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Basic Design and Simulation of Oil Process Train in Upstream Facilities

Thesis for MSc program in Petroleum Engineering

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Abstract

The oil process industries are developed to produce oil at required specifications. The equipment and its arrangement on the facility vary according to the feed and product specifications and the geomorphology of the location. The production fluids from the reservoir are separated in large vessels called separators into gas, oil and water. The petroleum oil and gas are source of energy for the industries. Different types of separators are combined along with the auxiliary equipments to meet the separation requirements. The configuration of this equipment should comply with the installation/operational cost restrictions and facilitate the process operation and the transient conditions such as the ones occurred during well shutdowns.

The equipment should be able to tolerate process changes such as increased water cut during water injections in the reservoir, or the formation of emulsions during workovers. These conditions should be well studied both experimentally as well as by software simulations prior to project investment. Using the Aspen HYSYS package it was possible to simulate an oil process train consisting of three reservoirs that produce to a common separation facility. The process was studied for the effects of heating, well shut down and different well flow rates. The simulation indicated the factors which affect the separation process and helped minimize the equipment and energy cost while maintaining the required process flexibility. The equipment's components are rated and sized according to the basic design calculations for initial cost estimation. The separator internals' performance was also included in the simulation to study the water carry over between the separators and the storage tank.

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1 Oil Production

The fossil fuels are the main source of energy since the 19 century. The fossil fuels are organic material which is combusted to produce energy. These organic materials are called kerogen which yields synthetic crude oil when they are pyrolyzed or heated. [1]

After industrial revolution, the development of new technology created the demand of energy for transportation, electric generation and petrochemical industries. Soon petroleum became vital to almost every energy and production sector. It accounts for energy consumption for production of chemical products, including pharmaceuticals, solvents, fertilizers, pesticides, synthetic fragrances, and plastics.

The petroleum industry includes the exploration, extraction, refining, transportation and marketing of petroleum products. During the exploration phase, the prospecting, seismic analysis and limited drilling activities are carried out before the development of the field is finally decided. The seismic survey searches for the geological structure that may form oil reservoirs. The extraction is then carried out by drilling one or multiple wells. Drilling and production of oil are expensive processes so oil companies spend much time analyzing the exploration data and drill only when the analysis concludes that there is good probability of oil reserves.

The petroleum geologists and geophysicist search for hydrocarbon deposits beneath the earth surface which are referred as reserves. A petroleum reservoir is subsurface pool of hydrocarbons contained in porous rock formations. In reservoirs the crude is trapped by overlying rock formations. These petroleum reservoir fluids consist of hydrocarbons and small amount of inorganic chemicals, among which water, carbon dioxide, and nitrogen and hydrogen sulphide are in abundance. The reservoirs are characterized by the type of fluids as following [2].

- **Natural Gas:** the reservoir fluid is gas phase and pressure decrease does not produce the formation of a new phase
- **Gas Condensate:** the reservoir fluid is a gas phase mainly. Pressure decrease leads to the formation of a liquid phase.
- **Near Critical:** the reservoir fluid is mainly a liquid phase. If the well temperature is smaller than the mixture's critical temperature, then by decreasing the pressure a gas phase is formed. If well temperature is higher than mixture's critical temperature, then decreasing pressure forms a liquid phase.
- **Black Oil:** the reservoir fluid is mainly a liquid phase and pressure decrease always leads to the formation of a gas phase.

After the exploration process the upstream oil production facilities are developed for production and stabilization of oil and gas. The produced oil and gas as per recommended standards are stored in

storage tanks or transported to processing facilities by pipelines or by vehicles [3]. During the refining process the oil and condensates are processed to marketable products with well-defined specifications such as gasoline, diesel or feedstock for the petrochemical industry. In petrochemical industry these hydrocarbon products are further processed to produce plastics, fertilizer and a wide range of industrial chemicals.

1.1 Oil Facility

There are many configurations of oil facilities. Based on the topographical location, there are two facilities On-Shore facility and offshore facility.

1.1.1 On Shore facility

The onshore production is the most economic oil production; it is viable starting from a few dozen barrels of oil a day. Onshore wells are high capacity wells producing thousands of barrels per day where several wells can be used to produce oil and gas. Since 2007, the fracturing technology on onshore sites of the reservoir has allowed the shale gas and liquids to be produced at increased volumes. Hydraulic fracturing enables the extraction of natural gas and oil from rock formations deep below the earth's surface (generally 5,000–20,000 ft) at on-shore ground [4].

1.1.2 Offshore Facility

When oil is extracted from the rock formations beneath the seabed, offshore facilities are developed. These offshore facilities have an offshore platform which enables the oil production. The offshore facilities can facilitate well drilling to explore, extract, store, process petroleum and gas which lies in rock formations beneath the seabed. There are many types of offshore facilities described as follows [5].

1.1.2.1 Shallow Water Complex Platform:

It is used at water depths up to 100 m and it consist of independent platforms connected using gangway bridges. The different platforms have different processing such as extraction and refining. Figure 1-1 shows a shallow water complex platform



Figure 1-1 : Shallow Water Complex Platform (Csanyi, 2017)

1.1.2.2 Gravity Base Platform

It consists of a platform placed on fixed and large steel reinforced concrete structures, built on the seabed. It is used in the case of large fields with a water depth between 100 m and 500 m .The Crude Oil storage tanks are at the bottom of the concrete support legs. Figure 1-2 shows the gravity base platform.



Figure 1-2 : Gravity Base Platform (Csanyi, 2017)

1.1.2.3 Floating production storage and offloading facility

On floating production, all topside systems are located on a floating structure with dry or subsea wells. The FPSO is a floating vessel used by the offshore oil and gas industry for the production and processing of hydrocarbon and for the storage of oil. Figure 1-3 shows a floating production storage offloading facility.

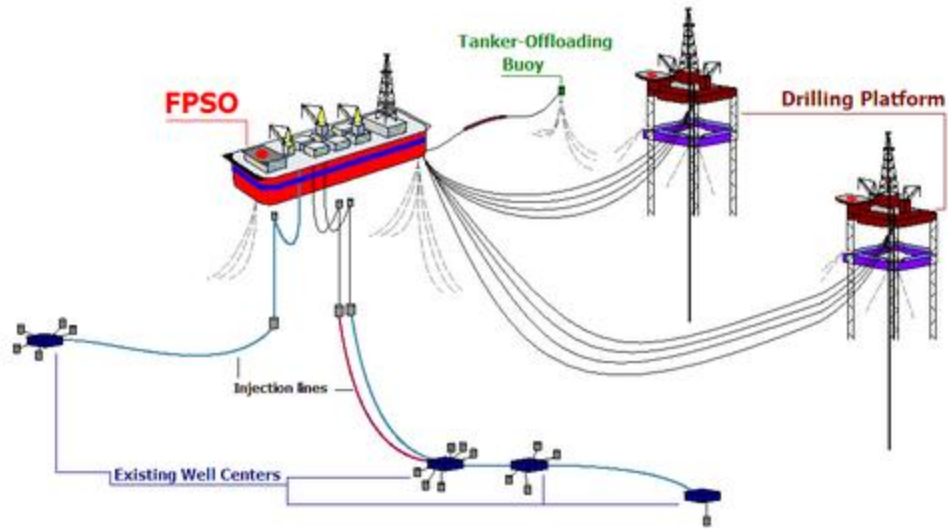


Figure 1-3 : Floating production storage and offloading

The FPSO are particularly effective in remote or deep water location, where external infrastructure such as pipelines or storage is difficult to install or they are not required. FPSO eliminates the need to lay expensive long distance pipelines from the processing facility to an onshore terminal. Once the field is depleted the FPSO can be moved to a new location.

