireside corrosion within air-firing utility boilers has been studied for many decades and, whilst largely understood, still poses a significant threat to the long term integrity of boiler tubing that is managed through planned maintenance, careful fuel selection (including coal blends) and materials selection. Several corrosion mechanisms may be active within different areas of the boiler.

External to the boiler, the hot gas path components needs only contain the flue gases at near ambient pressure. As such, high strength and creep strength are not as important, with components only being required to maintain structural stability. However, the requirement to resist the corrosive effects of the flue gases remains. It is likely that corrosion will only become a serious threat where the contained flue gases approach or go below the acid dew point temperature, at which point highly acid solutions can be formed and protective measures would be needed to combat corrosive attack.

5.5.1 Boiler – Furnace Section

Within the furnace section, severe fireside corrosion (≥ 200 nm/h) is most frequently associated with reducing conditions (>1% CO and <0.1% O_2) at the furnace walls, associated with either poor combustion (flame impingement as a result of poor fuel and air distribution at the burners, insufficient air supplied to the burners and oversized pulverised fuel), or deeply staged combustion designed to reduce NO_x emissions. Conditions such as these are frequently found around and in the area above the burners. Increasing the fuel chlorine content, and hence the HCl concentration within the flue gas in this high heat flux area, can dramatically increase wastage rates (Mehta et al, 1997 and Davis et al, 2001). It has been speculated that the deposition of pyrite and un-burnt carbon at the furnace wall under reducing conditions, followed by subsequent operation under oxidising conditions, could also lead to similar severe fireside corrosion, although evidence for such a mechanism is not conclusive (Kung and Bakker, 2000).

Irrespective of the actual damage mechanism, excessive wastage rates (>25 nm/h) can be largely overcome when air-fuel firing by ensuring good milling and air/fuel distribution, ensuring burners are tuned to prevent excessively long flames and supplying greater quantities of excess air where burners are close to side walls. However, in the worst case, wastage rates have been determined up to approximately 1000 nm/h, corresponding to approximately 8 mm metal loss in one year of continuous operation. As virtually all new boiler tubing enters service at less than 8 mm thick, it can be seen that with such severe attack, operating lives may be less than one year.

Changing the firing from air-firing to oxy-fuel has the potential to increase furnace fireside corrosion rates through increasing the concentrations HCl and sulphur-containing gases present in the furnace section. In-furnace HCl measurement is difficult and a rule of thumb is usually used to estimate the HCl concentration. For each 0.1% chlorine present in the as received coal, 80 ppm HCl will be found in the furnace gases under oxidising conditions. Excessive corrosion rates are not in general found with coal chlorine contents of less than 0.2%. HCl within the furnace section is particularly damaging under reducing conditions, but can be tolerated without significant attack provided that oxidising conditions are maintained at the furnace wall. HCl condenses from the flue gas and migrates to the coolest point at the furnace wall, i.e. the metal surface, where it may form a chloride-rich phase. This appears dark when examined using optical microscopy and is very defective and mechanically weak. Being defective, this phase permits rapid transport of metal ions and corrodents, thereby promoting rapid attack. The chloride-rich phase has limited (thermodynamic) stability and, for a given partial pressure, there will be an upper limit to the temperature at which it is formed, above which, corrosion rates will decrease to that likely to be found with no chlorine in the coal. Increasing the coal chlorine content increases the maximum stability temperature and, as such, increases the temperature range over which the chloride-rich phase can be formed.

It can be assumed that all of the HCl in the combustion gases will be removed in the flue gas desulphurisation plant and, as such, when oxy-fuel firing with the FGD plant in the recycle loop, there would be no increase in HCl concentration/partial pressure when compared with air-fuel operation assuming similar bulk flow rates. High oxygen enrichments and reduced bulk flow rate could be expected to increase the HCl concentration in the combustion gases. Increasing heat flux, as could occur with reduced bulk flow rates, also increases the rate of corrosion in the presence of HCl. If the FGD plant is located outside of the recycle loop, there would be a significant increase in the HCl present within the furnace and, hence, a significantly increased risk of excessive fireside corrosion. Such a condition may still be tolerable assuming that coal chlorine levels are not excessive (<0.2%), and that combustion is adequately controlled, i.e. that there is no flame impingement.

The sulphur present within the coal can be converted to several forms within the furnace. Under oxidising conditions, SO_2 is the predominant phase formed, with further catalytic oxidation of approximately 1% of the SO_2 to SO_3. Within the furnace area, SO_2 has no appreciable impact on corrosion rates, although it has been speculated, but vary rarely found in practice, that SO_3 can react with deposited alkali metal sulphates to yield low melting point alkali pyrosulphates ($(Na,K)_2S_2O_7$) that could cause accelerated wastage through fluxing of the normally protective corrosion scales. Where reducing conditions occur, sulphur is not completely oxidised, producing a number of aggressive species such as H_2S, CH_3SH, COS and elemental sulphur. Such species provide a ready transport mechanism for sulphur to the corroding tubing where they can form metal (iron) sulphides. Sulphides are frequently identified in corrosion scales formed under reducing conditions and are known to be more defective than oxides, thereby offering a reduced barrier to further diffusion of metal ions and corrodents. The various partially oxidised sulphur species would be expected to have been fully oxidised to SO_2 and SO_3 by the time they reach the furnace exit.

The introduction of flue gas recycling with oxy-fuel firing would not be expected to increase the concentration of partially oxidised sulphur species when compared with air-fuel firing, unless the plant operates with oxygen enrichment above that found in air, in which case the reduced bulk flow offers less scope for dilution of the sulphur species. As such, it would be unlikely that there would be a significant change in wastage rates under reducing conditions due to the sulphur in the coal. However, under oxidising conditions, and with the FGD plant located outside of the recycle loop, there remains the possibility of increased corrosion due to scale fluxing under deposited molten alkali pyrosulphates. The formation and stabilisation of molten pyrosulphates may be promoted by the increased partial pressure of SO_2 within the furnace, particularly if there is a greater conversion of SO_2 to SO_3. Insufficient evidence is currently available to determine whether or not this is a realistic threat, and to what extent, or at what rate, any attack would occur. Notwithstanding changes in flame shape (and hence furnace wall impingement), oxy-fuel firing with the FGD plant inside of the recycle loop is unlikely to experience any significant worsening of the furnace fireside corrosion rates associated with gas chemistry.

5.5.2 Boiler – Superheater/Reheater Areas

High temperature superheater/reheater fireside corrosion in air–coal fired boilers is associated with the deposition of alkali sulphates on to the tubing and the subsequent reaction to form molten alkali iron trisulphates ($(Na,K)_3Fe(SO_4)_3$). The sulphatic deposits will only be molten at temperatures in excess of 552°C and, as such, tubing with lower metal temperatures will not be affected by this mechanism. For this reason, plants operating with a modest final steam temperature of 540°C are relatively immune to damage from molten sulphate attack and predominantly suffer low rates of simple oxidation. In plant with higher steam temperatures, it is only the hottest operating penultimate and final superheater/reheater stages that are vulnerable to this form of attack.

Coals containing low levels of sulphur and alkali metals are generally considered relatively benign, whilst higher impurity contents increase the risk of significant fireside corrosion. Recycling of the flue gas, especially with the FGD plant external to the recycle loop, would likely increase the SO_2 partial pressure and increase the risk of significant fireside attack. Whilst not directly implicated in the high temperature superheater/reheater corrosion process, increasing coal chlorine content has been associated with increased wastage rates. It has been speculated that chlorine in the combustion gases promotes the release of alkali metals from the normally inert coal derived mineral matter, again promoting the formation and deposition of alkali sulphates. Flue gas recycling without the FGD plant in the loop would increase the chlorine/HCl content in the area of the superheaters/reheaters and hence risk the deposition of additional alkali sulphates when compared with air-fuel firing. It is currently unclear whether this would simply expand the area within a boiler that is affected by molten sulphatic attack, or whether the rates of attack would be increased.

5.5.3 Boiler – Refractory

Refractory materials are used in numerous locations with utility furnaces usually to seal around openings (burner quarls, soot blower apertures or tube penetrations) or to insulate access doors. Little information currently exists regarding the effect of oxy-fuel firing on the refractory materials used within furnaces, although some concerns have been raised. Experience from the glass making industry, where conversion to oxy-fuel firing has been ongoing for a number of years, suggests that alkali metal attack of silica containing materials has increased (Faberland and Verheijen, 2008).

5.5.4 Gas-Gas Heater

The gas–gas heater (GGH) operates at relatively low temperatures compared with the boiler tubing, but at a temperature significantly above any acid dew point in either air-fuel (~110°C) or oxy-fuel (~150°C) firing configurations. As such, attack of the heater would be limited to simple oxidation regardless of the firing method, or the inclusion of any FGD plant inside of the recycle loop. Acid dew point attack may pose a problem should there be any local air in leakage around the heater seals, with such leakage raising the possibility of local chilling.

5.5.5 Electrostatic Precipitator

In all cases of air-fuel and oxy-fuel firing, the electrostatic precipitator would operate at relatively low metal temperatures, but as with the gas–gas heater, at a temperature above the acid dew point. As such, it would not be expected to be adversely affected by changing to oxy-fuel firing. Again the exceptions are where tramp air finds ingress causing localised chilling, in which case, small areas may be subject to acid dew point corrosion.

5.5.6 Heat Exchanger after the Electrostatic Precipitator (FGD Outside Recycle Loop)

The use of some form of heat exchanger (or gas quench) would be required following the electrostatic precipitator prior to the gases entering the FGD plant outside of the recycle loop. Some form of gas cooling would be required in order to protect the corrosion resistant linings in the FGD from excessive temperatures. For example, vinyl ester-based coatings could not operate continuously at temperatures above approximately 130°C. This might take the form of an absorber liquor spray system in the FGD inlet duct, which may be economical in terms of capital expenditure (no heat exchanger, small area to protect), but could result in a significant efficiency penalty in terms of heat lost.

If a heat exchanger system was employed, it would probably necessitate the use of highly corrosion resistant alloy materials as normally seen in the FGD plant (see Section 5.5.8), as this represents the position where the gas temperature would be decreased below the sulphuric acid dew point temperature. This would render the heat exchanger and associated downstream ductwork vulnerable to sulphuric acid dew point corrosion and the deposition of sticky particulate ash material. The ductwork in the area of and downstream of the heat exchanger would similarly need protecting either with corrosion resistant alloys or protective coatings as currently used in FGD plants (see Section 5.5.8). Any booster fan downstream of the heat exchanger would similarly be operating below the sulphuric acid dew point and be subject to the same corrosive environment.

The extent of any dew point corrosion remains uncertain. In air-fuel fired systems, low alloys materials can often operate with relatively low wastage rates below the sulphuric acid dew point. It is only when the temperature decreases below the water dew point that very severe accelerated corrosion occurs. As yet no data exists to indicate whether the same will hold true in oxy-fuel fired systems where the water content of the flue gases is significantly elevated.

5.5.7 FGD Gas-Gas Reheater (FGD Plant Inside Recycle Loop)

Gas–gas reheaters are commonly employed on air-fuel fired power stations. In this application, they achieve relatively long operating lives (> 8 years typically), although planned replacement of elements is required during overhauls where they suffer from dew point corrosion. The structural steelwork of rotating gas–gas reheaters is usually of sufficiently large thermal mass that they remain above the sulphuric acid dew point during operation, even when intermittently exposed to gases whose temperatures are below the sulphuric acid dew point temperature. As such, the structural steel work usually only suffers significant localised corrosion damage on the coldest sections. As with the gas–gas heater, there remains risks of localised damage where there is the ingress of seal air that can locally chill the structures.

With operation in the oxy-fuel fired mode, the gas–gas reheater would be expected to operate at least partly below the elevated sulphuric acid dew point temperature of 150°C. As such, this structure would likely need corrosion protection or construction using relatively highly alloyed stainless or high nickel alloy corrosion resistant materials instead of the more normal, basic low alloy steels. Similarly, the raw gas ductwork exhausting from the gas–gas reheater would be expected to operate below the sulphuric acid dew point, and again require protection to combat dew point corrosion damage. With the gas temperature at approximately 100°C, protection could be provided through the use of typical vinyl ester coatings as used in existing FGD plants.

5.5.8 FGD Plant

Flue gas desulphurisation (FGD) plants for air-fired utility boilers are designed to operate in highly aggressive/corrosive environments subject to acid dew point corrosion and, as such, normally incorporate highly corrosion resistant materials or protective coatings. Most plants operate with limestone slurry used to absorb SO_x forming initially calcium sulphite, referred to as sludge. In some cases the sludge is the final product and is sent to landfill. The vast majority of air-fuel fired plants employ oxidation air sparges within the absorber tower to further oxidise the sulphite to sulphate, forming gypsum, a saleable product used in the construction industry. With the desire to create a CO_2-rich flue gas stream through oxy-fuel firing, it may be necessary to undertake the oxidation of sulphite to sulphate external to the absorber tower so as not to dilute the CO_2-rich gas, or alternatively to sparge with oxygen within the absorber tower. The concentrations of impurities such as chloride (or fluoride with lignite-fired plant) in the absorber fluid are dependant upon the chlorine content of the make-up water, the chloride content of the coal and the rate of absorber liquor purge. Different plant operators may chose to operate with widely varying chloride levels which would have a significant effect on the corrosivity of the absorber liquor.

Conversion to oxy-fuel firing may increase the levels of impurities likely to promote corrosive attack but, in general, the same protective measures currently employed to combat corrosion will still be applicable. The materials currently employed and their normal applications are detailed below.

Flake glass vinyl ester (FGVE) or mica-filled vinyl ester coatings are used in raw/dirty flue gases with maximum continuous operating temperatures of approximately 130°C, or in scrubbed, water-saturated flue gases at lower temperatures, where acid dew point corrosion is still likely to be active. Such coatings can tolerate short periods of excess temperatures up to approximately 180°C. The success of these coatings is highly dependant upon the QA/QC associated with the application process. In particular, attention must be paid to surface preparation, cleanliness, coating thickness (1–3 mm) and defect testing (spark testing). Regular condition assessment/maintenance is required in order to prevent coating deterioration (cracking) and maintain corrosion protection. The flake glass or mica fillers ensure an extended diffusion path for moisture and corrodents, thus ensuring good protection and long coating life is achieved from a relatively thin coating.

Several rubber lining materials are employed in FGD plant. The most common compositions are based on chlorobutyl or bromobutyl rubbers that are pre-vulcanised prior to application and adhesive bonded to the steel substrate. Rubber lining thickness varies from 4 mm to 8 mm and is usually supplied in 4 mm or 5 mm thick sheets. Double layers or thicker linings are applied where high diffusion/osmotic pressures are likely, for instance where there is a large temperature difference between the flue gases/absorber spray/liquor and the external or substrate surface. Rubber linings have a finite life of approximately 10 years due to moisture and contaminant (Cl^-, SO_4^{2-}) diffusion into the rubber and would be considered consumable. Life may be reduced further where erosion by the FGD slurry reduces the lining thickness. As with the vinyl ester linings, QA/QC during installation is critical in obtaining good lining performance. Routine in-situ testing at overhauls, coupled with laboratory examination of samples is required in order to assess the condition of the rubber. The extent of degradation is assessed by changes in mechanical properties such as hardness, elongation to failure, tensile strength, adhesive bond strength, in addition to determination of moisture content and concentration of impurities at the substrate surface. Over time, moisture will penetrate through the rubber transporting impurities such as dissolved chlorides and sulphates, which would eventually lead to rusting of the substrate.

Corrosion-resistant alloys may be deployed in various areas within the FGD plant. In some more benign areas, relatively low alloyed stainless steels such as the basic 300 series austenitic alloys, may offer sufficient corrosion resistance to have useful operating lives. However, such alloys are only likely to prove useful at near ambient temperatures and with low levels of contaminants present. Duplex stainless steels and higher alloyed austenitic materials containing high molybdenum contents offer greater corrosion resistance and find application in metallic components such as pump impellors and agitators. Corrosion resistance is of greater importance than erosion resistance for materials operating in the absorber slurry, although general wear of metallic components may be life limiting in some instances. De-alloying or selective phase dissolution can be a problem in metallic materials leading to pitting or subsurface/internal corrosive attack in the presence of highly acidic, chloride containing solutions. Titanium has been shown to possess very good corrosion resistance in FGD gaseous and liquid environments and has been used for structural members and bolting. However, its cost precludes its large scale use. High nickel alloys (HNA) such as C22 and C276 have also been shown to possess very good corrosion resistance. Again their cost has prevented large scale use as structural materials, but they have found application as cladding for ductwork in areas susceptible to intermittent exposure to wet dirty flue gases. HNAs may be supplied roll clad, explosively clad or wallpapered, with the latter method involving the application of thin (~ 1.6 mm HNA) sheets which are welded to the structural steelwork/duct plating. Whilst the use of HNA materials involves considerable initial capital expenditure, they are essentially fit and forget, requiring little or no maintenance once applied. However, care must be taken be taken during installation and when any subsequent work is carried out in the area of HNA materials, so as to prevent contamination with ferrous materials. Contamination with tools previously used to work steels, by dilution with iron during welding, or even by ferrous material trapped in the tread of workers boots, can severely compromise the corrosion resistance of HNA materials, leading to corrosion and premature or unexpected failure.

Lightweight, borosilicate foamed glass blocks applied to steel or concrete substrates using a flexible polymeric adhesive/mortar have found application in FGD plant ducts and chimneys. In addition to good chemical/corrosion resistance, the blocks are thermally insulating. When applied to the internal surfaces of ductwork, they can be used with reduced or no external lagging/cladding when compared with plain ductwork. The mortar can degrade at high temperatures, although the maximum continuous operating temperature for this system is reported to be 200°C. With the insulating effect of the blocks, mortar degradation is limited to the hottest area in contact with the flue gases and the bulk of the mortar remains unaffected. Such a lining system is also reported to require little or no maintenance.

Various plastic-based materials are commonly used in FGD plant for structural applications and are essentially immune to corrosion damage. Silicon carbide filled, epoxy absorber fluid pump impellors have proven to be an alternative to metallic impellors. These heavily filled materials undergo very slight erosion upon entering service, essentially removing the surface resin layer and exposing the wear resistant silicon carbide filler material. Similarly, fibreglass pipes are frequently used to transport absorber fluid within the absorber tower. Demister wash pipe work is frequently constructed from polypropylene which whilst essentially immune to corrosion damage, may be subject to embrittlement after long term exposure in the warm environment encountered within the absorber tower. Similarly demister packing designed to eliminate water/slurry droplets from the gas stream can also be produced using polypropylene.

Enamel coatings have been employed to prolong the life of certain components such as gas–gas heater elements, where the normally used weather type steels (Corten) have occasionally proved to have relatively short lives. Being a hard and brittle coating, it is susceptible to mechanical damage, particularly at edges of components, which can lead to premature failure.

A small number of ceramic materials may be used in areas subjected to high wear rates. Slurry spray nozzles are frequently formed from sintered silicon carbide that is essentially immune to both erosion and corrosion damage.

5.5.9 Recycle Gas Ductwork and Fans

Two distinct situations occur in the recycle gas ductwork dependant upon whether the FGD plant is inside or outside of the recycle loop. With the FGD plant outside of the recycle loop, all of the ductwork leading to the mills and back to the boiler, including the secondary flue gas recycle fan, would be expected to operate at intermediate temperatures, but above any acid dew point temperature. As such, these structures would be expected to suffer only minor oxidation, and could be manufactured from low alloys materials as currently employed in relatively high temperature ductwork.

In contrast, with the FGD plant within the recycle system, at least part of the ductwork would be operating below the sulphuric acid dew point temperature, with the ductwork after the FGD gas–gas reheater and the secondary flue gas recycle fan operating at temperatures close to the sulphuric acid dew point. These areas would likely need protecting with vinyl ester-type linings (FGD exit and FGD gas–gas reheater) or corrosion resistant alloys (downstream of the FGD gas–gas reheater). After passing through the second gas–gas heater, the gas temperatures would be raised significantly above any acid dew point temperature and normal low alloy materials would suffice.

The issue of oxygen compatibility is also of concern in the flue gas recycle ductwork, especially the secondary gas recycle duct, where oxygen concentrations in the region of 30% will be present, and where insufficient mixing of injected oxygen could result in even higher local oxygen partial pressures. The magnitude of the risk is unclear, although it is generally expected that metal components will be unaffected. However, non-metal materials (e.g. gaskets, instruments, lubricants) should be specified to ensure that they are compatible with the expected oxygen concentrations which may occur.

As a general note, somewhat related to materials selection, there will be increased pressure to ensure that ductwork operating above atmospheric pressure is gas-tight, as far as is practicable, to minimise CO_2 egress into confined spaces. Non-corrosion failure mechanisms, such as fatigue, expansion, fracture and erosion of ductwork, should be considered when selecting appropriate materials of construction.

5.5.10 Mills

The recycled flue gases are chilled significantly through the introduction of coal in the mills. Whilst the temperature falls significantly below the sulphuric acid dew point, it may still remain above the water dew point. This is largely dependant upon the exit temperature from the FGD plant. With higher exit temperatures, for example 68°C, the water-saturated gases contain significantly more water vapour than if the exit temperature were lower (for example, 55°C) as is common in existing air-fired FGD plants. Such differences may determine the extent of any dew point corrosion in the mills, with lower FGD exit temperatures being favoured.

The combination of corrosion below the dew point and mechanical wear in the mills themselves would likely result in very severe corrosion damage. The application of protective systems in areas subject to mechanical wear would be extremely difficult, if not impossible and, as such, alternative approaches may be required. In addition, where surfaces fall below the dew point, this would likely result in deposition of coal dust in damp/sticky conditions. In order to prevent such corrosion and deposition, alternative approaches may be required such as removal of water from the recycled flue gas prior to entering the mills.

6 GENERIC PIPELINE SIZE

Given the outlet conditions from the compressor (and therefore inlet conditions to the pipeline) selected in this study, a generic pipeline size has been estimated. This generic size only considers recommended velocities. However, in practice, the actual pipeline size will depend on factors such as power plant capacity, location of the power plant and storage site, changes of pressure of the CO_2 reservoir over time, etc. These factors cannot be accounted for in this generic study.

