NON-PROCESS DESIGN CONSIDERATIONS FOR CO_2 PROCESSING FACILITIES

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The processing of streams containing high concentrations of carbon dioxide (CO_2) is becoming more commonplace as enhanced oil recovery (EOR) projects come to reality. The process begins with production from naturally occuring CO_2 reservoirs in New Mexico, Colorado, Wyoming, Texas, and Mississippi shown in Figure 1, or with the recovery of CO_2 from vent or flue gases in chemical plants and power plants. These streams must be processed to produce a relatively pure stream of about 95% CO_2 to meet purchaser specifications.

Once the CO_2 has been purified, it will typically be transported long distances to oil fields in West Texas, Oklahoma, New Mexico, North Dakota, or Mississippi where it will be injected into the oil bearing formations. The CO_2 mixes with the reservoir fluid to expand it and produce a less viscous mixture that flows through the formation more easily, resulting in increased crude oil recovery. The components of the produced fluid, water, crude oil, and gas (hydrocarbon and CO_2), are separated into three phases.

The produced gas, which contains varying amounts of CO_2 must be processed before it is suitable for further use. Figure 2 shows a simplified Block Diagram for some process options. The water content of the gas makes it too corrosive to simply compress and reinject into the formation, and the high CO_2 content makes it unsuitable for sale to a natural gas pipeline. Several process schemes are available to separate and purify the components of the gas stream, but the simplest approach is to dehydrate the stream, to make it less corrosive, and then reinject it. As more complicated processes such as membranes, chemical solvents, physical solvents, and fractionation are used, the design problems become more complex. The purpose of this presentation is to highlight a few of the areas of non-process concern and offer possible design approaches. Some of the subjects discussed are specific to CO_2 processing units, and others, such as sparing and compression selection, apply to other types of facilities as well.

PHYSICAL PROPERTIES OF CO_2

Before reviewing specific topics, the physical properties of CO_2 should be examined. Selected properties are listed in Table 1.

CO_2 is a heavy gas with a molecular weight of 44.01, which is over 1.5 times as dense as air. This density difference can result in CO_2 accumulations in low spots which are dangerous to unsuspecting personnel. OSHA has established the permissible exposure limit (PEL) of carbon dioxide at 5000 ppm for a worker per eight hour shift. Appropriate warning signs should be installed outside areas where high concentrations of CO_2 can accumulate.

CO_2 has a critical pressure of 1071 PSIA and a critical temperature of 87.8°F. Above its critical pressure, CO_2 is in a dense phase and may be compressed or pumped. However, above its critical temperature, compressibility becomes more of a factor. This ability to be pumped or compressed can be beneficial for some process schemes where CO_2 is recovered in a liquid state. The fluid density at a typical injection pressure of 2000 PSIA is 50#/CF. Heat of vaporization ranges from 57 BTU/# @ 80°F to 143 BTU/# @ -60°F, and at atmospheric pressure the heat of sublimation is 246 BTU/#.

Most of these properties are shown on the pressure-enthalpy diagram in Figure 3. To illustrate the range of conditions that may be experienced in a CO_2 processing unit, two areas have been shaded on Figures 3A and 3B. The smaller area on Figure 3A represents the full range of conditions that might occur in a facility that only dehydrates the gas and compresses it for reinjection, or one where membranes or solvents are used to separate CO_2 from the hydrocarbon components. In this case, CO_2 remains in the gas phase throughout the processing steps. The larger area on Figure 3B represents the conditions that would be experienced in a fractionation process such as Ryan-Holmes. In this case, CO_2 may be liquified with temperatures in the -40°F range. In addition to these normal operating conditions, upsets can occur that may expose equipment to even more severe temperatures.

RELIABILITY

Reliability of plant operation is very important to prevent interruptions in production. Normally, casing head gas is flared to maintain crude production during a gas plant outage. But at EOR facilities, the casing head gas can amount to 20 times the flow of gas from a normal oil well. Flaring of the incoming gas is necessary for short term emergency situations, but represents a sizeable financial loss for long term outages. Even the loss of deferred income from the sale of oil represents a major financial loss for a large producing field. The economic value of CO_2 and hydrocarbon gases dictates their recovery, and since crude oil is produced in conjunction with the CO_2-rich gas, blocking in gas production also requires blocking in crude oil production. The net result is that the process facility must be as reliable as the need to produce the oil field. Understanding this need for reliability, several design options will be discussed for a large facility that provide a reliable plant and are economically realistic. Some of the items listed are not justified for smaller process units.

