Recovery of CO$_2$ from Flue Gases: Commercial Trends

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1.0 ABSTRACT

Interest in recovery of carbon dioxide (CO$_2$) from flue gases is being propelled by multiple factors: the merchant CO$_2$ market, renewed interest in enhanced oil recovery (EOR), and the desire to reduce greenhouse gas emissions. This paper reviews the latest operating and capital cost data for the Fluor Daniel Econamine FG^{SM} process. It also recaps the key process design and operating issues for amine chemical solvent CO$_2$ recovery processes and summarizes the competitive processes for CO$_2$ recovery from flue gases.

The Econamine FG process has proven, reliable operations with both natural-gas and fuel oil-derived flue gases in plants ranging in size from 6 to 1000 tonne/day (te/d) CO$_2$ and in pilot plant operation with coal-derived flue gases. No flue gas CO$_2$ recovery process can compete in the merchant CO$_2$ market in areas where CO$_2$ is available in sufficient quantity from by-product sources such as fermentation, natural gas sweetening and ammonia and hydrogen manufacture, or from CO$_2$ wells. However, where by-product CO$_2$ is not available, the Econamine FG process has favorable costs for plants of 6 te/d and larger. The precise cost of a given plant will vary due to the plant size, the market price of CO$_2$, the flue gas source, and government regulations, Single-train plants of more than 4000 te/d are now possible, and economy of scale, together with the ongoing development of the Econamine FG process, have the potential of delivering CO$_2$ at a price approximately half that of a 1000 te/d plant.

2.0 INTRODUCTION

Carbon dioxide is used in the food industry in carbonated beverages, brewing, and flash drying. Its industrial uses include enhanced oil recovery (EOR), welding, chemical feedstock, inert gas, firefighting, and solvent extraction as a supercritical fluid. It is an essential ingredient in medical oxygen, where in low concentrations it acts as a breathing stimulant.

The largest potential market for CO$_2$ is in EOR. The major CO$_2$ sources that can be considered for the EOR market are:

    Natural sources
            CO$_2$ wells
    Industrial byproducts
            natural gas sweetening
            synthesis gas production

Flue gases
        Fossil fuel-fired power plants
        Industrial furnaces
        Cement plants
        Engine exhausts
        Lime kiln exhausts

The most economical sources of CO_2 are CO_2 wells and natural gas sweetening or synthesis gas purification byproducts. The price of crude oil in 1999 ($12 to $16 per barrel) did not justify the recovery of CO_2 from flue gas sources for EOR purposes, however the recent crude price rise to $25 to $35 per barrel can justify flue gas derived CO_2 for EOR.

Flue gases have long been an important source of CO_2 for the merchant CO_2 market, especially in remote locations where by-product CO_2 sources are unavailable. In the simplest case, fuel is combusted to produce flue gas. CO_2 is then extracted from the flue gas using a dilute MEA solution, as sufficient heat is available from the combustion process to support the heat required for the CO_2 capture. This process is widely used but is wasteful of energy. Where a source of flue gas is available and lower energy consumption is desired, skid-mounted units employing the Econamine FG technology can be utilized. At present eleven such units are in operation to recover CO_2 for the food and beverage industries.

Enhanced oil recovery by CO_2 flooding has been described by Taber and others (1, 2). In many cases CO_2 flooding is the most cost-effective method for extracting the final amounts of recoverable oil from depleted fields. The Econamine FG process (known as the GAS/SPEC FT-1™ process prior to 1989 when Fluor Daniel purchased the technology from Dow Chemical) and related processes were used in several plants in West Texas to recover CO_2 from boiler flue gas for EOR purposes between 1982 and 1986. The plants were technical and commercial successes, and were shut down only because of the crude oil price collapse in 1986.

EOR by CO_2 flooding requires large quantities of CO_2 at low prices. The acceptable price of CO_2 depends critically on both the price of crude oil and the amount of CO_2 required to produce a barrel (Bbl) of oil. The market price of CO_2 varies widely, for instance $13/tonne delivered at pressure in Canada in 1997 and $55/tonne in the U.S. in 1986. In 1985, the North American EOR market was commercially successful with a US $30/Bbl oil price and a CO_2 price of approximately $1 to $2/10^{3}scf, which is equivalent to $19 to $38/tonne CO_2. The amount of CO_2 required for EOR is between 5 and 15x10^{3}scf/bbl oil recovered (3). At a makeup CO_2 rate of 6x10^{3}scf/bbl, suggested by Tontiwachwuthikul (4), and a CO_2 price of $19/tonne, CO_2 recovery from flue gas adds $6/bbl to the oil production cost.

No flue gas CO_2 recovery process can presently compete with by-product CO_2 where it is available in sufficient quantity. However, where by-product CO_2 is not available, or if the merchant price of crude oil remains at its present levels, the Econamine FG process and other similar competing processes will again become economically viable.

This paper provides the basic technical and economic guidelines for evaluating various flue gases as CO_2 sources and indicates the issues involved in an economic analysis. It also reviews important design and cost issues for flue gas recovery and the applicable processes.