It is assumed that a generic pipeline size of 16 inches in internal diameter is sufficiently adequate for the purposes of this study.

7 CONCLUSIONS

As part of their work investigating materials issues for carbon capture plants, Intetech have commissioned E.ON Engineering to produce base case simulations of the three main carbon capture options, namely pre-combustion capture, post-combustion capture, and oxy-fuel.

E.ON Engineering has modelled the following cases:

Fuel	**Technology**		
	Pre-combustion capture	**Post-combustion capture**	**Oxy-fuel**
Low sulphur coal (South African Douglas)	✓	✓	✓
High sulphur coal (USA Bailey)	✓	✓	✓
Natural gas	✓	✓	

This report included a description of the three capture technologies, highlighting the sections of the plant that are affected by CO_2 capture technologies.

For each case, a generic flowsheet diagram has been provided, including information on composition and operating conditions. Where applicable, guidance has been provided regarding the fate of trace species produced during coal gasification or combustion.

A summary of materials issues associated with the hot gas path components of an oxy-fuel plant has been presented.

Finally, based on the compressor outlet pressure selected in this study, a generic pipeline diameter has been provided.

8 REFERENCES

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Table 1: Coal properties

Coal name	Douglas	Bailey
Country	South Africa	USA
Moisture (% total)	7.8	8.2
Ash (% as received)	14.5	7.2
Volatile matter (% as received)	22.9	35.4
Net calorific value (kJ/kg as received)	25079	28398
Carbon (% as received)	67.00	71.16
Hydrogen (% as received)	3.60	4.71
Nitrogen (% as received)	1.66	1.35
Oxygen (% as received by difference)	4.90	5.31
Sulphur (% as received)	0.54	1.97
Chlorine (% as received)	0.01	0.11

Table 2: Typical natural gas composition

Component	% mol
Nitrogen	1.81
Methane	89.65
Carbon dioxide	0.94
Ethane	5.59
Propane	1.41
Butane	0.41
Pentane	0.19

Table 3: Indicative sizing for the main vessels in the AGR processes

Plant item	Indicative diameter (m)	Indicative height (m) (* indicates horizontal vessel)
H_2S absorber	4.0	45
CO_2 absorber	6.0 (reducing to 3.0)	45 (diameter change at around halfway)
H_2S concentrator	3.0	30
H_2S stripper	3.0	40
HP CO_2 flash vessel	5.0	15*
MP CO_2 flash vessel	5.0	15*
LP CO_2 flash vessel	5.0	15*

Table 4: IGCC simulations with separate capture of CO_2 and H_2S (South African Douglas coal)

Part 1 of 4							
Stream Name	**FUEL**	**SG1**	**SG2**	**SG3**	**SG4**	**SG5**	**SG6**
Component (Molar %)	**Coal Feed**	**Clean Syngas from Gasifier**	**Entry to Shift Stage 1**	**Exit from Shift Stage 1**	**Entry to Shift Stage 2**	**Exit from Shift Stage 2**	**Syngas to Cooling**
Water		53.1502	53.1502	30.5563	30.5563	27.0935	27.0935
Hydrogen		10.4525	10.4525	33.0427	33.0427	36.5055	36.5055
Carbon Dioxide		1.6988	1.6988	24.2915	24.2915	27.7543	27.7543
Carbon Monoxide		28.5789	28.5789	5.9899	5.9899	2.5271	2.5271
Nitrogen		6.0030	6.0030	6.0030	6.0030	6.0030	6.0030
Argon		0.0254	0.0254	0.0254	0.0254	0.0254	0.0254
Oxygen		0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Hydrogen Sulphide		0.0847	0.0847	0.0872	0.0872	0.0872	0.0872
Carbonyl Sulphide		0.0025	0.0025	0.0000	0.0000	0.0000	0.0000
Sulphur Dioxide		0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Ammonia		0.0028	0.0028	0.0040	0.0040	0.0040	0.0040
Hydrogen Cyanide		0.0012	0.0012	0.0000	0.0000	0.0000	0.0000
Dimethyl Ethers of Polyethylene Glycol		0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Nitrogen Oxide	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Temperature (°C)	Ambient	210	260	493	290	326	278
Pressure (bara)	Ambient	37.0	36.8	36.3	36.1	35.6	35.4
Mass Flow (kg/s)	48	177	177	177	177	177	177
Molar Flow (kmol/h)	N/A	31369	31369	31369	31369	31369	31369
Mole Percentage Vapour (%)	N/A	100	100	100	100	100	100

Table 4: IGCC simulations with separate capture of CO_2 and H_2S (South African Douglas coal)

Part 2 of 4							
Stream Name	**SG7**	**L1**	**SG8**	**SOLV1**	**SOLV2**	**AG**	**SOLV3**
Component (Molar %)	**Syngas to KO Drum**	**Liquid from KO Drum**	**Vapour to AGR**	**H_2S Loaded Solvent**	**Concentrated H_2S Loaded Solvent**	**Acid Gas to SRU**	**Semi Lean Solvent**
Water	27.0935	99.5298	0.2581	16.8203	23.9370	3.6294	23.3578
Hydrogen	36.5055	0.0238	50.0208	0.2668	0.0000	0.0001	0.0000
Carbon Dioxide	27.7543	0.4244	37.8792	34.4431	0.0211	1.0105	6.9297
Carbon Monoxide	2.5271	0.0017	3.4626	0.0613	0.0000	0.0000	0.0000
Nitrogen	6.0030	0.0029	8.2259	0.1480	2.1737	57.1677	0.0000
Argon	0.0254	0.0000	0.0348	0.0002	0.0000	0.0000	0.0000
Oxygen	0.0000	0.0000	0.0000	0.0000	<1ppmv	0.0008	0.0000
Hydrogen Sulphide	0.0872	0.0038	0.1181	1.4854	1.2156	31.9861	0.0028
Carbonyl Sulphide	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Sulphur Dioxide	0.0000	0.0000	0.0000	0.6305	0.8474	5.5675	0.6934
Ammonia	0.0040	0.0137	0.0004	0.0020	0.0004	0.0211	0.0003
Hydrogen Cyanide	0.0000	0.0000	0.0000	0.0002	0.0003	0.0002	0.0003
Dimethyl Ethers of Polyethylene Glycol	0.0000	0.0000	0.0000	46.1418	71.7810	0.0000	69.0157
Nitrogen Oxide	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Temperature (°C)	40	40	40	19	124	38	4
Pressure (bara)	34.4	34.4	34.4	45.0	38.2	1.8	1.2
Mass Flow (kg/s)	177	43	134	163	149	1	1287
Molar Flow (kmol/h)	31369	8480	22889	3415	2220	84	19721
Mole Percentage Vapour (%)	73	0	100	0	0	100	0

Table 4: IGCC simulations with separate capture of CO_2 and H_2S (South African Douglas coal)

Part 3 of 4

Stream Name	**SOLV4**	**SG9**	**MPCO2**	**LPCO2**	**SG10**	**FUEL1**	**DILN2**
Component (Molar %)	**Lean Solvent**	**HP Flash Gas**	**MP CO_2**	**LP CO_2**	**Sweet Syngas**	**CO_2 Free Syngas from AGR**	**Dilution Nitrogen**
Water	24.6337	0.0165	0.1500	0.4000	0.0074	0.0055	0.0000
Hydrogen	0.0000	36.2785	0.9023	0.0051	46.4794	74.9730	0.0000
Carbon Dioxide	0.0000	48.9524	97.9483	99.5601	39.7086	3.0249	0.0000
Carbon Monoxide	0.0000	3.6204	0.3027	0.0064	3.2236	5.1114	0.0000
Nitrogen	0.0000	11.1022	0.6875	0.0105	10.5454	16.8325	99.9995
Argon	0.0000	0.0264	0.0007	0.0000	0.0323	0.0521	0.0000
Oxygen	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0005
Hydrogen Sulphide	0.0000	0.0004	0.0011	0.0028	0.0011	0.0000	0.0000
Carbonyl Sulphide	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Sulphur Dioxide	0.6541	0.0032	0.0067	0.0140	0.0018	0.0006	0.0000
Ammonia	0.0000	0.0002	0.0005	0.0011	0.0003	0.0000	0.0000
Hydrogen Cyanide	0.0003	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Dimethyl Ethers of Polyethylene Glycol	74.7118	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Nitrogen Oxide	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Temperature (°C)	80	18	10	4	9	35	20
Pressure (bara)	8.5	25.0	5.0	1.2	33.7	33.5	35.0
Mass Flow (kg/s)	149	1	59	42	153	38	69
Molar Flow (kmol/h)	2159	95	4888	3423	24655	15214	8899
Mole Percentage Vapour (%)	0	100	100	100	100	100	100

Table 4: IGCC simulations with separate capture of CO_2 and H_2S (South African Douglas coal)

Part 4 of 4			
Stream Name	**FUEL2**	**EX1**	**EX2**
Component (Molar %)	**Fuel to GT**	**Combustion Products**	**Emissions to Atmosphere**
Water	0.0035	11.1390	11.1390
Hydrogen	47.3035	0.0000	0.0000
Carbon Dioxide	1.9085	1.1420	1.1420
Carbon Monoxide	3.2250	0.0000	0.0000
Nitrogen	47.5261	74.8875	74.8875
Argon	0.0329	0.7870	0.7870
Oxygen	0.0002	12.042	12.042
Hydrogen Sulphide	0.0000	0.0000	0.0000
Carbonyl Sulphide	0.0000	0.0000	0.0000
Sulphur Dioxide	0.0004	0.0001	0.0001
Ammonia	0.0000	0.0000	0.0000
Hydrogen Cyanide	0.0000	0.0000	0.0000
Dimethyl Ethers of Polyethylene Glycol	0.0000	0.0000	0.0000
Nitrogen Oxide	0.0000	0.0025	0.0025
Temperature (°C)	29	520	103
Pressure (bara)	33.5	1.0	1.0
Mass Flow (kg/s)	108	855	855
Molar Flow (kmol/h)	24113	111340	111340
Mole Percentage Vapour (%)	100	100	100

Table 5: IGCC simulations with separate capture of CO_2 and H_2S (USA Bailey coal)

Part 1 of 4

Stream Name	**FUEL**	**SG1**	**SG2**	**SG3**	**SG4**	**SG5**	**SG6**
Component (Molar %)	**Coal Feed**	**Clean Syngas from Gasifier**	**Entry to Shift Stage 1**	**Exit from Shift Stage 1**	**Entry to Shift Stage 2**	**Exit from Shift Stage 2**	**Syngas to Cooling**
Water		49.8787	49.8787	27.8742	27.8742	24.2652	24.2652
Hydrogen		14.0425	14.0425	36.0388	36.0388	39.6478	39.6478
Carbon Dioxide		1.6974	1.6974	23.7019	23.7019	27.3109	27.3109
Carbon Monoxide		28.4521	28.4521	6.4558	6.4558	2.8468	2.8468
Nitrogen		5.5648	5.5648	5.5648	5.5648	5.5648	5.5648
Argon		0.0246	0.0246	0.0246	0.0246	0.0246	0.0246
Oxygen		0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Hydrogen Sulphide		0.3317	0.3317	0.3399	0.3399	0.3399	0.3399
Carbonyl Sulphide		0.0082	0.0082	0.0000	0.0000	0.0000	0.0000
Sulphur Dioxide		0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Ammonia		0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Hydrogen Cyanide		0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Dimethyl Ethers of Polyethylene Glycol		0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Nitrogen Oxide	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Temperature (°C)	Ambient	210	260	490	290	328	280
Pressure (bara)	Ambient	37.0	36.8	36.3	36.1	35.6	35.4
Mass Flow (kg/s)	41	158	158	158	158	158	158
Molar Flow (kmol/h)	N/A	28975	28975	28975	28975	28975	28975
Mole Percentage Vapour (%)	N/A	100	100	100	100	100	100

Table 5: IGCC simulations with separate capture of CO_2 and H_2S (USA Bailey coal)

Part 2 of 4							
Stream Name	**SG7**	**L1**	**SG8**	**SOLV1**	**SOLV2**	**AG**	**SOLV3**
Component (Molar %)	**Syngas to KO Drum**	**Liquid from KO Drum**	**Vapour to AGR**	**H_2S Loaded Solvent**	**Concentrated H_2S Loaded Solvent**	**Acid Gas to SRU**	**Semi Lean Solvent**
Water	24.2652	99.5535	0.2571	12.3335	23.3274	3.6700	23.1939
Hydrogen	39.6478	0.0248	52.2829	0.2700	0.0000	0.0000	0.0000
Carbon Dioxide	27.3109	0.4030	35.8914	29.8996	0.0604	0.7133	7.2757
Carbon Monoxide	2.8468	0.0018	3.7540	0.0618	0.0000	0.0000	0.0000
Nitrogen	5.5648	0.0026	7.3386	0.1297	2.886	20.0231	0.0000
Argon	0.0246	0.0000	0.0324	0.0002	0.0000	0.0000	0.0000
Oxygen	0.0000	0.0000	0.0000	0.0000	<1ppmv	0.0005	0.0000
Hydrogen Sulphide	0.3399	0.0143	0.4437	9.4521	7.8778	75.5781	0.0025
Carbonyl Sulphide	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Sulphur Dioxide	0.0000	0.0000	0.0000	0.0012	0.0015	0.0148	0.0016
Ammonia	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Hydrogen Cyanide	0.0000	0.0000	0.0000	0.0001	0.0001	0.0001	0.0001
Dimethyl Ethers of Polyethylene Glycol	0.0000	0.0000	0.0000	47.8520	66.6442	0.0000	69.5263
Nitrogen Oxide	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Temperature (°C)	40	40	40	20	123	38	4
Pressure (bara)	34.4	34.4	34.4	45.0	38.2	1.8	1.2
Mass Flow (kg/s)	158	35	123	193	176	3	1297
Molar Flow (kmol/h)	28975	7006	21969	4054	2690	281	19133
Mole Percentage Vapour (%)	76	0	100	0	0	100	0

Table 5: IGCC simulations with separate capture of CO_2 and H_2S (USA Bailey coal)

Part 3 of 4

Stream Name	**SOLV4**	**SG9**	**MPCO2**	**LPCO2**	**SG10**	**FUEL1**	**DILN2**
Component (Molar %)	**Lean Solvent**	**HP Flash Gas**	**MP CO_2**	**LP CO_2**	**Sweet Syngas**	**CO_2 Free Syngas from AGR**	**Dilution Nitrogen**
Water	24.8999	0.0106	0.1500	0.4000	0.0052	0.0037	0.0000
Hydrogen	0.0000	41.0293	1.1618	0.0065	48.4558	76.4968	0.0000
Carbon Dioxide	0.0000	43.7883	97.4975	99.5707	38.2528	2.8058	0.0000
Carbon Monoxide	0.0000	4.1558	0.4022	0.0085	3.4819	5.3942	0.0000
Nitrogen	0.0000	10.9896	0.7867	0.0120	9.7738	15.2522	99.9995
Argon	0.0000	0.0261	0.0008	0.0000	0.0300	0.0474	0.0000
Oxygen	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0005
Hydrogen Sulphide	0.0000	0.0003	0.0009	0.0023	0.0005	0.0000	0.0000
Carbonyl Sulphide	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Sulphur Dioxide	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Ammonia	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Hydrogen Cyanide	0.0001	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Dimethyl Ethers of Polyethylene Glycol	74.1000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Nitrogen Oxide	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Temperature (°C)	100	17	10	4	10	35	20
Pressure (bara)	8.5	25.0	5.0	1.2	33.7	33.5	35.0
Mass Flow (kg/s)	175	1	50	42	142	36	72
Molar Flow (kmol/h)	2430	83	4122	3445	23769	14978	9255
Mole Percentage Vapour (%)	0	100	100	100	100	100	100

Table 5: IGCC simulations with separate capture of CO_2 and H_2S (USA Bailey coal)

Part 4 of 4			
Stream Name	**FUEL2**	**EX1**	**EX2**
Component (Molar %)	**Fuel to GT**	**Combustion Products**	**Emissions to Atmosphere**
Water	0.0023	11.1190	11.1190
Hydrogen	47.2820	0.0000	0.0000
Carbon Dioxide	1.7342	1.1260	1.1260
Carbon Monoxide	3.3341	0.0000	0.0000
Nitrogen	47.6180	74.9135	74.9135
Argon	0.0293	0.7860	0.7860
Oxygen	0.0002	12.0530	12.0530
Hydrogen Sulphide	0.0000	0.0000	0.0000
Carbonyl Sulphide	0.0000	0.0000	0.0000
Sulphur Dioxide	0.0000	0.0000	0.0000
Ammonia	0.0000	0.0000	0.0000
Hydrogen Cyanide	0.0000	0.0000	0.0000
Dimethyl Ethers of Polyethylene Glycol	0.0000	0.0000	0.0000
Nitrogen Oxide	0.0000	0.0025	0.0025
Temperature (°C)	28	520	103
Pressure (bara)	33.5	1.0	1.0
Mass Flow (kg/s)	108	857	857
Molar Flow (kmol/h)	24233	111605	111605
Mole Percentage Vapour (%)	100	100	100

Table 6: Expected ranges of stream properties for IGCC

Part 1 of 4							
Stream Name	**FUEL**	**SG1**	**SG2**	**SG3**	**SG4**	**SG5**	**SG6**
Component (Molar %)	**Coal Feed**	**Clean Syngas from Gasifier**	**Entry to Shift Stage 1**	**Exit from Shift Stage 1**	**Entry to Shift Stage 2**	**Exit from Shift Stage 2**	**Syngas to Cooling**
Water		1-66	1-66	25-35	25-35	20-30	20-30
Hydrogen		10-32	10-32	30-40	30-40	35-45	35-45
Carbon Dioxide		0-15	0-15	20-30	20-30	25-35	25-35
Carbon Monoxide		15-60	15-60	4-7	4-7	1-3	1-3
Nitrogen		0-3	0-3	0-3	0-3	0-3	0-3
Argon		0-1	0-1	0-1	0-1	0-1	0-1
Oxygen							
Hydrogen Sulphide		200-4000	200-4000	210-4200	210-4200	210-4200	210-4200
Carbonyl Sulphide		10-200	10-200	0	0	0	0
Sulphur Dioxide							
Ammonia		0-0.0040	0-0.0040	0-0.0060	0-0.0060	0-0.0060	0-0.0060
Hydrogen Cyanide		0-0.0020	0-0.0020				
Dimethyl Ethers of Polyethylene Glycol							
Nitrogen Oxide							
Temperature (°C)		200-260	250-270	480-500	280-300	320-330	270-290
Pressure (bara)		30-80	30-80	30-80	30-80	30-80	30-80
Mass Flow (kg/s)							
Molar Flow (kmol/h)							
Mole Percentage Vapour (%)							

Table 6: Expected ranges of stream properties for IGCC

Part 2 of 4

Stream Name	**SG7**	**L1**	**SG8**	**SOLV1**	**SOLV2**	**AG**	**SOLV3**
Component (Molar %)	**Syngas to KO Drum**	**Liquid from KO Drum**	**Vapour to AGR**	**H_2S Loaded Solvent**	**Concentrated H_2S Loaded Solvent**	**Acid Gas to SRU**	**Semi Lean Solvent**
Water	20-30	99-100	0.1-0.4	10-20	20-25	3-5	20-25
Hydrogen	35-45	0-0.0400	45-55	0-1			
Carbon Dioxide	25-35	0-0.5000	30-40	25-40	0-0.1	0-60	5-10
Carbon Monoxide	1-3	0-0.0030	3-4	0-0.2			
Nitrogen	0-3	0-0.0050	7-9	0-0.5	1-3	0-60	
Argon	0-1		0-1	0-0.0010			
Oxygen						0-0.0010	
Hydrogen Sulphide	210-4200	0-0.0200	800-8000	1-11	1-9	25-80	0-0.0100
Carbonyl Sulphide							
Sulphur Dioxide				0-1	0-1	0-6	0-1
Ammonia	0-0.0060	0-0.0200					
Hydrogen Cyanide							
Dimethyl Ethers of Polyethylene Glycol				40-50	65-75		65-75
Nitrogen Oxide							
Temperature (°C)	30-50	30-50	30-50	15-25	120-130	35-45	0-10
Pressure (bara)	30-80	30-80	30-80	40-80	40-80	1-2	1-2
Mass Flow (kg/s)							
Molar Flow (kmol/h)							
Mole Percentage Vapour (%)							

Table 6: Expected ranges of stream properties for IGCC

Part 3 of 4							
Stream Name	**SOLV4**	**SG9**	**MPCO2**	**LPCO2**	**SG10**	**FUEL1**	**DILN2**
Component (Molar %)	**Lean Solvent**	**HP Flash Gas**	**MP CO_2**	**LP CO_2**	**Sweet Syngas**	**CO_2 Free Syngas from AGR**	**Dilution Nitrogen**
Water	20-30	0-0.030	0-0.2	0-0.4	0-0.0100	0-0.0100	
Hydrogen		35-45	0-2	0-0.0100	45-50	70-80	
Carbon Dioxide		40-50	97-100	99-100	35-45	2-5	
Carbon Monoxide		3-5	0-0.5	0-0.0100	3-5	3-6	
Nitrogen		7-12	0-1	0-0.0200	8-12	10-20	98-100
Argon		0-0.0400	0-0.0010		0-0.0500	0-0.0600	
Oxygen							0-2
Hydrogen Sulphide		0-0.0010	0-0.0200	0-0.0200	0-0.0020	0-0.0020	
Carbonyl Sulphide							
Sulphur Dioxide		0-0.0050	0-0.0070	0-0.0200	0-0.0020	0-0.0010	
Ammonia		0-0.0010	0-0.0010	0-0.0020	0-0.0010		
Hydrogen Cyanide							
Dimethyl Ethers of Polyethylene Glycol	70-80						
Nitrogen Oxide							
Temperature (°C)	80-100	15-20	5-15	0-10	5-15	30-40	20-40
Pressure (bara)	1-80	20-30	3-7	1-2	30-80	30-80	30-80
Mass Flow (kg/s)							
Molar Flow (kmol/h)							
Mole Percentage Vapour (%)							