FPSO is currently preferred for water depth greater than 200 meters. An FPSO is typically a tanker type hull or barge, the main process is placed on the deck, while the hull is used for storage and offloading to a shuttle tanker. It may also be used as a transportation platform of pipelines. FPSOs can have additional processing and systems, such as drilling and production and stranded gas LNG production. The well fluids are routed to FPSO where Hydrocarbons are processed. FPSOs currently produce from around 10,000 to 200,000 barrels per day. The left over fluid from production is treated and discharged to the sea or used for re injection. [6, 7]

The most common structural configuration of FPSO is Tension leg platform and SPAR. The Tension leg platform TLP is a floating structure which is held in a specific position by tensioned tendons, fixed on the seabed through several piles. It can be used for a wide range of water depths up to 2000 m. The SPAR is a structure consisting of a floating cylindrical hull which supports a fixed platform [8]. Some of the FPSOs are shown in figure 1-4

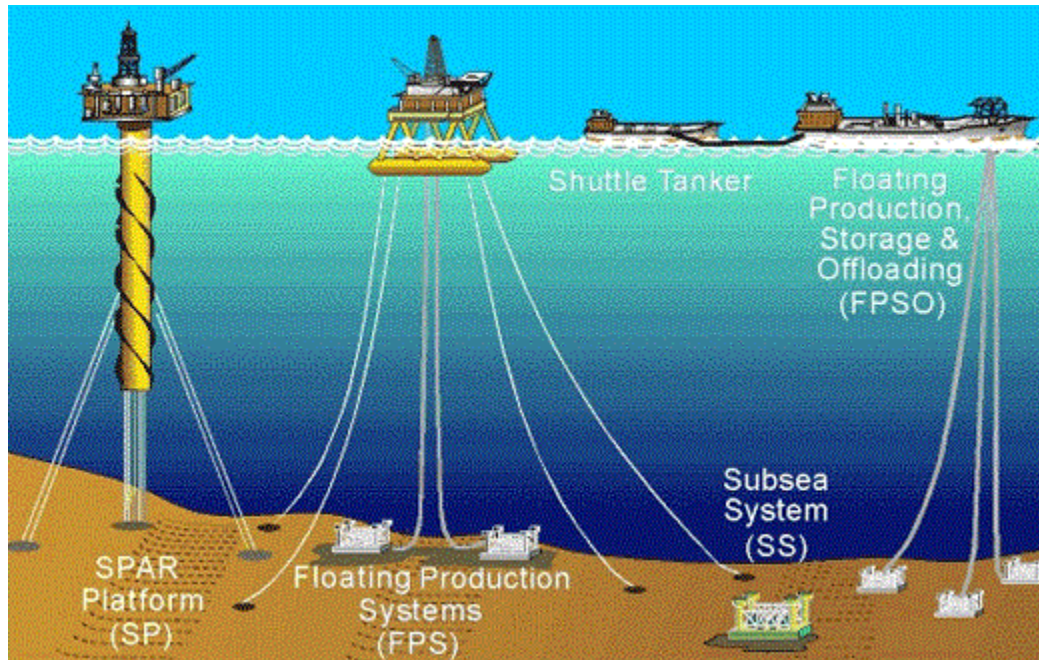


Figure 1-4 : Types of FPSO Configurations

The production processing takes place at top side of FPSO. The advantage of topside production facility is that it can accommodate the bulk separator(s). It allows varying flow conditions, a large interfacial area for separation and can tolerate slug flow to great extent.

Since the well head pressure is determined by the reservoir pressure and pressure difference between the wellhead and first stage separator, there is a significant pressure loss due to friction and hydrostatic pressure loss in the flow lines and the risers and the receiving unit at FPSO depending on the depth of the sea. Moreover, as the field matures; reservoir pressure will decline; subsequently the wellhead pressure will be reduced [6] and the water cut in the production increases with respect to time, thus imposing limitations on the production .Although a revamping is then required the limited space of these platforms is a disadvantage both to production units as well as to light weight handling capacity to facilitate the revamping [7]

1.1.2.4 Subsea production systems

The subsea production systems are located on the sea floor, as opposed to the surface. These production systems, can only extract and then transport reservoir fluids towards other facilities for the separation, through undersea pipelines [6].The figure 1-5 shows the subsea production system



Figure 1-5 : The subsea production system

Subsea systems are typically used at depths of 500 meters or more and they are used for extraction and transportation. Drilling and completion is performed from a surface rig and the extracted oil and natural gas is transported by undersea pipeline and riser to the processing facility, so that a single production unit can serve many wells over a large area. Horizontal subsea pipelines of up to 250 kilometers are currently possible. The future of this industry is to employ fully autonomous subsea production facilities, with multiple well pads, processing, and direct tie-back to shore. Subsea separation technology increases the lifetime of the field and the recovery rate. Subsea processing is usually selected for deep water, longer transportation distances, marginal fields and colder surroundings. [5, 6] Subsea separation technology increases the lifetime of the field and increase recovery economically.

The disadvantage of subsea installations is that the separator requires increased wall thickness to be installed at the greater depth, so the separator will be expensive as well as difficult to transport and install. On the other hand the separators being compact will have reduced volume ,they will be highly sensitive to flow velocities and composition, and it will reduce the separation efficiency and decrease the tolerance to fluctuating flows .The subsea separator technology is expensive and time consuming process, which needs to be justified for the investment. [6]

1.2 The process equipments

After the extraction, the productions well transmits the crude from the reservoirs to the oil and gas processing facility. The well provides a path for the production fluid to flow from bottom hole to surface. The choke controls the fluid production rate from the well. The wells are connected to the oil and gas processing facility via production manifold. The flow line leads the production fluids to separators where

gas and water are removed from the oil. Pumps and compressors are used to transport the oil and gas through pipelines to the sales points. The production separation facilities separates the well production stream into three phases oil, gas & water and processes them into marketable products or into production byproducts suitable for disposal in an environmentally acceptable manner. A complete oil or gas production system consists of a reservoir, wells, flow lines, separators, pumps, and transportation pipelines.

Separators

In separators, the gas is flashed from the liquid and water is separated from the oil. The two-phase separator separates only the gas from total liquid while three-phase separator separates the influent into gas, oil and water. The separated gas is then compressed and treated as per sales requirements. The Knock out drum removes any remaining liquid from the gas stream. They can also be used at compressors upstream to avoid liquid entrainment in the compressor.

Compressor

Compressor is used to increase the pressure and temperature and to reduce the volume of the gas. Compressors can be categorized as positive displacement (Reciprocating Piston) and dynamic displacement (centrifugal).

Positive displacement compressors have chambers which draw in a volume of air and reduce the volume of the chamber to compress the air. Dynamic displacement compressor do not reduce the volume of a captured pocket of air but it speeds up the air to high velocity, and then restrict the air flow so that the reduction in velocity causes pressure to increase.

Heat Exchanger

Heat exchangers can be used for heating and cooling the fluid. In Heat Exchanger, the heating or cooling fluid does not mix with the process stream. The heat transfer method in heat exchanger usually involves convection in each fluid and conduction through the wall separating the two fluids. The Shell-and-tube heat exchanger, Aerial Cooler and Plate & frame heat exchanger are commonly used in the oil & gas industry.

Shell-and-tube heat exchanger contains tubes packed in a shell. Heat transfer takes place as one fluid flows inside the tubes while the other fluid flows outside the tubes through the shell. Baffles are fixed in the shell to force the shell-side fluid to flow across the shell to enhance heat transfer and to maintain uniform spacing between the tubes.

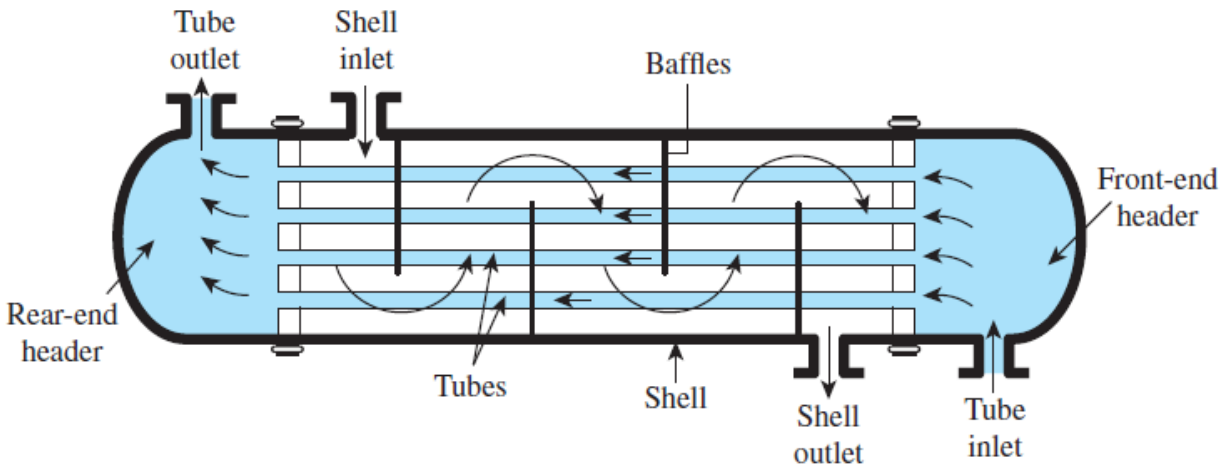


Figure 1-6 : The schematic of a shell-and-tube heat exchanger (one-shell pass and one-tube pass)

The air cooled heat exchangers are also known as Fin fan Coolers or Aerial Cooler. In the Fin fan coolers, the ambient air is used as the cooling media to cool. The hot fluid is used in tube side. All the tubes used in the coolers are finned tubes. The fins are extending surface from a tube to increase the rate of heat transfer to or from the environment by increasing convection.