3.0 ECONAMINE FG PROCESS

The Econamine FG process is today's premier commercially proven process for the recovery of CO_2 from flue gases, using an inhibited 30 wt.% MEA solution. These features allow the widespread use of carbon steel and give the process the lowest stripper reboiler steam demand of all of the well-established commercial processes. It can recover 85-95% of the CO_2 in the flue gas and produces a 99.95+% pure CO_2 product (dry basis). The inhibitor not only tolerates oxygen and NO_X-containing flue gas, but also requires oxygen to maintain its activity. The process can be used with SO_X-containing flue gas after SO_2 scrubbing. The additional SO_2 scrubbing returns an environmental benefit. Coal-derived flue gases usually have better economics as the process is more efficient with the higher CO_2 content.

The Econamine FG process is a typical, regenerable alkanolamine process. The standard process flow diagram is presented as Figure 1. The process is described by Mariz (3).

The Econamine FG process is not applicable to reducing gas streams, for instance streams containing large amounts of carbon monoxide and hydrogen, on streams that contain more than 1 ppm hydrogen sulfide, or on streams that have less than 1 vol% oxygen. The process is applicable to pressurized gas streams, but the full commercial advantage of this process lies in atmospheric pressure applications.

4.0 COMMERCIAL HISTORY OF THE ECONAMINE FG PROCESS

Dow Chemical and Union Carbide developed inhibited 30 wt.% MEA processes for recovery of CO_2 from flue gases in the 1970's and 1980's primarily for the EOR market. When the price of crude oil dropped dramatically in 1986, the EOR market disappeared and these licensors became less active. Dow Chemical sold its GAS/SPEC FT-1™ process to Fluor Daniel, Inc. in 1989. Fluor Daniel renamed the technology Econamine FG℠. The licensing history of the Econamine FG and predecessor FT-1 processes is shown in Table 1. Twenty-one commercial plants have been built, including ten large plants (60 te/d and larger) and eleven skid-mounted plants. Eight of the large plants are still operating. Fluor Daniel licensed three of these commercial plants, a 320 te/d CO_2 plant in Bellingham, Massachusetts for Northeast Energy Associates; a 150 te/d plant for Sumitomo Chemical in Chiba, Japan; and a 90 te/d plant for Prosint Produtos Sintéticos in Rio de Janeiro, Brazil. Fluor Daniel also constructed the Bellingham plant. Prior to this, Dow had licensed six commercial plants ranging from 6 to 1000 te/d. The eleven facilities employing skid-mounted Econamine FG process units have capacities ranging from 6 to 50 te/d and are manufactured by the Wittemann Company of Palm Coast, Florida and Union Engineering of Fredericia, Denmark.

All of the large commercial plants use flue gas resulting from the combustion of natural gas, except the Sumitomo plant which fires a variety of fuels including heavy fuel oil. The Econamine FG process has also been demonstrated with coal-derived flue gas in three pilot plants, a 4.5 te/d plant in Yokosuka, Japan for Tokyo Electric Power Co, a 2 te/d unit at the Sundance Generating Plant in Alberta (5, 6), and a 3 te/d unit at the Boundary Dam Power Plant in Saskatchewan (9, 10, 11). Fluor Daniel has also licensed a natural gas-fired 2 te/d pilot plant in Osaka, Japan for KEPCO (12, 13).

Of the ten large commercial plants, the 1000 te/d Carbon Dioxide Technology Corp. plant (26) serving the Garza field south of Lubbock, Texas, and the 90 te/d N-Ren Southwest plant (14) provided CO_2 for EOR; two others feed urea plants; and six serve the food and beverage industry. All the skid-mounted units serve the food and beverage industry.

5.0 GENERAL DESIGN ISSUES, RECOVERY OF CO_2 FROM FLUE GAS

The practical recovery of CO_2 from flue gas is sufficiently different from other gas treating applications such as natural gas and refinery gas sweetening and purification of ammonia and hydrogen plant synthesis gas that it requires its own specialized processes. Candidate processes must be active at low CO_2 partial pressure and tolerate oxygen and NO_X. Flue gases from coal-fired boilers also contain SO_X, soot, and fly ash, which must be dealt with. Design issues relevant to CO_2 recovery processes in general and to amine processes in particular are discussed below.

5.1 Low CO_2 Partial Pressure. Flue gases and engine exhausts have very low CO_2 partial pressures because they are typically available at or near atmospheric pressure with CO_2 concentrations of typically 3 to 13 vol%. Many acid gas treatment processes operate at thousands of kPag and cannot remove CO_2 to less than about 10 kPa partial pressure. These high-pressure processes can be used by compression to the normal operating pressure followed by recovery of a portion of the compression energy in expanders; however the overall energy consumption invariably results in unattractive economics. The only commercial absorbents active enough for recovery of dilute CO_2 from atmospheric pressure gas are monoethanolamine (MEA) and other primary amines including the newly developed hindered amines.

