HyNet CCUS Pre-FEED

Key Knowledge Deliverable

WP2: Refinery Capture Concept Study Report

DISCLAIMER

The information and data contained herein is not, and should not be construed as, a recommendation by WOOD Plc Ltd that any recipient of this document provide finance to the Project. Each recipient should make its own independent evaluation to determine whether to extend credit to the Project.

EXECUTIVE SUMMARY

The Essar CO Boiler Concept Study Report was generated by WOOD Plc as part of the Preliminary Front End Engineering and Design (pre-FEED) study for the HyNet Industrial CCUS Project. The HyNet CCUS pre-FEED project commenced in April 2019, and was funded under grant by the Department for Business, Energy and Industrial Strategy (BEIS) under the Carbon Capture Utilisation and Storage (CCUS) Innovation Programme.

Delivery of the project was through a consortium formed between Progressive Energy Limited, Essar Oil (UK) Limited, CF Fertilisers UK Limited, Peel Environmental Limited, University of Chester, and Cadent Gas Limited.

The main project objectives are as follows;

- To determine the technical feasibility of a full chain Industrial CCUS scheme comprising anchor loads from Stanlow Refinery and Ince Fertiliser Plant and storage in Liverpool Bay fields.
- To determine the optimised trade-off position between lowest initial cost and future scheme growth
- To determine capital and operating costs for the project to +/- 30% to support HMG development of a policy framework and support mechanism
- To undertake environmental scoping and determine a programme of work for the consent process

This document is one of a series of Key Knowledge Deliverables (KKD's) to be issued by BEIS for public information, as follows;

- HyNet CCUS Pre-FEED KKD WP1 - Basis of Design
- HyNet CCUS Pre-FEED KKD WP1 – Final Report
- HyNet CCUS Pre-FEED KKD WP2 - Refinery Concept Study Report
- HyNet CCUS Pre-FEED KKD WP2 - Hydrogen Production Plant
- HyNet CCUS Pre-FEED KKD WP3 - Fertiliser Capture Report
- HyNet CCUS Pre-FEED KKD WP4 - Onshore CO2 Pipeline Design Study Report
- HyNet CCUS Pre-FEED KKD WP4 - CO2 Road Rail Transport Study Report
- HyNet CCUS Pre-FEED KKD WP5 - Flow Assurance Report
- HyNet CCUS Pre-FEED KKD WP6 - Offshore Transport and Storage
- HyNet CCUS Pre-FEED KKD WP7 - Consenting and Land Strategy

HyNet is a project conceived and supported by numerous stakeholders to decarbonise heat, power and transport in the North West industrial cluster. The overall project produces hydrogen from natural gas feedstock using a reforming process, captures and stores the resultant carbon dioxide (CO_2) offshore, and transports the hydrogen to industrial consumers using a new-build pipeline with additional blending of hydrogen with natural gas for domestic consumers.

Phase 1 of the HyNet project captures existing emissions from the Essar Stanlow Refinery and the CF Fertiliser Plant at Ince. It uses repurposed infrastructure to transport the CO_2 offshore where it will be stored in depleted oil fields in Liverpool Bay.

The Essar Stanlow Refinery is one of the largest CO_2 emitters in the UK. UK Net Zero targets will require that facilities such as this must be decarbonised. While around 60% of emissions can be mitigated through fuel switching of process heaters and the Combined Heat and Power (CHP) plant from natural gas to hydrogen, the residual process emissions from the Catalytic Cracker Unit (CCU) require the deployment of post combustion capture processes.

The CO Boiler is the final stage of Catalytic Cracking Unit. In the Regenerator carbon deposition on the catalyst is burnt off in an oxygen lean atmosphere. This produces a low calorific value effluent gas which, owing to its volume, has a substantial heat content. The regeneration gas is fully combusted in the CO Boiler which raises a substantial amount of high-pressure steam.

The CO Boiler flue has a high CO2 concentration but also contains both NOx (nitrous oxides) and SOx (sulphurous oxides) as well as catalyst fines. The CO Boiler flue gas therefore requires major clean-up steps before the CO2 can be recovered in the CO_2 Removal Unit.

This document deals specifically with Work Package 2 (WP2) covering the development of carbon capture solutions for CO Boiler at the Essar Stanlow Refinery. The project proposes a post combustion Carbon Dioxide Capture Unit (CDCU) physically adjacent to the CCU. Compression and drying of the recovered CO_2 to 35 barg is included within the boundary of the CDCU facility.

There are numerous CO_2 recovery processes many of which are licensed processes. The basis of this study is 90% CO_2 capture using MEA (mono-ethanolamine). This is an open art process that is often used a benchmark process. Licensed processes are generally more energy efficient and have a lower capital cost. Alternative technology options have been considered for the flue gas clean-up process including some comparison of total installed cost.

The three major options that have been considered for the CO Boiler are listed below:

- Option 1: Existing CO Boiler modified to incorporate NOx removal
- Option 2: Existing CO Boiler with stand-alone NOx removal
- Option 3: New CO Boiler with integral NOx removal

However, option 1 was rejected early in the study owing to the very long turn-around time that would be required to retrofit NOx removal to the existing CO Boiler. Options 2 and 3 have been developed to an AACE Class 5 estimate.

The baseline TIC estimates are:

- Option 2: £264,950,000
- Option 3: £283,980,000

These estimates exclude forward escalation, client costs and contingency.

The initial step in the next phase of work would be to carry out a licensor selection exercise. This would cover the De-NOx and Desulphurisation steps, in addition to the CO_2 capture technology.

The selection process would evaluate the alternative technologies against the following criteria:

- Total Installed Cost
- Energy consumption
- Operating Costs
- License fees
- Integration with the Essar Refinery, in particular the rationalisation of services and utilities
- Reference facilities

David Parkin

Dave Parkin
HyNet Project Director

ABBREVIATIONS

AACE	American Association of Cost Estimators
AACE	Aspen Capital Cost Estimator
BFD	Block Flow Diagram
BFW	Boiler Feed Water
CAPEX	Capital Expenditure
CCU	Catalytic Cracking Unit
CDCU	Carbon Dioxide Capture Unit
COB	CO Boiler
FGD	Flue Gas Desulphurisation
GBP	British Pound Sterling
HIPS	High Integrity Protection System
HV	High Voltage
kV	Kilo Volt
LP	Low Pressure
LLP	Low Low Pressure
LoPA	Layer of Protection Analysis
MEA	Mono-ethanolamine
MP	Medium Pressure
MVA	Mega Volt Ampere
MVAR	Mega Volt Ampere Reactive
MW	Mega Watt
NOx	Nitrous Oxides
ONAF	Oil Natural Air Forced
PRT	Power Recovery Train
SCADA	Supervisory Control And Data Acquisition
SCR	Selective Catalytic Reduction
SOx	Sulphurous Oxides
SIS	Safety Instrumented System
TIC	Total Installed Cost
tpd	Tonnes per Day
tph	Tonnes per Hour
UPS	Uninterruptible Power Supply
VFD	Variable Frequency Drive
VHP	Very High Pressure

CONTENTS

1.0 INTRODUCTION

1.1 Project Background

HyNet is a project conceived and supported by numerous stakeholders to decarbonise heat, power and transport in the North West industrial cluster. The overall project produces hydrogen from natural gas feedstock using a reforming process, captures and stores the resultant CO_2 offshore, and transports the hydrogen to industrial consumers using a new-build pipeline with additional blending of hydrogen with natural gas for domestic consumers.

The initial project feasibility study was published in 2017, and a subsequent follow-up report was issued in 2018. A phased approach has been adopted to enable material decarbonisation at the earliest possible point and to increase confidence that cost reductions associated with the utilisation of currently operating gas fields as CO_2 stores can be realised.

Phase 1 of the HyNet project captures existing emissions from the Essar Stanlow Refinery and the CF Fertiliser Plant at Ince. It uses repurposed infrastructure to transport the carbon dioxide offshore where it is stored in the depleted oil fields in Liverpool Bay.

This document deals specifically with Work Package 2 (WP2), covering the development of carbon capture solutions for the CO Boiler at the Essar Stanlow Refinery. The majority of the emissions from the site are generated by the Catalytic Cracker Unit (CCU). The project proposes a post combustion Carbon Dioxide Capture Unit (CDCU) adjacent to the CCU. CO_2 pipeline compression to 35 barg is included within the boundary of the CDCU facility.

1.2 Study Objectives

The purpose of this study is to examine the recovery of CO_2 from the CO Boiler flue gas at the Essar Stanlow refinery complex, including the technology options available for the various processing stages.

The aim of the study is to provide a basis for a high-level techno-economic assessment of the options identified.

There are numerous CO_2 recovery processes available, many of which are licensed processes. The basis of this study is 90% CO_2 capture using MEA (mono-ethanolamine). This is an open art process that is often used as a benchmark process. Licensed processes are generally more energy efficient and lower capital cost. Alternative technology options have been considered for the flue gas clean-up process

2.0 CONCEPT STUDY METHODOLOGY

2.1 Execution

The execution of this concept study was broken down into the following phases:

- Gathering of initial data in relation to the CO Boiler:
- Site emission records to set the design basis for the CDCU
- Details of the CO Boiler & upstream equipment
- Existing layouts and plot plan
- Identification of technology options for the CO_2 capture plant and contaminant treatment or removal technologies
- Option screening
- Concept study
  - This Conceptual Design Study provides the basis for a high-level techno-economic assessment of the viable options identified in the screening exercise. To achieve this; high level engineering design is undertaken for the viable options, in sufficient detail to provide an AACE level 5 cost estimate.
- Cost estimate and final reporting
  - Production of AACE class 5 TIC estimates are then developed for the viable options based upon the high-level engineering design. For novel technology options where cost information is unavailable, order of magnitude estimates were used.
  - This concept study report summarises the project outcomes and makes recommendations on technology selection although further pre-FEED work is required to develop this.

2.2 Study Design Basis

CO_2 mass flow rate from the cracker varies annually dependent on production volumes, Flue gas composition is greater than 15 mol% CO_2 with majority of the balance being Nitrogen. This high concentration of CO_2 in the flue gas makes it a suitable target for post combustion capture using a chemical absorption process. Following discussions with Essar, the design flow rate and composition of effluent gas from the CO Boiler was agreed. Due to the sensitive nature of this information, the detailed composition table has been redacted from this report.