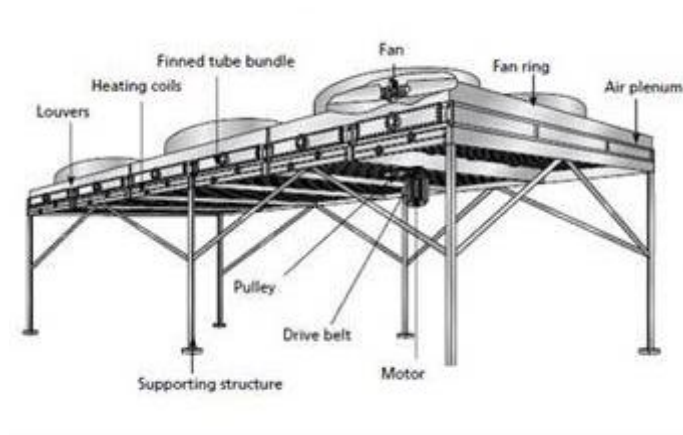


Figure 1-7 : The schematic of Aerial Cooler

Plate and frame heat exchanger has series of plates with corrugated flat flow passages .The hot and cold do not mix into each other and fluids flow in alternate passages ,so each cold fluid stream is surrounded by two hot fluid streams, resulting in very effective heat transfer. They are suited for liquid-to-liquid heat exchanges applications, close temperature approach and moderate pressure. They cannot be used for high viscosity liquids and slurry/suspended solids.

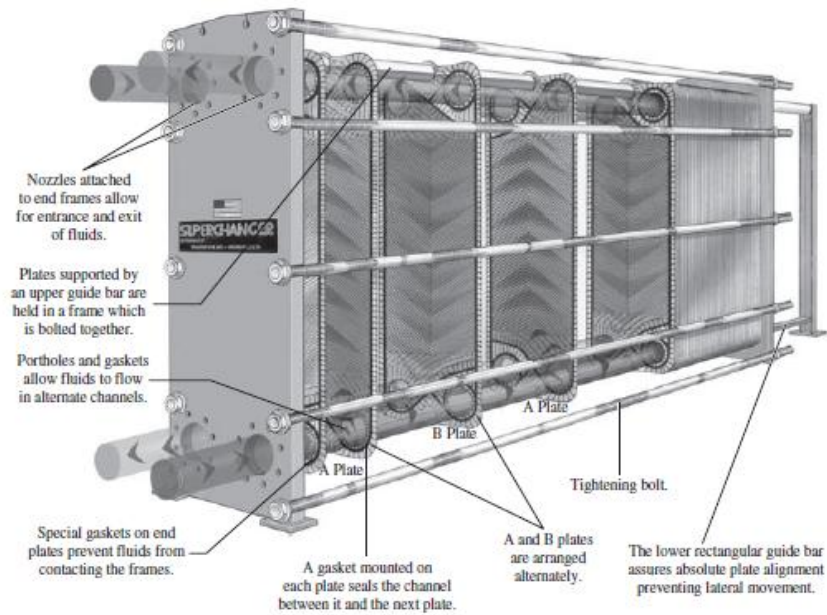


Figure 1-8: A plate-and-frame heat exchanger

Pipelines

The fluids from the well are transported for further processing towards the production facilities by pipelines. The pipeline systems associated with producing wells includes the well flowline, trunkline, facility interconnecting equipment piping within the production facility, gathering or sales pipelines, and transmission pipelines.

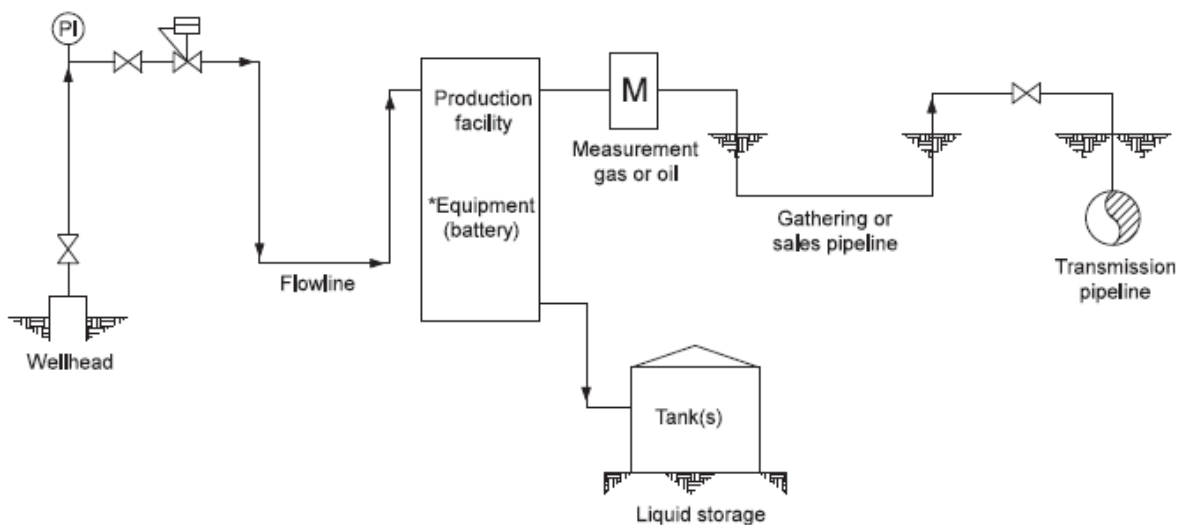


Figure 1-9 : The pipeline system

As shown in figure 1-9, a well flowline is a two-phase line from a wellhead to a production manifold or separator. A manifold is a combination of pipes, fittings, and valves used to combine production from

several sources and direct the combined flow into appropriate production equipment or multiple outlet streams. A gathering system consists of a line downstream of field manifolds or wellhead separators conveying fluid from multiple wells and leading to the production facility. Transmission lines transport hydrocarbon fluids from producing fields to processing plants or refineries and from plants and refineries to marketing centers. A transmission line can be called cross-country piping system for transporting gas or liquids, usually over long distances.

Tanks

In most of production facilities, crude oil is sent directly to refineries or tanker terminals through the pipeline, where 10 to 100 tanks of varying size and volume can store up to 50 million crude oil barrels. Oil can be stored into different kinds of tanks, by shape and size, throughout its production and distribution. The tank specification is based on product operating conditions, storage capacities, and specific design issues. The atmospheric storage tanks include open top tanks, fixed-roof tanks, external floating-roof tanks, or internal floating-roof tanks. Fixed roof tanks are common in production facilities to store hydrocarbon with vapor pressures close to atmospheric pressure. These tanks are equipped with pressure vacuum valves and purged with natural gas to eliminate air intake into the vapor space. In crude oil terminals and pumping stations, internal floating roofs may be added to the fixed-roof tank to reduce product vapor losses if the crude oil has been stabilized to vapor pressures less than 11 psia. If the offshore platform does not have a direct pipeline system, crude oil is stored on board into storage tanks, which are regularly offloaded by shuttle tankers (every two weeks mostly), storing several million barrels. The most widely used tanks are vertical cylinders, with capacity ranging between 100 to 1.5 million barrels where pressure and temperature are usually nearly atmospheric.

2 Separation Process

The mixing of oil, gas and water mixture is a natural occurring process in reservoir. It needs to be processed for commercial use. The separation of mixtures into its constituents was an art for millennia. In laboratory chemists separate and analyze light hydrocarbon by gas-liquid chromatography, while in processing industry the chemical engineer uses separators and distillation column to separate the same hydro carbon mixture. The classical separation techniques are; distillation, absorption, liquid- liquid extraction, leaching, drying, and crystallization, adsorption and membrane separation.