5.2 Regeneration Energy. Absorption processes that are effective at low pressure are those with higher reaction energies that require the most regeneration energy. The design challenges are to minimize regeneration energy by selecting a solvent with a relatively low reaction energy, and to use low-value heat sources to provide this energy.

5.3 Oxygen . Oxygen can cause corrosion and solvent degradation problems. Carbon steel is desirable from a cost standpoint, but it can rapidly corrode in the presence of oxygen, especially in hydrogen sulfide-free CO_2 recovery systems. Also, uninhibited alkanolamines such as diethanolamine (DEA) and MEA can be excessively degraded in an oxygen environment. The Econamine FG process employs an inhibitor to both passivate the metal and inhibit amine degradation. Flue gas streams with at least 1.5 vol% oxygen are preferred to maintain inhibitor activity.

Alternate approaches include the use of expensive alloys or the removal of all the oxygen with a combination of a near-stoichiometric burner waste heat boiler and a catalytic reactor. Mitchell Energy Corp.'s Bridgeport, Texas plant used the latter approach in the 1980's (11). Another alternative, continuous addition of an oxygen scavenger to the solvent system, has not been commercially demonstrated.

5.4 SO_X. Flue gases can contain significant concentrations of SO_X unless natural gas or very low sulfur fuels are being fired. SO_X reacts irreversibly with MEA to produce non-reclaimable corrosive salts that are very detrimental to plant operation. For MEA-based processes, it is less expensive to install a SO_X scrubber than to accept the solvent losses when the flue gas contains more than 10 ppmv SO_2. Coal fired boilers produce the highest concentrations of SO_X, often 300 to 5000 ppmv before flue gas desulfurization (FGD), but even oil firing can produce 100 ppmv SO_X (9, p. 475). The limestone or wet lime FGD

systems in large power boilers today achieve SO_X reductions in the 90-95% range. Therefore, even the flue gas from a low-sulfur liquid or solid fuel, or from a limestone FGD system needs further SO_2 removal. The 10 ppmv SO_2 requirement is met by using the active alkali metal neutralizing agents, caustic soda or soda ash, in a relatively inexpensive spray scrubber (10).

Sulfur trioxide, SO_3, presents additional problems. SO_3, like SO_2, leads to solvent losses due to the formation of non-reclaimable heat stable salts, but it also forms a corrosive H_2SO_4 aerosol in wet scrubbers. Furthermore, less than one-third of the SO_3 may be removed by the SO_2 scrubbing system unless a special mist eliminator is used. Therefore, most of the remaining SO_3 will form heat stable salts in the absorber. The fraction of SO_X which forms SO_3 is a function of combustion, fuel composition, and flue gas processing factors, but SO_3 typically accounts for a few percent of the total sulfur. Minimization of SO_3 is a boiler design issue preferably handled upstream of the SO_2 scrubber.

5.5 Fly Ash . Fly ash in the CO_2 absorption solvent may cause foaming in the absorber and stripper, scaling and plugging of equipment, erosion, crevice corrosion, and increased solvent loss through chemical degradation and physical association with removed sludge. Furthermore, fly ash may create significant difficulties in the upstream SO_2 scrubber.

If the fuel produces fly ash, the particulates should be removed upstream of the SO_2 scrubber. A coal-fired boiler flue gas has a typical loading of 2 grains of fly ash per dry standard cubic foot (gr/dscf). This amounts to about 20 te/d of fly ash per 1000 te/d CO_2. It is recommended that the loading be reduced to 0.006 gr/dscf (24), requiring a removal efficiency of about 99.7 weight percent.

5.6 Soot . Soot presents a special problem in the absorber. Soot derived from firing gas or very light fuel oils does not cause problems and passes harmlessly through the absorber tower. However, soot derived from heavy fuel oil stabilizes an amine mist above the CO_2 absorption zone that is not captured in the water wash zone. In this instance, a special mist eliminator must be employed in the absorber to capture the micron-sized MEA mist particles.

5.7 NO$_X$. Thus far, oxides of nitrogen have never created problems in Econamine FG units, however they have led to corrosion of steel and amine degradation in other plants. The Bridgeport CO_2 recovery plant did not eliminate some corrosion problems until the NO_X was reduced to less than 1 ppmv in the absorber feed. NO_X is best controlled though control of the peak flame temperature in the boilers. Also, any boiler NO_X reduction (SCR) equipment will benefit the absorption process. The chief culprit in NO_X is NO_2, which reacts to form nitric acid in the amine solvent and ultimately heat stable salts. However, typically only 10% of the NO_X is NO_2 and only a fraction of the NO_2 gas is absorbed in the solvent. NO_X can be a problem in the CO_2 product if it is to be used in the food and beverage industry and steps must be taken in the liquefaction unit for its removal.

5.8 High Flue Gas Temperature . Hot flue gases can cause solvent degradation and decrease absorber efficiency. The flue gas must be cooled to a water dew point of 50 ^{o}C (122 ^{o}F) prior to entering the absorber. This is accomplished either in the SO_2 scrubber, if present, or in a direct contact water cooler.