Table 6: Expected ranges of stream properties for IGCC

Part 4 of 4			
Stream Name	**FUEL2**	**EX1**	**EX2**
Component (Molar %)	**Fuel to GT**	**Combustion Products**	**Emissions to Atmosphere**
Water	0-0.0050	10-12	10-12
Hydrogen	45-50		
Carbon Dioxide	1-2	1-2	1-2
Carbon Monoxide	2-4		
Nitrogen	45-50	74-76	74-76
Argon	0-0.0300	0.5-1.0	0.5-1.0
Oxygen	0-0.0003	11-13	11-13
Hydrogen Sulphide	0-0.0010		
Carbonyl Sulphide			
Sulphur Dioxide	0-0.0005	0-0.0001	0-0.0001
Ammonia			
Hydrogen Cyanide			
Dimethyl Ethers of Polyethylene Glycol			
Nitrogen Oxide		0-0.0050	0-0.0050
Temperature (°C)	20-200	500-600	95-110
Pressure (bara)	25-40	1.0	1.0
Mass Flow (kg/s)			
Molar Flow (kmol/h)			
Mole Percentage Vapour (%)			

Table 7: IGCC simulations with co-capture of CO_2 and H_2S (USA Bailey coal)

Part 1 of 4							
Stream Name	**FUEL**	**SG1**	**SG2**	**SG3**	**SG4**	**SG5**	**SG6**
Component (Molar %)	**Coal Feed**	**Clean Syngas from Gasifier**	**Entry to Shift Stage 1**	**Exit from Shift Stage 1**	**Entry to Shift Stage 2**	**Exit from Shift Stage 2**	**Syngas to Cooling**
Water		49.8787	49.8787	27.8742	27.8742	24.2652	24.2652
Hydrogen		14.0425	14.0425	36.0388	36.0388	39.6478	39.6478
Carbon Dioxide		1.6974	1.6974	23.7019	23.7019	27.3109	27.3109
Carbon Monoxide		28.4521	28.4521	6.4558	6.4558	2.8468	2.8468
Nitrogen		5.5648	5.5648	5.5648	5.5648	5.5648	5.5648
Argon		0.0246	0.0246	0.0246	0.0246	0.0246	0.0246
Oxygen		0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Hydrogen Sulphide		0.3317	0.3317	0.3399	0.3399	0.3399	0.3399
Carbonyl Sulphide		0.0082	0.0082	0.0000	0.0000	0.0000	0.0000
Sulphur Dioxide		0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Ammonia		0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Hydrogen Cyanide		0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Dimethyl Ethers of Polyethylene Glycol		0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Nitrogen Oxide	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Temperature (°C)	Ambient	210	260	490	290	328	280
Pressure (bara)	Ambient	37.0	36.8	36.3	36.1	35.6	35.4
Mass Flow (kg/s)	41	158	158	158	158	158	158
Molar Flow (kmol/h)	N/A	28975	28975	28975	28975	28975	28975
Mole Percentage Vapour (%)	N/A	100	100	100	100	100	100

Table 7: IGCC simulations with co-capture of CO_2 and H_2S (USA Bailey coal)

Part 2 of 4							
Stream Name	**SG7**	**L1**	**SG8**	**SOLV1**	**SOLV2**	**AG**	**SOLV3**
Component (Molar %)	**Syngas to KO Drum**	**Liquid from KO Drum**	**Vapour to AGR**	**N/A**	**Concentrated CO_2 Loaded Solvent**	**Acid Gas to CO_2 Compressor**	**Semi Lean Solvent**
Water	24.2652	99.5535	0.2571		22.6142	1.4852	22.6142
Hydrogen	39.6478	0.0248	52.2829		0.0000	0.0000	0.0000
Carbon Dioxide	27.3109	0.4030	35.8914		7.6897	85.4830	7.6897
Carbon Monoxide	2.8468	0.0018	3.7540		0.0000	0.0002	0.0000
Nitrogen	5.5648	0.0026	7.3386		0.0000	0.0002	0.0000
Argon	0.0246	0.0000	0.0324		0.0000	0.0000	0.0000
Oxygen	0.0000	0.0000	0.0000		0.0000	0.0000	0.0000
Hydrogen Sulphide	0.3399	0.0143	0.4437		1.1727	13.0314	1.1727
Carbonyl Sulphide	0.0000	0.0000	0.0000		0.0000	0.0000	0.0000
Sulphur Dioxide	0.0000	0.0000	0.0000		0.0000	0.0000	0.0000
Ammonia	0.0000	0.0000	0.0000		0.0000	0.0000	0.0000
Hydrogen Cyanide	0.0000	0.0000	0.0000		0.0000	0.0000	0.0000
Dimethyl Ethers of Polyethylene Glycol	0.0000	0.0000	0.0000		68.5234	0.0000	68.5234
Nitrogen Oxide	0.0000	0.0000	0.0000		0.000	0.0000	0.000
Temperature (°C)	40	40	40		11	10	11
Pressure (bara)	34.4	34.4	34.4		1.5	0.8	1.5
Mass Flow (kg/s)	158	35	123		213	3	1921
Molar Flow (kmol/h)	28975	7006	21969		3047	274	27425
Mole Percentage Vapour (%)	76	0	100		0	100	0

Table 7: IGCC simulations with co-capture of CO_2 and H_2S (USA Bailey coal)

Part 3 of 4

Stream Name	**SOLV4**	**SG9**	**MPCO2**	**LPCO2**	**SG10**	**FUEL1**	**DILN2**
Component (Molar %)	**Lean Solvent**	**HP Flash Gas**	**MP CO_2**	**LP CO_2**	**N/A**	**CO_2 Free Syngas from AGR**	**Dilution Nitrogen**
Water	25.1000	0.0053	0.1500	0.4000		0.0011	0.0000
Hydrogen	0.0000	44.9205	1.9807	0.0139		80.1696	0.0000
Carbon Dioxide	0.0000	39.4380	95.4552	98.4722		3.0898	0.0000
Carbon Monoxide	0.0000	5.5813	0.8307	0.0210		5.6097	0.0000
Nitrogen	0.0000	9.8641	1.0977	0.0204		11.0801	99.9995
Argon	0.0000	0.0276	0.0012	0.0000		0.0497	0.0000
Oxygen	0.0000	0.0000	0.0000	0.0000		0.0000	0.0005
Hydrogen Sulphide	0.0000	0.1630	0.4845	1.0725		0.0000	0.0000
Carbonyl Sulphide	0.0000	0.0000	0.0000	0.0000		0.0000	0.0000
Sulphur Dioxide	0.0000	0.0000	0.0000	0.0000		0.0000	0.0000
Ammonia	0.0000	0.0000	0.0000	0.0000		0.0000	0.0000
Hydrogen Cyanide	0.0000	0.0000	0.0000	0.0000		0.0000	0.0000
Dimethyl Ethers of Polyethylene Glycol	74.9000	0.0000	0.0000	0.0000		0.0000	0.0000
Nitrogen Oxide	0.0000	0.0000	0.0000	0.0000		0.0000	0.0000
Temperature (°C)	84	18	15	11		36	20
Pressure (bara)	8.5	19.0	5.0	1.5		33.5	35
Mass Flow (kg/s)	210	1	35	55		30	77.5
Molar Flow (kmol/h)	2759	191	2904	4485		14255	9931
Mole Percentage Vapour (%)	0	100	100	100		100	100

Table 7: IGCC simulations with co-capture of CO_2 and H_2S (USA Bailey coal)

Part 4 of 4			
Stream Name	**FUEL2**	**EX1**	**EX2**
Component (Molar %)	**Fuel to GT**	**Combustion Products**	**Emissions to Atmosphere**
Water	0.0006	11.1190	11.1190
Hydrogen	47.2506	0.0000	0.0000
Carbon Dioxide	1.8211	1.1260	1.1260
Carbon Monoxide	3.3062	0.0000	0.0000
Nitrogen	47.5919	74.9135	74.9135
Argon	0.0293	0.7860	0.7860
Oxygen	0.0002	12.0530	12.0530
Hydrogen Sulphide	0.0000	0.0000	0.0000
Carbonyl Sulphide	0.0000	0.0000	0.0000
Sulphur Dioxide	0.0000	0.0000	0.0000
Ammonia	0.0000	0.0000	0.0000
Hydrogen Cyanide	0.0000	0.0000	0.0000
Dimethyl Ethers of Polyethylene Glycol	0.0000	0.0000	0.0000
Nitrogen Oxide	0.0000	0.0025	0.0025
Temperature (°C)	29	520	103
Pressure (bara)	33.5	1.0	1.0
Mass Flow (kg/s)	108	857	857
Molar Flow (kmol/h)	24186	111605	111605
Mole Percentage Vapour (%)	100	100	100

Table 8: IGCC simulations using natural gas

Part 1 of 4							
Stream Name	**FUEL**	**SG1**	**SG2**	**SG3**	**SG4**	**SG5**	**SG6**
Component (Molar %)	**Natural Gas Feed**	**Clean Syngas from Reformer**	**N/A**	**Exit from Shift Stage 1**	**Entry to Shift Stage 2**	**Exit from Shift Stage 2**	**N/A**
Water		34.5640		24.2995	24.2995	20.6648	
Hydrogen		49.4760		59.7405	59.7405	63.3752	
Carbon Dioxide		1.5960		11.8605	11.8605	15.4952	
Carbon Monoxide		14.3640		4.0995	4.0995	0.4648	
Nitrogen		0.0000		0.0000	0.0000	0.0000	
Argon		0.0000		0.0000	0.0000	0.0000	
Oxygen		0.0000		0.0000	0.0000	0.0000	
Hydrogen Sulphide		0.0000		0.0000	0.0000	0.0000	
Carbonyl Sulphide		0.0000		0.0000	0.0000	0.0000	
Sulphur Dioxide		0.0000		0.0000	0.0000	0.0000	
Ammonia		0.0000		0.0000	0.0000	0.0000	
Hydrogen Cyanide		0.0000		0.0000	0.0000	0.0000	
Dimethyl Ethers of Polyethylene Glycol		0.0000		0.0000	0.0000	0.0000	
Nitrogen Oxide		0.0000		0.0000	0.0000	0.0000	
Temperature (°C)	20	350		465	200	242	
Pressure (bara)	40.0	38		37.5	37.3	36.8	
Mass Flow (kg/s)	17	81		81	81	81	
Molar Flow (kmol/h)	3871	24256		24256	24256	24256	
Mole Percentage Vapour (%)	100	100		100	100	100	

Table 8: IGCC simulations using natural gas

Part 2 of 4

Stream Name	**SG7**	**L1**	**SG8**	**SOLV1**	**SOLV2**	**CO2**	**SOLV3**
Component (Molar %)	**Syngas to KO Drum**	**Liquid from KO Drum**	**Vapour to AGR**	**N/A**	**Concentrated CO_2 Loaded Solvent**	**To CO_2 Compressor**	**Semi Lean Solvent**
Water	20.6648	99.7299	0.2353		23.2874	1.5450	23.2874
Hydrogen	63.3752	0.0381	79.7408		0.0000	0.0001	0.0000
Carbon Dioxide	15.4952	0.2317	19.4391		6.8788	98.4548	6.8788
Carbon Monoxide	0.4648	0.0003	0.5849		0.0000	0.0000	0.0000
Nitrogen	0.0000	0.0000	0.0000		0.0000	0.0000	0.0000
Argon	0.0000	0.0000	0.0000		0.0000	0.0000	0.0000
Oxygen	0.0000	0.0000	0.0000		0.0000	0.0000	0.0000
Hydrogen Sulphide	0.0000	0.0000	0.0000		0.0000	0.0000	0.0000
Carbonyl Sulphide	0.0000	0.0000	0.0000		0.0000	0.0000	0.0000
Sulphur Dioxide	0.0000	0.0000	0.0000		0.0000	0.0000	0.0000
Ammonia	0.0000	0.0000	0.0000		0.0000	0.0000	0.0000
Hydrogen Cyanide	0.0000	0.0000	0.0000		0.0000	0.0000	0.0000
Dimethyl Ethers of Polyethylene Glycol	0.0000	0.0000	0.0000		69.8337	0.0000	69.8337
Nitrogen Oxide	0.0000	0.0000	0.0000		0.000	0.0000	0.000
Temperature (°C)	40	40	40		6	10	6
Pressure (bara)	35.8	35.8	35.8		1.5	0.8	1.5
Mass Flow (kg/s)	81	25	56		256	4	770
Molar Flow (kmol/h)	24256	4980	19277		4621	329	13864
Mole Percentage Vapour (%)	79	0	100		0	100	0

Table 8: IGCC simulations using natural gas

Part 3 of 4							
Stream Name	**SOLV4**	**SG9**	**MPCO2**	**LPCO2**	**SG10**	**FUEL1**	**DILSTEAM**
Component (Molar %)	**Lean Solvent**	**HP Flash Gas**	**MP CO_2**	**LP CO_2**	**N/A**	**CO_2 Free Syngas from AGR**	**Dilution Steam**
Water	25.9218	0.0303	0.0750	0.1500		0.0151	100.0000
Hydrogen	0.0000	68.5925	1.9807	0.0139		95.8845	0.0000
Carbon Dioxide	0.0000	30.5767	97.2316	99.8361		3.4062	0.0000
Carbon Monoxide	0.0000	0.8006	0.8307	0.0210		0.6941	0.0000
Nitrogen	0.0000	0.0000	0.0000	0.0000		0.0000	0.0000
Argon	0.0000	0.0000	0.0000	0.0000		0.0000	0.0000
Oxygen	0.0000	0.0000	0.0000	0.0000		0.0000	0.0000
Hydrogen Sulphide	0.0000	0.0000	0.0000	0.0000		0.0000	0.0000
Carbonyl Sulphide	0.0000	0.0000	0.0000	0.0000		0.0000	0.0000
Sulphur Dioxide	0.0000	0.0000	0.0000	0.0000		0.0000	0.0000
Ammonia	0.0000	0.0000	0.0000	0.0000		0.0000	0.0000
Hydrogen Cyanide	0.0000	0.0000	0.0000	0.0000		0.0000	0.0000
Dimethyl Ethers of Polyethylene Glycol	74.0782	0.0000	0.0000	0.0000		0.0000	0.0000
Nitrogen Oxide	0.0000	0.0000	0.0000	0.0000		0.0000	0.0000
Temperature (°C)	24	11	10	11		31	250
Pressure (bara)	8.5	19.0	5.0	1.5		33.5	35
Mass Flow (kg/s)	252	0.3	7	28		16	91
Molar Flow (kmol/h)	4291	68	637	2296		15987	18314
Mole Percentage Vapour (%)	0	100	100	100		100	100

Table 8: IGCC simulations using natural gas

Part 4 of 4			
Stream Name	**FUEL2**	**EX1**	**EX2**
Component (Molar %)	**Fuel to GT**	**Combustion Products**	**Emissions to Atmosphere**
Water	43.000	21.0100	21.0100
Hydrogen	53.0000	0.0000	0.0000
Carbon Dioxide	2.0000	0.8652	0.8652
Carbon Monoxide	2.0000	0.0000	0.0000
Nitrogen	0.0000	65.5270	65.5270
Argon	0.0000	0.7892	0.7892
Oxygen	0.0000	11.8100	11.8100
Hydrogen Sulphide	0.0000	0.0000	0.0000
Carbonyl Sulphide	0.0000	0.0000	0.0000
Sulphur Dioxide	0.0000	0.0000	0.0000
Ammonia	0.0000	0.0000	0.0000
Hydrogen Cyanide	0.0000	0.0000	0.0000
Dimethyl Ethers of Polyethylene Glycol	0.0000	0.0000	0.0000
Nitrogen Oxide	0.0000	0.0025	0.0025
Temperature (°C)	250	520	103
Pressure (bara)	33.5	1.0	1.0
Mass Flow (kg/s)	108	857	857
Molar Flow (kmol/h)	34301	111605	111605
Mole Percentage Vapour (%)	100	100	100

Table 9: IGCC simulation results for CO_2 compression (separate capture of CO_2 and H_2S)

Part 1 of 3

Stream Name	**1**	**2**	**3**	**4**	**5**	**6**	**7**
Component (Molar %)	**LP CO_2 Stage 1 Inlet**	**Stage 1 Exit / Stage 2 Inlet**	**Stage 2 Exit (before i/c)**	**Stage 2 Exit (after i/c)**	**MP CO_2**	**Stage 3 Inlet**	**Stage 3 Exit / Stage 4 Inlet**
Water	0.4000	0.4000	0.4000	0.4000	0.1500	0.2633	0.2633
Hydrogen	0.0065	0.0065	0.0065	0.0065	1.1618	0.6384	0.6384
Carbon Dioxide	99.5707	99.5707	99.5707	99.5707	97.4991	98.4377	98.4377
Carbon Monoxide	0.0085	0.0085	0.0085	0.0085	0.4022	0.2238	0.2238
Nitrogen	0.0120	0.0120	0.0120	0.0120	0.7852	0.4399	0.4399
Argon	0.0000	0.0000	0.0000	0.0000	0.0008	0.0004	0.0004
Oxygen	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Hydrogen Sulphide	0.0023	0.0023	0.0023	0.0023	0.0009	0.0015	0.0015
Carbonyl Sulphide	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Sulphur Dioxide	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Ammonia	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Hydrogen Cyanide	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Dimethyl Ethers of Polyethylene Glycol	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Nitrogen Oxide	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Temperature (°C)	4	63	129	40	10	23	85
Pressure (bara)	1.2	2.4	4.8	4.3	5	4.3	8.6
Mass Flow (kg/s)	42	42	42	42	50	92	92
Molar Flow (kmol/h)	3444	3444	3444	3444	4158	7602	7602
Mole Percentage Vapour (%)	100	100	100	100	100	100	100

Table 9: IGCC simulation results for CO_2 compression (separate capture of CO_2 and H_2S)

Part 2 of 3							
Stream Name	**8**	**9**	**10**	**11**	**12**	**13**	**14**
Component (Molar %)	**Stage 4 Exit**	**Stage 5 Inlet**	**Stage 5 Exit / Stage 6 Inlet**	**Stage 6 Exit**	**Water KO**	**Stage 7 Inlet**	**Stage 7 Exit / Stage 8 Inlet**
Water	0.2633	0.2633	0.2633	0.2633	98.1183	0.0200	0.0200
Hydrogen	0.6384	0.6384	0.6384	0.6384	0.0010	0.6399	0.6399
Carbon Dioxide	98.4377	98.4377	98.4377	98.4377	1.8799	98.6778	98.6778
Carbon Monoxide	0.2238	0.2238	0.2238	0.2238	0.0003	0.2244	0.2244
Nitrogen	0.4399	0.4399	0.4399	0.4399	0.0004	0.4360	0.4360
Argon	0.0004	0.0004	0.0004	0.0004	0.0000	0.0004	0.0004
Oxygen	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Hydrogen Sulphide	0.0015	0.0015	0.0015	0.0015	0.0000	0.0015	0.0015
Carbonyl Sulphide	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Sulphur Dioxide	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Ammonia	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Hydrogen Cyanide	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Dimethyl Ethers of Polyethylene Glycol	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Nitrogen Oxide	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Temperature (°C)	156	40	106	181	40	40	104
Pressure (bara)	17.2	16.7	33.4	66.8	64.8	64.8	129.6
Mass Flow (kg/s)	92	92	92	92	0.1	91.9	91.9
Molar Flow (kmol/h)	7602	7602	7602	7602	18.5	7584	7584
Mole Percentage Vapour (%)	100	100	100	100	0	100	100

Table 9: IGCC simulation results for CO_2 compression (separate capture of CO_2 and H_2S)

Part 3 of 3		
Stream Name	**15**	**16**
Component (Molar %)	**Stage 8 Exit**	**Final CO_2 Product**
Water	0.0200	0.0200
Hydrogen	0.6399	0.6399
Carbon Dioxide	98.6778	98.6778
Carbon Monoxide	0.2244	0.2244
Nitrogen	0.4360	0.4360
Argon	0.0004	0.0004
Oxygen	0.0000	0.0000
Hydrogen Sulphide	0.0015	0.0015
Carbonyl Sulphide	0.0000	0.0000
Sulphur Dioxide	0.0000	0.0000
Ammonia	0.0000	0.0000
Hydrogen Cyanide	0.0000	0.0000
Dimethyl Ethers of Polyethylene Glycol	0.0000	0.0000
Nitrogen Oxide	0.0000	0.0000
Temperature (°C)	118	40
Pressure (bara)	150.5	150
Mass Flow (kg/s)	91.9	91.9
Molar Flow (kmol/h)	7584	7584
Mole Percentage Vapour (%)	100	100

Table 10: IGCC simulation results for CO_2 compression (co-capture of CO_2 and H_2S)

Part 1 of 3							
Stream Name	**1**	**2**	**3**	**4**	**5**	**6**	**7**
Component (Molar %)	**VLP CO_2**	**Stage 1 Exit**	**LP CO_2**	**Stage 2 Inlet**	**Stage 2 Exit / Stage 3 Inlet**	**Stage 3 Exit (before i/c)**	**Stage 3 Exit (after i/c)**
Water	1.4852	1.4852	0.4000	0.4620	0.4620	0.4620	0.4620
Hydrogen	0.0000	0.0000	0.0139	0.0131	0.0131	0.0131	0.0131
Carbon Dioxide	85.483	85.483	98.4722	97.7301	97.7301	97.7301	97.7301
Carbon Monoxide	0.0002	0.0002	0.021	0.0198	0.0198	0.0198	0.0198
Nitrogen	0.0002	0.0002	0.0204	0.0192	0.0192	0.0192	0.0192
Argon	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Oxygen	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Hydrogen Sulphide	13.0314	13.0314	1.0725	1.7557	1.7557	1.7557	1.7557
Carbonyl Sulphide	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Sulphur Dioxide	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Ammonia	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Hydrogen Cyanide	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Dimethyl Ethers of Polyethylene Glycol	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Nitrogen Oxide	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Temperature (°C)	10	64	11	14	75	143	40
Pressure (bara)	0.8	1.5	1.5	1.5	3.0	6.0	5.5
Mass Flow (kg/s)	3	3	4522	58	58	58	58
Molar Flow (kmol/h)	274	274	55	4796	4796	4796	4796
Mole Percentage Vapour (%)	100	100	100	100	100	100	100