2.1 Criteria for Separation process

The most important factors affecting separation are feed composition and flow rate as the other conditions such as temperature, pressure and phase conditions can be altered by pumps, compressors, heat exchangers to fit the separation operation. Following factors are very important for designing the separation process.[9]

a. Feed conditions

1. Composition, particularly concentration of species to be recovered or separated
2. Flow rate
3. Temperature
4. Pressure
5. Phase state (solid, liquid, and/or gas)

b. Product conditions

1. Required purities
2. Temperatures
3. Pressures
4. Phase states

c. Characteristics of separation operation

1. Ease of scale-up
2. Ease of staging
3. Temperature, pressure, and phase-state requirements
4. Physical size limitations
5. Energy requirements

The operation issues such as surging tendencies of feed streams, physical properties of fluid such as density viscosity and compressibility, designed degree of separation (e.g., removing 100% of particles greater than 10 microns), presence of impurities (paraffin, sand, scale, etc.), foaming tendencies of the crude oil, corrosive tendencies of the liquids or gas should also be acknowledged when designing a separation system. The guide for selection suitable separation method for oil, water and gas on the bases of phases are given in table 2-1

Major Component	Minor Component	
	Liquid	Vapor
Liquid	Decanters Coalescers Solvent extraction Leaching Chromatography Distillation	Stripping
Vapor	Separating vessels Demisting pads Cyclones Wet scrubbers Electrostatic precipitators	Adsorption Absorption Membranes Cryogenic distillation Condensation

Table 2-1: A guide for selection of separation process based on the phases that are separated

2.2 Selection of separation equipment

The selection and design of separation equipments is based on the required degree of separation. The separation equipment is chosen after the detailed study of mixtures and the operation conditions.

The operating conditions such as temperature, pressure, velocity, concentrations can be modified to enhance the separation. The temperature affects the fluid viscosity and density of the mixture, as the temperature increases the viscosity and the density decreases which enhance the separation process. Equipment capital cost, operating cost, energy cost are also important factors in selection of processing equipments.

The separation process is developed before selecting the separation equipment, energy for separation, mass separating agent, the optimal arrangement or sequencing of the equipment, and the optimal operating conditions of temperature and pressure for the equipment. The separation of feed mixture into differing chemical composition stream is accomplished by one or combination of the flowing industrial techniques.

- Heat transfer or pressure reduction of a second phase

In this method, the separation is achieved by heat transfer, which causes the formation of a second phase. The components are separated by differences in volatility, thus causing each species to favor one phase over another.

- The introduction into the system of a second fluid phase

In this method a second phase is added to the separation unit in the form of a solvent that selectively dissolves the certain species of the mixture. A subsequent separation step is usually required to recover the solvent for recycle.

- The addition of a solid phase on which selective adsorption can occur

This method involves the addition of solid particles called adsorbing agents that selectively adsorb the species in mixture. Subsequently, the adsorbing agent is regenerated after the adsorption.

- The placement of a selective membrane barrier.

In this method membrane is used as a barrier that allows the permeation of some species over others.

2.3 Dispersion and Separation

2.3.1 Dispersion

When two or more fluids contact and mix; they disperse into each other. If the phases are immiscible or partially immiscible they will eventually form two separate phases if they are allowed to settle. The dispersion is formed after the high velocity process, which causes turbulent flow. Turbulence causes the undesired re-entrainment in liquid-liquid separation. The turbulence is chaotic motion of the fluid, when fluid moves randomly forming the different size eddies and swirls. The Reynolds number [10] is used to estimate for the laminar or turbulence behavior. Renoylds number is the ratio between the inertial and viscous forces.

$$Re = \frac{d u \rho}{\mu} \quad \text{Equation 2-1}$$

Where

d = characteristic measure of flow (m)

ρ = density of flow (kg/m³)

u = velocity of flow (m/s)

μ = viscosity of flow (Pas)

The hydraulic diameter (D_h) can be used as a characteristic measure to calculate the Reynolds number. The hydraulic diameter is calculated by [10]

$$D_h = \frac{4A_{flow}}{P_{flow}} \quad \text{Equation 2-2}$$

Where

D_h = hydraulic diameter (m)

P_{flow} = perimeter of flow (m)

A_{flow} = area of flow (m²)

2.3.2 Liquid-Liquid Separation and Gas-Liquid Separation

The liquid-liquid dispersion in oil processing can be characterized by water droplets in oil or oil droplets in water. In water-in-oil dispersion the water phase is dispersed into an oil phase as small droplets and the oil act as continuous phase. In oil-in-water dispersion the oil phase is dispersed into a water phase as small droplets and the water act as continuous phase. The dispersion between the water and oil phase is usually unstable and are easy to separate. The unstable dispersions are separated by gravity in the absence of mixing forces. The stability of dispersion can be described with the droplet diameter. Large droplet diameters result in poor stability and extraction efficiency because of a low surface-to-volume ratio. The stable dispersion is referred to as an emulsion. The smaller dispersed droplets form stable emulsions and a larger mass transfer area thus increasing the extraction efficiency. If the droplet diameters are too small, the emulsion is very difficult to break by any mechanical means [38, 39].

The oil-water separation can take place by coalescing these two immiscible phases. The dispersed droplets are coalesced and separate from the surrounding fluid. The coalescence takes place due to collision between droplets and its bulk phase. In coalescence, the collision of droplets causes the merging of two droplets into a large and uniform droplet which destabilizes the interfacial film and ruptures it and then combines droplet and bulk phase together. The frequency of collision between the droplets and the time of the collision, the contact and the mobility of droplet surface highly affects the coalescence. The large droplet being denser as compare to the other droplets, settle faster in which they are entrained either by falling or rising due to gravity or buoyancy effects and thus the phase dissociation take place. Higher the interfacial tension at the interface higher is the coalescence. The settling phenomenon is also the dependent on density and viscosity of liquids. Higher the density difference and lower viscosity of continuous phase, the efficient is the settling process. The temperature and pressure affect the density and viscosity of the fluids; which in turn effects the dispersed phase concentrations, droplet size distribution, continuous phase viscosity and surface reactions ;thus ultimately effecting the separation process.

The separation of vapor liquid is much easier as compare to liquid-liquid separation due to much larger density differences. In vapor-liquid separation the liquid droplets are removed from the continuous gas phase. The increase in temperature reduces the viscosity of the liquid phase and increases the vaporization of vapor phase which separates the two phases

2.4 The separators

Many techniques are used to separate different phases. The classical mechanical separation is based on gravity separation, centrifugal force, pressure reduction to separate the phase. The simplest method to

separate liquid phases is the gravity settling tank called the decanter. The Decaners are used to separate liquids where there is sufficient density difference between the liquids, so the droplets can settle readily. Decaners are tanks that give sufficient residence time for the droplets of the dispersed phase to rise or the settle to the interface between the phases and coalesce. The decanter has three distinct zones; the heavy liquid zone, the dispersed liquid zone and the light liquid zone.

In separator, the gravity segregation is the main force that accomplishes the separation. The heavy liquid is drawn from the bottom of the vessel and lighter from the top. The degree of separation between gas and liquid depends on the separator operating pressure, the residence time of the fluid mixture and the type of flow of the fluid.

The separators are classified by the geometry configuration; vertical and horizontal separator and by their function; two phase and three phase separators. The volume fraction determines the geometry configuration of the separator; if the liquid phase is dominant the horizontal separators are used; if the vapor phase is dominant the vertical separators are used. The two phase separator separates gas from the total liquid and the three phase separators separates gas liquid stream into its crude oil and water rich phase.

The vertical separator is used when there is relatively small flow rate of gas and liquid and very high gas oil ratio. It can also be used if the plot space is limited or an easy level control is required. The vertical separator has good bottom drain and clean out facilities. It can handle more sand, mud, paraffin and wax without plugging.

The horizontal vessel is used when the process fluid has large liquid volume. The horizontal vessels are preferable for the separation of water and hydrocarbons. The horizontal separators have smaller diameter for similar gas capacity as compared to vertical vessels. There is a large liquid surface area in horizontal separator for foam dispersion which reduces the turbulence. The liquid level in tank is more stabilized in horizontal separators than vertical separators.