6.0 OTHER PROCESSES FOR CO_2 RECOVERY FROM FLUE GAS

This section surveys other processes that have been proposed for CO_2 recovery from flue gas. CO_2 can also be recovered by caustic soda, ammonia, and various other weak acid-alkali salts. Additional processes are available for applications involving EOR where CO_2 is to be produced rather than removed. Pure oxygen boilers (15) and oxygen-blown gasifier derivatives can produce a nitrogen-free flue gas without CO_2 separation. Such processes are outside the scope of this article.

6.1 Higher Pressure Absorption Processes Absorption at atmospheric pressure severely handicaps processes that rely on higher pressures. This limitation is foremost on physical solvents, such as the Selexol process, where CO_2 recovery is directly proportional to the partial pressure of the CO_2 in the feed gas. This limitation also applies to a lesser degree to the less reactive chemical solvents, including methyldiethanolamine (MDEA), diethanolamine (DEA), diisopropanolamine (DIPA), triethanolamine (TEA), and hot potassium carbonate, and also to molecular sieves, membranes, and cryogenic separation (Ryan-Holmes process) (16). For these processes, the driving force for CO_2 absorption and the cyclic loading between absorption and desorption will be insufficient for economical CO_2 recovery. Alternately, compression costs to put the flue gas into the operational range of these processes are prohibitive.

6.2 Hot Potassium Carbonate. Hot potassium carbonate (HPC) or "Hot Pot" is effectively used in many ammonia, hydrogen, ethylene oxide and natural gas plants. To improve CO_2 absorption mass transfer and to inhibit corrosion, proprietary activators and inhibitors are added. These systems are known as "activated hot potassium carbonate" (AHPC) systems. The most widely licensed of these are the Benfield process, with over 675 units worldwide licensed by UOP (17, p. 93), and the Catacarb process, with over 100 units licensed as of 1992 by Eickmeyer & Associates (18, p. 91). Other commercial processes are the Exxon Flexsorb HP process, which uses a hindered amine activator, and Giammarco-Vetrocoke's new process, which uses an organic activator. The processes are designed for bulk CO_2 removal from high pressure streams but also produce CO_2 of high purity. The VLE curves for the partial pressure of CO_2 vs. solution loading of CO_2 for various activators (9, p.370), including the original Benfield activator, DEA, show that the full capacity of the "hot pot" family of processes requires a feed CO_2 partial pressure of about 700 kPa. The Benfield and Catacarb processes are commercially offered for applications at a minimum CO_2 partial pressure of 210 to 345 kPag. The Benfield process was once proposed for treating flue gases (19). Even so, that paper concluded that the optimum operating pressure for the process would be 700 kPag.

6.3 Membranes. Membranes suffer from both the cost of compression and heat exchange to obtain a high pressure feed and in that they produce an impure CO_2 product. For instance, Separex membrane systems are currently offered by UOP for feed pressures starting at 2750 kPag (17, p. 124). There are currently no commercial applications of membranes for recovery of CO_2 from flue gases, though they have been used in large EOR projects to recycle CO_2 from the associated gas. The presence of fly ash and the effects of trace components such as SO_X, NO_X, HCl, and HF are also potential complications. The most likely applications for membranes are in small skid-mounted plants where an impure CO_2 product is acceptable and offshore applications that can take advantage of their compact size and low weight. Membrane-amine and membrane-cryogenic separation hybrids have been considered for special applications such as offshore locations where again their compact size and low weight are beneficial (6, p. 1276; 18, p.104)

6.4 Other MEA. MEA has a long history of commercial CO_2 recovery with various feeds including flue gases. Uninhibited MEA is generally limited by corrosion problems to about 15-20 wt% MEA. Furthermore, many applications rely on the presence of hydrogen sulfide in the feed to provide a passivating layer of iron sulfide to reduce carbonic acid corrosion. This protection is absent in flue gas systems where H_2S is not present. The low MEA concentration raises the reboiler duty substantially. For example, the reboiler duty increases 20% when the MEA concentration decreases from 30 to 15 wt%. The required pump power increases even more. Since the reboiler heat duty is the most important key to operating costs, this is a significant handicap. However, Kerr-McGee/ABB Lummus Global has licensed four units that use 15-20 wt% MEA to recover CO_2 from coal-fired flue gas. The plant capacities vary between 180 and 720 te/day (11, p. 94).

Some corrosion inhibitors in conjunction with a quantitative oxygen and NO_x removal system allow the MEA concentration to be raised to 25-30 weight percent. The Bridgeport CO_2 plant referred to above, which used an early Amine Guard™ process, is one example. There are now over 500 Amine Guard units worldwide including the UCARSOL™ family of formulated amines, licensed by UOP. Ucarsol plants using atmospheric pressure absorption are offered; however, not on oxygen-containing gas streams.

