

Carbon Dioxide Capture for Storage in Deep Geologic Formations – Results from the CO₂ Capture Project

**Capture and Separation of Carbon Dioxide
from Combustion Sources**

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Chapter 6

POST-COMBUSTION SEPARATION AND CAPTURE BASELINE STUDIES FOR THE CCP INDUSTRIAL SCENARIOS

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ABSTRACT

The aim of the CO₂ Capture Project is to develop new and novel technologies that significantly reduce the cost of capturing and storing CO₂. The project has three distinct elements; pre-combustion de-carbonisation, the use of oxygen-rich combustion systems and post-combustion CO₂ capture. In order to evaluate any new or novel technology, baseline studies are required that quantify the current best available technology. This report summarises two such studies for the post-combustion CO₂ capture element based on two BP-owned or part-owned operating facilities:

- The Central Gas Facility, Prudhoe Bay, Alaska—representative of CO₂ recovery from the exhaust gas of multiple simple cycle gas turbines.
- BP's Grangemouth Complex, Scotland—representative of CO₂ recovery from multiple flue gas emissions from a refinery or petrochemical complex heaters and boilers.

The studies have been conducted by Fluor. They detail process designs and cost estimates to capture approximately 1.8–2 million tonnes of CO₂ per year and deliver the captured CO₂ to the battery limits of the particular site at a pressure of 220 barg and essentially water-free.

The specific conclusions drawn from the two studies are that:

- The capture of such large amounts of CO₂ is technically feasible.
- The installed costs are very high.
 - Prudhoe Bay capital cost is estimated at \$1.659 billion, equivalent to \$130 per tonne of emitted CO₂ avoided, and
 - Grangemouth capital cost is estimated at \$476 million, equivalent to \$50–60 per tonne of CO₂ captured. This range relates to the anticipated variation in operating costs.

The study assesses generic issues that will be common to any retro-fit post-combustion CO₂ Capture Project, and provides a suitable baseline against which developing technologies can be evaluated.

INTRODUCTION

The CO₂ Capture Project (CCP) is a joint project undertaken by eight major energy companies to develop new and novel technologies that significantly reduce the cost of capturing and storing CO₂. The project is split into three distinct elements:

Abbreviations: CGF, Central Gas Facility, Prudhoe Bay; DCC, direct contact cooler; Econamine FG, Fluor's proprietary CO₂ recovery process; EOR, enhanced oil recovery; GT, gas turbine; HRSG, heat recovery steam generator; HSE, health, safety and environment; HSS, heat-stable salts; MEA, monoethanol amine; NGL, natural gas liquids.

- pre-combustion de-carbonisation;
- the use of oxygen-rich combustion systems; and
- post-combustion CO₂ recovery.

For each element, technologies will be developed in the context of certain scenarios that relate to combustion sources and fuels common to the operations of the CCP participants. Four scenarios are considered:

- large gas-fired turbine combined cycle power generation;
- small- or medium-sized simple cycle gas turbines (GTs);
- petroleum coke gasification; and
- refinery and petrochemical complex heaters and boilers.

In order for any new or novel technology to be evaluated, baseline studies are required that quantify the current best available technology. Within the post-combustion element, the CCP concluded that amine scrubbing is the best available technology for CO₂ capture.

Fluor were subsequently contracted to produce process designs and cost estimates incorporating their proprietary Econamine FG amine technology for each of the above scenarios. It is based on the use of a 30 wt% aqueous *monoethanol amine* (MEA) solvent and incorporates inhibitors to counter the corrosion effects caused by high levels of oxygen in the flue gas. The process is capable of delivering almost pure CO₂ and is widely used in small-scale plants to produce high-purity CO₂ for industry. However, no unit has been built to the scale envisaged by the CCP project.

To provide additional context to the Fluor study, each process design is based on an actual operating facility. Two of the baseline studies for the post-combustion element are based on BP-owned or part-owned facilities. The Central Gas Facility (CGF) at Prudhoe Bay, Alaska is the basis for the simple cycle GT scenario and BP's Grangemouth complex in central Scotland for the refinery/petrochemical complex heaters and boilers.

This report summarises the process design and cost estimate provided by Fluor to capture post-combustion CO₂ from the Alaska and Grangemouth facilities.

RESULTS AND DISCUSSION

Small- or Medium-Sized Gas Turbine Scenario—Prudhoe Bay Study

This study is based on the CGF at Prudhoe Bay, Alaska and is representative of the “small- or medium-sized simple cycle gas turbine” scenario [1].

The CGF at Prudhoe Bay, Alaska processes associated gas from a number of fields on or close to the North Slope in Alaska. Dehydrated gas is fed from the gathering centres to the CGF and then dew pointed using refrigeration units to recover NGL's. These are then either used as miscible injectants for improved oil recovery or spiked into the crude oil product. The remaining light gas fraction is then compressed and re-injected back into producing reservoirs to maintain reservoir pressure.

The gas throughput of the CGF is huge with approximately 8 billion scfd of gas being processed.

Simple cycle GTs are used to provide mechanical shaft power to drive the gas re-injection and refrigeration compressors. The number and type of GTs selected for CO₂ capture in this study are listed in Table 1.