Table 10: IGCC simulation results for CO_2 compression (co-capture of CO_2 and H_2S)

Part 2 of 3							
Stream Name	**8**	**9**	**10**	**11**	**12**	**13**	**14**
Component (Molar %)	**MP CO_2**	**Stage 4 Inlet**	**Stage 4 Exit / Stage 5 Inlet**	**Stage 5 Exit**	**Stage 6 Inlet**	**Stage 6 Exit / Stage 7 Inlet**	**Stage 7 Exit**
Water	0.1500	0.3433	0.3433	0.3433	0.3433	0.3433	0.3433
Hydrogen	1.9807	0.7617	0.7617	0.7617	0.7617	0.7617	0.7617
Carbon Dioxide	95.4552	96.8646	96.8646	96.8646	96.8646	96.8646	96.8646
Carbon Monoxide	0.8307	0.3283	0.3283	0.3283	0.3283	0.3283	0.3283
Nitrogen	1.0977	0.4296	0.4296	0.4296	0.4296	0.4296	0.4296
Argon	0.0012	0.0004	0.0004	0.0004	0.0004	0.0004	0.0004
Oxygen	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Hydrogen Sulphide	0.4845	1.2721	1.2721	1.2721	1.2721	1.2721	1.2721
Carbonyl Sulphide	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Sulphur Dioxide	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Ammonia	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Hydrogen Cyanide	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Dimethyl Ethers of Polyethylene Glycol	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Nitrogen Oxide	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Temperature (°C)	15	30	93	165	40	106	161
Pressure (bara)	5.0	5.0	10	20	19.5	39	65
Mass Flow (kg/s)	35	93	93	93	93	93	93
Molar Flow (kmol/h)	2945	7741	7741	7741	7741	7741	7741
Mole Percentage Vapour (%)	100	100	100	100	100	100	100

Table 10: IGCC simulation results for CO_2 compression (co-capture of CO_2 and H_2S)

Part 3 of 3					
Stream Name	**15**	**16**	**17**	**18**	**19**
Component (Molar %)	**Water KO**	**Stage 8 Inlet**	**Stage 8 Exit / Stage 9 Inlet**	**Stage 9 Exit**	**Final CO_2 Product**
Water	100	0.0200	0.0200	0.0200	0.0200
Hydrogen	0.0000	0.7642	0.7642	0.7642	0.7642
Carbon Dioxide	0.0000	97.1788	97.1788	97.1788	97.1788
Carbon Monoxide	0.0000	0.3294	0.3294	0.3294	0.3294
Nitrogen	0.0000	0.4309	0.4309	0.4309	0.4309
Argon	0.0000	0.0005	0.0005	0.0005	0.0005
Oxygen	0.0000	0.0000	0.0000	0.0000	0.0000
Hydrogen Sulphide	0.0000	1.2762	1.2762	1.2762	1.2762
Carbonyl Sulphide	0.0000	0.0000	0.0000	0.0000	0.0000
Sulphur Dioxide	0.0000	0.0000	0.0000	0.0000	0.0000
Ammonia	0.0000	0.0000	0.0000	0.0000	0.0000
Hydrogen Cyanide	0.0000	0.0000	0.0000	0.0000	0.0000
Dimethyl Ethers of Polyethylene Glycol	0.0000	0.0000	0.0000	0.0000	0.0000
Nitrogen Oxide	0.0000	0.0000	0.0000	0.0000	0.0000
Temperature (°C)	40	40	105	122	40
Pressure (bara)	63	63	126	150.5	150
Mass Flow (kg/s)	0.13	93	93	93	93
Molar Flow (kmol/h)	25	7716	7716	7716	7716
Mole Percentage Vapour (%)	0	100	100	100	100

Table 11: Post-combustion capture simulations (South African Douglas coal)

Part 1 of 6							
Stream Name	**FG1**	**FG2**	**FG3**	**FG4**	**FG5**	**DCW1**	**DCW2**
Component (Molar %)	**Flue Gas from FGD Unit**	**Exit from DCC**	**Entry to SO_2 Polisher**	**Exit from SO_2 Polisher**	**Entry to CO_2 Absorber**	**Excess Water from DCC**	**Excess Water from SO_2 Polisher**
Carbon Dioxide	13.8347	14.6522	14.6453	14.6786	14.6786	0.0076	0
Water	9.6224	4.2796	4.3166	4.1101	4.1101	99.9914	95.2232
Oxygen	3.6155	3.8293	3.8274	3.8361	3.8361	8.1871E-05	0
Nitrogen	72.0692	76.3300	76.2945	76.4679	76.4679	0.0008	0
Sulphur Dioxide	0.0035	0.0037	0.0037	0.0004	0.0004	7.5991E-05	1.4561(1)
Argon	0.8547	0.9052	0.9048	0.9069	0.9069	2.0974E-05	0
Monoethanolamine	0	0	0	0	0	0	0
Sodium Hydroxide	0	0	0.0075	0	0	0	3.3207(2)
Temperature (°C)	45	30	31	31	39	30	31
Pressure (bara)	1.02	1.00	1.00	0.98	1.06	1.00	0.98
Mass Flow (kg/s)	433	418	418	418	418	14.8	0.6
Molar Flow (kmol/h)	52821	49873	49896	49783	49783	2949	113
Mole Percentage Vapour (%)	99.8	100	99.9	100	100	0	0

Note 1: This corresponds to the SO_2 removed as sulphate in the SO_2 polisher
Note 2: This corresponds to the NaOH that reacted with SO_2 in the polisher

Table 11: Post-combustion capture simulations (South African Douglas coal)

Part 2 of 6							
Stream Name	**NA1**	**RA1**	**RA2**	**RA3**	**LA1**	**LA2**	**LA3**
Component (Molar %)	**Sodium Hydroxide Solution**	**Rich Solvent from CO_2 Absorber**	**Rich Solvent Entering Lean/Rich Heat Exchanger**	**Rich Solvent Entering CO_2 Stripper**	**Lean Solvent Leaving CO_2 Stripper**	**Lean Solvent Entering CO_2 Stripper**	**Lean Solvent Entering Flash Drum**
Carbon Dioxide	0	6.0740	6.0740	6.0740	2.5489	4.1052	2.3795
Water	83.8199	82.2124	82.2124	82.2124	86.6715	95.3914	85.7228
Oxygen	0	6.9506E-05	6.9506E-05	6.9506E-05	0	0	0
Nitrogen	0	0.0007	0.0007	0.0007	0	0	0
Sulphur Dioxide	0	5.6831E-06	5.6831E-06	5.6831E-06	0	0	0
Argon	0	1.7653E-05	1.7653E-05	1.7653E-05	0	0	0
Monoethanolamine	0	11.7128	11.7128	11.7128	10.7796	0.5033	11.8976
Sodium Hydroxide	16.1801	0	0	0	0	0	0
Temperature (°C)	15	30	30	92	119	120	120
Pressure (bara)	1.5	1.06	7.06	6.06	1.85	1.84	1.84
Mass Flow (kg/s)	0.14	1185	1185	1185	1226	100	1126
Molar Flow (kmol/h)	23.2	173133	173133	173133	189247	18569	170678
Mole Percentage Vapour (%)	0	0	0	0	0	100	0

Table 11: Post-combustion capture simulations (South African Douglas coal)

Part 3 of 6							
Stream Name	**LA4**	**LA5**	**LA6**	**LA7**	**CD1**	**CD2**	**RF1**
Component (Molar %)	**Exit from Flash Drum**	**Lean Solvent Entering Lean/Rich Heat Exchanger**	**Lean Solvent Leaving Lean/Rich Heat Exchanger**	**Lean Solvent Entering CO_2 Absorber**	**CO_2-Rich Stream Leaving CO_2 Stripper**	**CO_2-Rich Stream Leaving Condenser**	**Liquid Leaving Reflux Drum**
Carbon Dioxide	2.3935	2.3935	2.3935	2.3702	64.2013	64.2013	0.0564
Water	85.2823	85.2823	85.2823	85.4285	35.7848	35.7848	99.9432
Oxygen	0	0	0	4.6412E-10	0.0012	0.0012	4.6552E-08
Nitrogen	0	0	0	2.4931E-09	0.0121	0.0121	2.5006E-07
Sulphur Dioxide	0	0	0	3.1158E-08	9.6529E-05	9.6529E-05	3.1253E-06
Argon	0	0	0	1.2651E-10	0.0003	0.0003	1.2689E-08
Monoethanolamine	12.3242	12.3242	12.3242	12.2013	0.0001	0.0001	0.0004
Sodium Hydroxide	0	0	0	0	0	0	0
Temperature (°C)	104	104	41	41	85	40	39
Pressure (bara)	1.06	7.06	6.06	1.4	1.6	1.5	1.4
Mass Flow (kg/s)	1094	1094	1094	1102.3	98.8	98.8	16.6
Molar Flow (kmol/h)	164543	164543	164543	166200	10247	10247	3314
Mole Percentage Vapour (%)	0	0	0	0	100	67.6	0

Table 11: Post-combustion capture simulations (South African Douglas coal)

Part 4 of 6							
Stream Name	**RF2**	**RF3**	**RF4**	**IC1**	**IC2**	**IC3**	**WW1**
Component (Molar %)	**Liquid Leaving Pump**	**Liquid Entering CO_2 Stripper**	**Liquid Recirculated to CO_2 Absorber**	**Side Stream from CO_2 Absorber**	**Side Stream Entering Intercooler**	**Side Stream Entering CO_2 Absorber**	**Side Stream from CO_2 Absorber**
Carbon Dioxide	0.0564	0.0564	0.0564	6.0353	6.0353	6.0353	3.6304
Water	99.9432	99.9432	99.9432	82.2269	82.2269	82.2269	85.1530
Oxygen	4.6552E-08	4.6552E-08	4.6552E-08	6.4750E-05	6.4750E-05	6.4750E-05	1.6576E-05
Nitrogen	2.5006E-07	2.5006E-07	2.5006E-07	0.0007	0.0007	0.0007	0.0002
Sulphur Dioxide	3.1252E-06	3.1252E-06	3.1252E-06	4.9438E-06	4.9438E-06	4.9438E-06	8.3524E-07
Argon	1.2689E-08	1.2689E-08	1.2689E-08	1.6370E-05	1.6370E-05	1.6370E-05	4.0725E-06
Monoethanolamine	0.0004	0.0004	0.0004	11.7370	11.7370	11.7370	11.2164
Sodium Hydroxide	0	0	0	0	0	0	0
Temperature (°C)	39	39	39	42	42	26	64
Pressure (bara)	6.4	5.4	5.4	1.05	3.05	2.55	1.01
Mass Flow (kg/s)	16.6	8.3	8.3	1182	1182	1182	1195.5
Molar Flow (kmol/h)	3314	1657	1657	172776	172776	172776	180905
Mole Percentage Vapour (%)	0	0	0	0	0	0	0

Table 11: Post-combustion capture simulations (South African Douglas coal)

Part 5 of 6							
Stream Name	**WW2**	**WW3**	**WW4**	**WW5**	**FA1**	**FA2**	**TG1**
Component (Molar %)	**Side Stream after Pump**	**Demineralised Water**	**Side Stream Entering Wash Water Cooler**	**Side Stream Entering CO_2 Absorber**	**To Vapour Compressor**	**To CO_2 Stripper**	**Treated Gas**
Carbon Dioxide	3.6304	0	3.6214	3.6214	2.0039	2.0039	1.6699
Water	85.1530	100	85.1898	85.1898	97.5388	97.5388	6.0178
Oxygen	1.6576E-05	0	1.6535E-05	1.6535E-05	0	0	4.3604
Nitrogen	0.0002	0	0.0002	0.0002	0	0	86.9206
Sulphur Dioxide	8.3524E-07	0	8.3317E-07	8.3317E-07	0	0	0.0004
Argon	4.0725E-06	0	4.0624E-06	4.0624E-06	0	0	1.0308
Monoethanolamine	11.2164	0	11.1886	11.1886	0.4573	0.4573	2.6041E-05
Sodium Hydroxide	0	0	0	0	0	0	0
Temperature (°C)	64	20	64	38	104	168	36
Pressure (bara)	5	5	5	4	1.06	1.85	0.99
Mass Flow (kg/s)	1195.5	2.25	1197.75	1197.75	32	32	340
Molar Flow (kmol/h)	180905	450	181355	181355	6135	6135	43795
Mole Percentage Vapour (%)	0	0	0	0	100	100	100

Table 11: Post-combustion capture simulations (South African Douglas coal)

Part 6 of 6	
Stream Name	**CO1**
Component (Molar %)	**CO_2 to Compressor**
Carbon Dioxide	94.8707
Water	5.1090
Oxygen	0.0017
Nitrogen	0.0180
Sulphur Dioxide	0.0001
Argon	0.0004
Monoethanolamine	1.2543E-11
Sodium Hydroxide	0
Temperature (°C)	39
Pressure (bara)	1.4
Mass Flow (kg/s)	82.2
Molar Flow (kmol/h)	6932
Mole Percentage Vapour (%)	100

Table 12: Post-combustion capture simulations (USA Bailey coal)

Part 1 of 6							
Stream Name	**FG1**	**FG2**	**FG3**	**FG4**	**FG5**	**DCW1**	**DCW2**
Component (Molar %)	**Flue Gas from FGD Unit**	**Exit from DCC**	**Entry to SO_2 Polisher**	**Exit from SO_2 Polisher**	**Entry to CO_2 Absorber**	**Excess Water from DCC**	**Excess Water from SO_2 Polisher**
Carbon Dioxide	13.3685	14.2720	14.2659	14.2981	14.2981	0.0074	0
Water	10.3415	4.2795	4.3134	4.1070	4.1070	99.9916	95.6022
Oxygen	3.5869	3.8295	3.8278	3.8365	3.8365	8.1875E-05	0
Nitrogen	71.8473	76.7055	76.6728	76.8462	76.8462	0.0008	0
Sulphur Dioxide	0.0032	0.0033	0.0033	0.0003	0.0003	6.9623E-05	1.3404(1)
Argon	0.8525	0.9102	0.9098	0.9118	0.9118	2.1088E-05	0
Monoethanolamine	0	0	0	0	0	0	0
Sodium Hydroxide	0	0	0.0069	0	0	0	3.0574(2)
Temperature (°C)	45	30	31	31	39	30	31
Pressure (bara)	1.02	0.99	0.99	100	1.06	0.99	0.98
Mass Flow (kg/s)	421	405	405.3	404.8	404.8	16.4	0.6
Molar Flow (kmol/h)	51689	48416	48436	48327	48327	3274	109.3
Mole Percentage Vapour (%)	99	100	99.9	100	100	0	0

Note 1: This corresponds to the SO_2 removed as sulphate in the SO_2 polisher
Note 2: This corresponds to the NaOH that reacted with SO_2 in the polisher

Table 12: Post-combustion capture simulations (USA Bailey coal)

Part 2 of 6							
Stream Name	**NA1**	**RA1**	**RA2**	**RA3**	**LA1**	**LA2**	**LA3**
Component (Molar %)	**Sodium Hydroxide Solution**	**Rich Solvent from CO_2 Absorber**	**Rich Solvent Entering Lean/Rich Heat Exchanger**	**Rich Solvent Entering CO_2 Stripper**	**Lean Solvent Leaving CO_2 Stripper**	**Lean Solvent Entering CO_2 Stripper**	**Lean Solvent Entering Flash Drum**
Carbon Dioxide	0	6.0725	6.0725	6.0725	2.5453	4.1050	2.3758
Water	83.8199	82.2324	82.2324	82.2324	86.6912	95.3926	85.7453
Oxygen	0	7.0914E-05	7.0914E-05	7.0914E-05	0	0	0
Nitrogen	0	0.0007	0.0007	0.0007	0	0	0
Sulphur Dioxide	0	5.4302E-06	5.4302E-06	5.4302E-06	0	0	0
Argon	0	1.8132E-05	1.8132E-05	1.8132E-05	0	0	0
Monoethanolamine	0	11.6942	11.6942	11.6942	10.7635	0.5024	11.8789
Sodium Hydroxide	16.1801	0	0	0	0	0	0
Temperature (°C)	15	29	29	92	119	120	120
Pressure (bara)	1.5	1.06	7.06	6.06	1.85	1.84	1.84
Mass Flow (kg/s)	0.12	1120	1120	1120	1158	94	1064
Molar Flow (kmol/h)	20.6	163645	163645	163645	178861	17537	161324
Mole Percentage Vapour (%)	0	0	0	0	0	100	0

Table 12: Post-combustion capture simulations (USA Bailey coal)

Part 3 of 6							
Stream Name	**LA4**	**LA5**	**LA6**	**LA7**	**CD1**	**CD2**	**RF1**
Component (Molar %)	**Exit from Flash Drum**	**Lean Solvent Entering Lean/Rich Heat Exchanger**	**Lean Solvent Leaving Lean/Rich Heat Exchanger**	**Lean Solvent Entering CO_2 Absorber**	**CO_2-Rich Stream Leaving CO_2 Stripper**	**CO_2-Rich Stream Leaving Condenser**	**Liquid Leaving Reflux Drum**
Carbon Dioxide	2.3897	2.3897	2.3897	2.3665	64.2586	64.2586	0.0564
Water	85.3056	85.3056	85.3056	85.4512	35.7272	35.7272	99.9432
Oxygen	0	0	0	4.7228E-10	0.0012	0.0012	4.7467E-08
Nitrogen	0	0	0	2.5428E-09	0.0124	0.0124	2.5557E-07
Sulphur Dioxide	0	0	0	2.9695E-08	9.2259E-05	9.2259E-05	2.9845E-06
Argon	0	0	0	1.2961E-10	0.0003	0.0003	1.3026E-08
Monoethanolamine	12.3047	12.3047	12.3047	12.1823	0.0001	0.0001	0.0004
Sodium Hydroxide	0	0	0	0	0	0	0
Temperature (°C)	104	104	40	40	85	40	39
Pressure (bara)	1.06	7.06	6.06	1.4	1.6	1.5	1.4
Mass Flow (kg/s)	1034	1034	1034	1041.8	93.4	93.4	15.7
Molar Flow (kmol/h)	155526	155526	155526	157089	9682	9682	3126
Mole Percentage Vapour (%)	0	0	0	0	100	67.6	0

Table 12: Post-combustion capture simulations (USA Bailey coal)

Part 4 of 6							
Stream Name	**RF2**	**RF3**	**RF4**	**IC1**	**IC2**	**IC3**	**WW1**
Component (Molar %)	**Liquid Leaving Pump**	**Liquid Entering CO_2 Stripper**	**Liquid Recirculated to CO_2 Absorber**	**Side Stream from CO_2 Absorber**	**Side Stream Entering Intercooler**	**Side Stream Entering CO_2 Absorber**	**Side Stream from CO_2 Absorber**
Carbon Dioxide	0.0564	0.0564	0.0564	6.0369	6.0369	6.0369	3.6462
Water	99.9432	99.9432	99.9432	82.2344	82.2344	82.2344	85.1400
Oxygen	4.7467E-08	4.7467E-08	4.7467E-08	6.6058E-05	6.6058E-05	6.6058E-05	1.6767E-05
Nitrogen	2.5557E-07	2.5557E-07	2.5557E-07	0.0007	0.0007	0.0007	0.0002
Sulphur Dioxide	2.9845E-06	2.9845E-06	2.9845E-06	4.7305E-06	4.7305E-06	4.7305E-06	7.8667E-07
Argon	1.3026E-08	1.3026E-08	1.3026E-08	1.6815E-05	1.6815E-05	1.6815E-05	4.1470E-06
Monoethanolamine	0.0004	0.0004	0.0004	11.7279	11.7279	11.7279	11.2136
Sodium Hydroxide	0	0	0	0	0	0	0
Temperature (°C)	39	39	39	41	41	24	63
Pressure (bara)	6.4	5.4	5.4	1.05	3.05	2.55	1.01
Mass Flow (kg/s)	15.7	7.8	7.8	1116	1116	1116	1128
Molar Flow (kmol/h)	3126	1563	1563	163177	163177	163177	170759
Mole Percentage Vapour (%)	0	0	0	0	0	0	0

Table 12: Post-combustion capture simulations (USA Bailey coal)

Part 5 of 6							
Stream Name	**WW2**	**WW3**	**WW4**	**WW5**	**FA1**	**FA2**	**TG1**
Component (Molar %)	**Side Stream after Pump**	**Demineralised Water**	**Side Stream Entering Wash Water Cooler**	**Side Stream Entering CO_2 Absorber**	**To Vapour Compressor**	**To CO_2 Stripper**	**Treated Gas**
Carbon Dioxide	3.6462	0	3.6366	3.6366	2.0035	2.0035	1.6175
Water	85.1400	100	85.1791	85.1791	97.5400	97.5400	6.0179
Oxygen	1.6767E-05	0	1.6723E-05	1.6723E-05	0	0	4.3428
Nitrogen	0.0002	0	0.0002	0.0002	0	0	86.9892
Sulphur Dioxide	7.8667E-07	0	7.8460E-07	7.8460E-07	0	0	0.0003
Argon	4.1470E-06	0	4.1361E-06	4.1361E-06	0	0	1.0322
Monoethanolamine	11.2136	0	11.1841	11.1841	0.4565	0.4565	2.6294E-05
Sodium Hydroxide	0	0	0	0	0	0	0
Temperature (°C)	63	20	63	38	104	167	36
Pressure (bara)	5	5	5	4	1.06	1.85	0.99
Mass Flow (kg/s)	1128	2.25	1130	1130	30	30	331.6
Molar Flow (kmol/h)	170759	450	171209	171209	5797	5797	42690
Mole Percentage Vapour (%)	0	0	0	0	100	100	100