6.5 Sterically Hindered Amines. Kansai Electric Power Company (KEPCO) and Mitsubishi Heavy Industries have been developing a proprietary hindered amine called KS-1 as an MEA replacement for flue gas applications. KS-1 has a lower circulation rate (due to its higher lean to rich CO_2 loading differential), lower regeneration temperature (110 $^{\circ}$C), and 10-15% lower heat of reaction with CO_2. It is non-corrosive to carbon steel (less than 5 mils/yr) at 130 $^{\circ}$C in the presence of oxygen (12, 13, 20). A second sterically hindered amine, AMP, (2-amino-1-methyl-1-propanol) may have similar properties to KEPCO's KS-1 (21). The first commercial plant using KS-1 for Petronas Fertilizer Kedah Sdn Bhd's fertilizer plant in Gurun Kedah, Malaysia is now in operation.

7.0 CAPITAL AND OPERATING COSTS OF THE ECONAMINE FG PROCESS

This section discusses the capital and operating costs for Econamine FG plants using coal-fired (high CO_2, SO_x-containing) and natural gas-fired (low CO_2, SO_x-free) flue gases. The information in this section reviews the important factors in all atmospheric pressure CO_2 recovery applications of the Econamine FG technology. This information can be used for a preliminary evaluation of Econamine FG process applicability, but the licensor should always be consulted due to the major variations in site-specific costs. Plants smaller than about 70 te/d can be purchased from licensed packaged-unit vendors as the Wittemann Co. of Palm Coast, Florida, or Union Engineering of Fredericia, Denmark.

7.1 Economic Studies. Mariz reported in 1998 on the main cost factors, potential savings, and capital and operating costs for a 1000 te/d CO_2 recovery plant over a range of flue gas CO_2 contents from 3 vol% for natural-gas-fired turbines to 13 vol% for coal-fired boilers (3). The costs from that study are the basis of this economic analysis.

A 1998 study by Tontiwachwuthikul, et. al., reexamines CO_2 recovery from coal-fired flue gas in large-scale plants for the purpose of EOR (4). An earlier and extensive study of CO_2 recovery from coal-fired power plant flue gases was commissioned by EPRI in 1991 (25). This report considered the ultimate

disposal of CO_2 in the ocean as an alternative to commercial use.

Sander et. al. in 1992 studied the recovery of 5800 te/d of CO_2 (equivalent to 90% of all the CO_2 in the flue gas) from a 800 MW combined cycle power plant (25). Gosar, et. al studied CO_2 recovery from natural-gas fired gas turbine flue gases in 1986 (26).

Both Suda, et. al. (14, 15, 16) and Tontiwachwuthikul considered the integration of the utility requirements for both the amine process and the downstream steam turbine driven CO_2 compressor with steam and waste heat sources from the power generation unit to reduce the operating and capital costs.

7.2 Promising Areas for Cost Reduction . The most promising areas for operating cost savings according to Mariz (3) are (1) reduction of steam consumption, (2) integration of power generation with the stripper reboiler, and (3) reduction of the absorber packing pressure drop. The most promising areas for capital cost savings are (1) absorber and flue gas cooling vessel materials, (2) absorber vessel size, (3) economies of scale, and (4) improved oxidation inhibitors. Improved technology in the form of new chemical solvents and more sophisticated process designs will reduce both steam consumption and solvent circulation rate. Reduced steam consumption will also help reduce capital costs as the stripper reboiler and overhead condenser will become smaller.

7.3 Plant Size. Commissioned Econamine FG plants range in size from 90 te/d to 1000 te/d CO_2 recovered. Larger single-train plants are feasible, limited by the maximum diameter of the absorber and DCC vessels. Using the equations below, the largest economic single train plant is approximately 4600 te/d from coal-fired flue gas or 2400 te/d from natural gas, based on a maximum column diameter of 12.8 m. This equation is applicable to conventional circular absorber vessels. For very large plants, larger vessels may be economic, and the vessel may be more cost effective if constructed with a rectangular cross section.

Further economy of scale may be possible in other areas of the plant; e.g. one solvent stripper can serve more than one absorber. The stripper size is limited by being able to accommodate no more than four reboilers. At the other end of the scale, plants employing skid-mounted units are built as small as 6 te/d.

7.4 Equipment Size. The absorber diameter can be approximated from equation 1:

$$\text{absorber diameter, m} = A * \text{sqrt}[(\text{te/d}) / (\% \ CO_2)] \tag{1}$$

where A= 0.56 at 3% CO_2 to 0.62 for 13% CO_2

For all equations:

te/d   = tonne/day CO_2 recovered
% CO_2 = volume% CO_2 in flue gas before cooling, wet basis
m   = meters

The flue gas cooling Direct Contact Cooler (DCC) vessel, if present, will be slightly larger in diameter than the absorber. If the flue gas is from a coal-fired boiler, the SO_X scrubber will perform the function of the DCC and a separate DCC vessel will not be required.

The diameter of a stripper serving a single absorber can be estimated with equation 2. Note that one stripper may serve multiple absorbers.

$$\text{stripper diameter, m} = 0.13 * \text{sqrt(te/d)} \qquad\qquad (2)$$

A single stripper may include up to four reboilers as noted above.