Each GT is fired with a portion of the processed gas. This produces a flue gas with only dilute levels of CO₂ (approximately 3.3 mol%), virtually no SO₂ (<20 ppmv) and low levels of NO_x (average of approximately 90 ppmv). Flue gas temperature is fairly high averaging about 480 °C.

Currently only a small proportion of the heat energy available in the GT exhaust is recovered using a single waste heat recovery unit connected to one of the Frame 5 machines.

TABLE 1
GAS TURBINES AT THE CENTRAL GAS FACILITY,
PRUDHOE BAY ALASKA USED IN BASELINE

Gas turbine type	Number
General Electric Frame 6-1B	4
General Electric Frame 5-2B	3
Rolls Royce RB-211C	4

Design basis for post-combustion CO₂ capture in the Prudhoe Bay scenario

The design criteria for the baseline study is to:

- capture 1.78 million tonnes of CO₂ per year emitted by the GTs;
- deliver the recovered CO₂ to the CGF battery limits:
 - at a pressure of 220 barg;
 - with a moisture content of less than 50 ppmv, and
 - with a minimum CO₂ content of 97 mol%.

The above battery limits conditions are intended to reflect those necessary for either Enhanced Oil Recovery (EOR) or subsurface storage purposes. They are also common, more or less, to each baseline study and thereby allow each process design to be compared on the same basis.

Proposed CO₂ capture facility configuration. The process selected by Fluor to meet the above design criteria is outlined in Figure 1.

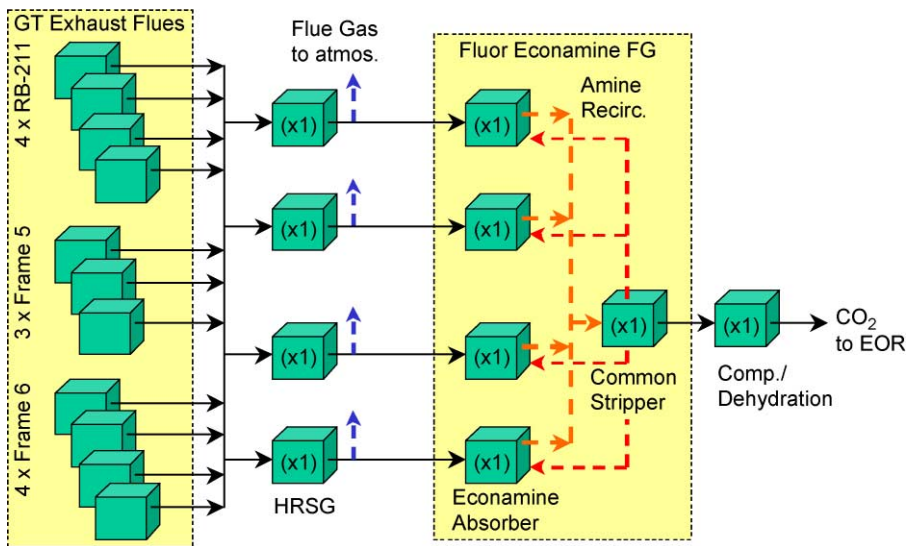


Figure 1: Proposed CO₂ capture facility design for the Prudhoe Bay Central Gas Facility.

The flue gas is collected from each of the 11 GTs and fed to one of four equally sized parallel trains. The size of each train, with consequential impact upon the number of trains needed, is limited by the size of the largest commercially available heat recovery steam generator (HRSG) and by the diameter of the largest Econamine FG absorber column that can be built with confidence.

Each train contains an HRSG, a direct contact cooler (DCC—note that this is not indicated in Figure 1), a blower (also not shown in Figure 1) and an Econamine FG absorber. Rich solvent from the four absorbers is collected and fed to a common solvent stripper tower to regenerate the solvent and liberate the captured CO₂. This CO₂ is then dehydrated and compressed to meet the required CGF battery limits specification.

Other than the supply of treated seawater to supply boiler feed water for the HRSG units and for make-up to the Econamine FG process, the CO₂ capture facility is essentially self-sufficient in terms of energy and utility supply. The heat recovery unit is used to raise steam, which, in turn, is used as the motive force for the CO₂ compressor, to generate power and as the heating medium for the Econamine FG solvent stripper reboiler and reclaimer. The electrical power raised by the CO₂ capture facility is not only sufficient to meet both its internal process and utility needs, but will also allow an export of approximately 18 MW to the local grid, thus creating the opportunity to displace power generation elsewhere in the CGF facility.

Flue gas gathering. The 11 GTs considered in this study are located fairly close to one another, thus limiting the extent of the flue gas gathering system. The flue gas is collected and split evenly between the four separation trains. There is no flow control as such between the four trains, merely identical train design creating similar pressure drops for similar gas throughputs.

The ducting is sized to limit the pressure drop between the GT exhaust and the HRSG to a maximum of 152 mm H₂O and is designed to be flexible to allow each GT and absorption train to be individually isolated as required by operations or for maintenance purposes.

Flue gas cooling/heat recovery. The collected flue gas must be cooled to around 38 °C before being fed to the blower and then the Econamine FG unit. Although amine–CO₂ reaction kinetics are promoted by high temperature, amine loadings are not and the optimum temperature is a compromise between amine loading and reaction kinetics. For a primary amine system such as the Econamine FG process, a temperature around 50 °C is considered suitable. The flue gas temperature increases across the blower and hence some additional cooling duty is required upstream in mitigation.