1. Use of parallel processing trains.
2. Sparing of mechanical equipment.
3. Use of secondary selective power distribution systems.
4. Use of refinery quality specifications.
5. Use of a computer to monitor the process.

The most effective design parameter available to improve plant reliability is the use of partial capacity parallel trains. In fact, the on stream reliability of the plant increases exponentially with the number of trains. Unfortunantely so does the capital cost. Thus, compromises must be made. In general, the more reliable multitrain plants minimize the interconnections between trains in order to contain any contamination of process units from moisture , glycol carry-over, H_2S, etc. Compression equipment is the exception. Due to their high capital cost, it is more cost effective to use common spare compressors than to provide complete parallel systems.

Sparing of mechanical equipment is another effective method of enhancing plant reliability. This is especially true with rotating equipment such as pumps and compressors. Reliability increases significantly with several partial duty units, such as 4-33% units compared to 2-100% units. Additional reliability can also be achieved by using steam turbine drivers in combination with electric motor drivers for large primary units. With all electric drivers, a power failure can instantly shut down the entire unit, whereas steam production may not be lost.

A secondary selective power distribution system is basically the electrical counterpart of spared mechanical equipment. With this power distribution system, transformers, high voltage switchgear, and feeders are all spared up to the motor control center. This allows switching power feeds to mechanical equipment in case of an electrical malfunction. Reliability of the power system can also be improved by providing the alternate power supply from different and non-parallel sources, thus minimizing susceptibility to outages from lightning strikes and high winds.

The selective use of refinery quality specifications, rather than gas plant standards, will improve reliability but at significantly higher cost. Extensive use of API Standards, for instance, will improve the reliability of rotating equipment. Overall system reliability can be improved by limited use of screwed fittings for piping and instruments. Greater corrosion allowances also reduce the number of outages.

Electronic instrumentation can enhance reliability through the use of digital computers for process control or simply as a process monitor. The computer can continuously monitor heat and material balances for the entire plant. With computer control, problems can be quickly detected and adjustments automatically made that otherwise could go unobserved by operations personnel for long periods of time.

From this discussion, it can be seen that reliability of a plant can be designed and maintained at very high levels. However, this cannot be accomplished without substantially increasing the plant capital cost. Each operator must decide for himself how much this reliability is worth and how far to carry it.

VARIABLE FLOWS

Continually changing inlet gas flow rates and composition require consideration for both process and non-process design decisions. A typical curve of flow rates relative to time is shown in Figure 4. This curve shows inlet gas flow rate increasing by a factor of 6 from the initial rate in a period of 6 years. The flow rate factor may vary from 4:1 to 8:1 or more, with peak rates occuring from 5-6 years after the start of injection.

Composition changes just as quickly, with initial CO_2 concentrations of 0.5% -10% increasing to 70% - 90% in 4 or 5 years. Figure 5 illustrates the CO_2 composition variation throughout a project's life. In the extreme case, CO_2 flow could increase by 1000 times in 5 years.

Once the processes are selected to handle these extreme flow and concentration changes, mechanical problems such as turndown must be solved. Compression is a key item, with requirement for 8:1 turndown or more possible. Multiple compression units of fractional size can allow for staged installation matching capacity requirements, and delaying capital expenditure. Two 50% process trains automatically double turndown capabilities. Large facilities will probably have multiple trains as a standard feature, while smaller units will have to achieve turndown by other means. Membranes can be installed sequentially in groups as needed to meet production rates for any size process plant.

ENERGY BALANCE

In any process plant, there is always a need to balance the energy available with the energy required to operate the facility. This balance is a factor in process selection, but after the process selection has been made, the type of compression, the need for waste heat recovery, the type of heating medium, and the selection of drivers for rotating equipment are significant design considerations.