The separators are sized to satisfy several criteria such as

- Provide sufficient time to allow the immiscible gas, oil and water phases to separate by gravity.
- Provide sufficient time to allow for the coalescence and breaking of emulsion droplets at the oil-water interface.
- Provide sufficient volume in the gas space to accommodate rises in the liquid level that result from the surge in the liquid flow rate.
- Remove solids that settle to the bottom of the separator.
- Allow variation in the flow rates of gas, oil and water into the separator without adversely affecting separation efficiency.

- The holdup time of 5 to 10 minutes is used when emulsions are not likely to appear and the velocity of the continuous phase should be less than settling velocity of the droplets of the dispersed phase.

The mechanism of separation in horizontal, vertical, two-phase and three-phase separator is explained in unit 2.6 and 2.7

2.5 Separation in horizontal separator

2.5.1 Two-Phase Separator

In two phase horizontal separator, the crude enters through the inlet nozzle and hits the inlet diverter. As the fluid strikes the inlet separator the impact causes sudden momentum change causes the initial gross separation liquid and vapor. The sudden change momentum changes the droplet distribution, reduces shear force and helps droplet coalescence. After the initial vapor/liquid separation the liquid droplet being denser with respect to vapor falls to the liquid collection section of the vessel with the gravitational force. The liquid exits the vessel through the liquid dump valve regulated by level controller. The level controller senses increase or decrease in liquid level and operates (opens/closes) the dump valve accordingly. The liquid collection section provides the retention time required to let entrained gas evolve out of the oil and rise to the vapor space and reach a state of equilibrium.

The vapor and oil mist (liquid entrained in vapor) flows horizontally parallel to the vessel's center line above the liquid. As the vapor flow, the oil mist falls to the gas liquid interface, so the small liquid droplets that were not separated by inlet diverter are separated. Some of the drops are of such a small diameter that they are not easily separated in the gravity settling section. Before the gas leaves the vessel, it passes through a coalescing section or mist extractor. The mist elimination section uses elements of vanes, wire mesh or plates to provide a large surface area to coalesce and remove the very small droplets to before the gas leaves the vessel.

The pressure in the separator is maintained by a pressure controller mounted on the gas outlet. The pressure controller senses changes in the pressure in the separator and sends a signal to either open or close the pressure control valve accordingly. By controlling the rate at which gas leaves the vapor space of the vessel, the pressure in the vessel is maintained. Normally, horizontal separators are operated half full of liquid to maximize the surface area of the gas-liquid interface. [11, 32] Figure 2-1 is a cutaway view of a typical horizontal two-phase separator.

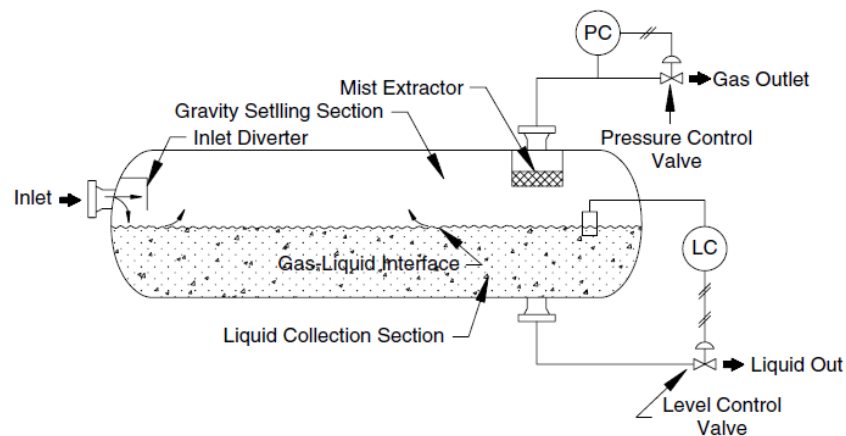


Figure 2-1 : Schematic of two-phase horizontal separator

2.5.2 Three-Phase Separator

In three-phase horizontal separators, the gross separation is carried out at inlet diverter as in two-phase separators. In most designs the inlet diverter has a down-comer that directs the liquid flow below the oil–water interface. This forces mixture of oil and water to mix with the water continuous phase in the bottom of the vessel and rise through the oil–water interface and water washing is carried out and it promotes the coalescence of water droplets, which are entrained in the oil continuous phase. Figure 2-3 shows the mechanism of water washing. The inlet diverter assures that little gas is carried with the liquid, and the water wash assures that the liquid does not fall on top of the gas–oil or oil–water interface. The liquid collecting section of the vessel provides sufficient time so that the oil and emulsion form a layer on top of the free water. The free water settles to the bottom. Figure 2-2 is a cutaway view of a typical horizontal three-phase separator with an interface level controller and weir. The weir maintains the oil level, and the level controller maintains the water level. The oil is skimmed over the weir. The level of the oil downstream of the weir is controlled by a level controller that operates the oil dump valve. The produced water flows from a nozzle in the vessel located upstream of the oil weir. An interface level controller senses the height of the oil–water interface. The controller sends a signal to the water dump valve, thus allowing the correct amount of water to leave the vessel so that the oil–water interface is maintained at the design height. The gas flows horizontally and exits through a mist extractor to a pressure control valve that maintains constant vessel pressure. The level of the gas–oil interface can vary from 50% to 75% of the diameter depending on the relative importance of liquid–gas separation. Both the oil and water flow over weirs where level control is accomplished by a simple displacer float. The oil overflows the oil weir into an oil bucket where its level is controlled by a level controller that operates the oil dump valve. The water flows under the oil bucket and then over a water weir. The level downstream of this weir is controlled by a level controller that operates the water dump valve. This differential height configuration of oil bucket assures oil will not flow over the back of the bucket and out with the water should the bucket become flooded. The height of the oil weir controls the liquid level in the vessel. The difference in height of the oil and water weirs controls the thickness of the oil pad due to specific gravity differences. It is critical to the operation of the vessel that the water weir height is sufficiently below the oil weir height so that the oil pad thickness provides sufficient oil retention time. If the water weir is too low and the difference in specific gravity is not as great as anticipated, then the oil pad could grow in thickness to a point where oil will be swept under the oil box and out the water outlet. Normally, either the oil or the water weir is made adjustable so that changes in oil or water specific gravities or flow rates can be accommodated. [11,32]