The hot flue gas is initially fed to an HRSG. The heat load of the flue gas is very high due to the high mass throughput and temperature, and the selected design seeks to utilise this available energy by recovering as much heat energy as possible and raising steam. Approximately 140 MW of heat energy is recovered per HRSG, i.e. a total of 560 MW.

Three levels of steam are generated—high, intermediate and low pressure. High-pressure steam is used to generate electricity via a steam turbine power generator and then used as motive steam to drive the CO₂ compression train. Intermediate-pressure steam is used to provide heat to the Econamine FG solvent stripper reboilers and reclaiming operation. Low-pressure steam is used to de-aerate the boiler feed water. Finally, in addition to raising steam, a heating coil in the HRSG is used to recover more energy for space heating of the new and existing CGF modules.

The partly cooled flue gas is then fed to the DCC, where it is quenched by direct contact with a descending water spray. The DCC circulating water is cooled and filtered, thereby removing any particulates from the flue gas upstream of the amine absorber.

As indicated above, the fully cooled flue gas is then re-pressured slightly by a blower to counter the pressure drop caused by both the Econamine FG absorber packing and the subsequent discharge stack.

Econamine FG process. A schematic of the Econamine FG process, incorporating the upstream DCC and blower is shown in Figure 2.

The process design for the CGF facility incorporates four absorbers feeding rich solvent to and receiving lean solvent from a single solvent system. This solvent system incorporates a single stripping column, solvent circulation pumps and solvent filtration.

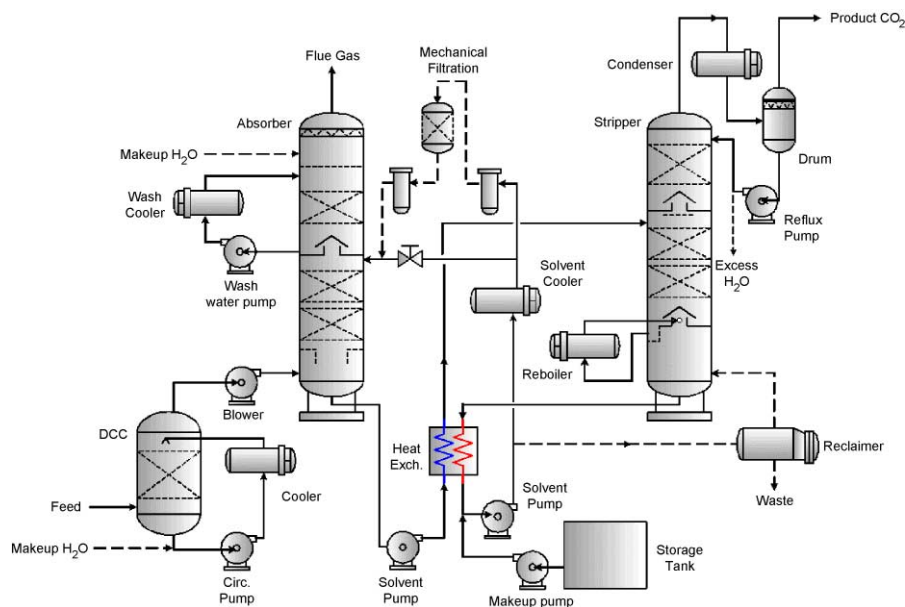


Figure 2: Schematic design of the proposed econamine FG CO₂ capture process.

Although the solvent contains inhibitors to limit solvent degradation, a certain amount of solvent will degrade and form heat stable salts (HSS). The amine bound by these salts cannot be regenerated merely by the action of heat, and hence a reclaimer is required. A slipstream of amine is fed to the reclaimer where sodium carbonate is added and heat applied to recover most of the bound amine. A residual slurry waste remains, which must be removed and disposed of off-site.

CO₂ dehydration and compression. CO₂ liberated from the amine unit stripping column is compressed using a 5-stage centrifugal machine to the required battery limits pressure of 220 barg. Dehydration using a proprietary glycerol process is undertaken between the 3rd and 4th stages in order to meet the water specification.

Utilities. The selected process configuration is almost self-sufficient in terms of utility demand with no additional requirement placed on existing CGF infrastructure other than the supply of treated seawater. Steam raised in the four HSRG units raises sufficient power to drive both the process and utility systems, and to export up to 18 MW of electricity to the local grid.

A summary of the utility demand of the CO₂ capture process is given in Table 2.

Construction strategy. The harsh climate of the North Slope of Alaska leads to a preference for a fully modularised construction strategy. All equipment would be pre-fabricated and arranged onto modules at Anchorage, Alaska, and then transported to the Prudhoe Bay site via two sea-lifts. The location of the Prudhoe Bay site means that on-site construction would be severely limited to certain times of the year and this leads to high labour costs. Pre-fabricating the equipment onto modules in southern Alaska minimises on-site construction activities and thus reduces both cost and schedule.

