FUNDAMENTALS OF OIL PRODUCTION PROCESSING

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INTRODUCTION

Crude oil as typically produced from petroleum bearing formations consists not only of oil or liquid hydrocarbons but associated with it will be hydrocarbon gas, salt water, and possibly some solids. The amount of produced water may vary from small natural occurring amounts to large amounts where water has been injected in secondary recovery operations. In some of the newer tertiary recovery systems carbon dioxide is injected into the formations to stimulate production, and therefore, some of it is returned with the oil production. It too must be processed with the crude oil stream.

There are several items of production equipment that are used in various combinations to make what is termed the "production facility" or "production battery." The term "tank battery" is normally associated with the group of oil production tanks that are connected in parallel to receive the oil and/or water production from the producing wells. The term "production battery" or "production facility" is used to include not only the tank battery but the other pieces of equipment associated with it to process, treat, and separate the liquid and gas streams.

First, this paper will discuss individually the various pieces of equipment that are used in oil production processing. Interconnection and system design using the various pieces of equipment will then be illustrated.

SEPARATORS

The first step of processing oil production is to separate the produced gas from the liquid stream. This separation of the liquids from the gas phase is accomplished by passing the wellstream thru an oil-gas or oil-gas-water separator. The principal items or features that should be present in a good liquid-gas separator are the same regardless of the overall shape or configuration of the vessel. Some of these features are itemized as follows:(1)

1. A centrifugal inlet device where the primary separation of the liquid and gas is made.
2. A large settling section of sufficient length or height to allow liquid droplets to settle out of the gas stream, or gas droplets to separate from the liquid stream with adequate surge room for slugs of liquid production.
3. A mist extractor or eliminator near the gas outlet that will coalesce small particles of liquid that will not settle out by gravity so that they will not leave the vessel with the gas stream.
4. Adequate controls consisting of level controls, liquid dump valves, gas back pressure valve, safety

relief valve, pressure gauge, gauge glass, instrument gas regulator and piping.

The two main types of vessels that are used in crude oil production are vertical separators or horizontal separators. Typically, vertical separators are used for crude oil production since they better handle large volumes of liquid with small amounts of gas than do horizontal vessels. They are also more suited for slugging liquids from wells because they have more surge room available than do horizontal vessels.

Separators may be equipped for two phase (liquid and gas separation) or three phase (oil-gas-water separation). In typical oil production installations three phase separators are used only for test separators where it is desirable to separate the oil and water produced immediately for metering purposes.

Separators are designed and sized based on their gas capacity and liquid capacity. The gas capacity of oil-gas separators has been calculated for many years from the following empirical relationship proposed by Souders-Brown.[2]

$$v = K\left[\frac{\rho_l - \rho_g}{\rho_g}\right]^{1/2} \tag{1}$$

$$\text{Then } A = \frac{q}{v} \tag{2}$$

$$\text{or} \quad Q = \frac{2.40(D)^2(K)(P)}{Z(T + 460)}\left[\frac{\rho_l - \rho_g}{\rho_g}\right]^{1/2} \tag{3}$$

Where: v = Superficial gas velocity based on cross-sectional vapor area of vessel, ft/sec
A = Cross sectional vapor area of separator, sq ft
q = Gas flow rate at operating conditions, cu ft/sec
ρ_l = Density of liquid at operating conditions, lb/cu ft
ρ_g = Density of gas at operating conditions, lb/cu ft
Q = Gas flow rate at std conditions, MMSCFD
D = Internal diameter, ft*
P = Operating pressure, psia
T = Operating temperature, °F
Z = Compressibility factor
K = Empirical factor

Vertical separators,	5' high	K = 0.12 to 0.24, avg 0.167
	10' high	K = 0.18 to 0.35, avg 0.21
Horizontal separators,	10' high	K = 0.40 to 0.50, avg 0.45
	other lengths	$K = 0.45\,(L/10)^{0.56}$

*For horizontal single tube separators, partially full of liquid, an equivalent diameter of vessel vapor area must be determined.

The liquid capacity of the separator is primarily dependent upon retention time of the liquid within the vessel. Good separation requires sufficient time to obtain an equilibrium condition between the liquid and gas at the temperature and pressure of separation. The liquid capacity of separator or the settling volume required based on retention can be determined from the following equation:[3]

$$W = \frac{1440(V)}{t} \quad \text{or} \quad t = \frac{1440(v)}{W} \quad \text{or} \quad V = \frac{W(t)}{1440} \tag{4}$$

Where: W = Liquid capacity, bbl/day
V = Liquid settling volume in vessel, bbl
t = Retention time, min

Basic design criteria for liquid retention times in separator have been determined by numerous field tests as follows:[4]

Two Phase Separation

API Oil Gravity	Retention Time
Above 35° API	1.0 minute
20 - 30° API	1 to 2 minutes
10 - 20° API	2 to 4 minutes

Three Phase Separation

API Oil Gravity	Retention Time
Above 35° API	3 to 5 minutes
Below 35° API	
100 + °F	5 to 10 minutes
80 + °F	10 to 20 minutes
60 + °F	20 to 30 minutes

TREATING

Once the gas has been separated from a liquid stream it is then desirable to treat or separate the crude oil from any water produced with it. This is accomplished by flowing the stream thru one or more treating vessels in the production facility. In treating vessels, retention time and gravity separation is used to separate the oil and water produced. Often heat is also supplied, in addition to settling time, to aid in the separation of the oil and water. Chemicals are sometimes injected ahead of the treating vessel to help break any emulsions that may have been formed between the produced oil and water. A complete detailed discussion of all types of treating vessels is beyond the scope of this paper and only general guidelines will be considered herein.