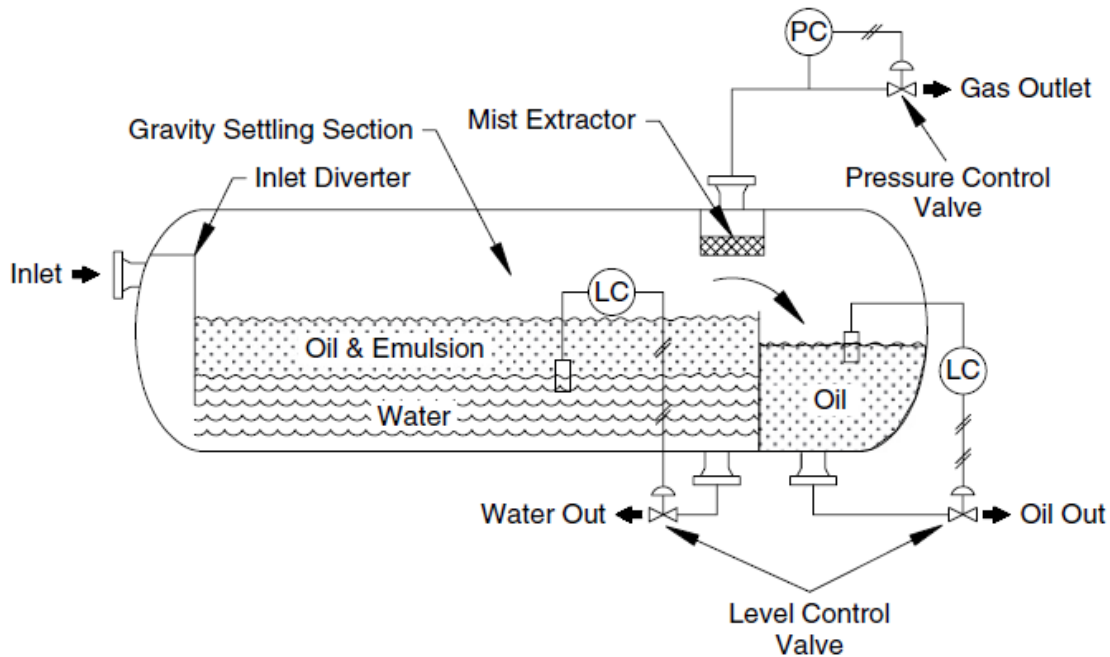


Figure 2-2 : Schematic of three-phase horizontal separator

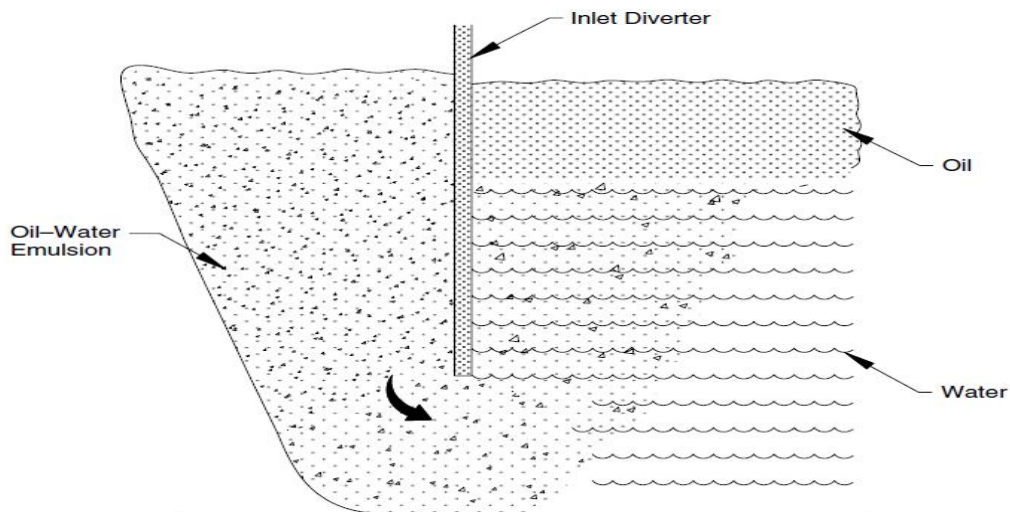


Figure 2-3 : Illustrating of water washing

2.6 Separation in Vertical separator

2.6.1 Two-Phase Separator

As shown in figure 2-4; in vertical two-phase separator configuration the inlet flow enters the vessel through the side and the inlet diverter does the initial gross separation. The liquid flows down to the liquid collection section of the vessel. Liquid continues to flow downward through this section to the liquid outlet. As the liquid reaches equilibrium, gas bubbles flow counter to the direction of the liquid flow and eventually migrate to the vapor space. The gas flows over the inlet diverter and then vertically

upward toward the gas outlet. Secondary separation occurs in the upper gravity settling section. In the gravity settling section the liquid droplets fall vertically downward counter-current to the upward gas flow. The settling velocity of a liquid droplet is directly proportional to its diameter. If the size of a liquid droplet is too small, it will be carried up and out with the vapor. Thus, a mist extractor section is added to capture small liquid droplets. Gas goes through the mist extractor section before it leaves the vessel. Pressure and level are maintained as in a horizontal separator. [11, 17]

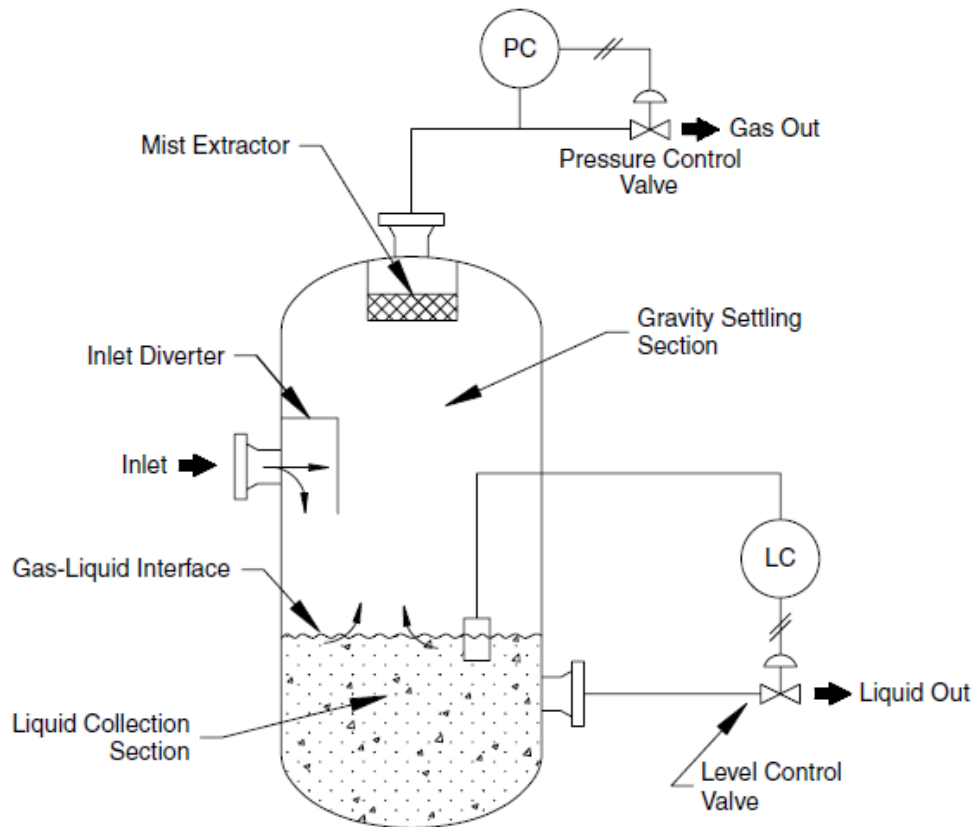


Figure 2-4 : Schematic of two-phase vertical separator

2.6.2 Three Phase Separators

Figure 2-5 shows a typical configuration for a vertical three-phase separator. The flow enters the vessel through the side as in the horizontal separator. The inlet diverter separates the bulk of the gas. Similar to horizontal three phase separator, a down-comer directs the liquid through the oil–gas interface. The spreader, or down-comer, outlet is located just below the oil–water interface for water washing the incoming stream. From this point as the oil rises, any free water trapped within the oil phase separates out. The water droplets flow countercurrent to the oil. Similarly, the water flows downward and oil droplets trapped in the water phase tend to raise countercurrent to the water flow. [11, 32]

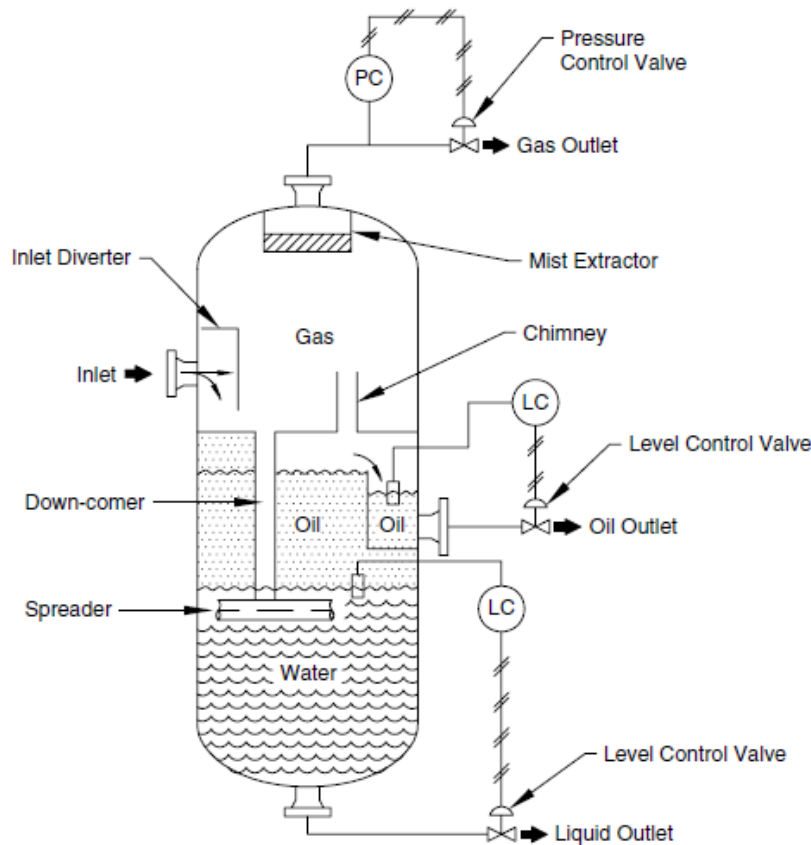


Figure 2-5: Schematic of three-phase vertical separator

2.7 Carry Over

In an ideal separator, a complete separation of the different phases is assumed and therefore phase flows are calculated based on the thermodynamic equilibrium. In real separators however the separation is not perfect: The liquid entrains the gas phase; and gas or droplets from another liquid phase get in the liquid phase.