Given the above construction strategy, all process and utility equipment has been arranged onto 7 modules. The size of each module is limited by the available plot space at Prudhoe Bay, the maximum dimensions

TABLE 2
UTILITY DEMAND IN THE PRUDHOE BAY CO₂ CAPTURE FACILITY

Utility	Demand	Comments
HP/IP Steam	721 tonnes/h	Steam turbine power generation, motive force for CO ₂ compression, solvent stripper reboiler/reclaimer heating duty
LP steam	28 tonnes/h	Boiler feed water de-aeration
Cooling medium	32,300 m ³ /h	
Heating medium	2310 m ³ /h	
Seawater supply	125 m ³ /h	Boiler feed water, solvent system water make-up
Demineralised water	43 m ³ /h	
Plant air	643 Nm ³ /h	
Instrument air	965 N m ³ /h	
Nitrogen	80 N m ³ /h	

of the sea-lift barge and the weight of the module. The equipment included on each module is summarised in Table 3.

TABLE 3
PROPOSED MODULAR CO₂ CAPTURE FACILITY

Equipment	Module
Heat recovery steam generator (HRSG), direct contact cooler (DCC), blower, solvent absorber—Train 1	1
HRSG, DCC, blower, absorber—Train 2	2
HRSG, DCC, blower, absorber—Train 3	3
HRSG, DCC, blower, absorber—Train 4	4
Steam turbine power generator, CO ₂ compression and dehydration train, plant air, instrument air and nitrogen units	5
Solvent circulation system (including filters), solvent stripping column, solvent reclaimer	6
Solvent storage and make-up, seawater treatment/waste storage	7

In addition to the above process and utility modules, 18 pipework and 60 ductwork modules are required to connect the GTs, process equipment and utility systems together.

Modularising the construction and the transportation to the Alaskan North Slope has a significant impact on both cost and schedule. The availability of transport routes from Anchorage to the North Slope is extremely limited with only one sea-lift planned per year.

Prudhoe Bay scenario study results

Costs. A summary of the Prudhoe Bay CO₂ capture facility capital cost is given in Table 4.

The estimated annual operating costs are shown in Table 5.

Based on the costs developed by Fluor, the cost of CO₂ capture is estimated at around \$137 per tonne of CO₂ captured (or \$130 per tonne of CO₂ emissions avoided). It is believed that this is representative of the cost of

TABLE 4
PRUDHOE BAY CO₂ CAPTURE FACILITY CAPITAL COST ESTIMATES

Description	Cost (\$MM)
Off-site direct field costs	705
Modules 1–4 (Process Trains 1–4 HRSG, DCC, Absorber)	427
Module 5 (utilities, power generation, CO ₂ compression)	81
Module 6 (Econamine FG circulation/stripping)	69
Module 7 (solvent storage, water treatment, waste storage)	53
Pipework modules	49
Ducting modules	17
Others	9
North slope direct field costs	251
Modules 1–4 (process trains 1–4 HRSG, DCC, absorbers)	70
Module 5 (utilities, power generation, CO ₂ compression)	10
Module 6 (Econamine FG circulation/storage)	9
Module 7 (solvent storage, water treatment, waste storage)	8
Pipework modules	26
Ducting modules	109
Others (e.g. operation and maintenance building)	19
Indirects	116
Home office costs	161
Other costs (license fees, owners costs, insurance)	149
Contingency (at 20%)	277
Total	1659

TABLE 5
ESTIMATED ANNUAL OPERATING COSTS
FOR THE PRUDHOE BAY CO₂ CAPTURE
FACILITY

Description	Cost (\$MM)
Chemicals	12.4
Maintenance	24.9
Labour	2.2
Overheads	21.5
Insurance and taxes	16.6
Total	77.7

retrofitting CO₂ capture technology at a location with a very harsh working environment. The cost of CO₂ capture in Alaska is clearly high and is attributable in part to the following reasons:

1. An execution strategy on the North Slope with a limited construction window of only 2–3 months per year.
2. A prolonged schedule due to limitations on the window within which sea-lifts can be undertaken.
3. A very high labour field cost.
4. A construction strategy based on super-modules weighing about 10,000 tonnes each.

5. A very dilute feed gas containing only 3.3 mol% CO₂.
6. A need for large collection ducts to gather flue gas from multiple sources.
7. A design for severely cold weather leading to the need for a costly glycol cooling system.
8. A lack of fresh water leading to an expensive water supply system incorporating a reverse osmosis unit.

Locations that have less harsh climates will clearly be capable of delivering a similar process design at significantly lower costs.

Schedule. A schedule of 57 months is estimated for the entire project and covers the period from the start of pre-engineering through the start-up of all four trains. The first sea-lift will transport all equipment necessary to construct and commission trains 1 and 2. The second sea-lift will transport the modules for trains 3 and 4 and will occur 12 months after the first. Hence start-up of the first two trains will occur 45 months after the initiation of the pre-engineering phase.

Health, safety, and environmental issues. In general, it is considered that implementing the CCP will not introduce any significant additional health and safety risks to the CGF plant. There are, however, a number of issues that will need to be addressed during the detailed engineering stage including:

- *Asphyxiation risk:* Compression of almost pure CO₂ will clearly create a significant asphyxiation risk should an atmospheric release occur.
- *Noise:* Noise levels from equipment such as blowers, compressors, turbines and large-scale pumps need to be addressed, for example, with acoustic insulation and housings.
- *Plant layout:* Plant layout needs to address issues such as maintenance access, chemical segregation, access for emergency services and vent locations. This is particularly significant given the choice to modularise the equipment, which could lead to greater congestion within the modules in an attempt to minimise module weight and size.