In selecting a treating system a number of factors should be considered to determine the most desirable method of treating the crude oil to pipeline requirements. Some of these factors are:[5]

1. Tightness of the emulsion.
2. Specific gravity of the oil and produced water.
3. Corrosiveness of the crude oil, produced water and gas.
4. Scaling tendencies of the produced water.
5. Quantity of the fluid to be treated and percent of water in the fluid.
6. Availability and operating pressure of a sales line for the produced and separated gas.
7. Desirable operating pressures for the equipment.
8. Paraffin forming tendencies of the crude oil.

Pressure type heater treaters in both a vertical and horizontal configuration are available for accomplishing the treating phase of the production processing. If large quantities of produced water are present, then either vertical or horizontal freewater knockouts are often used ahead of the treating vessels. These are large settling vessels where free water may be quickly separated from the oil and discharged from the produced oil and emulsion stream. If a small amount of heat is required to aid in the water separation, sometimes fireboxes are put in the freewater knockouts to aid in this process.

If no gas or very little produced gas is available to operate pressure equipment, gunbarrel treating tanks are often used. These are tall vertical atmospheric storage tanks equipped for the separation and discharge of produced water. Direct heaters, indirect heaters, or steam generators are often used, along with heating coils in gunbarrel tanks where particularly corrosive fluid is encountered, and a small amount of heat is required. The design of crude oil treating vessels is generally based on settling time of the oil and water, along with the amount of heat required if it is necessary. The settling volume or size vessels required for crude oil treating based on retention time may be determined from equation (4).

Gunbarrel Tanks	-	8 to 12 hours
Heater Treaters	-	1 to 2 hours
Freewater Knockouts	-	25 to 30 minutes for 60F fluid temperature
		20 to 25 minutes for 70F fluid temperature
		15 to 20 minutes for 80F fluid temperature
		10 to 15 minutes for 90F fluid temperature
		5 to 10 minutes for 100F and higher temperatures

The heat required to raise the temperature of crude oil/water streams for treating may be determined from the following equation:[6]

$$Q = W(6.25 + 8.33X)(T_2 - T_1) \tag{5}$$

Where:
- Q = Heat required, Btu/hr
- W = Quantity of emulsion (oil and water) heated, bbl/day
- X = Percent water in the emulsion
- T_2 = Treating temperature, °F
- T_1 = Inlet temperature, °F

Typical treating temperatures for various types of crude oil emulsions are listed below.

Emulsion Type	Heater Treaters	Gunbarrel Tanks
Loose	100 to 120°F	80 to 100°F
Moderate	120 to 140°F	100 to 120°F
Tight	140 to 180°F	120°F plus

PRODUCTION TESTING

In most cases, according to various state regulatory commissions, it is required to test wells periodically for their capacity to produce oil. In single well production facilities, a production storage tank may be isolated and used to measure the amount of oil produced in a given time.

In large consolidated facilities where many wells are produced in a single production facility, separate test vessels are used where each well may be individually switched thru it for test and metering purposes.

Vertical test separators are often used which are equipped for either volume measurement or positive displacement meter measurement of the produced oil and water. Along with this test vessel, inlet piping manifolds are equipped with valving so that each well may be individually switched thru the test separator. These inlet production manifolds may be either equipped with manual valves or automatic valves where each well may be periodically switched thru the test separator for a given period of time to measure its production rate. Test separators are also generally equipped with meters on the gas line from the vessel so that it may be also metered.

STORAGE TANKS

One of the most essential parts of crude oil production facilities is the storage tanks that are used for the collection of the oil and/or water that is produced from the wells. Atmospheric welded storage tanks are normally used that are available in a multitude of sizes for storage of the produced fluid. These tanks range in typical sizes from 200 barrels to 1000 barrels capacity. Bolted storage tanks that may be field erected are also available in similar sizes. Large field welded tanks, each holding several thousand barrels of oil, are often used where consolidated production facilities are installed, which collect produced oil from a multitude of wells in a large field.

WATER TREATING EQUIPMENT

Several items of specialized equipment have been developed for treating and processing of the produced water from crude oil production facilities. This water can be treated and then be reinjected back into the formation to aid in the stimulation of flow from the reservoir.