Total reinjection units or membrane-type plants may have no need for waste heat recovery. Their primary energy need, other than for compression, would be for glycol regeneration, which requires a relatively small heat source at about 500°F. This can best be supplied by a circulating heating oil system. Selexol, Benfield, Sulfinol, and other processes of this type need low pressure steam for regeneration of absorbing solutions, while fractionation processes such as Ryan-Holmes require medium pressure steam.. The choice of low temperature fractionation may justify the selection of gas turbine driven compressors with waste heat recovery, but selection of Selexol or a similar system could result in a choice of gas engine or electric driven compressors. Selection of a solvent process may also make the recovery of energy attractive through the use of hydraulic turbines in solvent pressure reduction systems. If the process selected has a low level heat requirement, the recovery of the heat of compression from the compressor aftercoolers should also be considered. High energy level waste heat recovery can provide energy to drive letdown steam turbines, which offset electical power needs. These choices are optimized based on cost of electricity vs. cost to purchase and operate alternate equipment.

A typical energy optmization study might involve the evaluation of a steam heat recovery system vs. a heating oil system. Some of the factors that go into such an evaluation include:

1. Heating oil requires 150 lb. rating for piping while the typical high pressure steam system requires 300 lb. rating.
2. Heating oil waste heat exchangers are less costly than high pressure waste heat boilers.
3. Heating oil requires no water treating system.
4. Steam systems allow significant power recovery.
5. Steam systems are more efficient for overall heat recovery since boiler feed water typically enters about 125^{o}F cooler than hot oil return.
6. Heating oil system require more fireproofing than steam.
7. Heating oil creates more significant housekeeping problems.
8 Steam systems require trap maintenance and freeze protection.
9. Steam heat reduces reboiler surface area required.

Some of these do not affect the economics, but others have large dollar values. For a large project of $100-150MM, a study of this type could show an economic impact of a million dollars or more.

DEHYDRATION

For all of the processes we have mentioned, the CO_2 stream must be dehydrated. The level of dehydration depends on temperatures and pressures to which the gas will be subjected. For reinjection or membrane systems, glycol dehydration to -40^{o}F dew point is sufficient. In the case of the Ryan-Holmes fractionation process, the stream must be dehydrated to a dew point in the -75^{o}F range and have an extremely low glycol concentration in the stream going to the fractionation section.

For the more extreme dehydration requirements, two stage dehydration as shown in Figure 6 has benifits over conventional single stage designs. In the first stage of dehydration, which can be done at low pressure, a sufficient quantity of water is removed to prevent condensation of free water at higher pressures. This has the benifit of limiting stainless steel metallurgy to the first stage dehydration. As a result, the next stage of compression and the final dehydration system can be of conventional metallurgy.

FLARES

Dual flare systems should be considered for a CO_2 processing plant due to different burning characteristics of low BTU gas (150 - 300 BTU/SCF) and high BTU gas (900+ BTU/SCF). 150 BTU/SCF (LHV) is regarded as the minimum BTU level that can be expected to burn without assist gas. Tests indicate that 160 BTU/SCF (LHV) gas can burn with a fairly stable flame provided the velocity is held to approximately 0.07 mach or below.

As mentioned earlier, some time is required to shut in all the producing wells in a field, therefore the low BTU flare must be capable of handling the full inlet gas rate while the wells are being shut in during an emergency. Numerous high CO_2 content streams within the process units must also be considered for the low BTU flare, including streams with significant hydrogen sulfide concentrations. The high BTU flare must be capable of handling refrigerants, high methane content gases, and NGL.

The low BTU flare will not create an opacity problem, but the high BTU flare system must be closely considered if smokeless operation is required. The higher the BTU value of the gas, the greater the exit velocity required to prevent smoking. High exit velocities create turbulence which draws more air into the burner. Three alternative flare designs are available if the high BTU flare must be smokeless; 1) steam assisted, 2) supplemental air assisted, and 3) staged combustion. The selection of a particular system will depend on the overall economic evaluation including capital cost, operating cost, availability of utilities, and enviromental regulations.