To be suitable for sequestration, the CO_2 export from the CDCU must meet the following specification in the HyNet Project Design Basis as follows:

Substance		Unit	Note
Ash	< 1	mg/Nm3	< 1 µm, Note 7
C2+	< 2.5	mol%	
Carbon Dioxide (CO_2)	> 95	mol%	
Carbon Monoxide (CO)	< 0.2	mol%	Notes 5, 9
Hydrogen (H2)	< 0.75	mol%	Notes 3, 9
Water (H2O)	< 250	ppmv	Note 2, 10
Hydrogen Sulphide	< 200	ppmv	Notes 1, 4, 9,10
Non-condensables (N2, Ar, CH4, etc.)	< 4	mol%	Notes 8, 9
Nitrogen Oxides (NOx)	< 50	ppmv	Note 1
Sulphur Oxides (SOx)	< 50	ppmv	Note 1
Oxygen (O2)	< 10	ppmv	Notes 6, 9

Table 2-1 Carbon Dioxide Specification

Notes:

1. BS ISO 27913:2016 Table A1
2. Avoidance of CO_2 hydrate formation, ref. "Evaluating the risk of hydrate formation in CO_2 pipelines under transient operation", International Journal of Greenhouse Gas Control, Vol 14, May 2013 pp 177-182
3. The bubble point for hydrogen within the CO2 stream should be determined for the lowest pressure and highest temperature in the pipeline. A design margin should be introduced such that the normal operating temperature is 10 % less than this, or the normal operating pressure is 5 % higher than this. (BS ISO 27913:2016 section C4)
4. "Effects of impurities on Geological Storage of CO_2", IEAGHG report 2011/4, June 2011
5. At this level the impact on respiration is less than that of the CO_2 itself, and is equivalent to a 110ppm CO-in Natural Gas SLOT exposure time of 120 minutes
6. Avoidance of SRB production, ref. "Selection of an active souring management solution for a Gulf of Mexico waterflood", ‘Corrosion’ periodical 2004 ref. 04759
7. Levels to avoid pore blocking are not known. These figures set by manufacturers of CO_2 compressors
8. Avoidance of running ductile fracture ref. "Pipeline transport for CO_2 mixtures: models for transient simulation", Aursand, Hammer, Munkejord, Wilhelmsen, SINTEF energy Research, Norway
9. Avoidance of running ductile fracture ref. "CO_2 pipeline integrity: Comparison of a fluid-structure model and uncoupled two-curve methods", Aursand, Dørum
10. Changes to these Design Basis figures are captured in KKD WP1 Final Report

3.0 PROCESS DESCRIPTION

3.1 Process Overview

The full processing train of the Carbon Dioxide Capture Unit (CDCU) overall block flow diagram (BFD) is shown in Figure 3.1 below.

The CO Boiler flue gas stream is very low pressure, only slightly above atmospheric pressure, containing around 16 mol% CO_2. For this application amine-based CO_2 removal processes are preferred to physical absorption processes. Physical absorption processes are more suited to gas streams which have a high CO2 partial pressure, such as synthesis gas. Chemical absorption processes are the natural choice for high volume, low pressure gas streams where the CO2 partial pressure is low.

There are numerous CO_2 recovery processes many of which are licensed processes. The basis of this study is 90% CO_2 capture using MEA (mono-ethanolamine). This is an open art process, often used as a benchmark process. Licensed processes are generally a little more energy efficient and lower capital cost. MEA therefore provides the worst case.

The CO Boiler flue gas also contains NOx (nitrous oxides), SOx (sulphurous oxides) and dust all of which must be removed before the Amine unit.

NOx and SOx both cause irreversible degradation of the amine solution, greatly increasing operating cost and down-time. Dust must also be removed as this will quickly accumulate in process equipment causing serious blockages.

Leaving the CO Boiler, the flue gas is only a slight positive pressure, insufficient to overcome the pressure loss of all of the process units in the processing train. Some booster compression is therefore required to overcome the pressure loss of the processing train, such that the treated gas from the Amine unit can be routed back to the stack where it is vented to atmosphere.

The dust is very abrasive and therefore the Flue Gas Blower (K-2351) is downstream of the Dust Filter. This may lead to a very slight negative pressure at the inlet to the Blower.

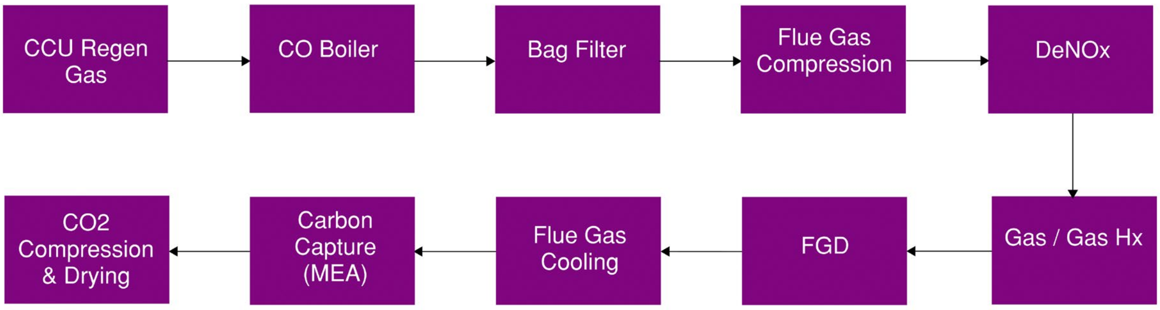


Figure 3.1 CDCU Overall BFD

There are technology options available for some of the gas clean-up processing stages. These are described later.

In all of the all options described in Section 4.0, the technology employed for CO_2 removal is MEA, with the differences occurring only where the NOx removal takes place i.e. whether this is within the CO Boiler itself or whether an external DeNOx unit is retrofitted to duct work downstream of the CO Boiler.

3.2 CO Boiler

In the CCU Regenerator carbon deposition on the circulating catalyst is removed by oxygen lean combustion in the Regenerator. The Regenerator off-gas is a low calorific value gas containing a significant amount of CO. In the CO Boiler the Regenerator effluent gas is combusted raising a significant amount of VHP (very high pressure) steam.

CO Boiler Break-in

The proposed break-in to the CO Boiler flue gas is described in section 11. A number of options have been reviewed. The preferred approach would be selected in the next phase. It is anticipated that during refinery start-up the CCU would be started up first and only when stable will the CDCU be brought online.

CO Boiler Relief Case

There is pre-existing relief case on the CO Boiler which must be accommodated in the final design.

3.3 NOx Removal

In the measured NOx levels in the CO Boiler flue gas it proved difficult to accurately determine the split between NO and NO_2. Typical figures were therefore assumed: 90% NO and 10% NO_2.

In Amine units the level of NO is not important. NO is not absorbed and will generally pass though the unit and leave the Amine unit in the treated gas. NO_2 however will form heat stable salts with the amine causing solvent degradation. Typically, NO_2 must preferably be removed to <1 ppmv.

The base case NOx removal technology is Selective Catalytic Reduction (SCR). This is a catalytic process which converts NOx into nitrogen (N_2) and water (H_2O) using ammonia as the reducing agent. The chemical equations for a stoichiometric reaction using NH_3 are shown below:

$$4NO + 4NH_3 + O_2 \rightarrow 4N_2 + 6H_2O$$

$$2NO_2 + 4NH_3 + O_2 \rightarrow 3N_2 + 6H_2O$$

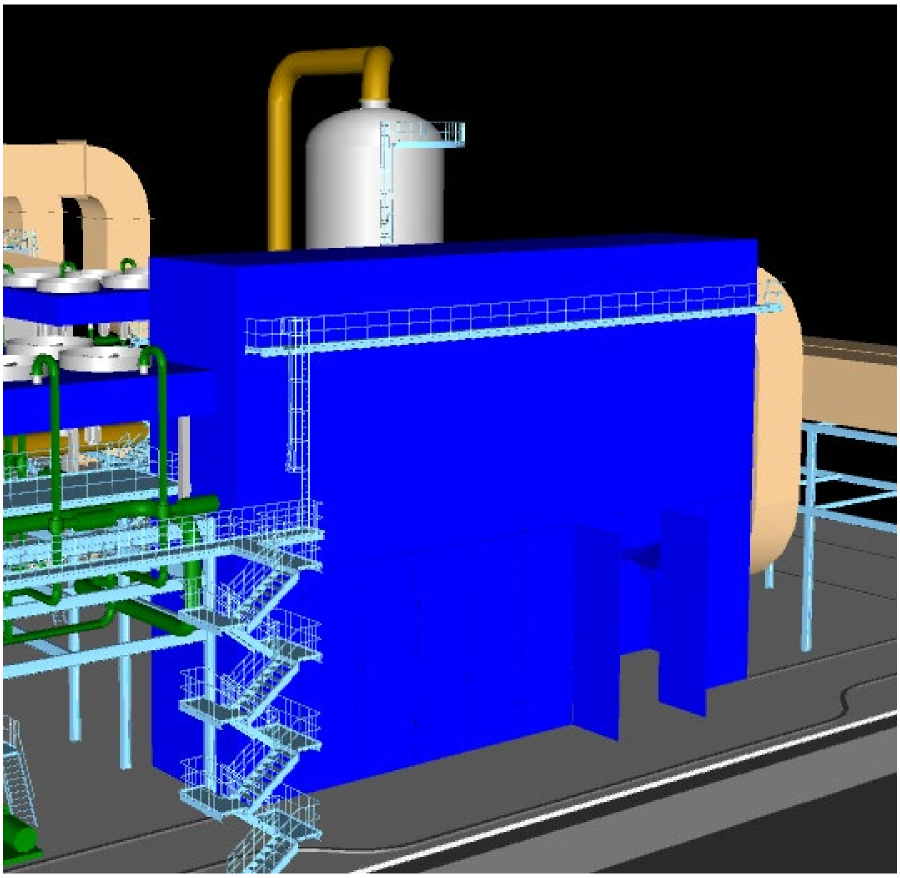
25% aqueous ammonia solution is generally used rather than gaseous ammonia for safety reasons. The reduction reaction takes place over a wide range of temperatures depending on the catalyst that is selected.