Table 12: Post-combustion capture simulations (USA Bailey coal)

Part 6 of 6	
Stream Name	**CO1**
Component (Molar %)	**CO_2 to Compressor**
Carbon Dioxide	94.8703
Water	5.1089
Oxygen	0.0017
Nitrogen	0.0183
Sulphur Dioxide	0.0001
Argon	0.0005
Monoethanolamine	1.2357E-11
Sodium Hydroxide	0
Temperature (°C)	39
Pressure (bara)	1.4
Mass Flow (kg/s)	77.7
Molar Flow (kmol/h)	6556
Mole Percentage Vapour (%)	100

Table 13: Post-combustion capture simulations (natural gas)

Part 1 of 4							
Stream Name	**FG1**	**FG2**	**FG3**	**DCW1**	**RA1**	**RA2**	**RA3**
Component (Molar %)	**Flue Gas from CCGT**	**Exit from DCC**	**Entry to CO_2 Absorber**	**Excess Water from DCC**	**Rich Solvent from CO_2 Absorber**	**Rich Solvent Entering Lean/Rich Heat Exchanger**	**Rich Solvent Entering CO_2 Stripper**
Carbon Dioxide	3.7851	3.8364	3.8364	0.0017	5.7785	5.7785	5.7785
Water	7.2358	5.9775	5.9775	99.9972	81.7161	81.7161	81.7161
Oxygen	13.0056	13.1820	13.1820	0.0003	0.0002	0.0002	0.0002
Nitrogen	75.0738	76.0921	76.0921	0.0007	0.0007	0.0007	0.0007
Argon	0.8996	0.9119	0.9119	1.9481E-05	1.7689E-05	1.7689E-05	1.7689E-05
Monoethanolamine	0	0	0	0	12.5044	12.5044	12.5044
Temperature (°C)	110	36	40	36	40	40	110
Pressure (bara)	1.02	1	1.04	1	1.04	14.3	13.3
Mass Flow (kg/s)	684	678	678	5.8	601	601	601
Molar Flow (kmol/h)	86370	85214	85214	1156	86924	86924	86924
Mole Percentage Vapour (%)	100	100	100	0	0	0	0

Table 13: Post-combustion capture simulations (natural gas)

Part 2 of 4							
Stream Name	**LA1**	**LA2**	**LA3**	**LA4**	**LA5**	**LA6**	**CD1**
Component (Molar %)	**Lean Solvent Leaving CO_2 Stripper**	**Lean Solvent Entering CO_2 Stripper**	**Lean Solvent Leaving Reboiler**	**Lean Solvent Entering Lean/Rich Heat Exchanger**	**Lean Solvent Leaving Lean/Rich Heat Exchanger**	**Lean Solvent Entering CO_2 Absorber**	**CO_2-Rich Stream Leaving CO_2 Stripper**
Carbon Dioxide	2.6314	3.6700	2.4817	2.4817	2.4817	2.4817	37.9165
Water	85.9649	95.7546	84.5537	84.5537	84.5537	84.5537	62.0714
Oxygen	0	0	0	0	0	0	0.0026
Nitrogen	0	0	0	0	0	0	0.0080
Argon	0	0	0	0	0	0	0.0002
Monoethanolamine	11.4037	0.5754	12.9646	12.9646	12.9646	12.9646	0.0013
Temperature (°C)	119	120	120	120	50	40	102
Pressure (bara)	1.83	1.83	1.83	10.4	9.4	1.02	1.76
Mass Flow (kg/s)	629	64.5	565	565	565	565	60
Molar Flow (kmol/h)	95924	12085	83838	83838	83838	83838	7768
Mole Percentage Vapour (%)	0	100	0	0	0	0	100

Table 13: Post-combustion capture simulations (natural gas)

Part 3 of 4							
Stream Name	**CD2**	**RF1**	**RF2**	**IC1**	**IC2**	**IC3**	**WW1**
Component (Molar %)	**CO_2-Rich Stream Leaving Condenser**	**Liquid Leaving Reflux Drum**	**Liquid Entering CO_2 Stripper**	**Side Stream from CO_2 Absorber**	**Side Stream Entering Intercooler**	**Side Stream Entering CO_2 Absorber**	**Side Stream from CO_2 Absorber**
Carbon Dioxide	37.9165	0.0659	0.0659	5.3272	5.3272	5.3272	0.9276
Water	62.0714	99.9319	99.9319	82.2074	82.2074	82.2074	98.1417
Oxygen	0.0026	2.0664E-07	2.0664E-07	0.0002	0.0002	0.0002	0.0002
Nitrogen	0.0080	3.2281E-07	3.2281E-07	0.0007	0.0007	0.0007	0.0007
Argon	0.0002	1.6430E-08	1.6430E-08	1.7613E-05	1.7613E-05	1.7613E-05	1.7653E-05
Monoethanolamine	0.0013	0.0021	0.0021	12.4644	12.4644	12.4644	0.9297
Temperature (°C)	40	40	40	46	46	36	45
Pressure (bara)	1.62	1.62	6.6	1.03	3	2.5	1.01
Mass Flow (kg/s)	60	23.5	23.5	600	600	600	300
Molar Flow (kmol/h)	7768	4682	4682	87223	87223	87223	57887
Mole Percentage Vapour (%)	39.7	0	0	0	0	0	0

Table 13: Post-combustion capture simulations (natural gas)

Part 4 of 4						
Stream Name	**WW2**	**WW3**	**WW4**	**WW5**	**TG1**	**CO1**
Component (Molar %)	**Side Stream after Pump**	**Demineralised Water**	**Side Stream Entering Wash Water Cooler**	**Side Stream Entering CO_2 Absorber**	**Treated Gas**	**CO_2 to Compressor**
Carbon Dioxide	0.9276	0	0.9118	0.9118	0.3927	95.3520
Water	98.1417	100	98.1733	98.1733	7.2465	4.6206
Oxygen	0.0002	0	0.0002	0.0002	13.4998	0.0067
Nitrogen	0.0007	0	0.0007	0.0007	77.9271	0.0202
Argon	1.7653E-05	0	1.7353E-05	1.7353E-05	0.9338	0.0005
Monoethanolamine	0.9297	0	0.9139	0.9139	1.6613E-05	1.9577E-10
Temperature (°C)	45	20	45	20	40	40
Pressure (bara)	3.95	3.95	3.95	3.45	1.01	1.62
Mass Flow (kg/s)	300	5	305	305	647	36.7
Molar Flow (kmol/h)	57887	1000	58887	58887	83207	3086
Mole Percentage Vapour (%)	0	0	0	0	100	100

Table 14: Compression system for post combustion capture

Part 1 of 4							
Stream Name	**CO1**	**CO2**	**L1**	**CO3**	**CO4**	**CO5**	**L2**
Component (Molar %)	**Inlet from Capture Plant**	**Inlet to First Compression Stage**	**Liquid from First Knock-Out Drum**	**Exit from First Compression Stage**	**Cooled Stream from First Compression Stage**	**Inlet to Second Compression Stage**	**Liquid from Second Knock-Out Drum**
Carbon Dioxide	94.8707	94.8707	0	94.8707	94.8707	97.2388	0.1103
Water	5.1090	5.1090	0	5.1090	5.1090	2.7404	99.8897
Oxygen	0.0017	0.0017	0	0.0017	0.0017	0.0018	9.3171E-08
Nitrogen	0.0180	0.0180	0	0.0180	0.0180	0.0184	5.0135E-07
Sulphur Dioxide	0.0001	0.0001	0	0.0001	0.0001	0.0001	6.0616E-06
Argon	0.0004	0.0004	0	0.0004	0.0004	0.0004	2.5371E-08
Monoethanolamine	1.2543E-11	1.2543E-11	0	1.2543E-11	1.2543E-11	2.1808E-18	5.1446E-10
Temperature (°C)	39	39	39	102	40	40	40
Pressure (bara)	1.4	1.4	1.4	2.8	2.76	2.76	2.76
Mass Flow (kg/s)	82.2	82.2	0	82.2	82.2	81.3	0.9
Molar Flow (kmol/h)	6932	6932	0	6932	6932	6763	169
Mole Percentage Vapour (%)	100	100	0	100	97.6	100	0

Table 14: Compression system for post combustion capture

Part 2 of 4							
Stream Name	**CO6**	**CO7**	**CO8**	**L3**	**CO9**	**CO10**	**CO11**
Component (Molar %)	**Exit from Second Compression Stage**	**Cooled Stream from Second Compression Stage**	**Inlet to Third Compression Stage**	**Liquid from Third Knock-Out Drum**	**Exit from Third Compression Stage**	**Cooled Stream from Third Compression Stage**	**Inlet to Fourth Compression Stage**
Carbon Dioxide	97.2388	97.2388	98.5557	0.2165	98.5557	98.5557	99.2223
Water	2.7404	2.7404	1.4233	99.7834	1.4233	1.4233	0.7565
Oxygen	0.0018	0.0018	0.0018	1.8616E-07	0.0018	0.0018	0.0018
Nitrogen	0.0184	0.0184	0.0187	1.0017E-06	0.0187	0.0187	0.0188
Sulphur Dioxide	0.0001	0.0001	0.0001	1.1699E-05	0.0001	0.0001	0.0001
Argon	0.0004	0.0004	0.0004	5.0682E-08	0.0004	0.0004	0.0005
Monoethanolamine	2.1808E-18	2.1808E-18	0	0	0	0	0
Temperature (°C)	103	40	40	40	103	40	40
Pressure (bara)	5.52	5.43	5.43	5.43	10.9	10.7	10.7
Mass Flow (kg/s)	81.3	81.3	80.9	0.4	80.9	80.9	80.7
Molar Flow (kmol/h)	6763	6763	6673	90	6673	6673	6628
Mole Percentage Vapour (%)	100	98.7	100	0	100	99.3	100

Table 14: Compression system for post combustion capture

Part 3 of 4							
Stream Name	**L4**	**CO12**	**CO13**	**CO14**	**L5**	**CO15**	**CO16**
Component (Molar %)	**Liquid from Fourth Knock-Out Drum**	**Exit from Fourth Compression Stage**	**Cooled Stream from Fourth Compression Stage**	**Inlet to Fifth Compression Stage**	**Liquid from Fifth Knock-Out Drum**	**Exit from Fifth Compression Stage**	**Cooled Stream from Fifth Compression Stage**
Carbon Dioxide	0.4156	99.2223	99.2223	99.5564	0.7698	99.5564	99.5564
Water	99.5844	0.7565	0.7565	0.4223	99.2302	0.4223	0.4223
Oxygen	3.6998E-07	0.0018	0.0018	0.0018	7.3676E-07	0.0018	0.0018
Nitrogen	1.9909E-06	0.0188	0.0188	0.0188	3.9665E-06	0.0188	0.0188
Sulphur Dioxide	2.1703E-05	0.0001	0.0001	0.0001	3.7463E-05	0.0001	0.0001
Argon	1.0069E-07	0.0005	0.0005	0.0005	2.0035E-07	0.0005	0.0005
Monoethanolamine	0	0	0	0	0	0	0
Temperature (°C)	40	104	40	40	40	105	40
Pressure (bara)	10.7	21.4	21.1	21.1	21.1	42.2	41.5
Mass Flow (kg/s)	0.2	80.7	80.7	80.6	0.1	80.6	80.6
Molar Flow (kmol/h)	45	6628	6628	6605	22.4	6605	6605
Mole Percentage Vapour (%)	0	100	99.7	100	0	100	99.8

Table 14: Compression system for post combustion capture

Part 4 of 4							
Stream Name	**CO17**	**L6**	**CO18**	**CO19**	**CO20**	**CO21**	**CO22**
Component (Molar %)	**Inlet to Dehydration Unit**	**Liquid from Sixth Knock-Out Drum**	**Inlet to Sixth Compression Stage**	**Exit from Sixth Compression Stage**	**Inlet to Seventh Compression Stage**	**Exit from Seventh Compression Stage**	**Cooled Stream from Seventh Compression Stage**
Carbon Dioxide	99.7142	1.3311	99.9687	99.9687	99.9687	99.9687	99.9687
Water	0.2644	98.6689	0.0100	0.0100	0.0100	0.0100	0.0100
Oxygen	0.0018	1.5026E-06	0.0018	0.0018	0.0018	0.0018	0.0018
Nitrogen	0.0189	8.1173E-06	0.0189	0.0189	0.0189	0.0189	0.0189
Sulphur Dioxide	0.0001	5.5244E-05	1.4811E-06	1.4811E-06	1.4811E-06	1.4811E-06	1.4811E-06
Argon	0.0005	4.0794E-07	0.0005	0.0005	0.0005	0.0005	0.0005
Monoethanolamine	0	0	0	0	0	0	0
Temperature (°C)	40	40	40	107	40	93	40
Pressure (bara)	41.5	41.5	39.5	79.1	77.9	152.3	150
Mass Flow (kg/s)	80.5	0.1	80.4	80.4	80.4	80.4	80.4
Molar Flow (kmol/h)	6595	10.6	6578	6578	6578	6578	6578
Mole Percentage Vapour (%)	100	0	100	100	100	100	100

Table 15: Predictions of maximum possible concentrations of mercury and SO_3 for oxy-fuel

Location	Maximum possible concentration (mg/kg) assuming no upstream removal	
	Mercury (total)	SO_3(a)
FGD outlet	0.02	6(b)/19(c)
Molecular sieve outlet	0.03	7(b)/23(c)
CO_2 export stream	0.04	9(b)/31(c)

(a) Assumes 2% SO_2 to SO_3 conversion rate.
(b) Low sulphur coal (South African Douglas = 0.54 % sulphur as received).
(c) High sulphur coal (USA Bailey = 1.97 % sulphur as received).

Table 16: Oxy-fuel simulations (South African Douglas coal) – Low CO_2 purity

Part 1 of 5							
Stream Name	**RCO1**	**RCO2**	**RCO3**	**RCO4**	**RCO5**	**RCO6**	**RCO7**
Component (Molar %)	**Exit from Flue Gas Condenser**	**Exit from Intermediate Compression Train**	**Entry to De-SO_X Reactor**	**Exit from De-SO_X Reactor**	**Entry to De-NO_X Reactor**	**Exit from De-NO_X Reactor**	**Exit from Molecular Sieves**
Water	4.2829	4.2829	4.2829	0.3208	0.3208	0.1838	0.0006
Carbon Dioxide	71.8017	71.8017	71.8017	74.7837	74.7837	74.9371	75.0746
Nitrogen	17.4873	17.4873	17.4873	18.2189	18.2189	18.2565	18.2901
Argon	2.1869	2.1869	2.1869	2.2783	2.2783	2.2830	2.2872
Oxygen	4.1495	4.1495	4.1495	4.3231	4.3231	4.3320	4.3399
Sulphur Dioxide	0.0194	0.0194	0.0194	0.0000	0.0000	0.0000	0.0000
Nitrogen Oxide	0.0723	0.0723	0.0723	0.0753	0.0753	0.0075	0.0076
Hydrogen Chloride	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Temperature (°C)	30.00	87.23	30.00	30.00	104.50	24.29	24.29
Pressure (bara)	1.00	15.20	15.00	14.60	30.50	30.00	30.00
Mass Flow (kg/s)	182.19	182.19	182.19	178.79	178.79	178.58	178.44
Molar Flow (kmol/h)	16606	16606	16606	15939	15939	15906	15877
Molar Fraction Vapour (%)	100.00	99.50	96.09	100.00	100.00	99.95	100.00

Table 16: Oxy-fuel simulations (South African Douglas coal) – Low CO_2 purity

Part 2 of 5

Stream Name	**RCO8**	**RCO9**	**RCO10**	**VEN1**	**VEN2**	**VEN3**	**VEN4**
Component (Molar %)	**Entry to Flash Separator 1**	**CO_2-Lean Vapour from Flash Separator 1**	**Entry to Flash Separator 2**	**CO_2-Lean Vapour from Flash Separator 2**	**CO_2-Lean Vapour in Heat Exchanger**	**Inlet to Membrane**	**Retentate from Membrane**
Water	0.0006	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Carbon Dioxide	75.0746	50.4566	50.4566	29.4753	29.4753	29.4753	7.2555
Nitrogen	18.2901	36.5757	36.5757	52.2056	52.2056	52.2056	73.2083
Argon	2.2872	4.4740	4.4740	6.3249	6.3249	6.3249	9.1913
Oxygen	4.3399	8.4791	8.4791	11.9750	11.9750	11.9750	10.3130
Sulphur Dioxide	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Nitrogen Oxide	0.0076	0.0145	0.0145	0.0192	0.0192	0.0192	0.0319
Hydrogen Chloride	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Temperature (°C)	-33.43	-33.43	-50.00	-50.00	-20.00	14.20	14.20
Pressure (bara)	29.80	29.80	29.70	29.70	29.68	29.65	29.65
Mass Flow (kg/s)	178.44	76.30	76.30	47.86	47.86	47.86	25.99
Molar Flow (kmol/h)	15877	7434	7434	5075	5075	5075	3050
Molar Fraction Vapour (%)	46.90	100.00	68.26	100.00	100.00	100.00	100.00

Table 16: Oxy-fuel simulations (South African Douglas coal) – Low CO_2 purity

Part 3 of 5							
Stream Name	**VEN5**	**VEN6**	**EXP1**	**EXP2**	**EXP3**	**EXP4**	**EXP5**
Component (Molar %)	**Inlet to Expander**	**Emissions to Atmosphere**	**IP CO_2**	**IP CO_2**	**IP CO_2**	**IP CO_2**	**IP CO_2**
Water	0.0000	0.0000	0.0010	0.0010	0.0010	0.0001	0.0001
Carbon Dioxide	7.2555	7.2555	96.7510	96.7510	96.7510	95.5860	95.5860
Nitrogen	73.2083	73.2083	2.1894	2.1894	2.1894	2.9567	2.9567
Argon	9.1913	9.1913	0.3618	0.3618	0.3618	0.4930	0.4930
Oxygen	10.3130	10.3130	0.6954	0.6954	0.6954	0.9596	0.9596
Sulphur Dioxide	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Nitrogen Oxide	0.0319	0.0319	0.0014	0.0014	0.0014	0.0046	0.0046
Hydrogen Chloride	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Temperature (°C)	300.00	4.91	-33.40	-38.80	10.00	-50.00	-42.97
Pressure (bara)	29.00	1.10	29.80	17.38	17.28	29.70	29.50
Mass Flow (kg/s)	25.99	25.99	102.14	102.14	102.14	28.44	28.44
Molar Flow (kmol/h)	3050	3050	8443	8443	8443	2359	2359
Molar Fraction Vapour (%)	100.00	100.00	0.00	5.67	100.00	0.00	0.82

Table 16: Oxy-fuel simulations (South African Douglas coal) – Low CO_2 purity

Part 4 of 5							
Stream Name	**EXP6**	**EXP7**	**EXP8**	**EXP9**	**EXP10**	**EXP11**	**EXP12**
Component (Molar %)	**IP CO_2**	**IP CO_2**	**IP CO_2**	**IP CO_2**	**IP CO_2**	**HP CO_2**	**HP CO_2**
Water	0.0001	0.0001	0.0001	0.0001	0.0001	0.0008	0.0008
Carbon Dioxide	95.5860	95.5860	95.5860	95.5860	95.5860	96.4966	96.4966
Nitrogen	2.9567	2.9567	2.9567	2.9567	2.9567	2.3570	2.3570
Argon	0.4930	0.4930	0.4930	0.4930	0.4930	0.3904	0.3904
Oxygen	0.9596	0.9596	0.9596	0.9596	0.9596	0.7531	0.7531
Sulphur Dioxide	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Nitrogen Oxide	0.0046	0.0046	0.0046	0.0046	0.0046	0.0021	0.0021
Hydrogen Chloride	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Temperature (°C)	-55.50	-46.08	10.00	80.61	40.00	32.78	40.00
Pressure (bara)	8.63	8.43	8.33	17.45	17.28	150.50	150.00
Mass Flow (kg/s)	28.44	28.44	28.44	28.44	28.44	130.57	130.57
Molar Flow (kmol/h)	2359	2359	2359	2359	2359	10802	10802
Molar Fraction Vapour (%)	11.12	97.87	100.00	100.00	100.00	100.00	100.00

Table 16: Oxy-fuel simulations (South African Douglas coal) – Low CO_2 purity

Part 5 of 5							
Stream Name	**FBA1**	**PFA1**	**FGDW1**	**GYP1**	**WWA1**	**WWA2**	**WWA3**
Component (Molar %)	**Furnace Bottom Ash**	**Pulverised Fuel Ash**	**FGD Make-Up Water**	**Gypsum**	**Wastewater from Flue Gas Condenser**	**Wastewater from De-SO_X Reactor**	**Wastewater from De-NO_X Reactor**
Water			100.0000		98.6231	98.9829	66.5259
Carbon Dioxide			0.0000		1.0336	0.5280	0.6483
Nitrogen			0.0000		0.0151	0.0030	0.0040
Argon			0.0000		0.0730	0.0008	0.0011
Oxygen			0.0000		0.2544	0.0014	0.0019
Sulphur Dioxide			0.0000		0.0009	0.4840	0.0000
Nitrogen Oxide			0.0000		0.0000	0.0000	32.8189
Hydrogen Chloride			0.0000		0.0000	0.0000	0.0000
Temperature (°C)			0.00		30.00	30.00	102.81
Pressure (bara)			0.00		0.00	0.00	0.00
Mass Flow (kg/s)	1.56	6.55	7.67	0.59	26.81	3.40	0.20
Molar Flow (kmol/h)	0	0	1534	30	5267	667	33
Molar Fraction Vapour (%)	N/A	N/A	0.00	N/A	0.00	0.00	0.00