CO_2 VENTING

At least two major safety concerns must be considered when venting CO_2. The release of high pressure CO_2 liquids and vapors at cool temperatures can result in downstream temperatures below -50°F and the formation of solid CO_2. This represents a serious problem if the release is discharging into a flare header from a safety relief valve. The formation of solid CO_2 could plug the relief valve and header, resulting in overpressure of the system intended to be protected. API Publication RP 521, suggests an increase of one size for both the relief valve and its discharge piping to compensate for possible solids formation. This problem will be more pronounced in fractionation type processes where low temperatures already exist. If potential problems are identified, the possibility of relocating the vents to warmer locations should be considered.

The second concern deals with what happens after the CO_2 is vented to the atmosphere. As pointed out earlier, CO_2 is 1.5 times more dense than air which means it will have a tendency to collect in low places with poor ventilation. Detailed studies are necessary to calculate the ground level concentrations using sophisticated modeling techniques with various combinations of meteorologicial parameters, wind speeds, and stability classes. OSHA's exposure standard of 5000 PPM CO_2 in air per eight hour shifts is designed to protect workers from harmful effects of CO_2, however unusual conditions that cause high concentrations can be dangerous. More than 11% CO_2 in air causes unconsciousness to occur in one minute or less.

METALLURGY

Corrosion due to carbonic acid is the primary concern in several areas of a CO_2 processing facility. The plant inlet, where the gas is water saturated, must definitely be designed to prevent this problem. Calculations show that the flare line can also be subject to carbonic acid attack under certain conditions. These corrosive conditions should be anticipated through the dehydration portion of the plant and materials resistant to carbonic acid attack used throughout.

When hydrogen sulfide is also present in a system, corrosion problems become more complicated. With special materials and alloys that are subject to stress cracking, or in carbon steel at high temperatures, several secondary reactions occur that increase the corrosivity beyond expectations for either gas when singularly present. 316L stainless steel should be used for this situation, rather than 304L stainless steel, which would be used if H_2S were not present.

Additional corrosion problems will be experienced with the presence of oxygen which can be pulled into the system when gathering systems operate at atmospheric pressure or below. Oxygen is highly undersirable since it promotes secondary reactions with the acid gases and also promotes decomposition of glycols producing acid constituents corrosive to type 304 stainless steel.

When produced gas contains salts such as chlorides or sulfates, corrosion protection against pitting is necessary. In this case, plastics and molyldenum bearing stainless steel are satisfactory. Plastic lined pipe is available through 12 inch size, and in wet CO_2 service, both polypropylene and Saran-lined piping should be evaluated with stainless steel. A complete evaluation will include capital cost and mechanical considerations.

If the process stream contains significant H_2S and water, all material selection should comply with National Association of Corrosion Engineers (NACE) standard MR-01-75 requirements. For situations requiring NACE materials, annealed 304 and 316 are acceptable austenitic stainless steels. Components made from these materials should be free of cold-work and be softer than Rockwell C-22. After dehydration, NACE MR-01-75 does not specifically apply since free water does not exist in the gas stream. But for start-up conditions prior to and during dry-out, the possibility of free water being present should not be ignored.

Carbon steel is satisfactory for CO_2 piping systems after dehydration, including reinjection pipelines. A major concern for injection systems is the presence of H_2S. Due to Texas Railroad Commission Rule 36, or similar requirements for other states, operators must abide by those requirements or keep the H_2S concentration below 100 ppm.

EQUIPMENT PURGING

Clearing equipment for maintenance is a seemingly trivial item that needs to be addressed in a detailed design. If a pump or other piece of equipment contains liquid carbon dioxide, the temperature could drop below the design temperature of the item when venting occurs, causing metal embrittlement. Severe hazards could exist with equipment operating well below design temperature. However, purging equipment with fuel gas or nitrogen can prevent this problem. Once a piece of equipment is ready to be returned to service, care must be taken to clear the equipment so that water is not left to freeze somewhere in the process causing mechanical problems and corrosion.