There are numerous options for SCR catalysts. For this application Vanadium-titania based catalysts are likely to be preferred which are suited to the required operating temperature. This form of catalyst can be in pelletised, monolithic, plate or corrugated form.

In modern CO Boilers, SCR is integrated into the design where the SCR catalyst is installed at a suitable point in the convective coils to provide the preferred operating temperature.

3.4 Dust Filter

The Dust Filter will be a very large multi-modular unit. See model extract below.



To avoid downstream contamination, dust in the flue gas are removed in a Bag Filter (S-2351). The Bag Filter will have multiple compartments to allow collected dust to be removed without having to take the Filter offline.

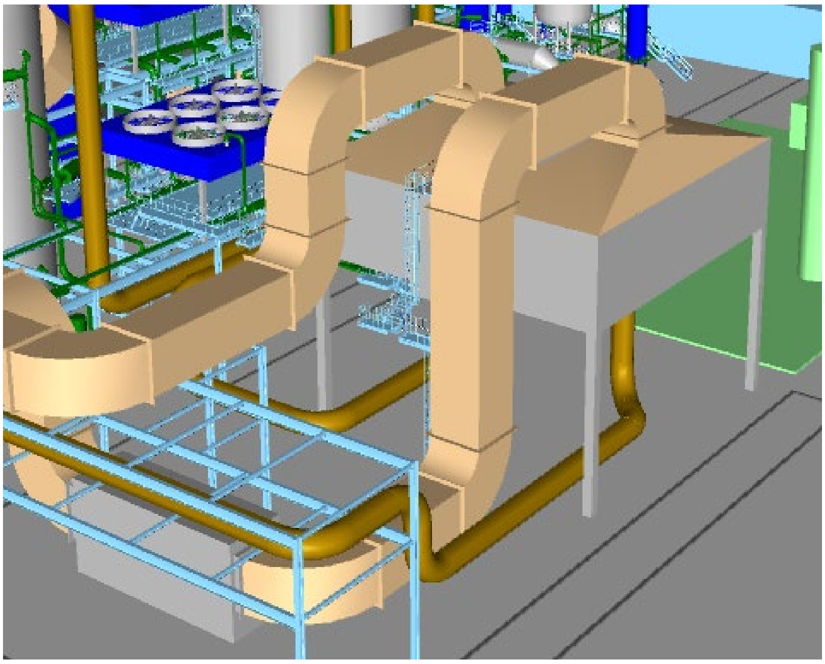
The location of the Filter in the process train has been assessed in some detail. If it is located upstream of the Filter, then the Booster Fan would need to be able to withstand severe erosion from the aluminium oxide and silicon oxide in catalyst fines. This would require specialist metallurgy which would considerably increase the cost of the Booster Fan and reduce its maintenance interval.

If the Gas/Gas Exchanger is removed (discussed later) and the Flue Gas Desulphurisation Absorber can be designed to tolerate dust then it may be possible to remove the Bag Filter but there would still be the impact on the Booster Fan to consider.

3.5 Gas/Gas Exchanger

The Gas/Gas Exchanger (E-2362) cools the flue gas leaving the SCR whilst heating the treated gas from the Amine Absorber. This reduces the load on the downstream Direct Contact Cooler (C-2352) and increases the treated gas temperature to provide sufficient buoyancy to be emitted from the stack.

This is a very large rotary-type heat exchanger, typically used for combustion air preheat in large-scale power generation. Its typical footprint is ~20m x 20m and occupies a significant portion of the plot area and weighs several hundred tonnes. In addition to this the exchanger must be mounted on a structure to allow large ductwork connections to the top and bottom. See model extract below.



3.6 De-Sulphurisation

The CO Boiler flue gas must also be de-sulphurised to minimise solvent degradation in the Amine Unit. This has been accomplished in two stages in this study. The first stage is bulk SOx removal and the base case technology adopted in this study is wet limestone scrubbing

However other technologies are available which are described in section 7. In wet limestone scrubbing, SO_2/SO_3 react with limestone ($CaCO_3$) slurry in the Flue Gas Desulphurisation (FGD) scrubber to create insoluble calcium sulphite ($CaSO_3$). This then undergoes oxidation with air to produce gypsum. Gypsum can be recovered as a saleable product but requires additional equipment. At present, gypsum product manufacturing equipment is excluded. See section 5.1 for a detailed discussion of Wet FGD and other FGD technologies.

3.7 DCC/Caustic Wash

After bulk desulphurisation, the flue gas is further cooled in the Direct Contact Cooler (C-2351). The DCC is a packed column in which the flue gas is cooled to circa. 40°C by counter-current contact with cold water.

Water from the bottom of the DCC is circulated by the DCC Pump (P-2351) through the DCC Cooler (E-2368). The water dewpoint of the flue gas is typically less than the DCC outlet temperature, so water is knocked out of the flue gas. This is withdrawn under level control in the DCC in the purge water. The circulating quench water is dosed with caustic solution. This controls pH and further removes SOx down to ~ 5 - 10ppm.

3.8 Amine Unit

The two main equipment items in the MEA unit are the Amine Absorber (C-2353) and the MEA Regenerator (C-2354).

Chemical absorption of CO_2 with amines is an exothermic reaction. The design proposed in study involves a total draw-off and pump down cooler to reduce the bulge in the Absorber temperature profile. Without pump down cooling the amine solution temperature in the Absorber can reach very high temperatures which adversely affects the chemical equilibrium and increases equipment sizes. Pump down cooling reduces energy consumption and reduces the column diameter and the number of theoretical stages.

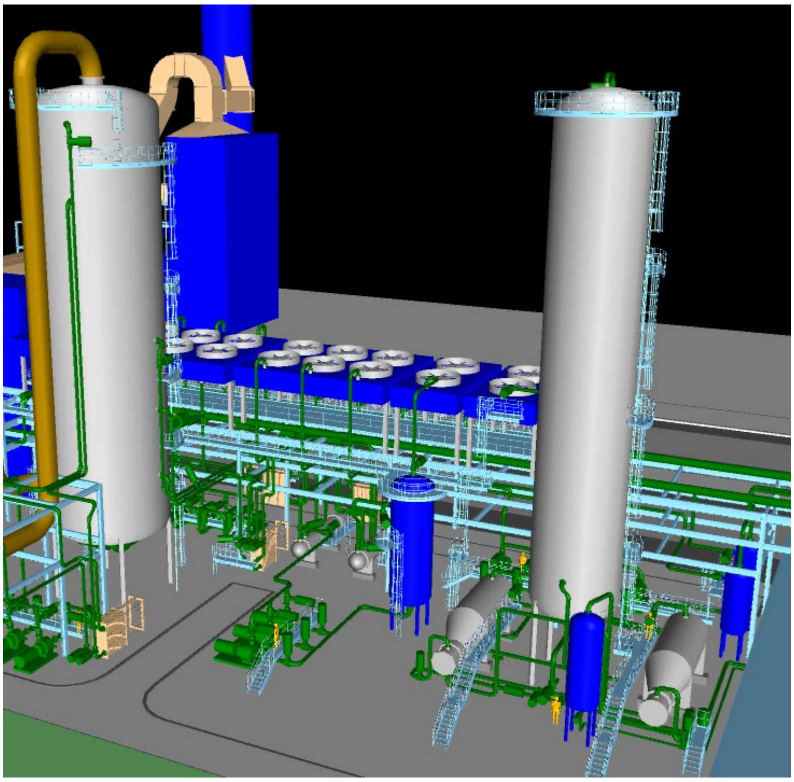
Split absorption has been incorporated giving a lean and semi-lean amine solution. Rich solution from the bottom of the absorber is split 75/25, where 75% of the rich solution is routed to the MEA Regenerator and the remaining 25% is heated in the 1st and 2nd stage preheaters (E-2356 and E-2357 respectively) and then sent to the Semi-Lean Solution Flash Drum (V-2352). Vapour from V-2352 is air cooled and then flashed in the Flashed Gas KO Drum (V-2353) to produce a low pressure (LLP) CO_2 product. The fractional split between lean and semi-lean is a typical value based on experience.

Semi-lean solution from the Semi-lean Flash drum (V-2352) is mixed with the extraction stream drawn from the Amine Absorber, is cooled and then returned to the Amine Absorber below the draw point.

The rich solution is preheated in the Cross-over Exchanger (E-2353) and then fed to the MEA Regenerator. Amine regeneration is the opposite of absorption and Regenerator

Reboiler (E-2359) has a high heat duty requiring a significant amount of low-pressure steam.

Lean amine solution from the MEA Regenerator (C2354) and is cooled in 2nd Flash Cooler (E2357) and the Cross-over Exchanger (E-2353), Lean Solution Coolers (E-2359 and E-2354) before being returned to the Amine Absorber. The screen shot model shown below, gives a representation of the scale. The Absorber Column (C-2353) is ~ 9m diameter and the MEA Regenerator Column (C2354) ~ 6m diameter.



Overhead vapour from the Amine Absorber (C-2353) is partially condensed and separated in the Stripper Accumulator (V-2351). Condensate is returned to the Amine Absorber as reflux and the overhead LP CO_2 product is sent to the CO_2 Compressor (K-2352). The pressure of the LP CO_2 is reduced sufficiently so that the LP CO_2 stream can be mixed with the LLP CO_2 stream from the Flash Gas KO Drum.

3.9 CO_2 Compression & Drying

The combined low-pressure CO_2 stream is compressed in CO_2 Compressor (K-2352) to the final export pressure of 35 barg. The CO_2 Compressor is a multi-stage centrifugal compressor with inter-stage cooling and condensate removal. The process condensate would be recycled back the Amine unit.

Originally in the study, a five-stage machine was considered for the CO_2 Compressor, with the first stage increasing the pressure of the LLP CO_2 from the Flash Gas KO Drum to the pressure of the LP CO_2 from the Amine unit. As the difference in pressure between the LLP CO_2 and the LP CO_2 is quite small (approximately 0.4 bar) the pressure ratio of the first stage would be quite low compared to stages 2-5. Vendors advised that this may cause the machine to become unbalanced.