A summary of the key waste emissions from the plant is shown in Table 6.

TABLE 6
EXPECTED WASTE STREAMS FROM THE PRUDHOE BAY CO₂ CAPTURE FACILITY

Type	Emission description	Rate	Frequency
Slurry	Reclaimer waste	Up to 100 tonnes/week	Intermittent
Gas	Flue gas from solvent absorbers	1,073,000 m ³ /h	Continuous
Gas	Vent from the nitrogen generation unit	322 Nm ³ /h	Intermittent
Gas	Steam vent from blowdown drum	Normally no flow	Intermittent
Gas	Moisture vent from dehydration unit	Small	Continuous
Liquid	Boiler drum blowdown	15 m ³ /h	Continuous
Liquid	Excess water from stripper reflux	Normally no flow	Intermittent
Liquid	Reject water from water treatment unit	55 m ³ /h	Continuous
Liquid	Filter backwash	Normally no flow	Intermittent
Solid	Spent carbon from amine filter	63,500 kg	Every 6 months
Solid	Disposable filter cartridges	Infrequent	Intermittent

The most notable waste is the reclaimer waste stream, which equates to around 5000 tonnes per year. It will contain a mixture of organic and inorganic compounds, typically including higher molecular weight nitrogen compounds, sodium salts and other metal salts, and a suitable disposal route needs to be identified. This is a significant problem, given the remote location of the site. Furthermore, a similar amount of aqueous amine solution must be added to maintain the system inventory. Again, this will create a significant logistical problem to transport up to 1500 tonnes (30% of 5000) of MEA to the Alaskan North Slope.

The overall purpose of the capture plant is to reduce CO₂ emissions to the atmosphere by capturing CO₂ for subsequent subsurface disposal. The total amount of CO₂ targeted by this study is 1.78 million tonnes/a but the export of up to 18 MW of electrical power to the local grid will mean that the total reduction of CO₂ emissions will be slightly higher. If it is assumed that this electrical export will effectively displace the output of a Frame 5 GT, then the total CO₂ emission reduction rises by a further 98,000 tonnes/year to 1.88 million tonnes/year. It is on this basis that the cost of CO₂ capture reduces from \$137 per tonne to \$130 per tonne of CO₂ emission avoided.

Refinery Scenario—Grangemouth Study

The study is based on BP's Grangemouth facilities and is representative of the "refinery and petrochemical complex heaters and boilers" scenario [2].

BP Grangemouth is fed, via the Forties Pipeline System, with oil and gas from a number of fields in the Central North Sea. It is an integrated site and consists of the following:

- *Kinneil*—to which the oil and gas from the Central North Sea is fed, and which stabilises the oil either for further processing in the refinery or for export, and provides the gas feedstock to the chemicals factory.
- *Refinery*—which refines crude oil from Kinneil to produce LPG, alkylate, petrol, diesel, jet fuel, kerosene and fuel oil.
- *Chemical Factory*—which produces a range of petrochemical products from the gas feed from Kinneil and light distillate from the refinery.
- *Power Station*—which provides power and steam to the complex.

The Grangemouth site is split into two halves by a public road. Kinneil, the refinery, the power station and part of the chemicals factory lie in the *North site*, whereas the bulk of the chemicals factory is located in the *South site*.

The complex has a large number of point CO₂ flue gas emission sources, scattered throughout the complex. The sources are varied in terms of composition, flow rate and temperature. The variation in composition relates to differing fuels being used throughout the complex with those used on the refinery typically containing sulfur and those in the chemical factory being sulfur-free.

Grangemouth currently emits 3½–4 million tonnes of CO₂ per year. There is also currently no recovery of CO₂ from flue gas at the Grangemouth complex.

Design basis for post-combustion CO₂ capture in the Grangemouth scenario

The design basis for the Grangemouth study is to:

- capture 2 million tonnes of CO₂ per year, and
- deliver the recovered CO₂ to the complex battery limits:
 - at a pressure of 220 barg,
 - with a moisture content of less than 50 ppmv, and
 - with a minimum CO₂ content of 97 mol%.

The above battery limits conditions have been chosen to provide a source of high-purity, high-pressure CO₂ suitable for North Sea Enhanced Oil Recovery or subsurface storage purposes.

The study target of 2 million tonnes per annum of CO₂ is selected to match the requirements of a potential North Sea EOR project.

Proposed CO₂ recovery facility configuration

The configuration proposed by Fluor is outlined in Figure 3. Flue gas from the North and South Sites is collected in two separate gathering systems and processed separately. Each site separately treats the flue gas to firstly remove NO_x and, in the case of the North site, SO_x components, and then to cool the flue gas prior to it being fed into the Econamine FG absorber (coolers not indicated on the above diagram). The rich

Econamine FG solvent from the absorbers on both sites is collected and fed to a common solvent stripper, which, in turn, liberates the captured CO_2 . This CO_2 is then dried and compressed to meet the required battery limits specification.