Table 17: Oxy-fuel simulations (South African Douglas coal) – High CO_2 Purity

Part 1 of 7

Stream Name	**RCO1**	**RCO2**	**RCO3**	**RCO4**	**RCO5**	**RCO6**	**RCO7**
Component (Molar %)	**Exit from Flue Gas Condenser**	**Exit from Intermediate Compression Train**	**Entry to De-SO_X Reactor**	**Exit from De-SO_X Reactor**	**Entry to De-NO_X Reactor**	**Exit from De-NO_X Reactor**	**Exit from Molecular Sieves**
Water	4.1949	4.1949	4.1949	0.3199	0.3199	0.1339	0.0005
Carbon Dioxide	71.9106	71.9106	71.9106	74.7459	74.7459	74.9415	75.0417
Nitrogen	17.4388	17.4388	17.4388	18.2175	18.2175	18.2653	18.2896
Argon	2.1913	2.1913	2.1913	2.2892	2.2892	2.2952	2.2982
Oxygen	4.1596	4.1596	4.1596	4.3453	4.3453	4.3567	4.3625
Sulphur Dioxide	0.0261	0.0261	0.0261	0.0000	0.0000	0.0000	0.0000
Nitrogen Oxide	0.0787	0.0787	0.0787	0.0822	0.0822	0.0074	0.0074
Hydrogen Chloride	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Temperature (°C)	30.00	82.32	30.00	30.00	104.55	24.31	24.29
Pressure (bara)	1.02	15.20	15.00	14.60	31.00	30.00	30.00
Mass Flow (kg/s)	182.02	182.02	182.02	177.99	177.99	177.74	177.64
Molar Flow (kmol/h)	16578	16578	16578	15869	15869	15828	15807
Molar Fraction Vapour (%)	100.00	99.51	96.10	100.00	100.00	99.95	100.00

Table 17: Oxy-fuel simulations (South African Douglas coal) – High CO_2 Purity

Part 2 of 7							
Stream Name	**RCO8**	**RCO9**	**RCO10**	**RCO11**	**RCO12**	**RCO13**	**RCO14**
Component (Molar %)	**Entry to Cold Box**	**Entry to Reboiler**	**Exit from Reboiler**	**Entry to Flash Separator 1**	**CO_2-Rich Exit from Flash Separator 1**	**CO_2-Rich Entry to Distillation Column**	**Raw CO_2 Entry to Distillation Column**
Water	0.0004	0.0004	0.0004	0.0004	0.0005	0.0005	0.0005
Carbon Dioxide	80.0036	80.0036	80.0036	80.0036	95.3563	95.3563	95.3563
Nitrogen	14.3910	14.3910	14.3910	14.3910	3.0659	3.0659	3.0659
Argon	1.9228	1.9228	1.9228	1.9228	0.5320	0.5320	0.5320
Oxygen	3.6748	3.6748	3.6748	3.6748	1.0420	1.0420	1.0420
Sulphur Dioxide	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Nitrogen Oxide	0.0074	0.0074	0.0074	0.0074	0.0033	0.0033	0.0033
Hydrogen Chloride	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Temperature (°C)	26.25	-5.16	-19.96	-53.71	-53.71	-29.09	-37.55
Pressure (bara)	30.00	30.00	30.00	29.70	29.70	30.00	16.97
Mass Flow (kg/s)	275.54	275.54	275.54	275.54	226.15	226.15	226.15
Molar Flow (kmol/h)	24089	24089	24089	24089	18775	18775	18775
Molar Fraction Vapour (%)	100.00	100.00	71.45	22.06	0.00	4.47	11.64

Table 17: Oxy-fuel simulations (South African Douglas coal) - High CO_2 Purity

Part 3 of 7							
Stream Name	**RCO15**	**RCO16**	**RCO17**	**RCO18**	**RCO19**	**VEN1**	**VEN2**
Component (Molar %)	**CO_2-Lean Vapour Exit from Distillation Column**	**CO_2-Lean Vapour In Heat Exchanger**	**CO_2-Lean Vapour Exit from Cold Box**	**CO_2-Lean Vapour**	**CO_2-Lean Vapour**	**CO_2-Lean Vapour Exit from Flash Separator**	**CO_2-Lean Vapour In Heat Exchanger**
Water	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Carbon Dioxide	89.4735	89.4735	89.4735	89.4735	89.4735	25.7572	25.7572
Nitrogen	6.9506	6.9506	6.9506	6.9506	6.9506	54.4064	54.4064
Argon	1.2062	1.2062	1.2062	1.2062	1.2062	6.8367	6.8367
Oxygen	2.3623	2.3623	2.3623	2.3623	2.3623	12.9775	12.9775
Sulphur Dioxide	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Nitrogen Oxide	0.0074	0.0074	0.0074	0.0074	0.0074	0.0221	0.0221
Hydrogen Chloride	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Temperature (°C)	-28.79	-24.00	11.22	65.46	30.00	-53.71	-23.00
Pressure (bara)	16.97	16.87	16.77	30.50	30.00	29.70	29.68
Mass Flow (kg/s)	97.90	97.90	97.90	97.90	97.90	49.39	49.39
Molar Flow (kmol/h)	8282	8282	8282	8282	8282	5314	5314
Molar Fraction Vapour (%)	100.00	100.00	100.00	100.00	100.00	100.00	100.00

Table 17: Oxy-fuel simulations (South African Douglas coal) – High CO_2 Purity

Part 4 of 7							
Stream Name	**VEN3**	**VEN4**	**VEN5**	**VEN6**	**EXP1**	**EXP2**	**EXP3**
Component (Molar %)	**Inlet to Membrane**	**Retentate from Membrane**	**Inlet to Expander**	**Emissions to Atmosphere**	**IP CO_2**	**IP CO_2**	**IP CO_2**
Water	0.0000	0.0000	0.0000	0.0000	0.0008	0.0008	0.0008
Carbon Dioxide	25.7572	6.0511	6.0511	6.0511	99.9992	99.9992	99.9992
Nitrogen	54.4064	73.7254	73.7254	73.7254	0.0000	0.0000	0.0000
Argon	6.8367	9.8250	9.8250	9.8250	0.0000	0.0000	0.0000
Oxygen	12.9775	10.3631	10.3631	10.3631	0.0000	0.0000	0.0000
Sulphur Dioxide	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Nitrogen Oxide	0.0221	0.0354	0.0354	0.0354	0.0000	0.0000	0.0000
Hydrogen Chloride	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Temperature (°C)	11.22	11.22	300.00	4.91	-24.70	-29.00	-29.41
Pressure (bara)	30.00	30.00	29.50	1.10	16.97	14.74	14.54
Mass Flow (kg/s)	49.39	28.20	28.20	28.20	128.25	2.57	2.57
Molar Flow (kmol/h)	5314	3322	3322	3322	10494	210	210
Molar Fraction Vapour (%)	100.00	100.00	100.00	100.00	0.00	3.04	46.94

Table 17: Oxy-fuel simulations (South African Douglas coal) – High CO_2 Purity

Part 5 of 7							
Stream Name	**EXP4**	**EXP5**	**EXP6**	**EXP7**	**EXP8**	**EXP9**	**EXP10**
Component (Molar %)	**IP CO_2**	**IP CO_2**	**IP CO_2**	**IP CO_2**	**IP CO_2**	**IP CO_2**	**HP CO_2**
Water	0.0008	0.0008	0.0008	0.0008	0.0008	0.0008	0.0008
Carbon Dioxide	99.9992	99.9992	99.9992	99.9992	99.9992	99.9992	99.9992
Nitrogen	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Argon	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Oxygen	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Sulphur Dioxide	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Nitrogen Oxide	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Hydrogen Chloride	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Temperature (°C)	-24.70	-56.00	-25.00	11.20	125.72	40.00	35.63
Pressure (bara)	16.97	5.30	5.10	5.00	17.45	17.25	150.50
Mass Flow (kg/s)	125.69	125.69	125.69	125.69	125.69	125.69	128.25
Molar Flow (kmol/h)	10284	10284	10284	10284	10284	10284	10494
Molar Fraction Vapour (%)	0.00	17.94	100.00	100.00	100.00	100.00	100.00

Table 17: Oxy-fuel simulations (South African Douglas coal) – High CO_2 Purity

Part 6 of 7							
Stream Name	**EXP11**	**FBA1**	**PFA1**	**FGDW1**	**GYP1**	**WWA1**	**WWA2**
Component (Molar %)	**HP CO_2**	**Furnace Bottom Ash**	**Pulverised Fuel Ash**	**FGD Make-Up Water**	**Gypsum**	**Wastewater from Flue Gas Condenser**	**Wastewater from De-SO_X Reactor**
Water	0.0008			100.0000	0.0000	99.5892	90.9537
Carbon Dioxide	99.9992			0.0000	0.0000	0.3240	8.4293
Nitrogen	0.0000			0.0000	0.0000	0.0616	0.0048
Argon	0.0000			0.0000	0.0000	0.0151	0.0006
Oxygen	0.0000			0.0000	0.0000	0.0505	0.0011
Sulphur Dioxide	0.0000			0.0000	98.1790	-0.0202	0.6105
Nitrogen Oxide	0.0000			0.0000	0.0000	-0.0202	0.0000
Hydrogen Chloride	0.0000			0.0000	1.8210	0.0000	0.0000
Temperature (°C)	40.00	0.00	0.00	0.00	0.00	30.00	30.00
Pressure (bara)	150.00	0.00	0.00	0.00	0.00	0.00	0.00
Mass Flow (kg/s)	128.25	1.56	6.55	7.55	0.59	26.17	4.03
Molar Flow (kmol/h)	10494	N/A	N/A	1510	N/A	5208	709
Molar Fraction Vapour (%)	100.00	N/A	N/A	0.00	N/A	0.00	0.00

Table 17: Oxy-fuel simulations (South African Douglas coal) - High CO_2 Purity

Part 7 of 7	
Stream Name	**WWA3**
Component (Molar %)	**Wastewater from De-NO_X Reactor**
Water	71.1976
Carbon Dioxide	0.1960
Nitrogen	0.0050
Argon	0.0008
Oxygen	0.0015
Sulphur Dioxide	0.0000
Nitrogen Oxide	28.5991
Hydrogen Chloride	0.0000
Temperature (°C)	102.81
Pressure (bara)	0.00
Mass Flow (kg/s)	0.25
Molar Flow (kmol/h)	42
Molar Fraction Vapour (%)	0.00

Table 18: Oxy-fuel simulations (USA Bailey coal) – Low CO_2 purity

Part 1 of 5							
Stream Name	**RCO1**	**RCO2**	**RCO3**	**RCO4**	**RCO5**	**RCO6**	**RCO7**
Component (Molar %)	**Exit from Flue Gas Condenser**	**Exit from Intermediate Compression Train**	**Entry to De-SO_X Reactor**	**Exit from De-SO_X Reactor**	**Entry to De-NO_X Reactor**	**Exit from De-NO_X Reactor**	**Exit from Molecular Sieves**
Water	4.2003	4.2003	4.2003	0.3205	0.3205	0.1814	0.0005
Carbon Dioxide	72.6315	72.6315	72.6315	75.5329	75.5329	75.6857	75.8228
Nitrogen	16.5922	16.5922	16.5922	17.3417	17.3417	17.3767	17.4082
Argon	2.2447	2.2447	2.2447	2.3461	2.3461	2.3508	2.3551
Oxygen	4.2005	4.2005	4.2005	4.3903	4.3903	4.3992	4.4071
Sulphur Dioxide	0.0652	0.0652	0.0652	0.0000	0.0000	0.0000	0.0000
Nitrogen Oxide	0.0656	0.0656	0.0656	0.0686	0.0686	0.0062	0.0062
Hydrogen Chloride	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Temperature (°C)	30.00	82.31	70.00	30.00	102.69	24.29	24.29
Pressure (bara)	1.02	15.20	15.00	14.60	30.50	30.00	30.00
Mass Flow (kg/s)	190.99	190.99	190.99	186.64	186.64	186.44	186.29
Molar Flow (kmol/h)	17335	17335	17335	16585	16585	16552	16522
Molar Fraction Vapour (%)	100.00	99.50	96.09	100.00	100.00	99.95	100.00

Table 18: Oxy-fuel simulations (USA Bailey coal) - Low CO_2 purity

Part 2 of 5							
Stream Name	**RCO8**	**RCO9**	**RCO10**	**VEN1**	**VEN2**	**VEN3**	**VEN4**
Component (Molar %)	**Entry to Flash Separator 1**	**CO_2-Lean Vapour from Flash Separator 1**	**Entry to Flash Separator 2**	**CO_2-Lean Vapour from Flash Separator 2**	**CO_2-Lean Vapour in Heat Exchanger**	**Inlet to Membrane**	**Retentate from Membrane**
Water	0.0005	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Carbon Dioxide	75.8228	50.4531	50.4531	29.4672	29.4672	29.4672	7.2558
Nitrogen	17.4082	35.9177	35.9177	51.2751	51.2751	51.2751	73.2116
Argon	2.3551	4.7464	4.7464	6.7110	6.7110	6.7110	9.1917
Oxygen	4.4071	8.8708	8.8708	12.5302	12.5302	12.5302	10.3135
Sulphur Dioxide	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Nitrogen Oxide	0.0062	0.0120	0.0120	0.0165	0.0165	0.0165	0.0274
Hydrogen Chloride	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Temperature (°C)	-33.43	-33.43	-50.00	-50.00	-40.00	14.20	14.20
Pressure (bara)	29.80	29.80	29.70	29.70	29.68	29.65	29.65
Mass Flow (kg/s)	186.29	76.72	76.72	48.15	48.15	48.15	26.15
Molar Flow (kmol/h)	16522	7465	7465	5095	5095	5095	3068
Molar Fraction Vapour (%)	45.19	100.00	68.25	100.00	100.00	100.00	100.00

Table 18: Oxy-fuel simulations (USA Bailey coal) – Low CO_2 purity

Part 3 of 5							
Stream Name	**VEN5**	**VEN6**	**EXP1**	**EXP2**	**EXP3**	**EXP4**	**EXP5**
Component (Molar %)	**Inlet to Expander**	**Emissions to Atmosphere**	**IP CO_2**	**IP CO_2**	**IP CO_2**	**IP CO_2**	**IP CO_2**
Water	0.0000	0.0000	0.0010	0.0010	0.0010	0.0001	0.0001
Carbon Dioxide	7.2558	7.2558	96.7361	96.7361	96.7361	95.5657	95.5657
Nitrogen	73.2116	73.2116	2.1502	2.1502	2.1502	2.9045	2.9045
Argon	9.1917	9.1917	0.3838	0.3838	0.3838	0.5232	0.5232
Oxygen	10.3135	10.3135	0.7276	0.7276	0.7276	1.0042	1.0042
Sulphur Dioxide	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Nitrogen Oxide	0.0274	0.0274	0.0014	0.0014	0.0014	0.0023	0.0023
Hydrogen Chloride	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Temperature (°C)	300.00	4.91	-33.40	-38.76	13.23	-50.00	-42.97
Pressure (bara)	29.00	1.10	29.80	17.45	17.25	29.70	29.50
Mass Flow (kg/s)	26.15	26.15	109.57	109.57	109.57	28.57	28.57
Molar Flow (kmol/h)	3068	3068	9057	9057	9057	2370	2370
Molar Fraction Vapour (%)	100.00	100.00	0.00	5.68	100.00	0.00	0.82

Table 18: Oxy-fuel simulations (USA Bailey coal) - Low CO_2 purity

Part 4 of 5

Stream Name	**EXP6**	**EXP7**	**EXP8**	**EXP9**	**EXP10**	**EXP11**	**EXP12**
Component (Molar %)	**IP CO_2**	**IP CO_2**	**IP CO_2**	**IP CO_2**	**IP CO_2**	**HP CO_2**	**HP CO_2**
Water	0.0001	0.0001	0.0001	0.0001	0.0001	0.0008	0.0008
Carbon Dioxide	95.5657	95.5657	95.5657	95.5657	95.5657	96.4933	96.4933
Nitrogen	2.9045	2.9045	2.9045	2.9045	2.9045	2.3066	2.3066
Argon	0.5232	0.5232	0.5232	0.5232	0.5232	0.4127	0.4127
Oxygen	1.0042	1.0042	1.0042	1.0042	1.0042	0.7850	0.7850
Sulphur Dioxide	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Nitrogen Oxide	0.0023	0.0023	0.0023	0.0023	0.0023	0.0016	0.0016
Hydrogen Chloride	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Temperature (°C)	-55.50	-45.88	14.20	80.46	40.00	32.78	40.00
Pressure (bara)	8.65	8.45	8.35	17.45	17.28	150.50	150.00
Mass Flow (kg/s)	28.57	28.57	28.57	28.57	28.57	138.14	138.14
Molar Flow (kmol/h)	2370	2370	2370	2370	2370	11427	11427
Molar Fraction Vapour (%)	11.13	97.88	100.00	100.00	100.00	100.00	100.00

Table 18: Oxy-fuel simulations (USA Bailey coal) - Low CO_2 purity

Part 5 of 5							
Stream Name	**FBA1**	**PFA1**	**FGDW1**	**GYP1**	**WWA1**	**WWA2**	**WWA3**
Component (Molar %)	**Furnace Bottom Ash**	**Pulverised Fuel Ash**	**FGD Make-Up Water**	**Gypsum**	**Wastewater from Flue Gas Condenser**	**Wastewater from De-SO_X Reactor**	**Wastewater from De-NO_X Reactor**
Water			100.0000		98.2435	90.0646	69.0574
Carbon Dioxide			0.0000		1.0883	8.4206	0.0149
Nitrogen			0.0000		0.2827	0.0047	0.0034
Argon			0.0000		0.0933	0.0006	0.0005
Oxygen			0.0000		0.2695	0.0012	0.0009
Sulphur Dioxide			0.0000		0.0115	1.5082	0.0000
Nitrogen Oxide			0.0000		0.0112	0.0000	30.9229
Hydrogen Chloride			0.0000		0.0000	0.0000	0.0000
Temperature (°C)			0.00		30.00	30.00	102.69
Pressure (bara)			0.00		0.00	0.00	0.00
Mass Flow (kg/s)	0.78	3.46	3.45	2.00	28.32	4.35	0.20
Molar Flow (kmol/h)	0	0	689	113	5548	749	33
Molar Fraction Vapour (%)	N/A	N/A	0.00	N/A	0.00	0.00	0.00

Table 19: Oxy-fuel simulations (USA Bailey coal) – High CO_2 purity

Part 1 of 7

Stream Name	**RCO1**	**RCO2**	**RCO3**	**RCO4**	**RCO5**	**RCO6**	**RCO7**
Component (Molar %)	**Exit from Flue Gas Condenser**	**Exit from Intermediate Compression Train**	**Entry to De-SO_X Reactor**	**Exit from De-SO_X Reactor**	**Entry to De-NO_X Reactor**	**Exit from De-NO_X Reactor**	**Exit from Molecular Sieves**
Water	4.1951	4.1951	4.1951	0.3201	0.3201	0.1812	0.0005
Carbon Dioxide	72.6359	72.6359	72.6359	75.5337	75.5337	75.6863	75.8233
Nitrogen	16.5927	16.5927	16.5927	17.3414	17.3414	17.3764	17.4079
Argon	2.2447	2.2447	2.2447	2.3460	2.3460	2.3508	2.3550
Oxygen	4.2007	4.2007	4.2007	4.3902	4.3902	4.3991	4.4070
Sulphur Dioxide	0.0653	0.0653	0.0653	0.0000	0.0000	0.0000	0.0000
Nitrogen Oxide	0.0656	0.0656	0.0656	0.0686	0.0686	0.0062	0.0062
Hydrogen Chloride	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Temperature (°C)	30.00	82.29	70.00	30.00	104.42	24.31	24.29
Pressure (bara)	1.02	15.20	15.00	14.60	31.00	30.00	30.00
Mass Flow (kg/s)	190.99	190.99	190.99	186.64	186.64	186.44	186.29
Molar Flow (kmol/h)	17334	17334	17334	16586	16586	16552	16522
Molar Fraction Vapour (%)	100.00	99.50	96.10	100.00	100.00	99.95	100.00

Table 19: Oxy-fuel simulations (USA Bailey coal) – High CO_2 purity

Part 2 of 7							
Stream Name	**RCO8**	**RCO9**	**RCO10**	**RCO11**	**RCO12**	**RCO13**	**RCO14**
Component (Molar %)	**Entry to Cold Box**	**Entry to Reboiler**	**Exit from Reboiler**	**Entry to Flash Separator 1**	**CO_2-Rich Exit from Flash Separator 1**	**CO_2-Rich Entry to Distillation Column**	**Raw CO_2 Entry to Distillation Column**
Water	0.0003	0.0003	0.0003	0.0003	0.0004	0.0004	0.0004
Carbon Dioxide	82.5562	82.5562	82.5562	82.5562	95.3324	95.3324	95.3324
Nitrogen	12.2772	12.2772	12.2772	12.2772	3.0140	3.0140	3.0140
Argon	1.7877	1.7877	1.7877	1.7877	0.5631	0.5631	0.5631
Oxygen	3.3728	3.3728	3.3728	3.3728	1.0872	1.0872	1.0872
Sulphur Dioxide	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Nitrogen Oxide	0.0058	0.0058	0.0058	0.0058	0.0028	0.0028	0.0028
Hydrogen Chloride	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Temperature (°C)	26.77	-5.16	-19.96	-53.71	-53.71	-29.09	-37.55
Pressure (bara)	30.00	30.00	30.00	29.70	29.70	30.00	16.99
Mass Flow (kg/s)	338.24	338.24	338.24	338.24	288.14	288.14	288.14
Molar Flow (kmol/h)	29300	29300	29300	29300	23920	23920	23920
Molar Fraction Vapour (%)	100.00	100.00	61.32	18.36	0.00	4.50	11.67