REFRIGERATION SYSTEMS

Some of the processes, such as Selexol and Ryan-Holmes, require considerable quantities of refrigeration at different temperature levels. For Selexol, a conventional three-stage propane system can provide adequate refrigeration with a minimum refigerant temperature in the -20°F range. Numerous design options are available in refrigeration type processes which require different refrigeration temperatures. A conventional three-stage propane system might prove to be appropriate for one design, while another design would require additional levels of refrigeration using other refrigerants and temperatures below the -40°F range.

The design of the refrigeration system needs to be optimized as part of the process evaluation since it could impact the final process selection. The impact of changing flow rates and composition on the design of the refrigeration system must be considered. Compressor re-staging versus compressor recycle versus process recycle must be evaluated as part of the refrigeration system optimization.

PUMPING CO_2

In some of the low temperature process schemes, CO_2 can be recovered as a liquid. In these situations, the CO_2 can be pumped to reinjection pressures above the critical point. With the solvent and membrane type CO_2 removal systems, as well as some fractionation processes, the CO_2 is recovered as a vapor. These streams could be cooled to condensation temperature to allow pumping as an alternate to CO_2 compression. If this is considered, the refrigeration and pumping horsepower are weighed against compression horsepower.

Liquid CO_2 can be pumped using either reciprocating or centrifugal pumps. Several design parameters must be considered in making the evaluation required for the selection of liquid CO_2 pumps.

1. Substantial operating experience exists for low flow, high head plunger pumps in liquid CO_2 service. No operating experience exists for high head, multistage centrifugal pumps in liquid CO_2 service, although some shop tests have been conducted.

2. The physical size of reciprocating pumps are prohibitive above approximately 300 gpm flow rate.

3. The initial cost, installation cost, and maintenance costs are higher for reciprocating pumps than for centrifugal units. The efficiency achievable with reciprocating pumps is higher, resulting in reduced operating costs compared to centrifugal pumps.

4. Due to the lack of lubricity of liquid CO_2, the design of the seal system for centrifugal pumps and the packing system for plunger pumps must be given close scrutiny. The flashing of high pressure liquid CO_2 which leaks past the seal can form ice which will damage the seal face. Double mechanical seals with a pressurized seal oil system should be considered as a solution to this problem. Plunger pumps are faced with a similar problem. Leakage of CO_2 past the packing can form ice which will damage the plunger. The pump plungers can be flushed with pressurized lubrication oil before the plunger enters the atmosphere to minimize this problem.

5. Since liquid CO_2 is generally recovered as a bubble point fluid, careful consideration must be given to the NPSH available versus the NPSH required by the pump. Booster pumps may be required by both reciprocating and centrifugal pumps to minimize cavitation.

6. Liquid CO_2 is somewhat compressible, resulting in density changes of 5-15% depending on the suction and discharge pressures. This slight compressibility results in lower efficiency and less predictable performance than would be expected pumping a non-compressible fluid.

7. Careful consideration must be given to the materials of construction used in liquid CO_2 pumps. CO_2 plunger pumps will typically have stainless steel valve seats and valve springs and will have a forged steel stuffing box with bronze throat bushings and lantern rings. Centrifugal CO_2 pumps will be standard construction with the exception of graphite-coated wear rings to compensate for CO_2's lack of lubricity.

Although the above design considerations are directed primarily at high pressure CO_2 product pumps, similiar considerations must be addressed in the design of other process pumps, such as reflux pumps, which are pumping high CO_2 content fluids.

COMPRESSION

Compressor selection is one of the major decisions related to any CO_2 processing facility. It represents at least 25% of the total capital cost for a complex process facility, and the percentage is much greater for the most basic systems such as dehydration and compression for reinjection. In this case, compression could represent more than 50% of the total cost.

A complete compressor evaluation should include both technical and economic studies. This applies to refrigeration compressors, inlet/recycle gas compressors and CO_2 compressors. Assuming that there are no restrictions on types of compressors to start with, numerous combinations will be offered by the various vendors. Some of the offerings can be eliminated early based on:

1. Lack of capacity fit for varying flow rates.
2 Non-competitiveness due to capital cost.
3. Non-competitiveness due to fuel consumption
4. Lead time needed for delivery of electric power.
5. Duplication of offerings by different vendors

The shortened list should then be evaluated in detail.