7.5 Steam Consumption . The consumption of steam is the most important component of the operating cost and is strongly influenced by the process design. Some important parameters are the lean-rich cross-exchanger approach temperature, the stripper reflux rate, and the stripper pressure. Well-designed Econamine FG plants have been proven to use less than 4.2 GJ/t CO_2 (3.6×10^6 Btu/ton), which is equivalent to 115 kg of 345 kPag saturated steam/m^3 solvent (0.95 lb/gal). This relatively low rate reflects the high solvent concentration and high net CO_2 loading employed in the Econamine FG process. Typical steam levels are 345 kPag (50 psig) for the reboiler and 520 kPag (75 psig) for the reclaimer. Minimum steam levels are 210 kPag (30 psig) for the reboiler and 310 kPag (45 psig) for the reclaimer.

A split flow solvent process shows promise in providing significant further energy savings. The precise savings obtainable with split flow schemes are a function of the inlet CO_2 concentration with the greatest savings occurring at CO_2 levels obtained from coal-fired boilers. Additional savings from the integration of the CO_2 recovery plant steam system with a power generation cycle are discussed at the end of this section.

7.6 Solvent Loading and Circulation Rate. Unhindered primary amine solvents have a maximum theoretical loading of 0.5 mole CO_2 per mole of amine. The Econamine FG process removes a net of approximately one-quarter mol CO_2 per mol solvent between lean and rich loadings, which is somewhat dependent on the CO_2 content of the flue gas. The rich solvent flow can be determined approximately using equation 3:

$$\text{rich solvent circulation rate, m}^3\text{/h} = 0.71 * \text{(te/d)} \qquad\qquad (3)$$

7.7 Power Consumption . The chief power consumer over the entire range of CO_2 concentrations is the flue gas blower. The flue gas blower power, DCC circulation pump power, and absorber wash water pump power per te/d CO_2 are all inversely proportional to the CO_2 concentration in the flue gas. The plant electrical consumption for a water-cooled plant can be estimated using equation 4.

$$\text{kW} = (0.4 + 16.4/(\% \ CO_2))*\text{(te/d)} \qquad\qquad (4)$$

For example, the electrical consumption is 2.45 kW/(te/d), or 60 kWh per tonne CO_2, for a flue gas containing 8 vol% CO_2.

7.8 Solvent Consumption . Solvent losses result from degradation, vapor losses, leaks, and spills. The major factors in amine degradation are temperature and solution maintenance. Thermal degradation is limited by minimizing skin and bulk temperatures and residence times in the reboiler, stripper and reclaimer. In addition, the Econamine FG process adds water to the reclaimer to reduce the reclaimer operating temperature, reducing degradation during reclaiming and reducing the required steam pressure

to operate the reclaimer. The carbon beds remove degradation products to prevent the acceleration of the solvent degradation processes. Sufficient oxygenation of the solution is needed to maintain the effectiveness of the corrosion inhibitor that controls corrosion-related amine solvent losses. Solvent losses by vaporization and entrainment are controlled with well-designed water wash sections and mist eliminators. No amine is lost with the product CO_2.

Total solvent losses average 1.6 kg solvent per tonne CO_2 for gas-fired flue gas feed streams in a well-managed plant.

If SO_X is present in the flue gas, an additional two moles of MEA are lost per mol SO_X entering the absorber. SO_X scrubbers are designed to reduce SO_2 to below 10 ppmv but most of the SO_3 present will pass through the scrubber and react with the MEA in the same way as the residual SO_2. The additional solvent loss due to non-reclaimable sulfur salts is estimated by equation 5. This loss is approximately twice the stoichiometric amount because of the additional degradation in the reclaimer attributable to these salts.

$$\text{kg MEA/te } CO_2 = 0.5 * (\text{ppmv } SO_X \text{ entering the absorber/\% } CO_2) \tag{5}$$

7.9 Additive Consumption . The cost of the inhibitor additive is approximately 20% of the cost of the makeup amine.

7.10 Process Water Consumption . A CO_2 recovery plant can be a net producer or a net consumer of water, depending on the water content of the flue gas. The major process loss is the humidification loss in the absorber wash water system. The Direct Contact Cooler usually produces water, which can be filtered to remove solids and used within the plant. In most cases the temperature of the absorber vent can be adjusted in order to maintain a water balance in the solvent loop.

7.11 Process Cooling. Air cooling is a feasible option where cooling water is not available. Air cooling is, however, more expensive.

The circulating cooling water rate is approximately 4.6 m³/h cooling water per te/d CO_2 for an 8 vol% CO_2 flue gas.

7.12 Carbon Consumption . The activated carbon consumption will typically average 0.075 kg activated carbon per tonne CO_2. This rate is based on changing out the carbon every three months.