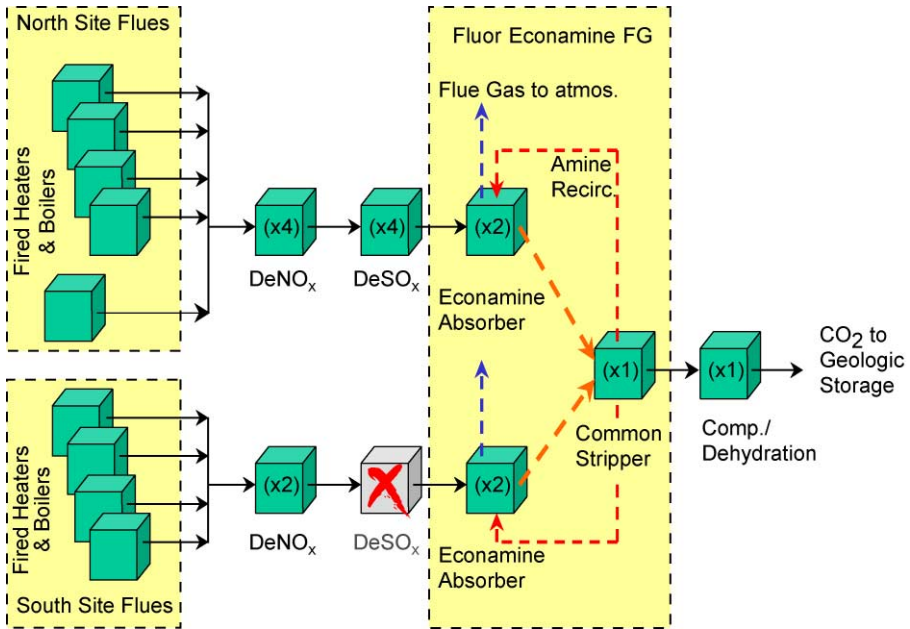


Figure 3: Proposed CO_2 recovery facility for the refinery (Grangemouth) scenario diagram.

Flue gas gathering. The study target of 2 million tonnes/year of CO_2 capture represents around 55% of the annual CO_2 production from the complex's many heater and boiler stacks. Selection of the most appropriate sources was based largely on layout and proximity issues in an attempt to minimise the site cost of flue gas ducting. Final source selection grouped together seven sources from the North site and two sources from the South site from a total of 20 potential sources.

Detailed ducting layout and optimisation studies were conducted by Fluor that resulted in a flue gas collection network comprising about 2 km of ducting and having a maximum cross-sectional area of 9 m^2 . Blowers are required to push flue gas through this ducting network and to overcome the pressure drop imposed by the structured packing of the Econamine FG absorbers and downstream emission stack. The total power demand for these two blower duties is 15 and 10 MW, respectively. Although the ducting network and blower power demand is very large, the system is regarded as technically feasible.

The ducting studies conducted by Fluor provide an accurate basis for the cost estimate. However, if such a system were to be built, careful consideration must be given to the safety hazards related to low-level flue gas ducting and the inter-connection of heater fire boxes via the duct system.

SO_x/NO_x removal. Pre-treatment of the flue gas upstream of the Econamine FG absorber is necessary to reduce NO_x and SO_2 levels and avoid excessive degradation of the Econamine FG solvent. NO_x is present in the flue gas gathered from both North and South sites to levels of up to 300 ppmv and is best reduced to less than 20 ppmv. SO_2 removal is only required from the North site flue gas and is best reduced to less than 10 ppmv.

Selective catalytic reduction (SCR) is selected for NO_x removal. This involves reacting the NO_x with injected ammonia over a titanium catalyst bed to convert the NO_x to water and nitrogen. A wide range of SCR processes are available although the choice of catalyst is somewhat reduced by the relatively low flue gas temperature of 250–300 °C. This is a lower temperature than the majority of current commercial installations, but there are suitable catalysts available that will meet the required performance criteria.

The Cansolv process is selected for SO₂ removal. This is an amine-based process and produces significantly less secondary waste than rival options. The process is commercially available, although there is limited industrial experience of its operation. Fluor undertook a review of several processes capable of removing SO₂ at the prevailing process conditions and concluded that at the time of the study, only Cansolv could readily achieve the preferred performance of < 10 ppmv SO₂ in the flue gas to the Econamine FG unit.

Econamine FG process. Fluor's Econamine FG process was selected to capture the CO₂ and is schematically shown in Figure 2. The flue gas must be cooled to about 40–50 °C upstream of the Econamine FG absorbers in order to achieve acceptable solvent loading. Water quench columns are included in the design to meet this cooling duty.

As mentioned previously, two separate Econamine FG absorption units are required to absorb the CO₂ from the North and South site flue gas systems. The gas throughput and CO₂ absorption demand is huge and dictates that each absorption unit consists of two parallel absorption columns (on both the North and South sites), each with a diameter of approximately 10.3 m.

Rich amine from all four columns is collected and fed to a common stripping tower located on the South site. Again, the size of this column is very large with the diameter being approximately 10.4 m. The Layout section gives further detail on equipment size and complexity.