The economic comparison is based on:

1. Equipment cost.
2. Installation cost.
3. Compressor fuel cost.
4. Waste heat recovery equipment cost.
5. Cost of extra fuel for auxiliary boiler.
6. Maintenance cost.
7. Cost of conversion for alternate flow rates.

The equipment cost is based on quoted prices from vendors and the fuel cost can be calculated from vendor data and known fuel values. These two items represent about 75% of the total cost of compression equipment. The remaining items can be estimated without significant error in the total dollar estimate.

The installation cost should include buildings, cranes, foundations, floors, service personnel, piping and installation. The waste heat recovery equipment cost can be easily estimated based on a common steam pressure and scaling size factors up or down from a mid range.

Some units consume less fuel for compression but also have less waste heat available. With fuel efficient machines, an auxiliary boiler may be needed to supply the steam needed for process requirements.

Maintenance costs vary for each type of compressor. Typical maintenance cost used for evaluation are:

Reciprocating compressors (intergrals) - $20/HP-YR
High speed reciprocating compressors (separables) - $40/HP-YR
Gas turbines with centrifugal compressors - $12/HP-YR

As the gas to oil ratio (GOR) changes, some conversions may be required in the compression equipment. An analysis should include this as part of the evaluation since changing cylinders or changing services of cylinders will also result in piping changes and extra cost. In some cases, entire machines could need replacement.

The list can be further shortened after the economic evaluation to include only the most competitive offerings for the technical evaluation. This evaluation should include:

1. Comparison of capacity vs. horsepower
2. Turndown capabilities
3. Mechanical limitations
4. Exhaust emissions
5. Alternate services

Some units may have more reduction in available horsepower with ambient temperature changes than others, or one may have a greater tolerance on rated horsepower vs. capacity. These factors could leave one compressor short on capacity at off-design conditions.

Capacity control can be achieved by engine speed control, using clearance pockets, and process recycle. Maximum turndown should be evaluated since gas rates vary so greatly.

Each compressor has mechanical limitations, such as cylinder rod loadings, which limit its capabilities. A unit being offered at its maximum allowable working pressure could eliminate it in the choice of compressors.

Enviromental permitting agencies will require minimum NO_x emission consistant with Best Available Control Technology (BACT). Engine manufacturers use different schemes to reach the required NO_x emission levels, but they all mean an increase in fuel consumption, which cannot be ignored.

As mentioned in the economic evaluation, alterations to the compressors for changing flows may be needed. The changes must be evaluated from the physical view point, as they may create excessive piping modifications or other mechanical problems.

One other very important factor that must be evaluated is delivery schedule. This can eliminate an excellent bid or force the purchase from more than one manufacturer.

In summary, the purpose of this presentation is to highlight areas of concern in the design of CO_2 processing facilities and offer possible design approaches. Some of the concerns are universal with any type processing facility whether it is treating naturally occuring CO_2 or processing recovered CO_2 from a major EOR project. Other subjects are relative to specific processes employed. Regardless of which topic is being considered, none of the solutions are necessarily universal. Each facility is unique and must be custom designed.

Table 1

CARBON DIOXIDE PHYSICAL PROPERTIES

MOLECULAR WEIGHT	44.01
CRITICAL TEMPERATURE	87.8 °F
CRITICAL PRESSURE	1071. PSIA
HEAT OF VAPORIZATION @ − 60 °F @ 80 °F	143 BTU/LB. 57 BTU/LB.
HEAT OF SUBLIMATION @ ATM.P.	246 BTU/LB.
LIQUID DENSITY @ − 50 °F @ 88 °F	69 LB/CF 25 LB/CF
DENSITY AT INJECTION 2000 PSIA & 100 °F	50 LB/CF
SPECIFIC GRAVITY AIR = 1.	1.529