7.13 Waste Disposal. A CO_2 recovery plant produces three waste streams: reclaimer waste, spent carbon from the activated carbon filters, and filter elements from the slip-stream solvent filters at the carbon bed. The amount of amine waste generated in the process is a function of flue gas composition and plant operating conditions. The reclaimer waste will be about 0.003 m³/tonne (0.8 gal per tonne) of CO_2. This waste can be disposed of by incineration. The spent carbon can be returned to the vendor. The filter elements may contain flue gas particulate, though an upstream FGD scrubber will collect most of the fly ash and soot which otherwise would be filtered from the water.

Table 2
Operating Cost for a Standard Design, 1000 tonne/day,
Coal-Fired Econamine FG CO$_2$ Recovery Plant

	US $/tonne
Steam, 345 kPag sat.($4.40/tonne=$2.20/MMBtu)	7.90
Electric Power ($0.07/kWh)	2.77
Cooling Water, 11°C rise ($0.0045/m³=$0.017/1000 gal)	0.34
TOTAL UTILITIES	**11.01**
Make-up Solvent ($0.58/lb) & Inhibitor @ 20% of Make-up Solvent cost	2.40
Caustic (soda ash @ $510/ton)	0.07
Activated Carbon ($1.75/lb)	0.19
TOTAL CHEMICALS	**2.66**
Labor, Maintenance (Labor & Materials), Taxes, & Insurance	
OPERATIONS AND MAINTENANCE	**3.31**
SUBTOTAL EXCLUDING SO$_2$ REMOVAL	**16.98**
SO$_2$ REMOVAL @ 250 ppmv SO$_2$	**1.72**
TOTAL OPERATING COST (US $/tonne CO$_2$)	**18.70**
Cost per 1000 scf CO$_2$	$0.98
Cost per 1000 Nm³ CO$_2$	$36.69

This is the high end of the operating cost range because of the standard plant design. It does not take credit for any savings due to integration with a steam power system or process optimization, which are currently active areas of research and development.

The above estimate assumes a flue gas with 13 percent CO$_2$ and 250 ppmv SO$_2$. The corresponding operating cost for a 3 percent CO$_2$, sulfur-free flue gas plant is $25.14/tonne. This estimate assumes a net zero water consumption. It excludes reclaimer and solid waste disposal costs, SO$_2$ scrubber waste disposal costs, downstream CO$_2$ drying and compression costs, and pipeline costs. These costs can be significant. Disposal of scrubber waste has not been an important cost to date so there is no relevant historical cost basis. The cost to add and operate drying and 13.8 MPag (2000 psig) CO$_2$ compression facilities would increase the cost of the CO$_2$ by approximately US $8/tonne.

7.18 Capital Cost. Capital costs for flue gas plants using the Econamine FG process were reported by Mariz (3) for a 1000 TPD plant for a variety of investment assumptions. For the particular case of a 20 year project life and 15% Return On Investment, U.S. Gulf Coast location, and fourth quarter 1997 pricing, the capital recovery cost was U.S. $10.83/(te/d) for a coal-fired flue gas (13 vol% CO$_2$) and $17.85/(te/d) for a gas-turbine flue gas (3 vol% CO$_2$). This price includes an allowance for initial solvent and adsorbents fill, spare parts, startup costs, owners costs, licensing fee, and similar charges. Income taxes were excluded. The capital cost includes the CO$_2$ recovery equipment and SO$_2$ scrubber (if required), but not the CO$_2$ drying and compression equipment and pipelines.

For larger plants, Mariz suggests a 40% to 50% capital cost increase for doubling the plant size, equivalent to a power law exponent between 0.5 and 0.6.

7.19 SO_2 Scrubber Capital Cost. When SO_2 is present in the flue gas, the cost of the SO_2 removal equipment, the cost of caustic soda or soda ash, and the cost of waste disposal from the SO_2 scrubber must be added to the capital and operating costs. However, the extra capital cost is offset by the elimination of the flue gas cooling vessel (named the Direct Contact Cooler vessel (DCC) in the Econamine FG process) and the necessity of pH control in the scrubbing system allows the use of a carbon steel scrubber instead of a stainless steel DCC. In fact, Mariz claims that the net impact of adding a simple, nonregenerable SO_2 scrubber may be a slight capital savings (3).

7.20 Total Cost of a Standard Design Econamine FG Plant. The total operating plus capital cost of a 1000 te/d CO_2 Econamine FG plant of current standard design, including operating cost, capital cost recovery, and SO_2 scrubbing, for a low sulfur coal-fired flue gas would be:

US $29.50/tonne = $26.80/ton = $1.55/1000 scf = $57.90/1000 Nm³.

The total cost for a 1000 te/d plant with gas turbine-fired flue gas:

US $43.50/tonne = $39.50/ton = $2.29/1000 scf = $85.40/1000 Nm³.

The assumptions, including those about site-specific factors, are detailed in the operating cost, capital cost, and SO_2 scrubber capital cost sections above. A number of assumptions concerning owner's cost are implicit in the capital cost recovery. For more accurate costing, consult the specific process licensor.