In common with the Prudhoe Bay process design, a reclaimer will be required to recover bound amine from HSS and remove degraded material from the system. Although the Econamine FG process incorporates inhibitors to limit solvent degradation, a certain amount of solvent will degrade nonetheless. Bound amine in these salts needs to be recovered to reduce amine make-up demand and HSS must be removed to maintain performance.

The concept of absorbing CO₂ from the North and South site flue gas separately avoids the need for excessive lengths of large cross-sectional ducting and associated blower power demand that would be required to move flue gases between the two sites. However, the amine system is extremely substantial requiring large diameter circulating pipework, high pump power loads and a very large site-wide inventory of amine.

Even though the scale of the amine unit is considerable, it is believed that there are no technical barriers to overcome in order to deliver the process design. Significant site fabrication would, however, be required due to the size of equipment required.

CO₂ dehydration and compression. The Econamine FG solvent stripper produces a water-saturated CO₂ stream at a pressure of approximately 1.5 bara. A 6-stage, electrically driven compressor is then used to meet the required battery limits pressure of 220 barg. Molecular sieves are used to dry the gas between the 3rd and 4th stages of compression.

The scope of the project does not account for the delivery of the CO₂ to a suitable subsurface storage zone or EOR project. Hence, no account has been taken in the process design or cost estimate beyond the battery limits of the Grangemouth site.

Utilities. Installing a post-combustion CO₂ capture process of the scale considered by the Fluor study requires the provision of significant utility systems. A summary of the utility demand of the CO₂ capture process is given in Table 7.

TABLE 7
ESTIMATED UTILITY DEMAND FOR THE CO₂ CAPTURE
FACILITY IN THE REFINERY—GRANGEMOUTH SCENARIO

Utility	Quantity
Steam	480 tonnes/h
Power	72 MW
Cooling water	18,139 m ³ /h
Natural Gas	396 MW
Water	1025 tonnes/h

To deliver the required steam and power demand, a combined heat and power (CHP) plant has been included. This would be fired using natural gas with an energy content of approximately 396 MW (assuming 18% power generation efficiency).

The additional cooling demand to quench the flue gas upstream of the Econamine absorbers requires two additional cooling towers.

One critical point to note relates to the additional CO₂ emissions that result from the firing of the CHP plant, which equates to about 0.6 million tonnes of CO₂ per year. This is not subsequently recovered by the Fluor process design and therefore, the NET capture of CO₂ is reduced from 2 to 1.4 million tonnes/year.

Layout. As mentioned in the previous sections, the physical size of the equipment considered by this study is huge. Integration of such large plants into an already congested complex poses significant problems. Fluor have used their Optimeyes visualisation software to help address these problems. Figure 4 clearly shows the scale of the equipment—note the man standing in front of the two large absorbers.

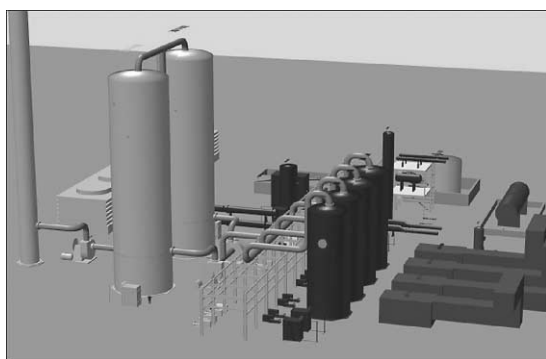


Figure 4: Visualization of the refinery scenario CO₂ capture plant shown to scale. (Note the human figure in front of the two large absorbers.)

Sufficient space is available on both the North and South sites at Grangemouth to install the required equipment, although an HSE study would be required to fully assess the impact of such large equipment and chemical/hydrocarbon inventories on the adjacent plants and nearby population.

Construction strategy. Grangemouth is located on the banks of the Firth of Forth in central Scotland. Other than some consideration for a saline environment, no significant construction issues are envisaged beyond those created by the large size of the equipment.

Some pre-assembled and skid-mounted modules would be used but, in general, the construction would probably be carried out by conventional (i.e. stick-build) construction techniques.

Refinery—grangemouth scenario study results

A breakdown of the capital cost for the Grangemouth CCP is given in Table 8. A full breakdown of the annual operating costs is not available. However, preliminary calculations indicate that the dominant factor is the cost of natural gas to raise steam and generate power in the CHP plant.

TABLE 8
REFINERY—GRANGEMOUTH SCENARIO CAPITAL EQUIPMENT COSTS

Description	Cost (\$millions)
Direct field costs	255
Gas gathering systems	21
NO _x /SO _x removal	40
Econamine FG	89
CO ₂ dehydration and compression	25
Utility and offsite systems	80
Indirects	63
Home office costs	34
Contingency (at 20%)	71
Other costs (license fees, owners costs, insurance)	53
Total	476

Based on the above costs developed by Fluor, the cost of CO₂ capture from the Grangemouth facilities is in the range of \$50–60 per tonne of CO₂ captured. This range relates to the likely variation in operating costs and will be sensitive to future swings in the price of natural gas.

Schedule. A schedule of 45 months is estimated from the start of pre-engineering to completion. This includes start-up of both North and South site flue gas gathering and processing equipment and start-up of the CO₂ dehydration and compression unit. Conventional, non-fast track scheduling has been assumed at this stage.