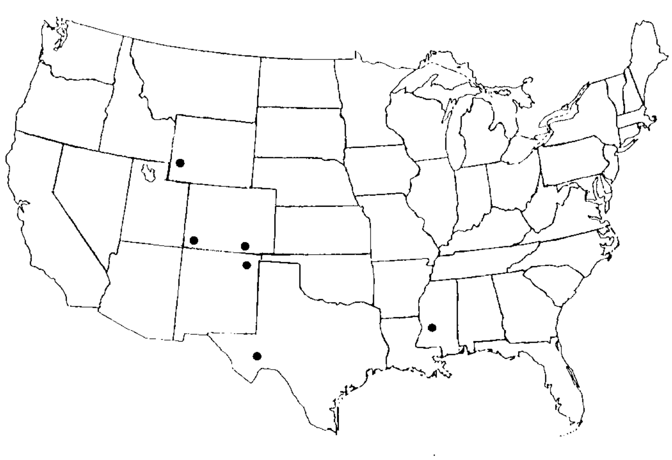


Figure 1 - Major natural CO_2 deposits

SIMPLIFIED BLOCK DIAGRAM

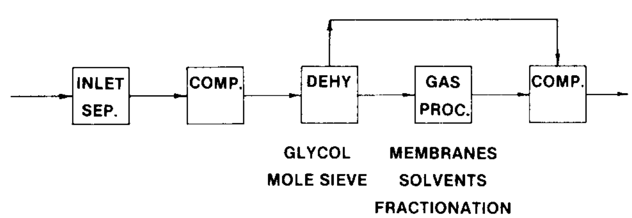


Figure 2 - Simplified block diagram

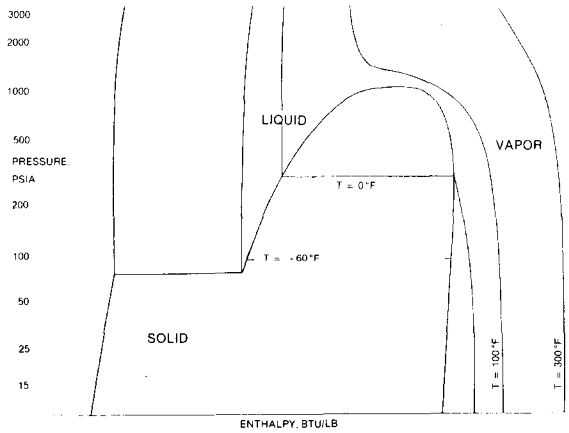
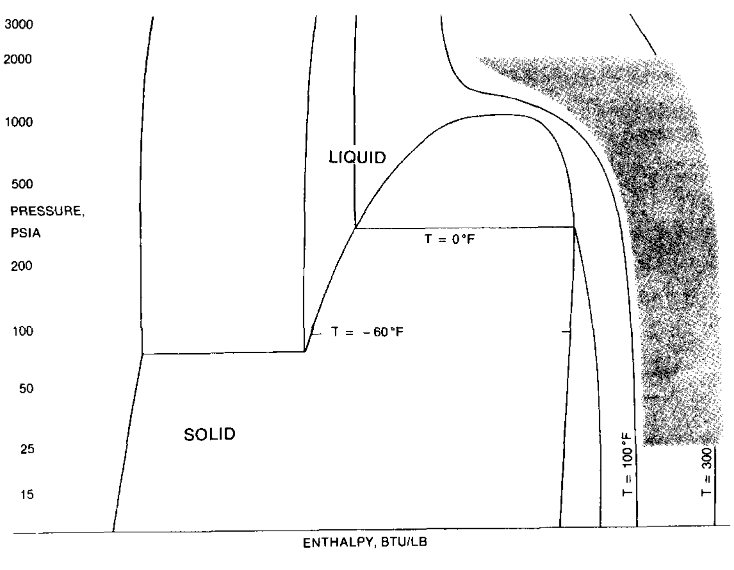

3000
2000
1000
500
PRESSURE,
PSIA
200
100
50
25
15
LIQUID
VAPOR
T = 0°F
T = -60°F
SOLID
T = 100°F
T = 300°F
ENTHALPY, BTU/LB