Vendors recommended to balance the machine by removing the 1st stage which left then two options. A small booster compressor could be added to boost the pressure of the LLP CO2 stream up to the pressure of the LP CO2. This would add cost and some complexity.

Alternatively, the LP CO2 stream could be let down in pressure to the LLP CO2 to produce a combined LLP stream. This increases the power consumption and also increase the cost of the machine but not to the same extent. The basis of this study is the latter option, to let down the pressure of the LP CO2 stream to the LLP CO2 stream.

After compression, the CO_2 is dried in the CO_2 Drier Package (PK-2352) to remove any remaining water and is then fed into the CO_2 pipeline system.

4.0 STUDY OPTIONS

The three major options considered are shown below. Only options 2 and 3 have been developed to a Total Installed Cost.

4.1 Option 1 (Modifications to the CO Boiler)

NOx abatement can be retrofitted to the CO Boiler, one option being burner replacement and possibly the introduction of internal baffles to induce turbulence. The proportion of the NOx produced in the CCU Regenerator upstream of the CO Boiler may also contribute the total NOx. Any modifications to the burners in the CO Boiler would have no effect on regenerator NOx.

Regardless of this, it is not certain what degree of NOx reduction could be achieved with these measures, but it is very unlikely that an economic level of NOx could be achieved by these means.

SCR could be retrofitted but the turn-around duration to implement this option is prohibitive. This has not therefore been pursued.

4.2 Option 2 (Stand-alone SCR)

A stand-alone SCR unit can be installed after the CO Boiler in a suitable duct. This would need to be downstream of the Dust Filter (S-2351) and Flue Gas Blower (K-2351) and upstream of the Gas/gas Exchanger (E-2362).

An in-line burner in the ductwork provides trim preheating to maintain a constant flue gas temperature for the catalytic reaction.

A preliminary cost estimate for the actual break-in work to the CO Boiler is included in the cost estimate for Option 2.

4.3 Option 3 (New CO Boiler with Integral SCR)

In option 3 it is proposed to install a new CO Boiler having integral SCR NOx abatement. This would need to be located on the CDCU plot.

However, this would allow the new CO boiler will be fully constructed prior to a turn-around leaving only the final tie-ins to be carried out during shutdown.

Duct work as described in section 4.2 is also required for this option.

Option 3 provides the opportunity to de-constrain the CCU.

Increasing the CO Boiler steam capacity would also require a wider site review to consider impact on the refinery steam balance. This review is outside of the scope of this concept study. This opportunity should be examined further in the next phase.

5.0 ALTERNATIVE TECHNOLOGIES

5.1 Flue Gas Desulphurisation (FGD)

5.1.1 Wet Limestone FGD

The base case technology used in this study is Wet Limestone Slurry wash. This type of FGD uses a limestone ($CaCO_3$) slurry to remove SOx from flue gas.

As discussed in section 3.0, the flue gas has already passed through the Dust Filter. After the Dust Filter the flue gas enters the bottom of the absorber where it contacts counter currently with the limestone slurry flowing from the top. See Figure 5.1 below for a diagram showing the Wet FGD process.

The limestone reacts with the SO2 in the flue gas to create insoluble calcium sulphite (CaSO3):

$$CaCO_3 + SO_2 \rightarrow CaSO_3 + CO_2$$

The calcium sulphite is then oxidised to produce gypsum:

$$CaSO_3 + \frac{1}{2} O_2 + 2H_2O \rightarrow CaSO_4 \cdot 2H_2O$$

The scrubbed gas exits the top of the absorber. The gypsum slurry exits the bottom of the absorber and is filtered and separated to remove excess water. The water is sent to the waste water treatment plant and gypsum can either be recovered and sold or can be disposed of in landfill.

This process requires large amounts of limestone and water and generates large amounts of waste (gypsum).

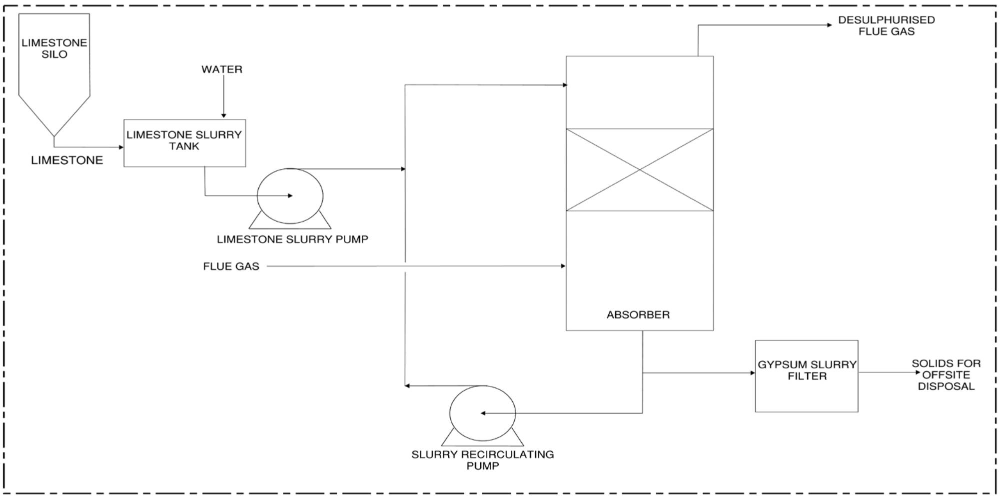


Figure 5.1 Wet FGD process

5.1.2 SNOx (Option 2 only)

SNOx flue gas treatment is a licensed process from Haldor-Topsoe which removes, SOx, NOx and particulates from flue gas. This process produces fertiliser grade concentrated sulphuric acid as a by-product that can be sold to generate additional revenue.

First step in the SNOx process is to remove any dust from the flue gas using a bag filter. If the dust is not captured in the filter it will clog up the SO2 Converter and if not below 1-2 mg/Nm3, the pressure drop across the converter will become too high.

After the bag filter, the flue gas undergoes SCR as described in section 3.0. The licensor prefers to place the SCR together with the SO_2 converter to avoid any ammonia bisulphate issues such as fouling of the economisers, therefore, SNOx for FGD is only suitable for Option 2.

After SCR, the SO_2 in the flue gas is converted to SO3 in an SO2 Converter, after which it is then converted into a concentrated sulphuric acid gas. The sulphuric acid gas is then condensed to liquid in the Wet Sulphuric Acid (WSA) Condenser. The moisture required to form the H_2SO_4 comes from the H_2O already in the flue gas. The conversion of sulphur to sulphuric acid is around 98%:

$$SO_2 + 0.5O_2 \rightarrow SO_3$$

$$SO_3 + H_2O \rightarrow H_2SO_4$$

After this process, the flue gas is now considered clean. The licensor has confirmed they can reach the required SOx level in the flue gas of 50 ppmv, as per Table 2-1 and has noted that 10 ppmv SOx can be achieved by adding more catalyst.

This type of process uses no water, no limestone and produces a very small amount of fly ash waste.

In addition, the hot combustion gas from SNOx WSA Condenser can be recycled back to the CO Boiler as preheated combustion air which enables up to an extra 5% steam production, consuming the same amount of fuel.

All inclusive, the total pressure drop over the SNOx unit is approximately 100 mbar.

SNOx units are modularised, see Figure 5.2 below which is a Google Earth image of a plant in Austria that has a SNOx unit.

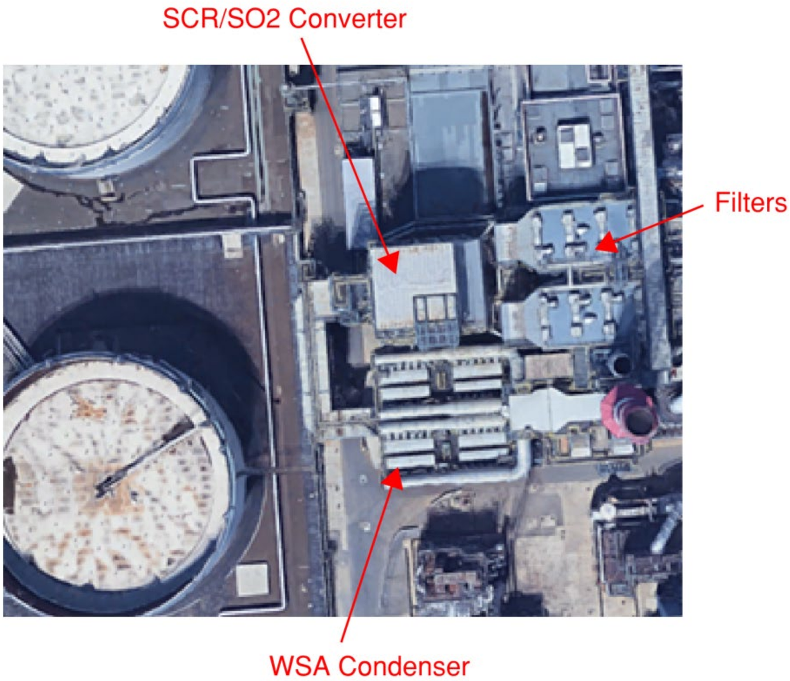


Figure 5.2 SNOx Unit Plan Eye View (Google Earth)

SNOx unit includes all the equipment as shown in Figure 5.3 SNOx Process below plus an ammonia vaporiser. Therefore, if the SNOx unit was to be incorporated into Option 2, the Dust Filter (S-2351), Flue Gas Blower (K-2351), Aqueous Ammonia Vaporiser (E-2372) plus the static mixer and SCR catalyst that are situated in the duct work could be removed from Option 2. The licensor estimates that the plot space for the SNOx unit to be 50 m x 60 m.