When free water or oil escapes from the gas phase of a separator it is referred as carry over. Carryover is a measure of the amount of liquid entrained in the gas stream after passing through the separation module. The carry over analyses is conducted for the three major sections of a separator: inlet diverter, liquid gravity settling and mist extractor section. The carryover is reduced by internal equipment. The internal equipments reduce the amount of phase dispersion in the vessels at the inlet and outlet. Carryover can be indicative of high liquid level in the separator, damaged vessel internals, foam, improper design, plugged liquid outlets or/and flow rates exceeding the design values.

2.7.1 Inlet Diverter Section

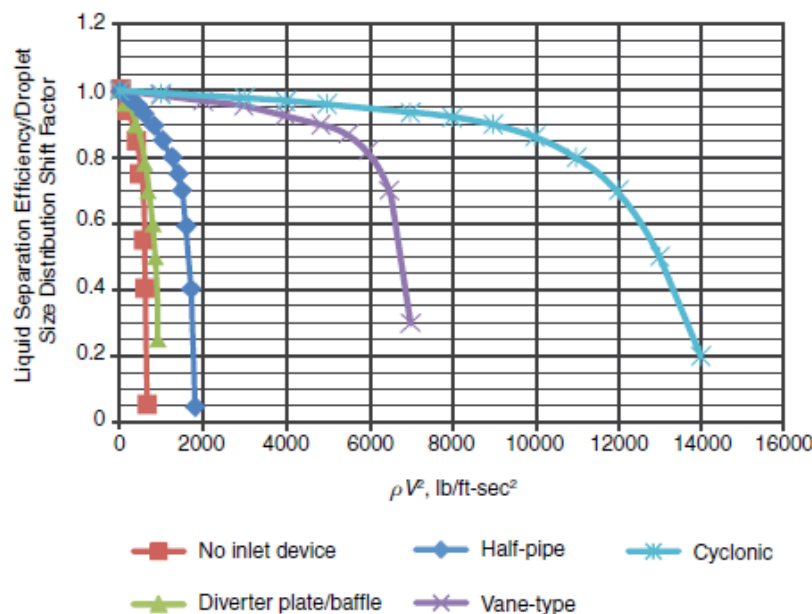
The inlet diverter is the primary separation section, the inlet stream enters the separator with high momentum and it abruptly changes the direction of flow by absorbing the momentum of the liquid and

allowing the liquid and gas to separate. At the high velocity the higher density liquid does not change the direction and falls at the bottom but the gas being less dense easily changes the direction and dissociates from the liquid. An inlet diverter can be a spherical dish, flat plate, angle iron or another type of structural steel, the design should be able to resist the momentum of incoming fluid. [11, 38]

The inlet devices reduce the velocity of the feed fluids, straighten the velocity profile of the continuous phases and promote droplet coalescence to improve separation performance and/or reduce separator size. Inlet devices diffuse the momentum of the incoming feed stream and allow the removal of any bulk liquids

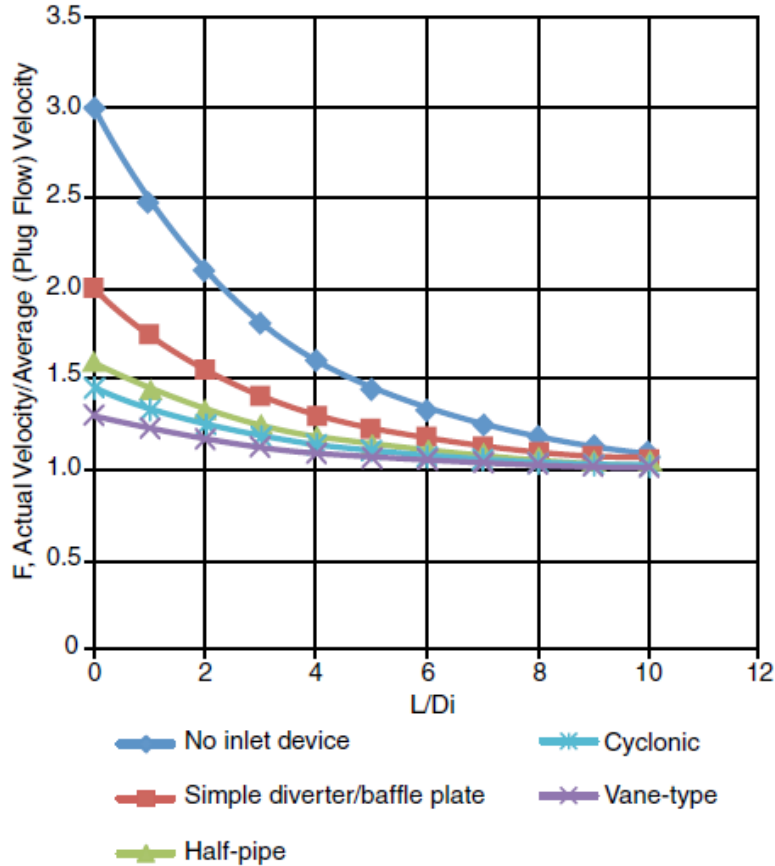
After the inlet section, the liquid entrained in the vapor, enters the gravity separation section. In real cases, when the fluid flow exits the inlet device, the flow is chaotic and turbulent. The release point from inlet nozzle is significance for the entrainment of droplet. For simplicity the most conservative approach would be the release of all droplets at the top (inlet) of the gas gravity separation section and the released entrained droplets fall uniformly over the vertical height of the gas gravity separation section. A release point closer to the vapor-liquid interface results in lower entrainment as droplets can be easily removed.

Inlet devices are typically selected and sized based on the inlet momentum ($\rho_m V_m^2$) of the feed stream. Bothamley (2013) used mostly anecdotal information obtained from various sources, mainly technical literature available in the public domain, is to quantify inlet device efficiency in relation to feed momentum producing graph 2-1 which shows the droplet shattering effect due to momentum created at the divergent inlet devices. The fall off in separation performance with increasing feed pv^2 reflects a larger fraction of the feed liquid in entrained droplet form, breakup of bulk liquid into droplet form and smaller droplet sizes associated with higher inlet velocities.[34]



Graph 2-1 : Inlet device liquid separation efficiency and effect on droplet sizes (Bothamley M., 2013).

Graph 2-2 shows an estimation of the quality of the flow distribution immediately after the inlet device ($L/D_i=0$) and of the flow profile with the distance downstream of the inlet device. The quality of the flow distribution is characterized by the factor F , the actual average velocity/ideal plug flow velocity. F values greater than 1.0 imply unused cross-sectional flow area. The use of this factor will allow estimation of the effective actual velocity, which can be used in the droplet settling calculations for the gas (and liquid) gravity sections. The calculated effective actual velocity for the gas gravity section will be the entrance velocity to the mist extractor section. [34]



Graph 2-2: Effect of inlet device on downstream gas and liquid velocity profiles [34]

2.7.2 Liquid Collection Section

After the initial separation in inlet diverter, the vapors entrained in the liquid are separated by providing required retention time to escape to the gravity settling section. Higher the retention time better is the separation. The retention time is dependent on the liquid handling of separator, the incoming fluid flow rate and the differential density of the fluids. Since the density difference of the vapor and liquid (oil and water) is higher than the liquid (oil) and liquid (water); the vapor liquid separation requires less time. [11, 17]

The Water-oil separation and liquid degassing takes place in liquid settling section. The removal of oil droplets from the water phase is much easier than the one of water droplets from oil phase due to higher viscosity of the continuous phase. The liquid-liquid separation is calculated from the settling velocities for each liquid (oil and water) droplet size in the gas phase and the residence time for the gas in the vessel. The gas-liquid separation is also calculated using settling velocities for each droplet of liquid or gas in the liquid phases and residence time for each liquid phase. The settling velocities are calculated using the GPSA correlations (table 2-2) for all dispersions, except for the water in oil dispersion, for which the settling velocity is calculated by the method of Barnea and Mizrahi. It can also be predicted independently as a function of flow conditions and liquid physical properties (table 2-3).