Various types of filtering vessels are used such as oil skimmers, oil wetted particle removers, and filters for coalescing and removing any fine oil particles that may be left in the water stream, along with filtering out any solid particulate matter. Removal of these two items is necessary to prevent plugging of the injection wells and formation when the water is reinjected into the reservoir. Oxygen desorption vessels are often used if the produced water from the oil production facility contains small amounts of oxygen. This oxygen in the water promotes corrosion and shortens the life of flow lines and tubing in the injection wells. Pumps, both low and high pressure, along with storage tanks are also used in water treating facilities to handle, process and store the produced water.

GAS PROCESSING EQUIPMENT

The gas separated from crude oil production must be processed and sometimes treated before it is sold into a gas sales system. Equipment here can consist of multi-stage compressors, liquid scrubbers or separators, and aerial coolers to recompress the gas, separate any liquids from it and put it into the gas sales line.

In the case where carbon (CO_2) is used to stimulate reservoir production, it must be separated from the hydrocarbon system, so that it may be recompressed and reused in the recovery operations. Special equipment and processes are necessary to separate the CO_2 from the hydrocarbon gas and these are described later in this paper. The CO_2 must then also be dehydrated (removal of water vapor). Once the CO_2

has been separated and dehydrated, it can then be recompressed and re-injected for oil stimulation recovery.

SPECIAL AUTOMATIC EQUIPMENT

Other special equipment is often used, especially in consolidation production facilities, to aid in the production recovery and sale of the produced oil. Lease automatic custody transfer (LACT) units are often used to automatically pump and meter the produced oil into the sales pipeline. These are small skid mounted units consisting of pumps, meters, monitoring, and sampling equipment that will automatically meter and transfer the oil into the production sales line. Vented gas from storage tanks is often recovered thru the use of vapor recovery units. These units consist of small rotary compressors, associated scrubbers, and automatic instrumentation used to recover hydrocarbon vapors vented from storage tanks so that they may be recompressed and sold in a gas sales line.

SINGLE WELL PRODUCTION BATTERY

The first type of oil production facility that will be discussed is a typical single well production battery. This type of installation is illustrated in the schematic drawing shown in Figure 1. The oil production which is typically a mixture of crude oil, produced water, and gas flows from the wellhead illustrated with a pumping unit through the flow line to the production battery. Well fluids first enter a vertical two phase oil and gas separator. The oil and/or water that is produced as a liquid is separated from the gas in this vessel. The gas is discharged from the top of the vessel thru a gas back pressure valve and into a low pressure gas sales line, generally operating in the range of 25 to 30 psig pressure. The total liquid stream of oil and water is discharged thru a float operated liquid dump valve and flows to the inlet of a vertical emulsion treater.

In the treater the oil and water is separated by the use of settling time and heat supplied by the firebox in the vessel. Any additional gas that is liberated and separated from the liquid stream is discharged out the top of the heater treater thru another gas back pressure valve and is also connected into the low pressure gas sales line. If any chemical needs to be added to the crude oil emulsion before it enters the heater treater to aid in the separation of the oil and water, it is generally injected by a small chemical pump connected to the line flowing from the production separator to the treater.

The oil is discharged from the top of the settling section in the treater thru an oil dump valve and into the oil f1ll line passing to the crude oil storage tanks. The illustration shows two oil storage tanks connected in parallel, and the oil may be dumped into either tank. The oil storage battery may consist of any number of tanks, depending on the amount of oil produced at the installation. The oil is discharged into the top of either or both tanks which are also interconnected by an equalizer line near the top of the tanks. The crude oil is in turn drawn off the pipeline connection close to the bottom of either tank and into the oil sales line. This connection may be a terminal point at the battery where the oil is transported away from the location by tank truck. Connected to the bottom of each tank is a recirculating line with valving and a recirculating pump where the bottoms of the tank or any bad oil may be recirculated back thru the heater treater for further treatment. As illustrated, this line is also connected to a pit for dumping of any BS&W that may collect in the bottom of the oil storage tanks that cannot be retreated thru the heater treater.

The water separated from the crude oil in the heater treater is discharged thru another dump valve from the treater and into a separate water storage tank. The produced salt water is drawn off of this tank and disposed of into typically a salt water disposal well at some other location. All storage tanks are generally vented thru a vent line with a stack vent valve away from the battery area.

CONSOLIDATED PRODUCTION FACILITY

Figure 2 illustrates a typical hookup for a consolidated production facility where production from several wells is connected into a central battery for processing. As illustrated, several flow lines from different wells would connect to a production manifold at the inlet of the production facility. The inlet production manifold is equipped with valving where the production may be routed either thru the production separator or from each well individually thru a test separator.

Normally, all fluid would be comingled and flow to a vertical production separator. In this vessel the liquid stream consisting of the produced oil and water would be separated from the gas. The gas would leave the top of the vessel thru a back pressure valve and would be connected into a common gas system line which would collect all the gas from the facility and put it into a low pressure gas gathering system for sales. The liquid consisting of the oil and produced water would be discharged from the bottom of the production separator thru a float and valve mechanism and flow to the inlet of a freewater knockout. Since this type of consolidated production facility could be used where water flooding is being used to aid in the production of the oil from the reservoir formation, large amounts of free water are produced back with the oil stream. Therefore, the use of a freewater knockout ahead of conventional treating vessels aids in a more efficient system and unloads the requirements of the treating vessels.