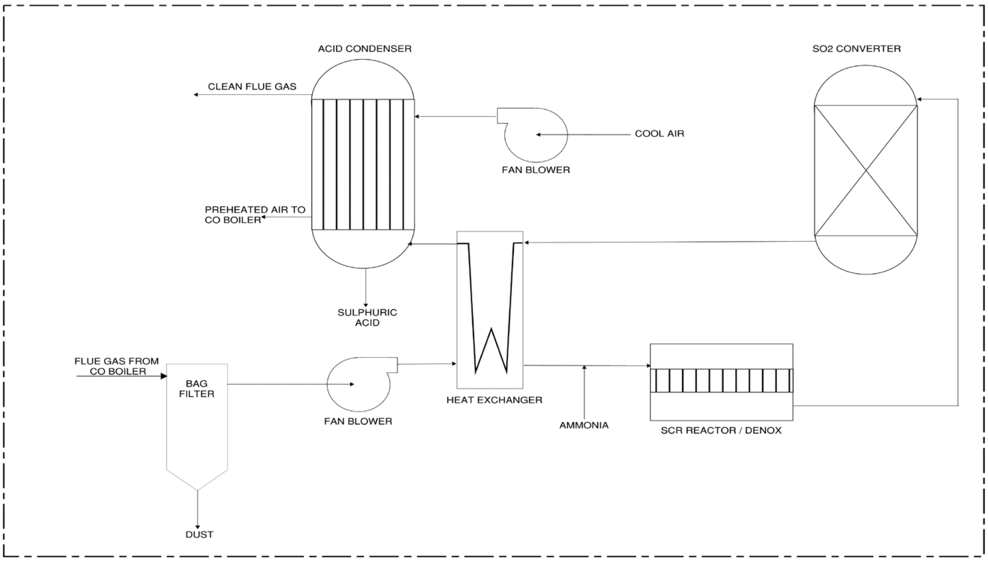


Figure 5.3 SNOx Process

5.1.3 Dry FGD

Lime-spray drying is a dry scrubbing process which uses a lime (CaO) slurry to remove sulphur from flue gas.

Flue gas from boilers is treated in an absorber, where it flows concurrently with atomised lime slurry droplets. The water in the spray droplets evaporates, which cools the gas. The droplets absorb SO_2 from the gas, which reacts with the lime in the slurry to form calcium sulphite ($CaSO_3$):

$$SO_2 + CaO + \frac{1}{2}H_2O \rightarrow CaSO_3 \cdot \frac{1}{2}H_2O$$

Some of the $CaSO_3$, reacts with the oxygen in the flue gas to form calcium sulphate ($CaSO_4$):

$$CaSO_3 + \frac{1}{2}O_2 + 2H_2O \rightarrow CaSO_4 \cdot 2H_2O$$

After absorption, the flue gas, along with reaction products, unreacted lime and the fly ash, passes out of the dry scrubber to the baghouse where the waste products are collected.

The waste products: $CaSO_3$, $CaSO_4$, calcium hydroxide and fly ash are produced in dry form and can be handled with conventional pneumatic fly ash handling equipment.

This type of FGD uses less water than Wet FGD. Dry FGD, produces significant amounts of waste for disposal but unlike the waste products from Wet FGD (gypsum), Dry FGD waste products are not suitable for recycling due to their permeability and solubility.

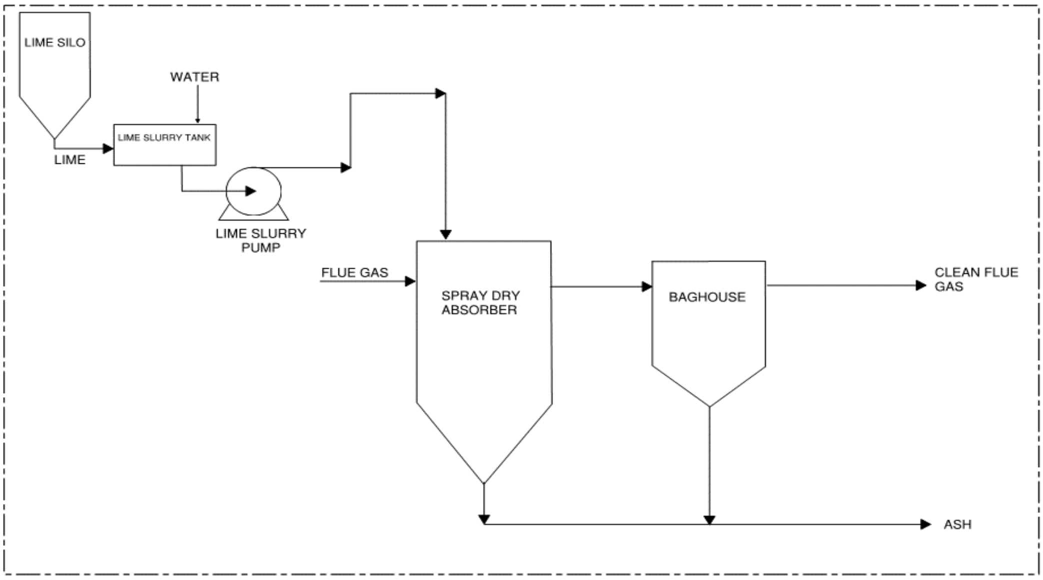


Figure 5.4 Dry FGD Process

5.1.4 Wet FGD Vs SNOx Vs Dry FGD

All three FGD technologies remove sufficient SOx from the flue gas to meet the CO_2 specification set out in Table 2-1 , so all are technically feasible. In summary, Wet FGD has a high consumption of natural resources and a high environmental impact due to disposal of the waste products if not recycled. Dry FGD consumes approximately half the quantity of water required for Wet FGD and also has a high environmental impact since the waste products cannot be recycled. SNOx does not consume any limestone or water and has very little waste for disposal and also produces concentrated fertiliser grade sulphuric acid which can be sold to generate additional revenue.

For this study, Wet FGD is considered as the base case for FGD as it is considered to be the most conservative (worst case) in terms of estimates of utility consumptions and waste production.

5.2 Alternative DeNOx - Non-Selective Catalytic Reduction (NSCR)

An alternative to SCR is Non-Selective Catalytic Reduction (NSCR). In NSCR, CO, NOx and hydrocarbons are converted into CO_2 and N_2 via a catalyst. This technique does not need additional reagents to be injected because the unburnt hydrocarbons are used as a reductant. NSCR generally operates at much higher temperatures than SCR, however oxygen content in the flue gas must be low, perhaps as low as 0.5%. This would correspond to very low excess air which is not acceptable for a large combustion plant.

5.3 Alternative CO_2 Removal Processes

MEA has been used in this study for several reasons. It is an open art process that can be readily simulated to provide good approximation heat & material balance. Of course, were this scheme to progress to FEED stage then licensors such as Shell (CANSOLV) and MHI (KS-1) would be approached. Using licensed processes, the energy consumption of the amine unit would decrease. Initial indications are that a reduction in energy consumption of at least 10% could be expected. The heat & material balance in this study is therefore conservative.

5.4 Gas/Gas Heat Exchanger

The Gas/Gas Exchanger (E-2362) occupies significant plot space (~20m x 20m) weighs almost 500 tonnes and is a high CAPEX item.

An alternative is to vent the treated gas from the Amine Absorber (C-2353) direct to atmosphere. Additional quench cooling of the SCR effluent gas would be required in the FGD.

The composition of the treated gas is shown below:

	Mol %
Nitrogen	92.76
CO_2	1.74
CO	0.13
Oxygen	2.26
H2O	3.11

This stream is essentially non-toxic but being water saturated will produce a visible plume, particularly during cold weather. However, with some form of plume abatement could be acceptable.

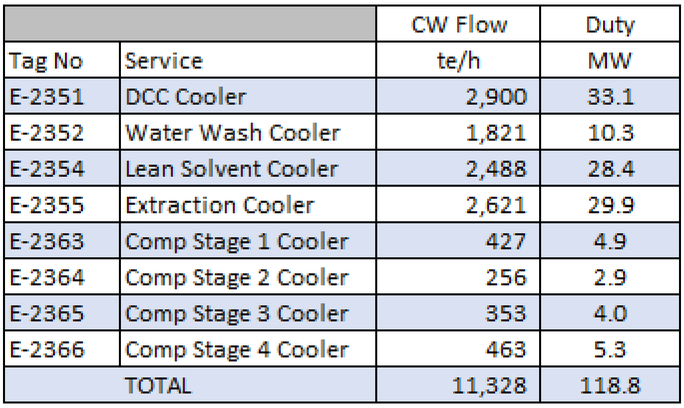
Removal of the Gas/Gas Exchanger would also eliminate the need for a return duct to the stack and would simplify structural requirements around the CO Boiler/stack, as well as significantly reducing pressure losses within the CDCU.

Essar are reviewing this option.

6.0 UTILITIES & SERVICES

6.1 Cooling Water

Where possible air cooling has been used to minimise the requirement for cooling water. Where cooling is required, such as in the Amine unit, air cooling to typically to 45°C is used followed by "trim" cooling using cooling water. A summary of the "trim" cooling water loads is below.



		CW Flow	Duty
Tag No	Service	te/h	MW
E-2351	DCC Cooler	2,900	33.1
E-2352	Water Wash Cooler	1,821	10.3
E-2354	Lean Solvent Cooler	2,488	28.4
E-2355	Extraction Cooler	2,621	29.9
E-2363	Comp Stage 1 Cooler	427	4.9
E-2364	Comp Stage 2 Cooler	256	2.9
E-2365	Comp Stage 3 Cooler	353	4.0
E-2366	Comp Stage 4 Cooler	463	5.3
	TOTAL	11,328	118.8

Although water cooling has been minimised the cooling water load above is still substantial. On the plot plan and in the cost estimates, modular packed-type cooling water units have been assumed. These are supplied in modular form and it is estimated that 10 modules would be required to provide the above duty.

6.2 Storage Tanks

Storage tanks are shown on the equipment summaries but are not currently shown on the plot plan as there is insufficient space available. The intention is to re-use existing storage tanks where possible.