Table 19: Oxy-fuel simulations (USA Bailey coal) - High CO_2 purity

Part 3 of 7							
Stream Name	**RCO15**	**RCO16**	**RCO17**	**RCO18**	**RCO19**	**VEN1**	**VEN2**
Component (Molar %)	**CO_2-Lean Vapour Exit from Distillation Column**	**CO_2-Lean Vapour In Heat Exchanger**	**CO_2-Lean Vapour Exit from Cold Box**	**CO_2-Lean Vapour**	**CO_2-Lean Vapour**	**CO_2-Lean Vapour Exit from Flash Separator**	**CO_2-Lean Vapour In Heat Exchanger**
Water	0.0004	0.0004	0.0004	0.0004	0.0004	0.0000	0.0000
Carbon Dioxide	95.3324	95.3324	95.3324	95.3324	95.3324	25.7442	25.7442
Nitrogen	3.0140	3.0140	3.0140	3.0140	3.0140	53.4674	53.4674
Argon	0.5631	0.5631	0.5631	0.5631	0.5631	7.2333	7.2333
Oxygen	1.0872	1.0872	1.0872	1.0872	1.0872	13.5360	13.5360
Sulphur Dioxide	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Nitrogen Oxide	0.0028	0.0028	0.0028	0.0028	0.0028	0.0190	0.0190
Hydrogen Chloride	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Temperature (°C)	-28.05	-24.00	11.22	65.17	25.00	-53.71	-24.61
Pressure (bara)	16.99	16.89	16.79	30.00	30.00	29.70	29.68
Mass Flow (kg/s)	288.14	288.14	288.14	288.14	288.14	50.10	50.10
Molar Flow (kmol/h)	23920	23920	23920	23920	23920	5379	5379
Molar Fraction Vapour (%)	100.00	100.00	100.00	100.00	100.00	100.00	100.00

Table 19: Oxy-fuel simulations (USA Bailey coal) – High CO_2 purity

Part 4 of 7							
Stream Name	**VEN3**	**VEN4**	**VEN5**	**VEN6**	**EXP1**	**EXP2**	**EXP3**
Component (Molar %)	**Inlet to Membrane**	**Retentate from Membrane**	**Inlet to Expander**	**Emissions to Atmosphere**	**IP CO_2**	**IP CO_2**	**IP CO_2**
Water	0.0000	0.0000	0.0000	0.0000	0.0008	0.0008	0.0008
Carbon Dioxide	25.7442	6.0514	6.0514	6.0514	99.9992	99.9992	99.9992
Nitrogen	53.4674	73.7291	73.7291	73.7291	0.0000	0.0000	0.0000
Argon	7.2333	9.8255	9.8255	9.8255	0.0000	0.0000	0.0000
Oxygen	13.5360	10.3636	10.3636	10.3636	0.0000	0.0000	0.0000
Sulphur Dioxide	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Nitrogen Oxide	0.0190	0.0304	0.0304	0.0304	0.0000	0.0000	0.0000
Hydrogen Chloride	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Temperature (°C)	11.22	11.22	300.00	4.91	-24.67	-24.67	-29.41
Pressure (bara)	30.00	30.00	29.50	1.10	16.99	16.99	14.54
Mass Flow (kg/s)	50.10	28.61	28.61	28.61	2.72	2.72	2.72
Molar Flow (kmol/h)	5379	3370	3370	3370	223	223	223
Molar Fraction Vapour (%)	100.00	100.00	100.00	100.00	0.00	3.07	65.57

Table 19: Oxy-fuel simulations (USA Bailey coal) – High CO_2 purity

Part 5 of 7							
Stream Name	**EXP4**	**EXP5**	**EXP6**	**EXP7**	**EXP8**	**EXP9**	**EXP10**
Component (Molar %)	**IP CO_2**	**IP CO_2**	**IP CO_2**	**IP CO_2**	**IP CO_2**	**IP CO_2**	**HP CO_2**
Water	0.0008	0.0008	0.0008	0.0008	0.0008	0.0008	0.0008
Carbon Dioxide	99.9992	99.9992	99.9992	99.9992	99.9992	99.9992	99.9992
Nitrogen	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Argon	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Oxygen	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Sulphur Dioxide	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Nitrogen Oxide	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Hydrogen Chloride	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Temperature (°C)	-24.67	-56.00	-25.00	11.20	125.72	40.00	35.63
Pressure (bara)	16.99	5.30	5.10	5.00	17.45	17.25	150.50
Mass Flow (kg/s)	133.47	133.47	133.47	133.47	133.47	133.47	136.19
Molar Flow (kmol/h)	10920	10920	10920	10920	10920	10920	11143
Molar Fraction Vapour (%)	0.00	17.96	100.00	100.00	100.00	100.00	100.00

Table 19: Oxy-fuel simulations (USA Bailey coal) – High CO_2 purity

Part 6 of 7							
Stream Name	**EXP11**	**FBA1**	**PFA1**	**FGDW1**	**GYP1**	**WWA1**	**WWA2**
Component (Molar %)	**HP CO_2**	**Furnace Bottom Ash**	**Pulverised Fuel Ash**	**FGD Make-Up Water**	**Gypsum**	**Wastewater from Flue Gas Condenser**	**Wastewater from De-SO_X Reactor**
Water	0.0008			100.0000	0.0000	99.0880	90.0515
Carbon Dioxide	99.9992			0.0000	0.0000	0.5587	8.4304
Nitrogen	0.0000			0.0000	0.0000	0.1434	0.0047
Argon	0.0000			0.0000	0.0000	0.0545	0.0006
Oxygen	0.0000			0.0000	0.0000	0.1327	0.0012
Sulphur Dioxide	0.0000			0.0000	94.7037	0.0114	1.5116
Nitrogen Oxide	0.0000			0.0000	0.0000	0.0114	0.0000
Hydrogen Chloride	0.0000			0.0000	5.2963	0.0000	0.0000
Temperature (°C)	40.00	0.00	0.00	0.00	0.00	30.00	30.00
Pressure (bara)	150.00	0.00	0.00	0.00	0.00	0.00	0.00
Mass Flow (kg/s)	136.19	0.78	3.46	3.36	2.00	27.72	4.34
Molar Flow (kmol/h)	11143	N/A	N/A	672	N/A	5484	749
Molar Fraction Vapour (%)	100.00	N/A	N/A	0.00	N/A	0.00	0.00

Table 19: Oxy-fuel simulations (USA Bailey coal) – High CO_2 purity

Part 7 of 7	
Stream Name	**WWA3**
Component (Molar %)	**Wastewater from De-NO_X Reactor**
Water	69.0300
Carbon Dioxide	0.0149
Nitrogen	0.0034
Argon	0.0005
Oxygen	0.0009
Sulphur Dioxide	0.0000
Nitrogen Oxide	30.9503
Hydrogen Chloride	0.0000
Temperature (°C)	102.69
Pressure (bara)	0.00
Mass Flow (kg/s)	0.20
Molar Flow (kmol/h)	33
Molar Fraction Vapour (%)	0.00

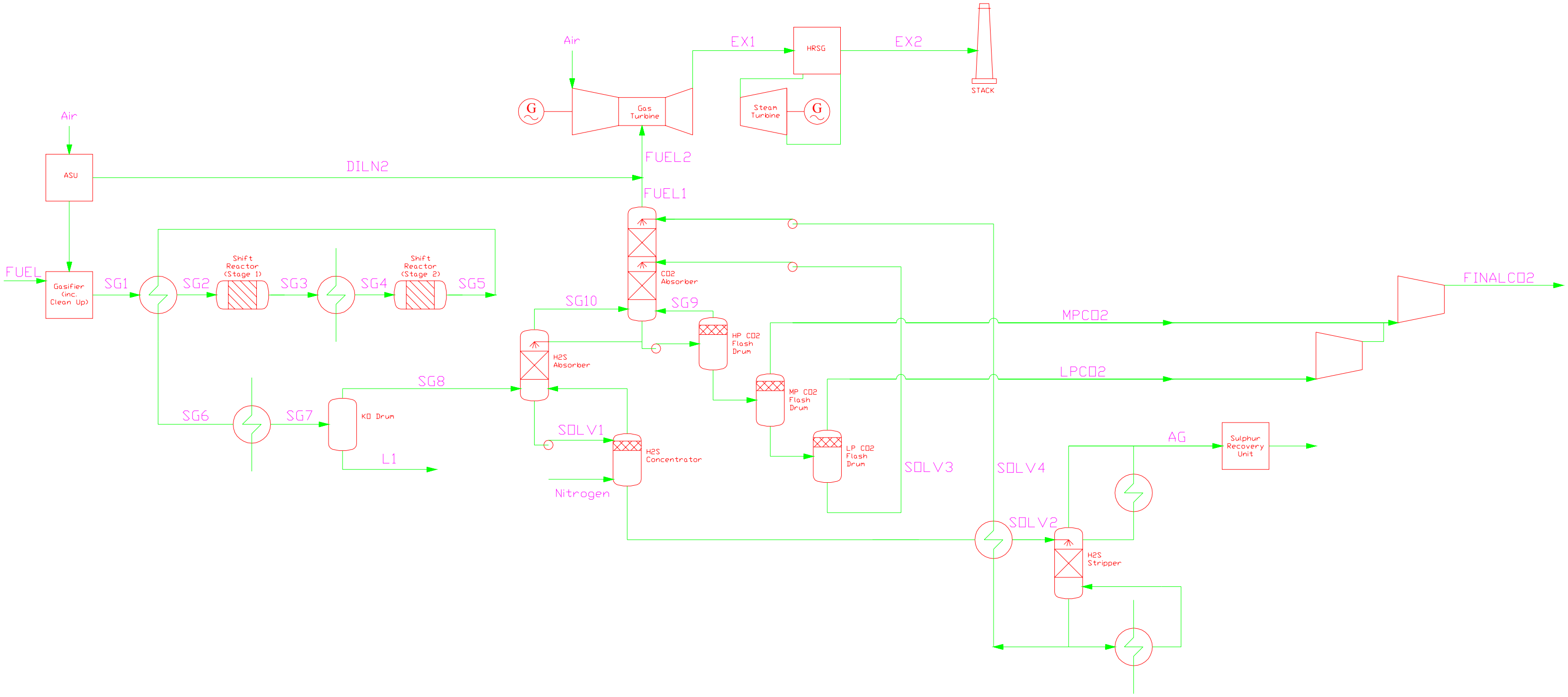

Figure 1: IGCC plant layout with separate capture of CO_2 and H_2S

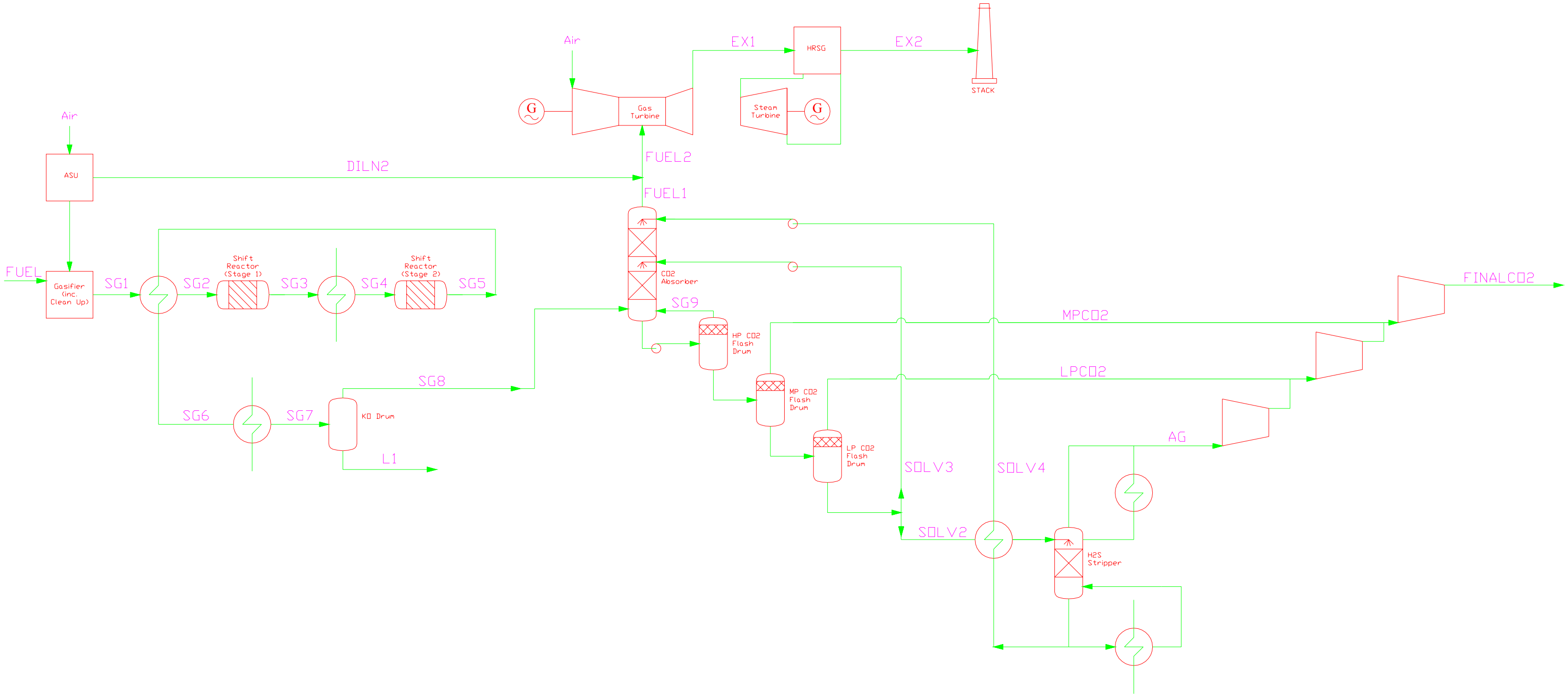

Figure 2: IGCC plant layout with co-capture of CO_2 and H_2S

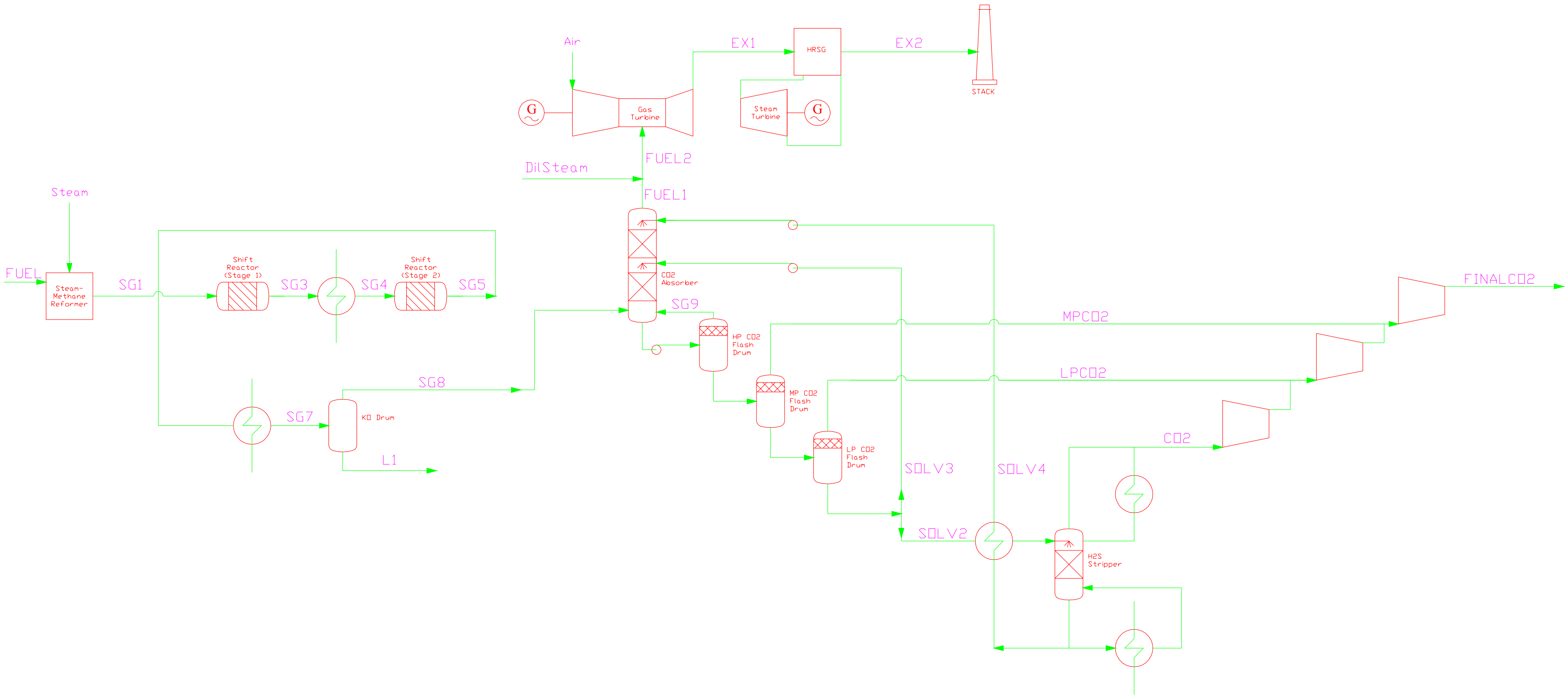

Figure 3: IGCC plant layout for natural gas

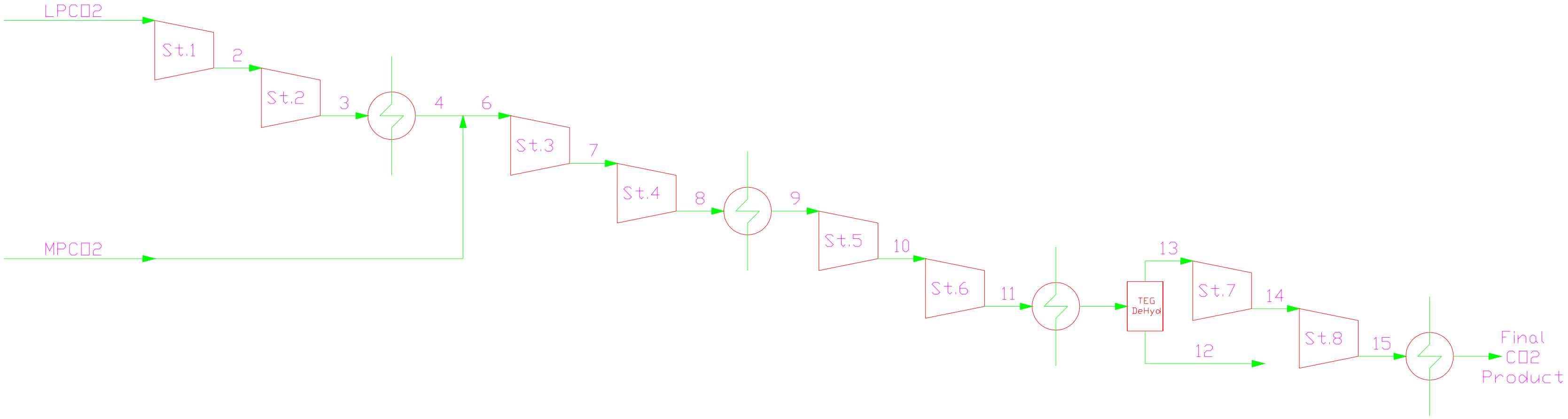

Figure 4: Layout of CO_2 compressor system for case when CO_2 and H_2S are captured separately