In this particular case a heated freewater knockout is shown where the freewater knockout would be equipped with a firebox for providing a small amount of heat to aid in the quick separation of the produced oil and free water. Again, any liberated gas separated in the freewater knockout leaves the top of the vessel thru a back pressure valve and is connected into the gas sales line. The produced free water is separated from the vessel and is discharged thru a dump valve into the water storage tank or tanks. The produced oil and water emulsion is discharged from the vessel and passes into the inlet connection of a horizontal heater treater.

If any chemical is required to aid in the separation of the oil and water emulsion in the heater treater a chemical pump is usually connected on the fill line to the treater. In the heater treater, a firebox is used to supply heat to the crude oil emulsion to aid in the separation along with settling time of the oil and water mixture. Gas liberated in the heater treater again leaves the top of the vessel thru a gas back pressure valve and is connected into the low pressure gas system. Water separated from the oil is discharged thru another dump valve into the fill line of the water storage tank. The oil separated passes thru another dump valve and into the fill line system to the crude oil storage tanks. As illustrated these tanks may be equipped with a manifold system where the oil may be discharged into one of several tanks and/or equalized from tank to tank.

As illustrated here, the oil discharges from the oil production tanks thru the pipeline connection into a lease automatic custody transfer unit (LACT). This is an automatic unit that will pump and meter the oil and turn it directly into an oil sales pipeline. The LACT unit is normally equipped with an automatic BS&W monitor to monitor the quality of the oil sold down the pipeline. If the monitor detects that the oil is not of pipeline quality it is automatically directed back through the treating system for retreatment.

In the case of large consolidated production facilities, a large number of oil storage tanks are often required, and therefore, a large quantity of gas vapor is vented from the storage tanks. This may vary depending on the API gravity of the oil produced at the facility. It is sometimes desirable to equip these tanks with a vapor recovery unit, as illustrated, consisting of a small compressor and associated control equipment for gathering the gas vapors from the tanks, recompressing them, and reinjecting them back into the gas sales line.

As illustrated, the inlet production to each well may be diverted thru a test separator for metering purposes to determine the amount of oil produced from each well. The test separator is normally a vertical three phase oil-gas-water separator. The gas separated from the test fluid is discharged from the top of the vessel thru a gas meter, a gas back pressure valve and into the common gas gathering line. The oil and water are each discharged separately and then returned back to the common line to the inlet of the freewater knockout, along with the rest of the production fluid. The test separator may be equipped to meter the oil and water by volume dump chambers, or thru the use of positive displacement meters to measure the amount of free water and oil produced from each well.

WATER TREATING FACILITY

In the case of water flood fields it is desirable to do some treatment of the produced water separated from the production fluids and use this water for reinjection to stimulate the flow of oil from the reservoir. Figure 3 is a typical water treatment facility showing how the various pieces of equipment could be installed for this purpose.

The inlet water separated and collected in the production facility, as illustrated in Figure 2, would flow into this facility and first into an oil wetted particle remover. In this vessel a coalescing media or filter section would coalesce and separate any small oil particles that may have been entrained and flow along with the water production. This oil and any gas that is in the water is separated in the oil wetted particle remover and passes out the top of the vessel thru a combination gas and liquid back pressure valve and into a separate oil storage tank. Here the oil is returned back to the oil production facility. The water flowing thru the oil wetted particle remover passes out the far end of the vessel thru a water dump valve and into the top of a water filter vessel. This water filter may be a single vessel or a series of vessels depending on the water flow rate. The water flows down thru a filter media in the water filter which may be either sand and/or a mixture of gravel and anthracite coal to filter out any solid particles in the water stream. This is necessary so that no solid foreign matter will be reinjected along with the water into the formation.

The water then passes to an oxygen absorption tower. Here a vertical vessel is used with a series of countercurrent trays to strip any oxygen out of the produced water to help aid in corrosion control of the flow lines and injection wells of the water system. Natural gas is used as a stripping media, and flows into the bottom of the oxygen absorption tower and up thru the vessel countercurrent to the water flow to aid in stripping out any oxygen that is present in the water. The gas and any oxygen leaves the top of the vessel thru a gas back pressure valve. The water leaves the bottom of the oxygen absorption tower thru a level control and liquid discharge valve and into a series of water storage tanks. These are typical API storage tanks connected in a conventional manner with fill lines, equalizer lines, and discharge connections. The produced water leaves the tanks thru the pipeline connections near the bottom and is picked up by a high pressure water injection pump. It is pumped back thru flow meters and flow lines to the water injection wells. The bottom connections on the water storage tanks can be used, as illustrated, to provide a feed to the water backwash pumps which are used to backwash the filter beds in the oil wetted particle remover and the water filters. Typically, on a large production facility these baskwash pumps are controlled by automatic control panels which periodically switch the valving as illustrated and backwash the filter beds in a reverse flow manner and discharge the backwash water to an evaporation pit.