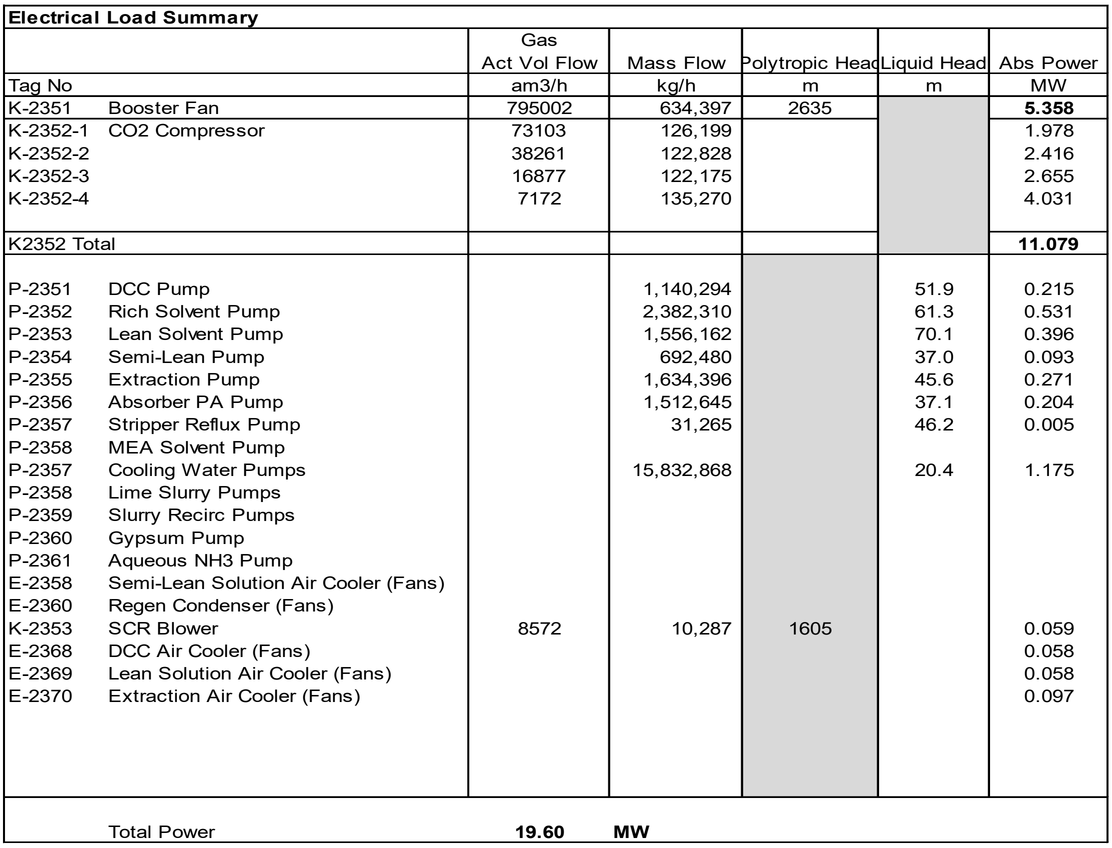
7.0 ELECTRICAL ASSESSMENT

7.1 HyNet Project Electrical Requirements

7.1.1 HyNet Electrical Power Requirements

The HyNet Project electrical absorbed power requirements for process equipment (only) are shown in Table 7-1 indicates a total absorbed power demand of 19.6 MW. Other addition power requirements for utilities, lighting and small power are an unknown quantity at this stage, however a conservative estimation of between 200 kW to 400 kW would raise the overall total absorbed power demand to approximately 20 MW.

The bulk of the power demand is based around the Booster Fan (K-2351) and the CO_2 Compressor (K-2352). It's highly probable that a reduced current starting method (VFD or Auto-Transformer) will be required for starting of the Booster Fan (K-2351) and CO_2 Compressor (K-2352), thus minimising the transient volt drop on the power system.



Electrical Load Summary

Tag No		Gas Act Vol Flow am3/h	Mass Flow kg/h	Polytropic Head m	Liquid Head m	Abs Power MW
K-2351	Booster Fan	795002	634,397	2635		**5.358**
K-2352-1	CO2 Compressor	73103	126,199			1.978
K-2352-2		38261	122,828			2.416
K-2352-3		16877	122,175			2.655
K-2352-4		7172	135,270			4.031
K2352 Total						**11.079**
P-2351	DCC Pump		1,140,294		51.9	0.215
P-2352	Rich Solvent Pump		2,382,310		61.3	0.531
P-2353	Lean Solvent Pump		1,556,162		70.1	0.396
P-2354	Semi-Lean Pump		692,480		37.0	0.093
P-2355	Extraction Pump		1,634,396		45.6	0.271
P-2356	Absorber PA Pump		1,512,645		37.1	0.204
P-2357	Stripper Reflux Pump		31,265		46.2	0.005
P-2358	MEA Solvent Pump					
P-2357	Cooling Water Pumps		15,832,868		20.4	1.175
P-2358	Lime Slurry Pumps					
P-2359	Slurry Recirc Pumps					
P-2360	Gypsum Pump					
P-2361	Aqueous NH3 Pump					
E-2358	Semi-Lean Solution Air Cooler (Fans)					
E-2360	Regen Condenser (Fans)					
K-2353	SCR Blower	8572	10,287	1605		0.059
E-2368	DCC Air Cooler (Fans)					0.058
E-2369	Lean Solution Air Cooler (Fans)					0.058
E-2370	Extraction Air Cooler (Fans)					0.097
	Total Power	**19.60**	**MW**			

Table 7-1 HyNet Electrical Power Requirements

7.1.2 Feasibility

The Refinery's existing electrical power system has spare capacity on the network; however the current infrastructure set-up does not allow for supplying of the Hynet Project loads. To enable loads to be supplied from the Refinery's power system, the only feasible option is to install a new electrical substation local to the new CDCU. Due to the high-power demand of 20 MW, the new electrical substation would require connection directly to the Refinery's 33 kV ring system. The electrical substation would be expected to consist of, but not be limited to the following:

- Switchroom Building
- Transformer Bay/Bunded Area
- 33 kV Switchboard
- 6.6 kV Switchboard
- 400 V Switchboard
- 2-off 33/6.6 kV Transformers
- 2-off 6.6/0.43 kV Transformers
- 2-off VFD units or Auto-Transformers (for motor current starting reduction)
- Switchgear Trip/Close UPS System
- Small Power and Lighting Distribution Boards

Figure 7.1 and Figure 7.2 below, show the proposed 33 kV substation location and tie-in point to the existing 33 kV system.

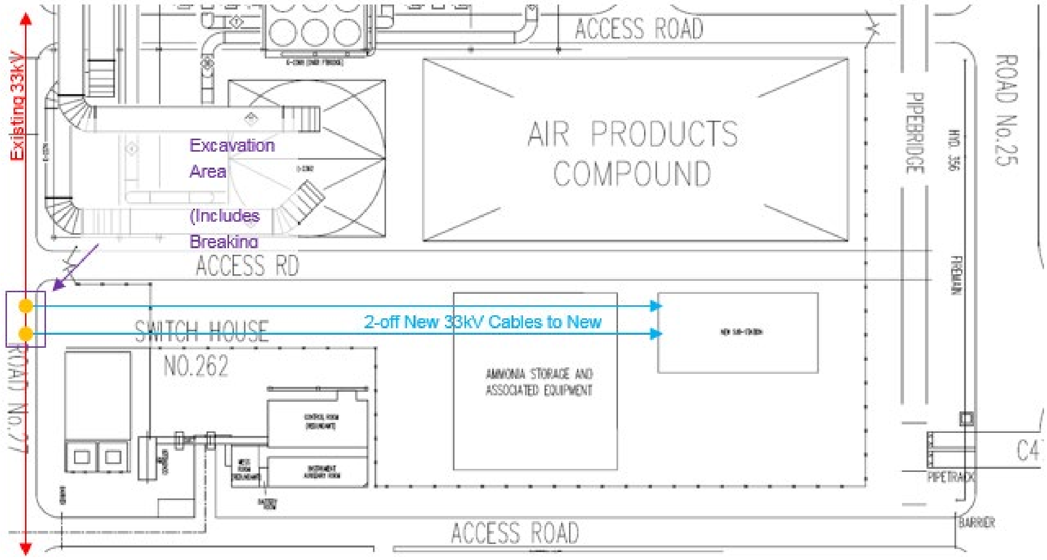


Figure 7.1 Extract from Plot Plan Layout (720063-8230-51-02-0001)

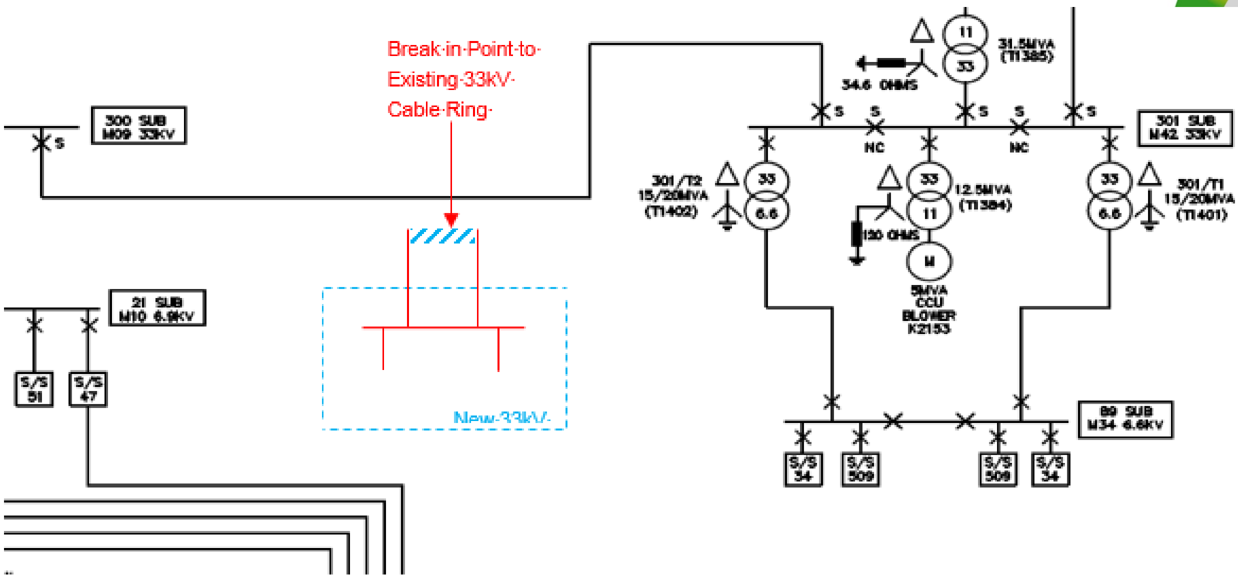


Figure 7.2 Extract from ESSAR HV SLD (00468844S004P00001)

7.2 Further Considerations and Opportunities

7.2.1 Increased Electrical Load Implications

Increasing the electrical power consumption at the Refinery by 20 MW will increase the power import from the National Grid. The power import increase will trigger the requirement for a revised connection agreement with the National Grid to ensure financial penalties are not applicable.