7.21 Future Reductions in the Total Cost of an Econamine FG Plant. There are still large opportunities for future reductions in the total costs of large Econamine FG plants. The capital cost of a maximum single train size plant would be reduced on a per-tonne basis by 30 to 36% for a 2400 te/d natural gas-fired plant and 47 to 54% for a 4600 te/d coal-fired plant. Fluor Daniel is performing engineering studies on large plants in this size range.

Suda (14, 15, 16) has studied the savings from thermal integration of a CO_2 recovery unit processing the entire flue gas stream with a 600 MW, LNG-fired boiler. When the CO_2 recovery unit uses steam extracted from the low pressure steam turbine to reboil the stripper, and preheats boiler feedwater using the stripper overhead cooler, and uses the KS-1 proprietary amine with a regeneration energy 12% lower than MEA, the steam demand of the CO_2 recovery unit drops from 20% to 7.3% of the total usable power plant steam enthalpy. Most of this 64% energy savings is applicable to the Econamine FG process as well. Furthermore, Suda also concludes that use of KP-1, a proprietary low pressure drop structured absorber packing under development by KEPCO, could save an amount equivalent to 1.4% of the total power plant electrical output.

Tontiwachwuthikul (4) has studied a similar plant integration scheme for an Econamine FG or AMP-solvent plant in western Canada. This study concludes that a CO_2 production cost of US $0.90-1.10/1000 scf (reported as Canadian $1.25-1.50) is achievable. This is the equivalent of US $17.50-20.90/tonne. This study also reexamines EOR pricing factors and concludes that the resulting total production cost of an incremental barrel of Saskatchewan oil would be US $13-15.

Additional operating cost savings on the order of several percent have been identified in recent licensor studies when a split flow solvent (lean and semi-lean) process is applicable.

These opportunities when taken together would cut the price of CO_2 approximately in half.

8.0 CONCLUSIONS

The technology to recover CO_2 from flue gases is commercially available and, though mature, is being significantly improved. The Econamine FG process can be utilized to produce liquid CO_2 for the merchant CO_2 market at reasonable prices for projects where by-product CO_2 is not available. The process is most attractive for very large plants and is also routinely used for small, skid-mounted units for remote site applications. This paper provides an up-to-date review of the factors that determine Econamine FG process plant costs. A 1000 te/d plant of conservative design can produce CO_2 for \$29.50/tonne or \$1.55/1000 scf from coal-fired flue gas. However, 4600 te/d single-train plants are possible. Economy of scale, together with the ongoing development of the Econamine FG process, have the potential of delivering CO_2 at a price approximately half that of the reference 1000 te/d plant.

9.0 NOTICES

Econamine FGSM is a service mark of Fluor Daniel, Inc.
GAS/SPEC FT-1TM is a trademark of the Dow Chemical Company.
KS-1 is a proprietary hindered amine developed by the Kansai Electric Power Company.
KP-1 is a proprietary structured packing developed by the Kansai Electric Power Company.
Amine GuardR is a registered trademark of the UOP Company.

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Table 1

FLUOR DANIEL ECONAMINE FG^{sm}
COMMERCIAL PLANTS

OWNER	LOCATION	SIZE, Te/D	CO_2 USE
Plants no longer in operation			
N-Ren Southwest	Carlsbad, New Mexico	90	EOR
Carbon Dioxide Tech. Corp.	Lubbock, Texas	1000	EOR
Paca	Israel	25	Food Industry
Plants in operation			
Liquid Air Australia	Altona, Australia	60	Food Industry
Liquid Air Australia	Botany, Australia	60	Food Industry
*Industrial de Gaseoses Cia. Ltda.	Quito, Ecuador	6.0	Food Industry
*Pepsi Cola	Manila, Philippines	6.0	Food Industry
*Pepsi Cola	Quezon City, Philippines	6.0	Food Industry
*Cosmos Bottling Co.	San Fernando, Philippines	6.0	Food Industry
*San Miguel Corp.	San Fernando, Philippines	45	Food Industry
Indo Gulf Fertilizer Co.	Uttar Pradesh, India	150	Urea Plant Feed
Luzhou Natural Gas	Sechuan Province, PRC	160	Urea Plant Feed
Northeast Energy Associates	Bellingham, Mass.	320	Food Industry
Kansei Electric Power Co.	Osaka, Japan	2.0	Pilot Plant
Tokyo Electric Power Co.	Japan	5.0	Pilot Plant
Sumitomo Chem/Nippon Oxygen	Chiba, Japan	160	Food Industry
*Cervezaria Baveria	Barranquilla, Colombia	25	Food Industry
Prosint	Rio de Janeiro, Brazil	90	Food Industry
*Coca Cola	Cairo, Egypt	6.0	Food Industry
*Azucar Liquida SA	Santo Domingo, Dom. Rep.	6.0	Food Industry
# European Drinks	Sudrigiu, Bihor County, Romania	36	Food Industry
*Messer Greisheim do Brazil Ltda	Sao Paulo, Brazil	50	Food Industry
# Messer Greisheim do Brazil/SPAL	Sao Paulo, Brazil	80	Food Industry

Skid-mounted plants built by Union Engineering A/S
*Skid-mounted plants built by Wittemann