CARBON DIOXIDE PROCESSING FACILITY

With the recent popular use of carbon dioxide in tertiary production stimulation, it is appropriate that a CO_2 production processing facility be described. Figure 4 illustrates a typical processing facility used to recover the CO_2 produced with the oil and water production for reinjection into the formation. As illustrated at the left of the schematic flow sheet, the field gas first enters a field compressor. The field gas produced from a CO_2 flood consists of natural gas and CO_2 combined at a low pressure which would come from a typical consolidated production facility. This field gas must be compressed to several hundred psig before it can be processed thru the CO_2 processing facility.

Illustrated is a two stage field gas compressor where the gas first flows thru an inlet liquid scrubber, then to the first stage of the compressor. From the first stage it goes thru an aerial cooler section thru another interstage scrubber and into the second stage compressor section. From the second stage it flows thru a final cooler and thru another liquid knockout scrubber. All of the inlet and interstage scrubbers are equipped with liquid level controls and liquid dump valves so that any liquid condensate that is separated out in the scrubbers will be discharged separately. From the field gas compressor the gas flows to a CO_2/hydrocarbon gas separation process.

There are several processes on the market for separating CO_2 and hydrocarbon gases. Illustrated is a hot potassium carbonate (K_2CO_3) Benfield process which is currently in common use for this purpose. This is a regenative process using a solution of hot potassium carbonate and water for removing the CO_2 from the hydrocarbon gases. The inlet combination gas stream enters a heat exchanger where it is preheated by warm outlet gases from the absorber tower. The gas then flows into the bottom of the absorber tower and flows up thru several trays countercurrent to the flow of hot potassium carbonate solution flowing downward thru the tower. The hydrocarbon gas that is left passes out the top of the tower, thru the heat exchanger, and is discharged into a gas sales line. In the absorber tower the potassium carbonate solution flows downward thru the vessel reacting with and absorbing the CO_2 from the gas stream and leaves the bottom of the vessel thru a liquid discharge valve. The rich K_2CO_3 solution then flows to a stripping system where the CO_2 is separated from the potassium carbonate solution so that it may be reused.

In the regenerator section of the plant the solution passes down thru a stripping tower again consisting of several trays. The bottom of the tower is fitted with a steam heated reboiler which provides heat to the solution for stripping out the CO_2 from the rich solution. From the top of the stripping tower passes the vapors consisting of CO_2 and some steam. It then flows thru an aerial cooler and into a reflux accumulator vessel. The steam that flowed with the outlet CO_2 is condensed in the aerial cooler, collects in the bottom of the reflux accumulator, and is pumped back to the top of the stripping still. The reflux liquid flows down thru the still along with the rich solution. From the top of the reflux accumulator the CO_2 flows thru a gas back pressure valve and into the CO_2 compressor.

The reconcentrated potassium carbonate solution passes from the bottom of the stripping still thru a circulating pump and back into the top of the absorber tower for reuse. This process is particularly desirable since it employs a hot potassium carbonate solution, and therefore, requires a minimum amount of heat exchange to cool down the solution from the regeneration process before it is reused in the absorber.

The CO_2 when it leaves the hot potassium carbonate separation process is back down to a very low pressure of approximately 5 to 8 psig. This CO_2 must be recompressed before it is injected into the oil production formation for use in driving the oil production into the producing wells. Illustrated is a three stage compressor again with the same features as described above for field gas compressors with interstage scrubbers and coolers to compress the CO_2 for reinjection.

Between the second and third stage, the CO_2 passes thru a glycol dehydrator so that the water vapor will be removed from the CO_2 prior to its final compression and injection. If any appreciable amount of water is left in the CO_2 it will cause problems in solidifying and plugging up the CO_2 lines and injection facilities. A triethylene glycol process is illustrated for dehydration of CO_2 between the second stage and third stage of the compressor.

The CO_2 passes thru an inlet scrubber on the inlet of the glycol dehydrator unit and then thru a vertical absorber tower again flowing up thru several trays in the vessel. Triethylene glycol is circulated down thru the tower and absorbs the water vapor from the CO_2. The CO_2 passes out the top of the vessel thru a heat exchanger and back to the final third stage of the CO_2 compressor.

The glycol that has absorbed the water from the CO_2 passes out the bottom of the tower, and as illustrated, thru a glycol powered glycol pump where it is used to drive the dry glycol back into the top of the absorber tower. The wet or rich glycol passes thru a heat exchange coil in the surge tank, thru a glycol/gas flash separator, and into the stripping still on the reboiler of the dehydrator unit. In the reboiler the water is heated and driven out of the glycol solution and the glycol passes then from the reboiler, thru the shell side of the heat exchanger surge tank, and is again picked up by the glycol pump and reinjected into the absorber for reabsorbing more water vapor.

REFERENCES

1. Sivalls, C. R., "Oil and Gas Separation Design Manual", Sivalls, Inc., Nov. 1980 P 1.
2. Same as reference 1, P 5.
3. Same as reference 1, P 6.
4. API Spec 12J "Oil and Gas Separators", American Petroleum Institute, Jan. 1982, P 13.
5. Sivalls, C. R., "Crude Oil Treating Design Manual", Sivalls, Inc., Apr. 1979, P 1.
6. Same as reference 5, P 5.