The critical path runs through pre-engineering, project funding approval, detail engineering and design, procurement of the CO₂ compressor, piping/ductwork hook-up, testing, mechanical completion, commissioning and start-up. The tie-ins to the existing stacks are significant construction activities and could adversely affect the schedule critical path.

HSE issues/emissions. In general, none of the materials handled in the CO₂ capture process pose particular health and safety risks. Nonetheless, there are a few issues that need to be addressed:

- *Noise:* Noise transmission through the long lengths of ducting needs to be carefully considered. Flexible duct mountings and acoustic insulation are suggested as mitigation measures.
- *Fire Propagation:* The ducting will create a potential pathway interconnecting fireboxes that are currently separate. The use of induced draft fans and blowers increases the risk of flame propagation from one plant area to another via the flue gas ducting.
- *Asphyxiation Risk:* The CO₂ capture process incorporates the compression of essentially pure CO₂ to high pressure. Release of this gas to atmosphere will create a significant asphyxiation hazard.

A summary of the waste emissions resultant from the Grangemouth CCP is given in Table 9.

TABLE 9
EXPECTED WASTE STREAMS FROM THE GRANGEMOUTH CO₂ CAPTURE FACILITY

Source	Emission	Quantity
CHP Stack	CO ₂	0.6 million tonnes/year
Cooling towers	Water vapour	8 million tonnes/year
Amine reclaimer waste	Organic waste material	Up to 150 tonnes/week
Cansolv unit	Sulfur dioxide	100 tonnes/week
Cansolv unit	High total dissolved solids water	Zero—recycled to cooling towers
Econamine unit blowdown	Medium total dissolved solids water	
Utility plant blowdown	High total dissolved solids water	

The additional CO₂ emissions result from the need to generate significant power and steam in order to meet the CO₂ capture processing demands. This is not recovered by the Fluor process design and hence reduces the net CO₂ capture from 2 million tonnes per year to 1.4 million.

The largest single emission is the water vapour from the cooling towers. This is the evaporation load associated with the plant cooling systems. Further, water vapour emissions will also occur from the utility plant boiler stack and are not included in the above table. Water vapour emitted from the cooling towers will form a low temperature vapour plume that will be highly visible. De-carbonised flue gas will also be rejected to atmosphere at low temperature, again generating a highly visible stack plume.

Degradation of MEA solvent will be significant, creating a substantial waste stream for disposal. Locating an acceptable disposal route and the scale of the disposal operation needs to be carefully considered. The Cansolv and Econamine processes will also produce small effluent streams for disposal. Furthermore, some small slippage of ammonia from the SCR unit is possible.

An environmental impact study is required to address the issues outlined above. This is beyond the scope of the Fluor study and has not therefore been considered.

CONCLUSIONS

Both the Prudhoe Bay and Grangemouth studies have shown that despite the unprecedented scale of the facilities, post-combustion capture of up to 2 million tonnes of CO₂ per year is technically feasible, using current best-in-class technology.

The cost, however, of recovering such amounts of CO₂ is extremely high, with the capital expenditure of the Prudhoe Bay facilities estimated at \$1.659 billion and those at Grangemouth at \$476 million. The two facilities have, more or less, the same design basis and the significantly higher cost for the Prudhoe Bay facilities is considered to be due to a combination of the following:

- The location of the Prudhoe Bay facilities on the North Slope of Alaska creates a considerable cost penalty. The modular construction strategy, equipment transportation costs and the cost of labour lead to higher inherent costs than an equivalent stick-build construction in Central Scotland.
- Prudhoe Bay facilities include four HRSGs to provide bulk removal of the heat energy upstream of the Econamine FG absorbers. These are expensive units and are not selected for the Grangemouth facilities where a simple water quench column performs the entire cooling duty. Whilst the water quench option proves economically optimum for the Grangemouth study, it does not do so for Prudhoe Bay as the flue gas temperature is considerably higher, thus leading to a significant increase in the cooling duty. Furthermore, it is not considered prudent to install a large-scale water quench column in the severely cold conditions at Prudhoe Bay.

- As a result of incorporating the HRSG units, the Prudhoe Bay facilities are considerably more energy efficient and virtually self-sufficient in terms of energy demand. Consequently, the overall CO₂ emissions to atmosphere are significantly lower than for the Grangemouth design where the design has not been optimised from an energy perspective. The Prudhoe Bay facilities do however, pay a capital cost premium for this energy efficiency. This will be offset by lower operating costs although this has yet to be evaluated in full.

It must also be noted that this study has neither considered the cost of transporting the captured CO₂ to a suitable location for subsurface storage or re-use, nor the cost of a re-injection well. Both will clearly increase the cost of any re-injection project with the former potentially proving very expensive depending on the distance between CO₂ capture and re-injection sites. However, should the CO₂ be used for EOR purposes, some benefits would accrue from increased hydrocarbon recovery.

For both Prudhoe Bay and Grangemouth, the size of the process equipment and the associated infrastructure required to support the capture plants will have a significant impact on the existing production complex. The Fluor studies highlight and assess a wide range of issues that will be common to any retrofit, post-combustion CCP.

Finally, the results of the two studies provide a suitable baseline against which developing technologies can be assessed.

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