7.2.2 Substation 26 Removal

Figure 7.3 below, shows the location of existing Substation No.26 in relation to the new CDCU. Further development of the plot plan may see the new CDCU encroach on the area where Substation No.26 currently resides. If this is the case, then Substation No.26 will require destructing and all power supplies re-routing into the new 33 kV substation. However, in order to simplify the Refinery power system, it would still be a great operational benefit to destruct Substation No.26 and re-route supplies into the new 33 kV substation, even if not deemed a project necessity.

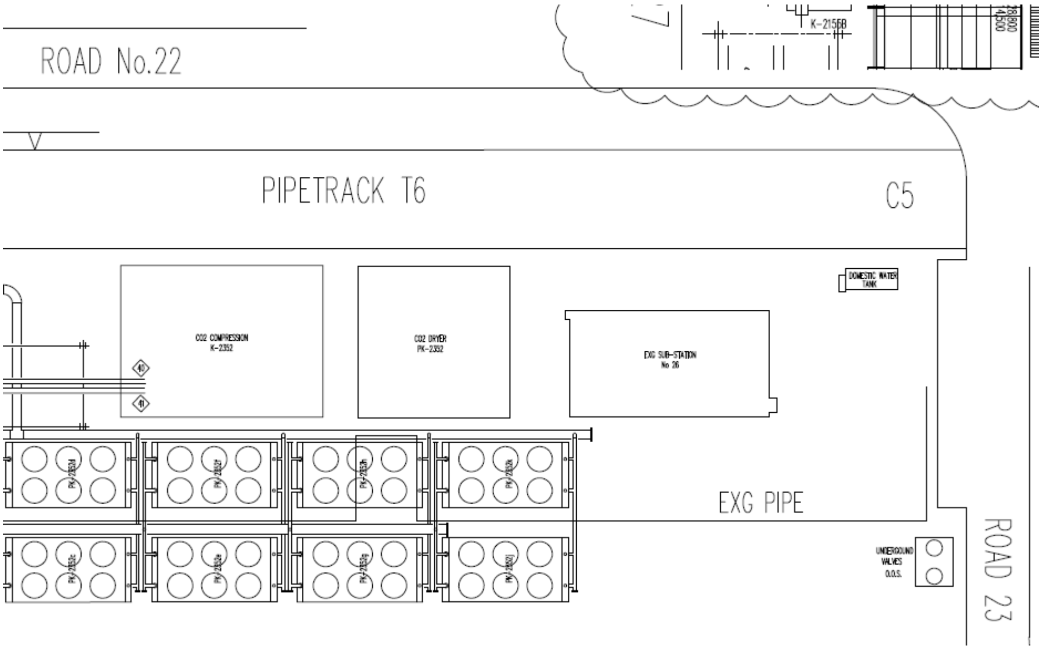


Figure 7.3 Extract from Plot Plan Layout (720063-8230-51-02-0001)

8.0 CO BOILER RELIEF CASE

As the CO Boiler is a large combustion plant its flue gas path must not be interrupted and upstream relief scenarios must be considered. There are a number of options to ensure that this is the case.

8.1 Fast Acting Diverter Valves

This is the option that is shown on the Process Flow Diagrams. It involves two fast acting multi-vane dampers which are SIS interlocked to ensure that there is always an open path from the CO Boiler to either the CDCU or the Stack. Within the CDCU there are no potential obstructions other than the Flue Gas Blower (K-2351).

Figure 8.1 below shows how this would be implemented.

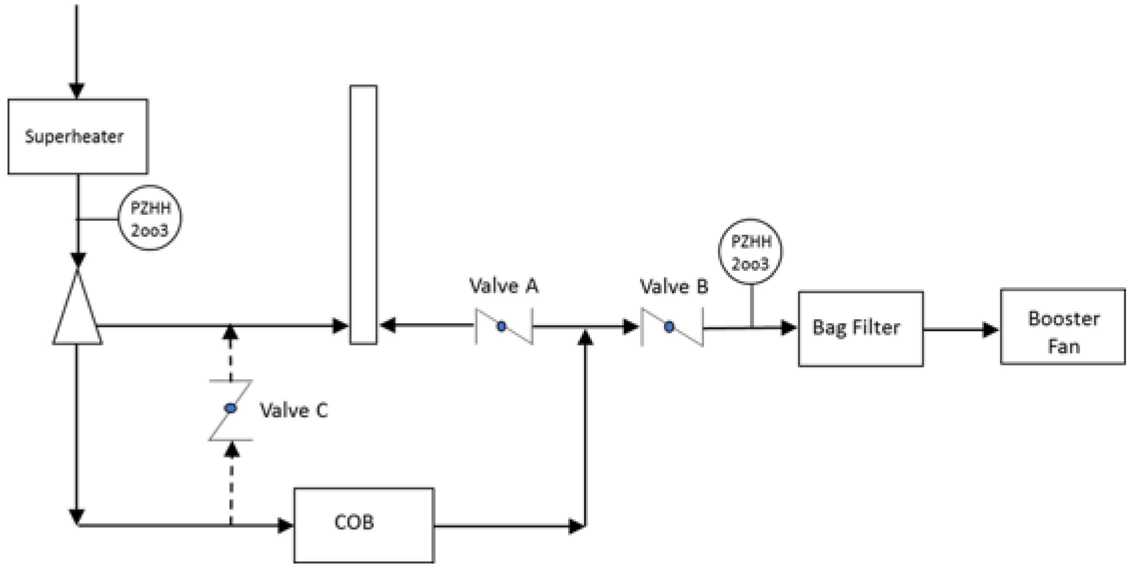


Figure 8.1 CO Boiler Relief Case Arrangement

In normal operation:

- Fast acting damper to the stack (Valve A) is closed
- Fast acting damper to the CDCU (Valve B) is fully open

At onset of upstream pressure relief scenarios, the flow will increase and the pressure in the CO Boiler will begin to rise. The CDCU flue Gas Blower (K-2351) would continue to run (loss of the Blower in this scenario would be double jeopardy) i.e. the relief stream itself would not cause the Blower to fail or stop. The Flue Gas Blower capacity controller could be designed such that an increase in suction pressure would increase fan speed to restore suction pressure. It would be prudent to specify the Blower with an increased design margin of 15-20% to accommodate the relief scenario.

One concern is the amount of soot/catalyst fines that could be blown over. This is likely to increase in differential pressure across the bag filter. At present (and after the CDCU is implemented) the outlet pressure of the CO Boiler will be atmospheric pressure which provides a margin below its design pressure.

The proposed solution is to use a High Integrity Protection System (HIPS) involving two 2 out of 3 high pressure trips upstream of the Diverter Valve and at the Bag Filter inlet (with different trip settings). Either would initiate the trip.

Trip Initiators:

- PZHH upstream Diverter Valve
- PZHH upstream Bag Filter
- Flue Gas Blower tripped or stopped

Trip Actions:

- Valve B (damper to the CDCU) could remain open as there seems no reason to close it in this scenario.
- Valve A (Damper to the stack) would open - fast acting

Potential Failures:

- Valve A fails to open or fails to open quickly enough
- Other failures (not associated with the relief stream) but which put a demand on the HIPS include:
    - Spurious closure of valve B during normal operation
    - Flue Gas Blower stops or trips

Layers of Protection:

- A dynamic simulation and Layers of Protection Analysis (LoPA) should be carried in the next phase. The likely layers of protection are:
    - Fast acting damper valve (Valve A) which would open direct to the Stack.
    - Damper valves A&B are interlocked such that one of the valves must always be proved open to a determined extent.
    - Flue Gas Blower designed to accommodate the increase in flow.
- The HIPS would require a proof test regime to be developed and implemented. The proof test interval would be determined as part of the LoPA.
- No credit taken for the existing Diverter Valve owing to its slow operation.

Additional Protection:

- If the LoPA does not provide acceptable risk reduction, an additional bypass around the CO Boiler direct to the Stack (Valve C) could be added. This would provide an additional layer of protection, although common mode failure would need to be addressed.

8.2 Gas Bleed Flow to Stack

In this option the Damper valve to the Stack (Valve A) is removed leaving a constant open path from the CO Boiler to the Stack. How this option would be implemented would depend on whether the option to remove the Gas/Gas Exchanger (E-2362) is selected.

Gas/Gas Exchanger Removed

In this scenario the Flue Gas Blower would pull a slight negative pressure to draw the bulk of the flue gas into the CDCU. When the CDCU is online the sweet gas would be vented to atmosphere directly from the Amine Absorber (C-2352). A small bleed flow of flue gas from the CO Boiler would always be required to prevent cold air to be drawn down the stack as this could cause condensation and lead to accelerated corrosion. Drawing air in from the Stack is undesirable as this would increase the level of oxygen in the feed gas to the CDCU. Although this is not a hazard, increased oxygen levels will lead to increased solvent degradation of the amine solution.

The precise bleed flow required would need to be determined. This could be controlled by a speed controller on the Flue Gas Blower. The Blower has an absorbed power of over 5 MW so this could have a significant cost impact. The disadvantage is that a proportion of the CO_2 would be vented rather than fed to the CDCU.