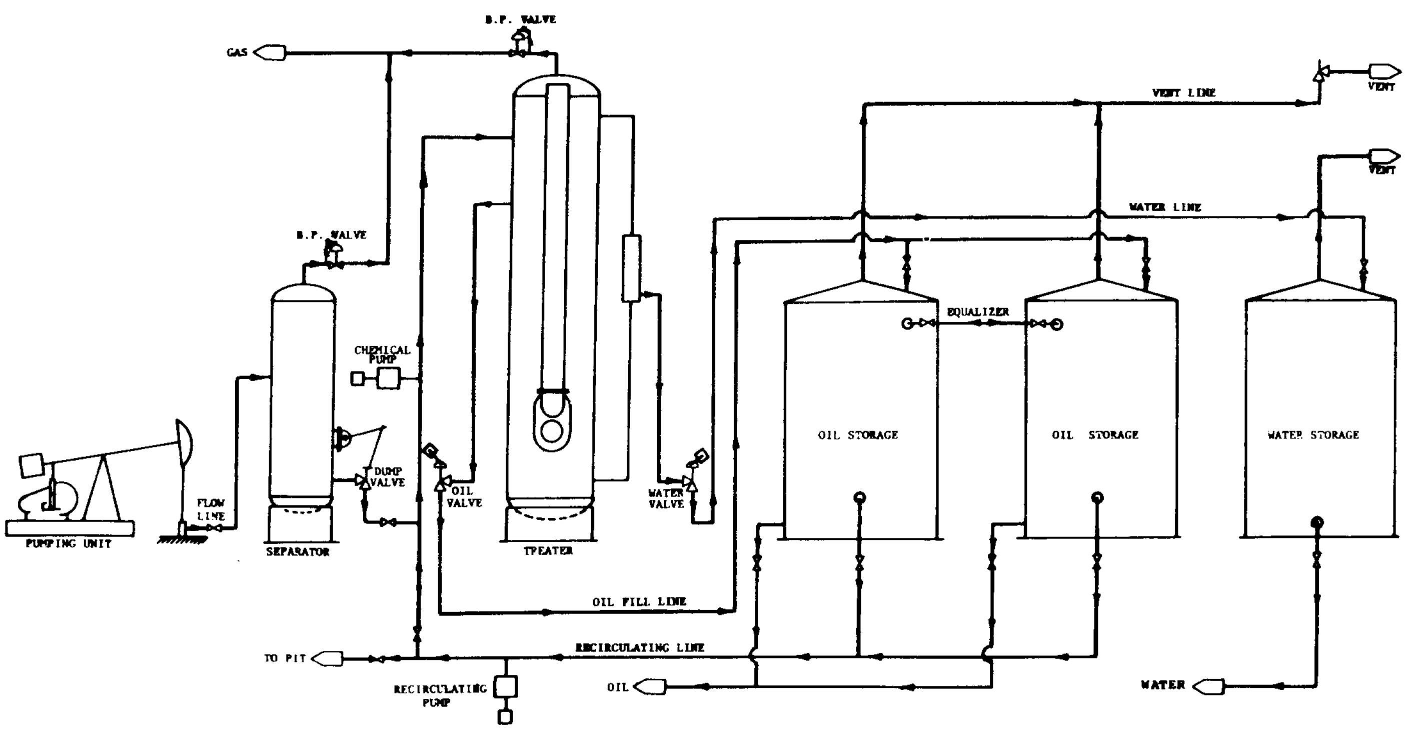

FIGURE 1 — SINGLE WELL PRODUCTION BATTERY

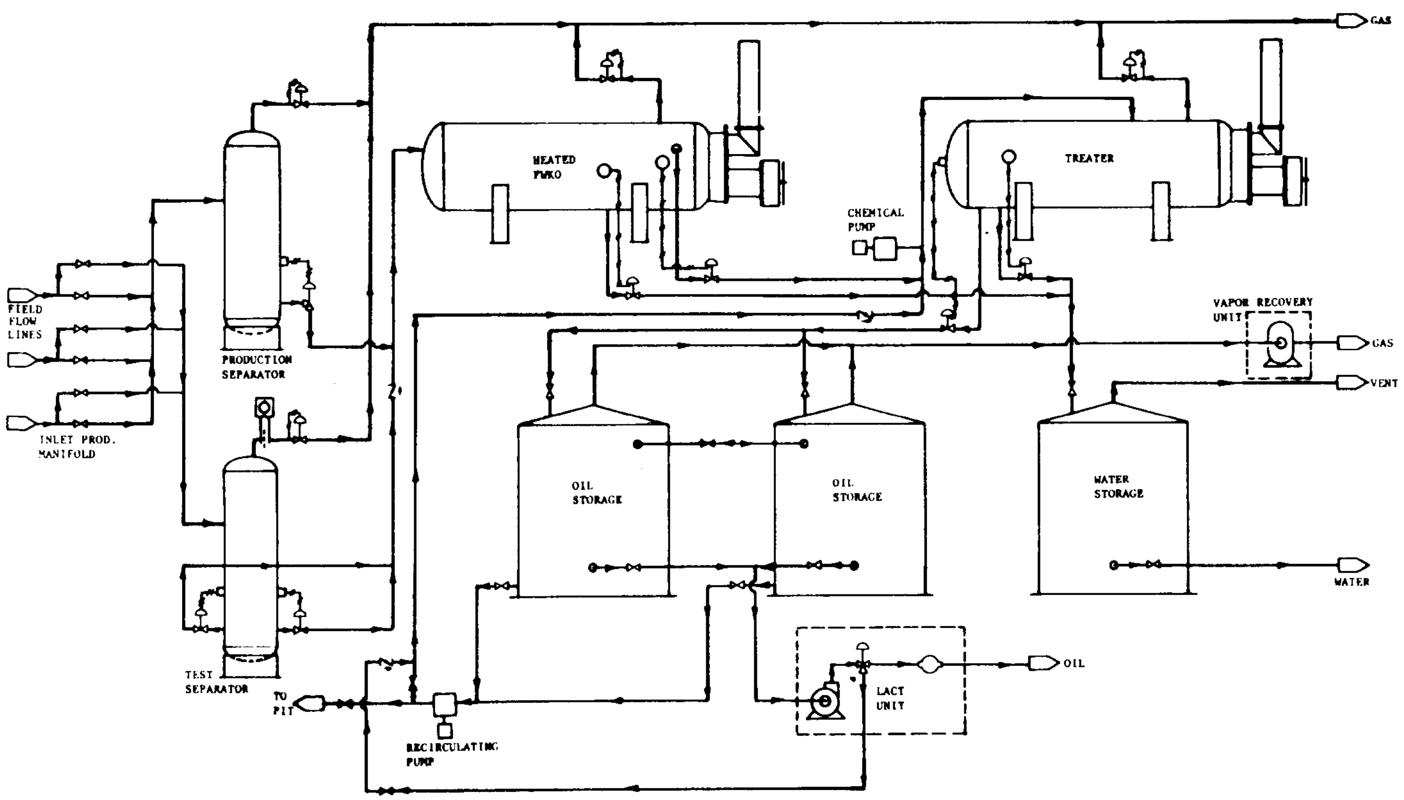