Figure 3


3000
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PRESSURE,
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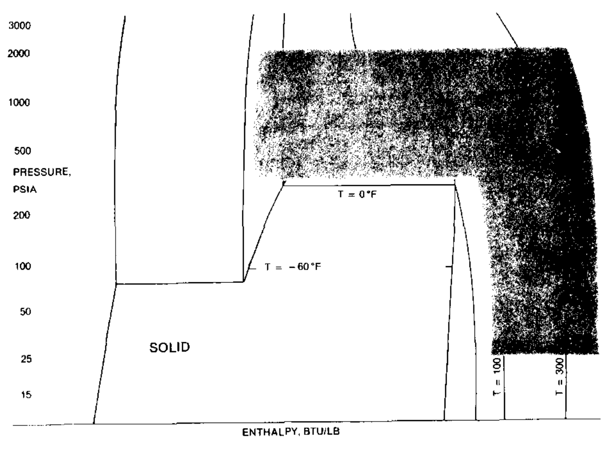
T = 300
ENTHALPY, BTU/LB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ENTHALPY, BTU/LB

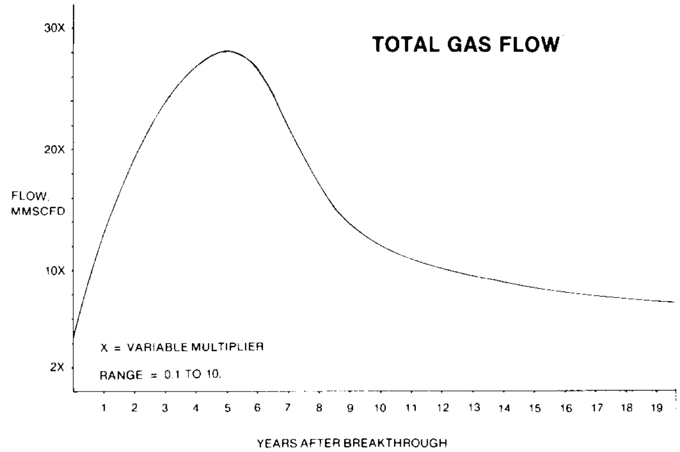

Figure 4

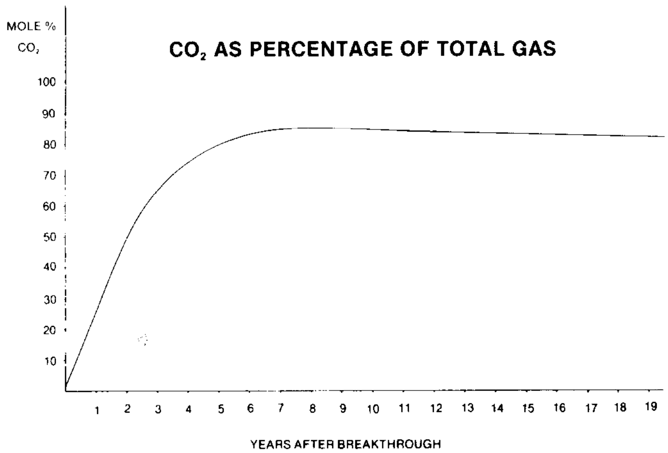

Figure 5

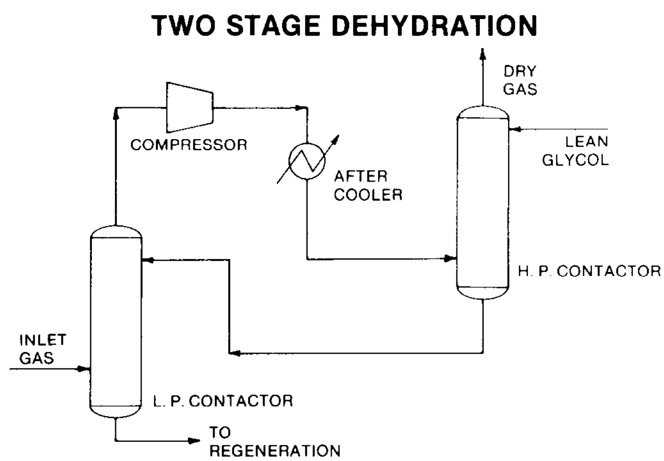

Figure 6