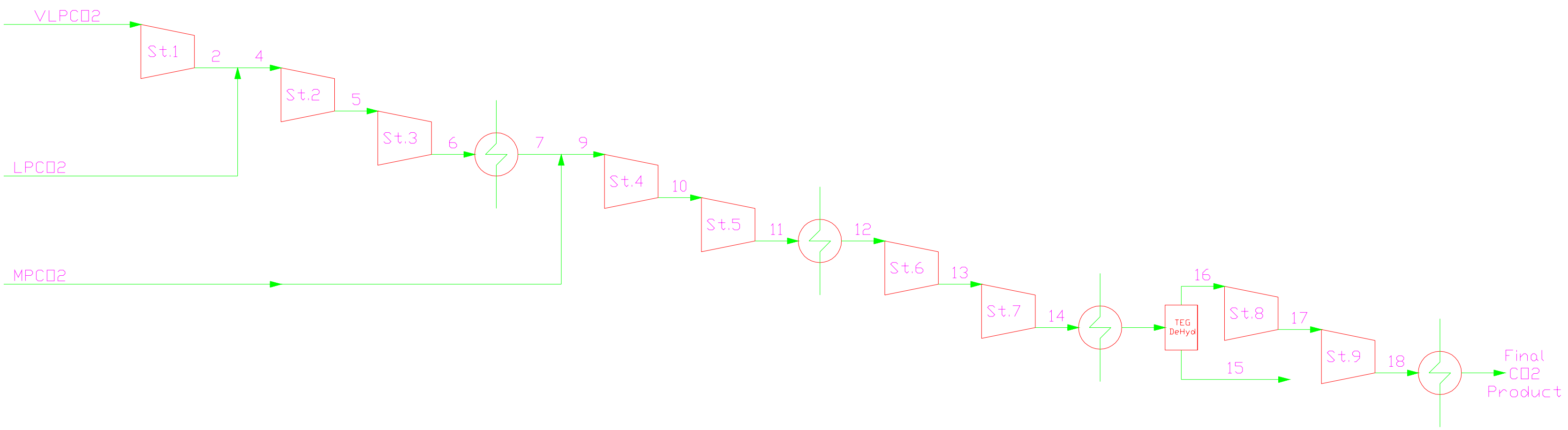

Figure 5: Layout of CO_2 compressors for case when CO_2 and H_2S are co-captured

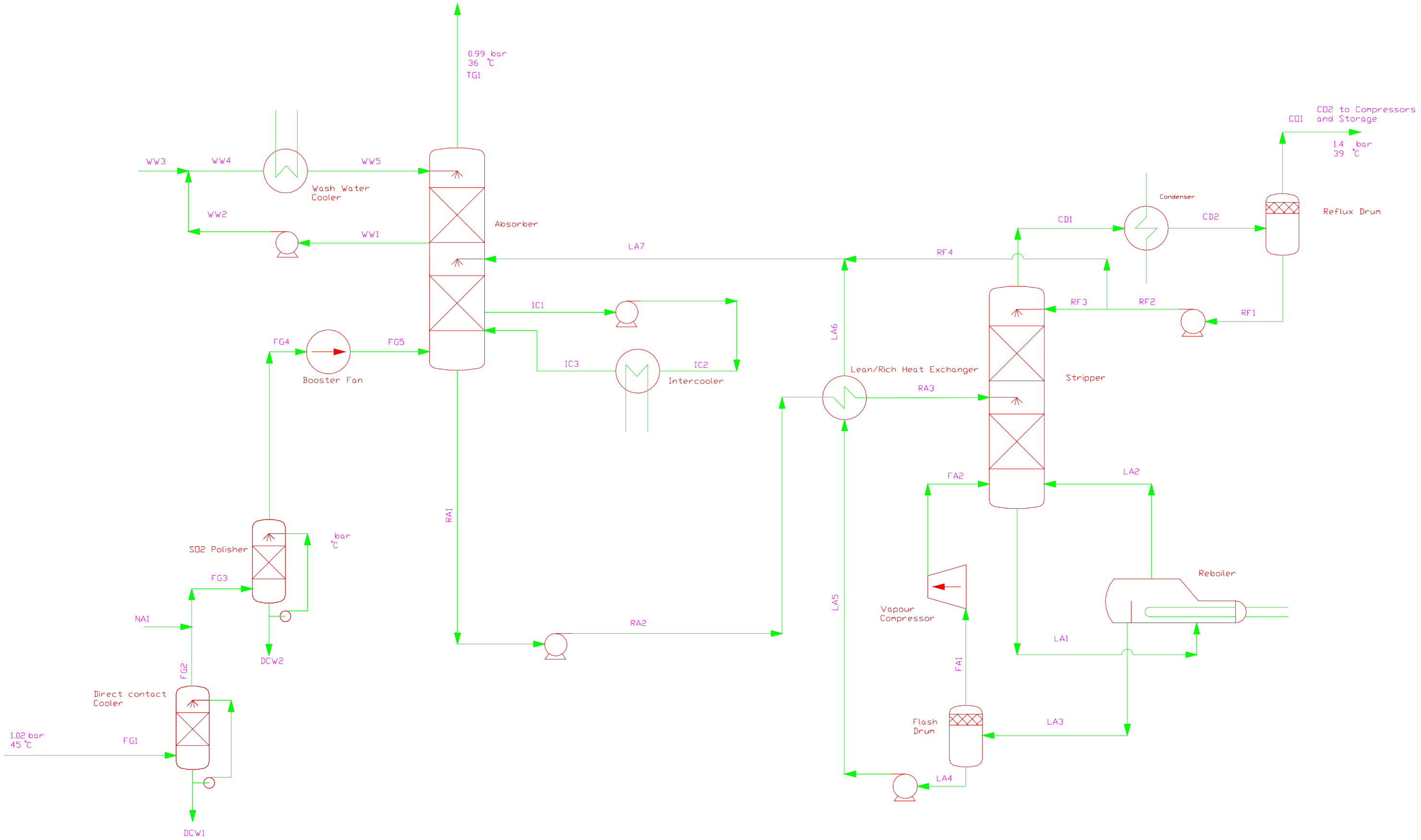

Figure 6: Post-combustion capture plant layout for flue gas from coal combustion

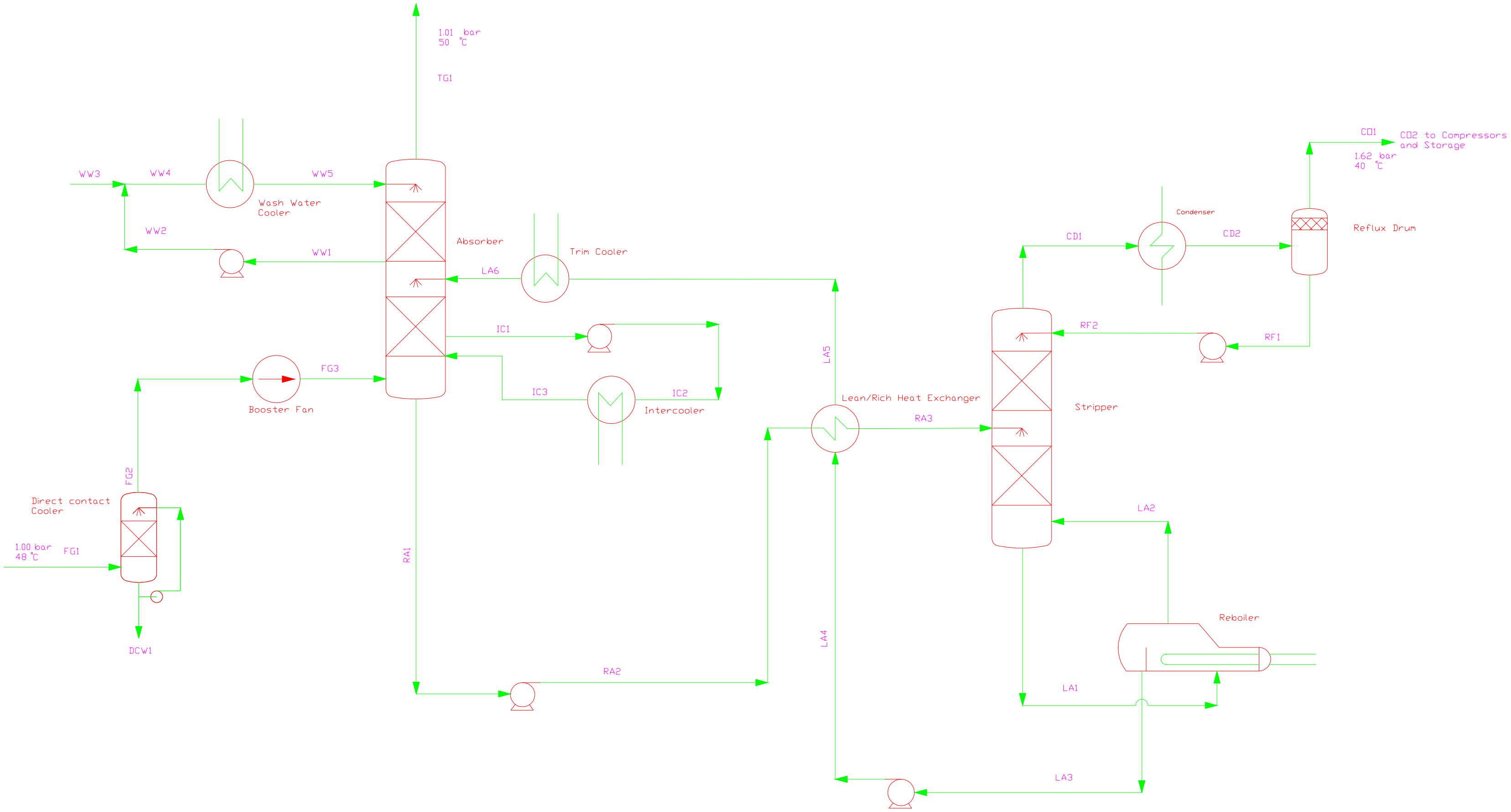

Figure 7: Post-combustion capture plant layout for flue gas from natural gas combustion

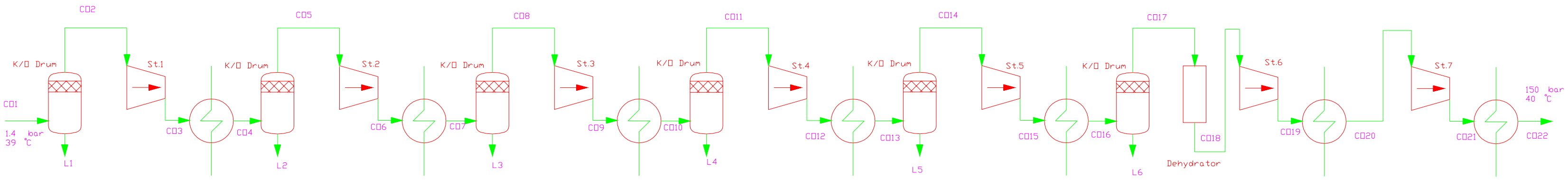

Figure 8: Typical compression system for post-combustion capture

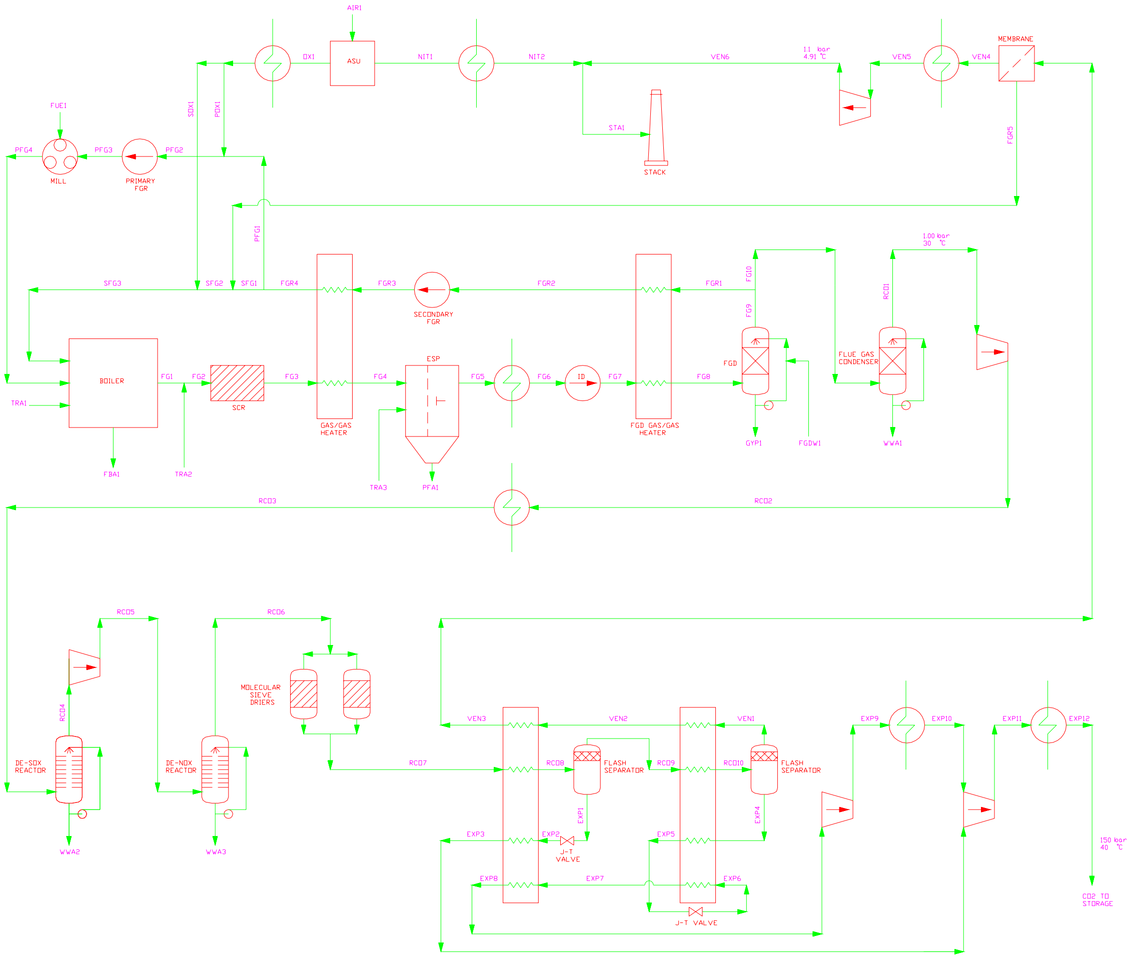

Figure 9: Oxy-fuel plant layout – FGD in recycle loop, low CO_2 purity (< 97.5 %mol)

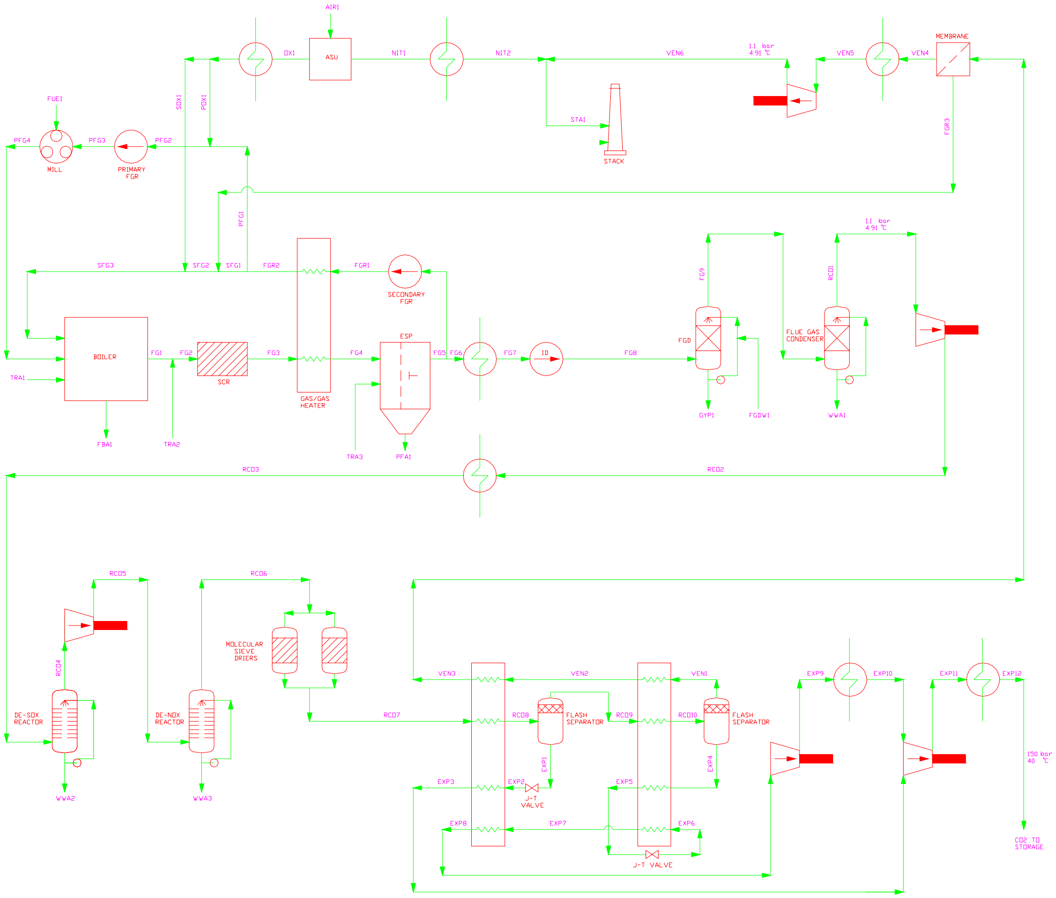

Figure 10: Oxy-fuel plant layout – FGD outside recycle loop, low CO_2 purity (< 97.5 %mol)

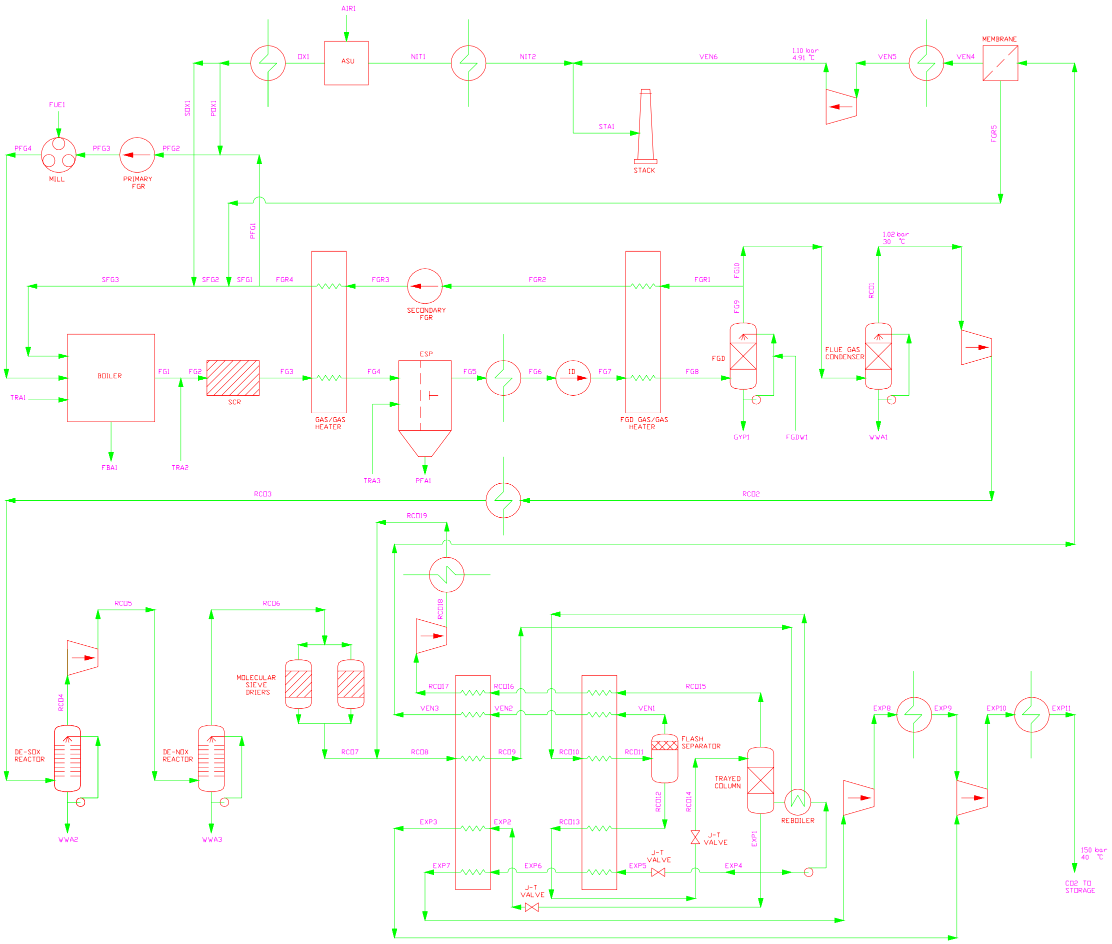

Figure 11: Oxy-fuel plant layout – FGD in recycle loop, high CO_2 purity (> 99.5 %mol)

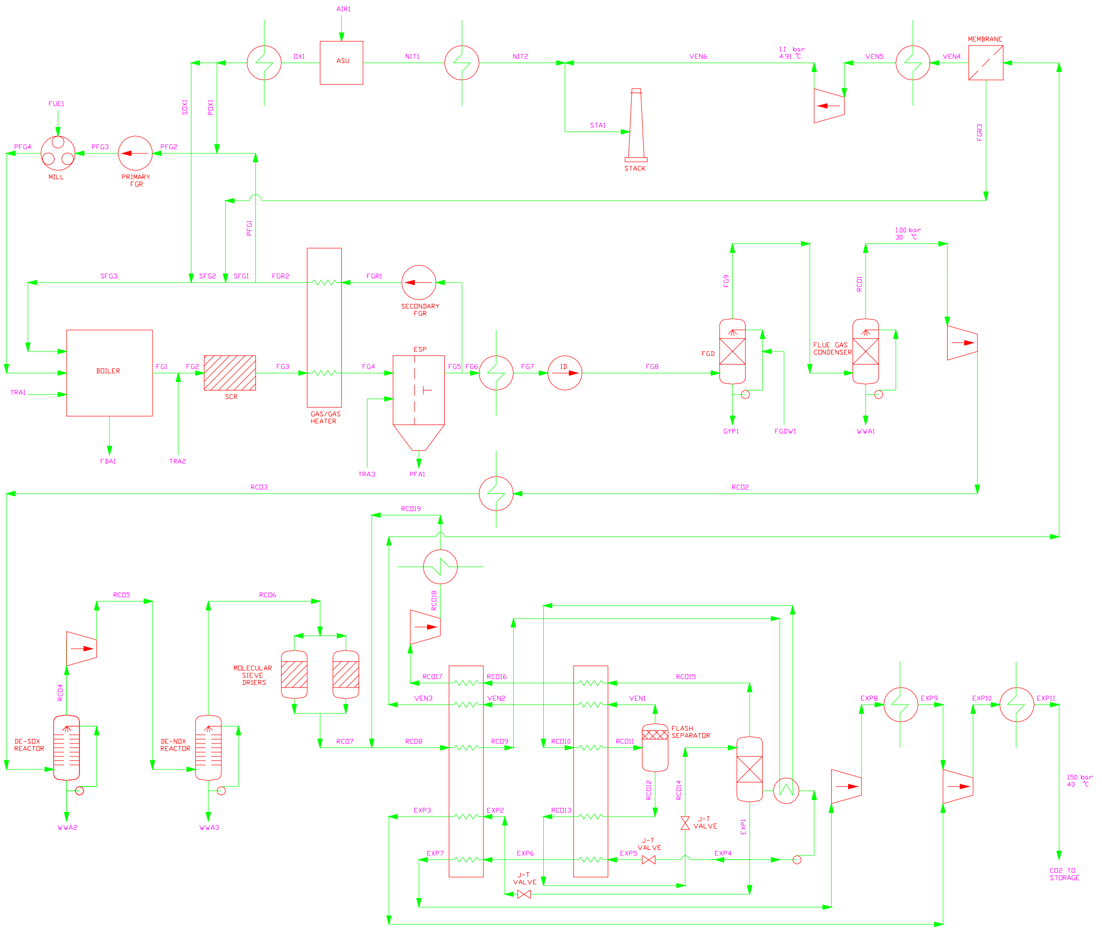

Figure 12: Oxy-fuel plant layout - FGD outside recycle loop, high CO_2 purity (> 99.5 %mol)