FIGURE 2 — CONSOLIDATED PRODUCTION FACILITY

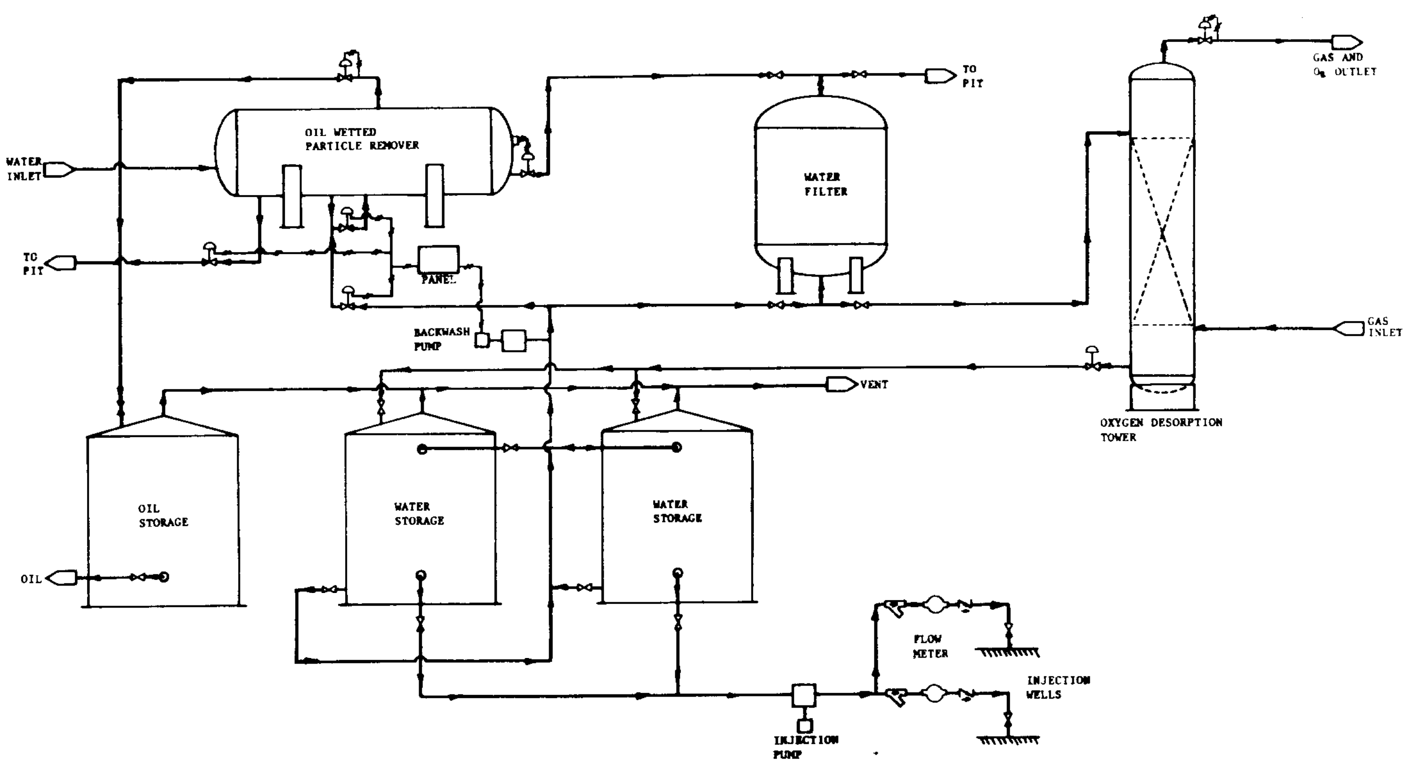