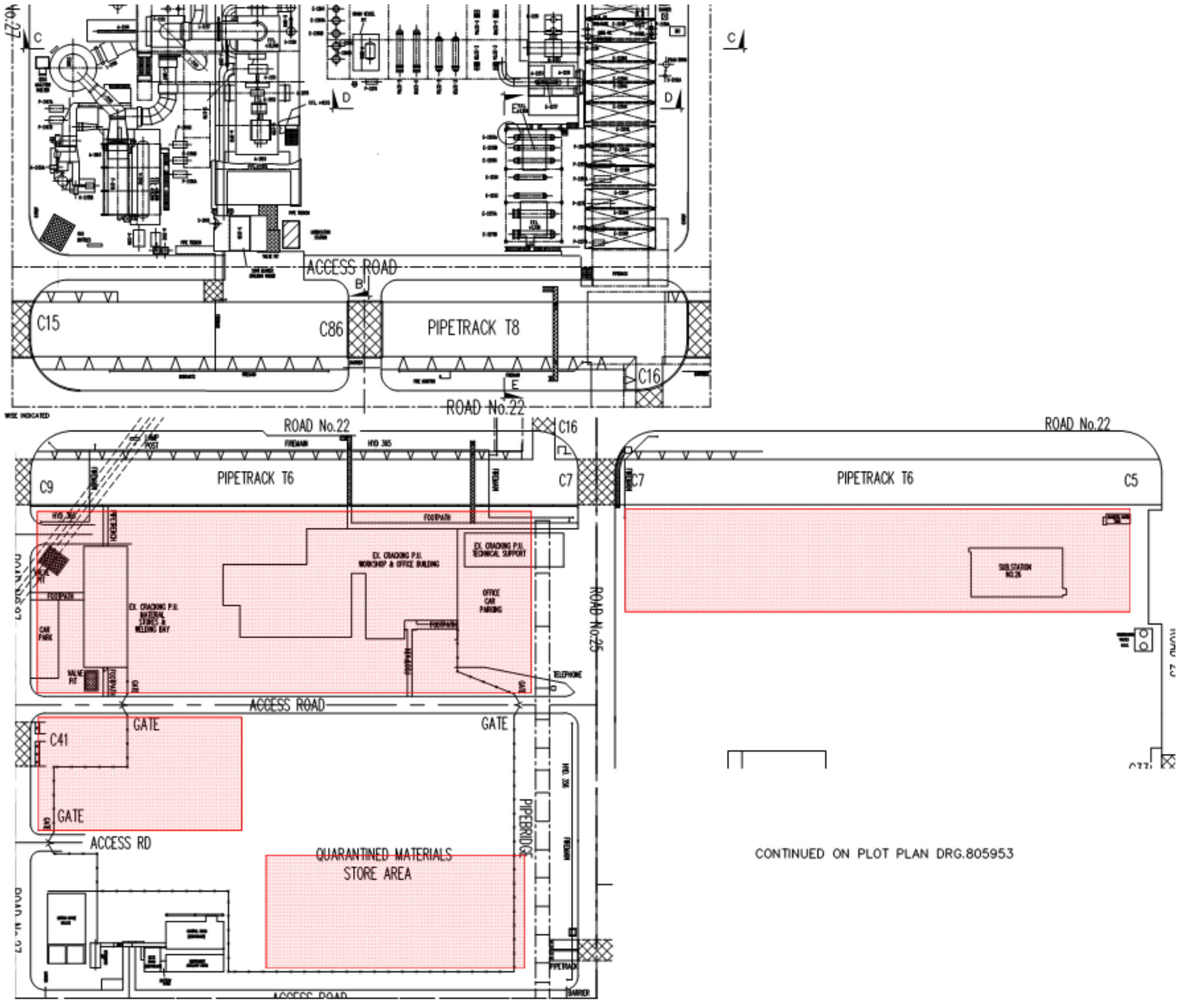
Gas/Gas Exchanger not Removed

If the Gas/Gas Exchanger (E-2362) is not removed then when the CDCU is online, treated gas will be returned to the Stack using the spare aperture. This would then then provide a net positive flow up the Stack preventing the back flow of air. Fine control would be required but it should be possible to maintain the pressure at the CO Boiler outlet such that the flow of treated gas drawn into the CDCU is not excessive. The disadvantage is that if treated gas is drawn into the feed gas to the CDCU there may be some loss of capacity or performance.

9.0 PRELIMINARY PLOT PLAN

A preliminary Plot Plan for Option 2 is included in Attachment 7.

The areas identified by Essar as available for the CDCU are shown below.



As can be seen from the preliminary plot plan, all of these areas are required. Note that the plot space identified does not provide sufficient for storage tanks. The re-use of existing storage tanks would need to be reviewed.

As can be seen in

Figure 9.1 below, the existing duct from the CO Boiler to the stack is very short and a significant additional structure would be required to accommodate the valves and ductwork. Owing to the proximity of the CO Boiler to the road, this new structure would need to span Road 27.

Even if the Gas/Gas Exchanger (E2362) is deleted and there is no return duct to the stack it is likely that this structure would still be required.

Figure 9.1 CO Boiler Outlet Duct & Stack

There is an existing stack aperture approximately 16 m above grade where the return duct work from the CDCU would be tied into, see

Figure 9.2 below. At this height, any such structure should not impede construction / TAR traffic. However, an alternative could be to incorporate removable sections in each of the road crossing bridges for shutdown purposes, if height restrictions are an issue above 16 m. There is also a width restriction present on all roads of approximately 6 m.

Figure 9.2 Lower Stack Access Point

10.0 TIE-IN TO THE CO BOILER

Wood Fired Heaters Division have carried a brief review of the tie-in to the CO Boiler. To provide a suitable duct off-take to the CDCU, the top would need to be removed to provide a central off-take.

11.0 TIC ESTIMATES

A summary of the CAPEX estimates for Options 2 and 3 is shown in Table 11-1 below. The estimate is aligned to AACE Class 5 and is in the +/- 40% accuracy range.

Wood has access to market positions in respect of the global equipment and labour markets. The cost estimates reflect a best assessment of the selected market.

The CAPEX estimates are largely based on a Wood indexed version of Aspen Capital Cost Estimator (ACCE) programme. The ACCE programme is used to generate the base equipment, bulk material costs and direct labour manhours. The prime input to the cost estimates is the sized equipment lists. Refer to Attachments X and X for Option 2 and 3 equipment list respectively.

The estimate for Wet FGD is an order of magnitude estimate pro-rated on capacity from a similar UK project.

The estimate for SNOx FGD was provided by the technology licensor, Haldor-Topsoe.

The estimate for the replacement CO Boiler was obtained from Wood Fired Heaters Division.

Major Equipment	Option 2 (Stand-alone SCR) with Wet FGD	Option 2 (Stand-alone SCR) with SNOx	Option 3 (New COB with integral SCR) with Wet FGD
	GBP	GBP	GBP
CO Boiler tie-in + Dampers + Ductwork	3,600,000	3,600,000	
CO Boiler with integral SCR + Dampers + Ductwork (HOLD1)			16,630,000
Bag Filter	3,320,000		3,320,000
Flue Gas Compression	2,090,000		2,090,000
De-NOx (SCR)	4,200,000		
Gas / Gas HX	2,100,000	2,100,000	2,100,000
Wet FGD	14,910,000		14,910,000
SNOx FGD		24,897,836	
DC Cooler / Caustic Wash	2,500,000	2,500,000	2,500,000
MEA Unit	22,070,000	22,070,000	22,070,000
CO_2 Compression & Drying	6,180,000	6,180,000	6,180,000
Services and Utilities	5,180,000	4,296,000	5,180,000
Total Major Equipment Cost	66,150,000	65,643,836	74,980,000
Total Installed Cost	264,950,000	262,922,666	283,980,000

Table 11-1 Summary of CAPEX Estimates

12.0 FURTHER WORK

12.1 Gas/Gas Exchanger

As discussed in section 7.4 the Gas/Gas Exchanger could be removed if it is acceptable to vent the overhead gas (sweet gas) from the Amine Absorber direct to atmosphere. The issue being the potential for a visible plume particularly in cold weather. Essar will review this option prior to commencing the FEED phase. This will require discussion with the Regulator.

12.2 Cooling Water Make-up

The existing cooling water system at Stanlow draws make-up water from the nearby river Mersey which is brackish and requires a high purge blowdown rate to limit the build-up of salts. This has not been fully addressed within the scope of this study and requires detailed evaluation in the next phase.

Filtration requirements similarly should be addressed in the next phase in discussion with potential vendors.

12.3 Wastewater Recovery

There numerous places where wastewater streams are produced;

- Purge from the DCC Circulation Loop
- CO2 Compression Condensate
- Purge from the Amine Lean Solution

Some of these streams can be re-used without treatment. For example, the CO2 compression condensate can be used a make-up water in the MEA unit.

12.4 CO2 Compressor

The configuration of the CO2 Compressor is discussed in section 3.9. The discussion regarding combining the LLP and LP stages only applies if the Amine unit incorporates a semi-lean flash stage. Some licensors may not wish to incorporate this.

12.5 Amine Unit LP Steam Demand

The Amine Regenerator Reboilers E-2359A&B require 177 te/h of low-pressure steam. Within the scope of this study there is no provision to meet this steam demand. There are many ways that this steam demand could be provided. Essar have identified the options below.

- Possibility of increasing the CO Boiler VHP steam capacity. Reference Essar Stanlow CO Boiler Study Final Report, (21434-8490-RP-000-0001, Rev A1) for constraints. Carry out a site wide review to ensure that the site is COB robust.

- Consideration of the possible scope items for synergy with low grade heat sources with the existing CCU2 plant. Items that need further review on their feasibility include:
    - The possibility of replacing the CO Boiler (as in Option 3) with a different technology such as a gas turbine to generate electricity followed by a waste heat boiler to raise MP steam.
    - There are two large condensing turbines on the CCU. Determine if it’s possible to convert these to LP steam backpressure turbines and use this as a source to provide a considerable fraction of the LP steam required by the MEA Regenerator. This would eliminate the need to raise this elsewhere. Additional MP steam would be needed to drive the turbines. The existing arrangement requires considerable cooling water demands from an existing tower, this could be re-purposed and reduce the new cooling water capacity required by the new plant.
    - There is a low-grade heat source available from the fractionator overheads stream, if this could be cooled via a closed loop heat pump then this could be recycled to any new process stream.

There is an existing MP steam line which passes through the plot that the CDCU may occupy which will need to be relocated. Whilst this is not a high cost item, it introduces logistical issues. A transition plan may be required to ensure that disruption is kept to a minimum.