FIGURE 3 — WATER TREATING FACILITY

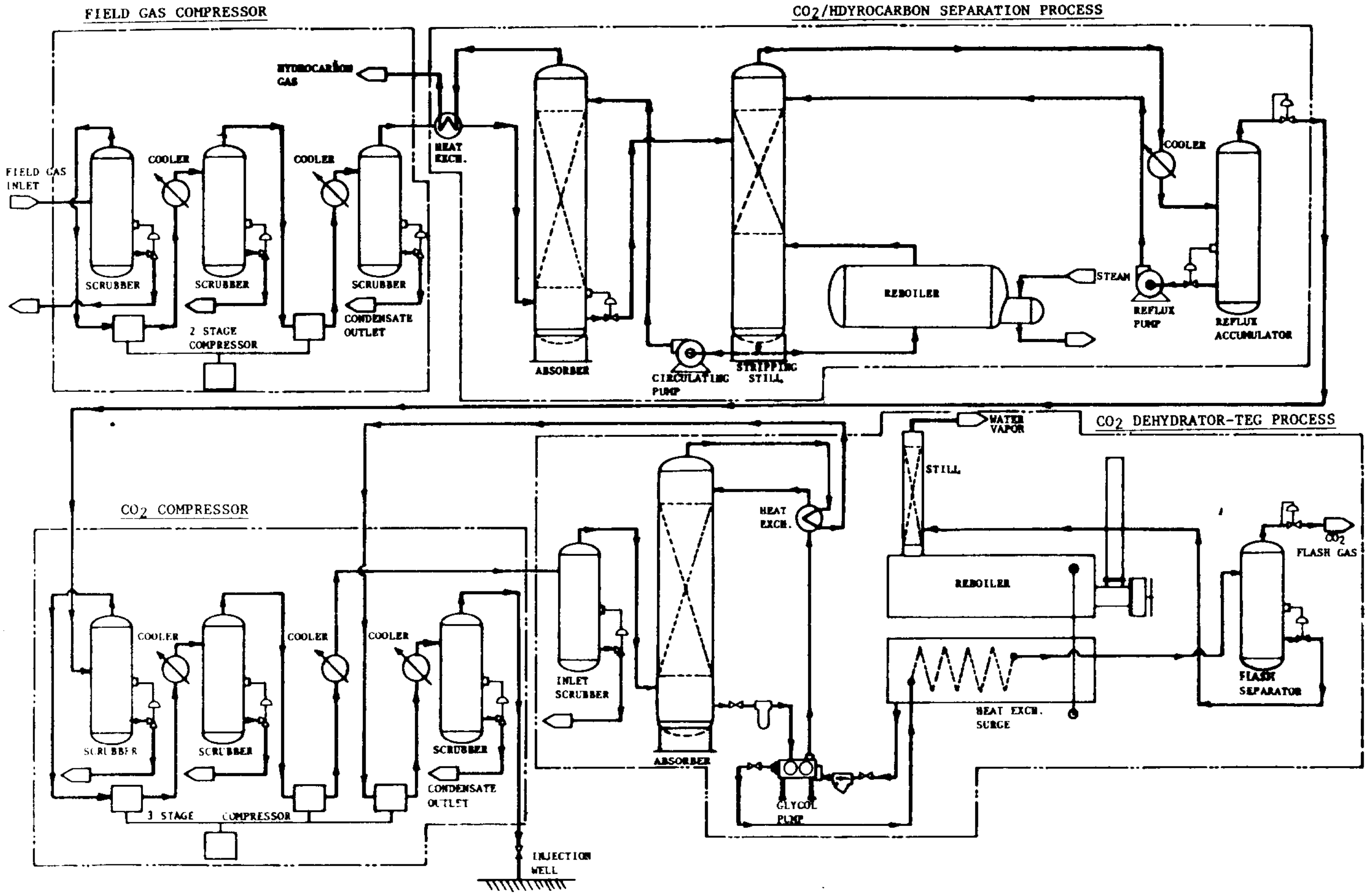

FIGURE 4 — CO_2 PROCESSING FACILITY