Settling Law	Reynolds Number (Re_p)	Terminal Velocity Equation
Stokes' Law	<2	$V_t = \frac{gd_p^2(\rho_l - \rho_g)}{18\mu_g} \dots\dots\dots(4)$
Intermediate Law	$2-500$	$V_t = \frac{0.1529g^{0.714}d_p^{1.142}(\rho_l - \rho_g)^{0.714}}{\rho_g^{0.206}\mu_g^{0.428}} \dots\dots\dots(5)$
Newton's Law	$500-200,000$	$V_{max} = K_s \sqrt{\frac{\rho_l - \rho_g}{\rho_g}} \dots\dots\dots(6)$
Note: For calculations involving separation of gas bubbles from liquid, the gas viscosity (μ_g) in the equations is replaced with the liquid viscosity.		

Table 2-2: Settling velocity equations for settling law regions (Gas Processors Suppliers Association, EDB, 2014)

$$\frac{d_{95}}{D} = 4.0 We^{-0.5}$$

where $We = D\rho_c\bar{U}^2/\sigma$ is a dimensionless Weber number based on pipe diameter and mean velocity.

Table 2-3 : d95 calculation (Karabelas, 1978)

2.7.3 Gravity Settling Section

Similarly after the initial separation at inlet diverter, as the vapors enters the gravity settling section, its velocity decreases and the liquid entrained in the vapor are separated by providing required retention time to escape to the gas-liquid interface. The gravity settling section allows the liquid droplets greater than 100 to 140 microns to settle and the droplets less than 100 to 140 microns are a separated in mist elimination section.[17,9]

2.7.4 Mist Extractor Section

The droplets that are carried over after the gravity separation section are less than 150-500 micron in diameter. It is not economical to remove these droplets by gravity separation, i.e. by making the separator larger, so it they are separated from the gas by mist extractor. The mist extractor is the final gas cleaning device in a conventional separator. The mist extraction section uses coalescing elements

that provide a large amount of surface area to coalesce and remove the small droplets of liquid. As the gas flows through the coalescing elements, it must make numerous directional changes. Due to their greater mass, the liquid droplets cannot follow the rapid changes in direction of flow. These droplets impinge and collect on the coalescing elements, where they fall to the liquid collection section. [9, 11] The selection of the mist extractor is based on the amount of liquid carryover remaining in the gas phase. The most common types include wire mesh pads and vane packs and axial flow demisting cyclones.

In mesh pads, the small droplet of liquid in vapor, impinge into the wires and therefore separation takes place. They capture small droplets with high efficiency and are preferred to low gas capacities. Mesh pads are not recommended for dirty or fouling service as they tend to plug easily. Their cost is the lowest among the other devices while they cause relatively low pressure drop.

Table 2-4 shows a few of the more common mesh styles available, together with mesh density, void fraction, the diameter and specific surface area (i.e. the target density) of filaments used. Table 2-5 shows the mesh pad characteristics and performance parameters.

Density	Surface Area	%Voids	Wire Dia	Mesh Styles			
Lb/Ft ³	Ft ² /Ft ³		inch	Koch	Otto York	ACS	Description
12.0	115	97.6	.011	4120		4BA	
10.8	110	97.7	.011	4210	421		All Around, Heavy Duty
10.0	163	94.0	.006	3710	371		Liq-Liq Coalescer, Fog
9.0	86	98.2	.011	4310	431	4CA	Standard, good all around
8.0	140	98.4	.006	3260	326	3BF	Super High Eff, fine mist
7.3	65	98.5	.011	6440	644		High Eff - anti fouling
7.0	65	98.6	.011	5310	531	5CA	Economy Performance
5.0	48	99.0	.011	9310	931	7CA	High Thruput
20.0	450	96.0		5520		X200	
27.0	610	94.6		5540	333	X100	

Table 2-4 : Mesh pad styles (www. oilgasprocessing.com)

Description	Density, kg/m³, (lb/ft³)	Voidage, %	Specific surface area, m²/m³, (ft²/ft³)	K_s, m/s, (ft/sec)	Separable droplet size, 90% removal, microns	Liquid Load Before Capacity Deteriorates, L/min/m² (gal/min/ft²)
"Standard" mesh pad	144 (9)	98.5	279 (85)	0.107 (0.35)	5	31.5 (0.75)
"High capacity" mesh pad	80 (5)	99.0	148 (45)	0.12 (0.4)	8 – 10	63 (1.5)
"High efficiency" co-knit mesh pad	192 (12)	96.2	365 (12 000)	0.07 (0.22)	2 – 3	21 (0.5)

Table 2-5 : Mesh pad characteristics and performance parameters (Snow-Mcgregor)

Vane packs, like mesh pads, capture droplets primarily by inertial impaction. The vane bend angles force the gas to change direction while the higher density liquid droplets tend to travel in a straight line path, and impact the surface of the vane where they are collected and removed from the gas flow. They can handle higher gas capacity, solids and they are especially suited for low pressure applications. They are however more expensive than mesh pads and less efficient for small droplets.

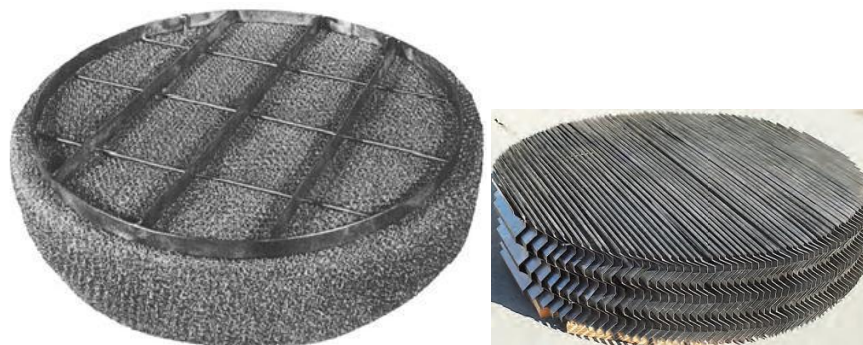


Figure 2-6 : Mesh pad demister (left); Vane type demister (right)

Cyclonic mist extractors use centrifugal force to separate solids and liquid droplets from the gas phase based on density difference. Very high G forces are achieved, which allows for efficient removal of small droplet sizes. These units can be more efficient than either wire-mesh or vanes and are the least

susceptible to plugging. They perform better in high pressure and high gas capacity applications. However, they are not in common use in production operations, because their removal efficiencies are sensitive to small changes in flow pattern and velocity. In addition, they require relatively large pressure drops to create the centrifugal force.

The demisters are used at the upstream of the compressors to minimize the liquid entrainment. The demisters are used to increase the separation efficiency. The inertia is the separating mechanism used in the mesh demister do high gas velocity improves the separation. The accumulated liquid in the demister pad is drained and hence there is the limit to its free volume until the demister over floods. [9, 17]

2.8 Separator Vessel's internals

Wave Breakers

In long horizontal vessels, the waves are formed from the surges of liquids entering the vessel or gas eddy currents near the gas-liquid interface to prevent liquid re-entrainment into the gas stream. The wave action is stabilized by wave breakers. Wave breakers are perforated baffles or plates perpendicular to the flow located in the liquid collection section of the separator. These baffles dampen any wave action that may be caused by incoming fluids. The wave action in the vessel must be maintained so that liquid level controllers, level safety switches, and weirs perform properly. The minimizing of waves prevents large amount of wet oil (emulsion) from spilling over the weir. [32, 11]

De-foaming Plates

The Foam at the interface at the may occur when gas bubbles are liberated from the liquid. Foam can severely degrade the performance of a separator. The Defoaming plates are closely spaced, parallel plates or tubes provide additional surface area, which breaks up the foam and allows the foam to collapse into the liquid layer. [11, 17]

Vortex Breaker

Liquid leaving a separator may form vortices, which induces negative pressure to pull gas down into the liquid outlet. Therefore, horizontal separators are equipped with vortex breaker at the outlet nozzle of the separator, which prevent a vortex from developing when the liquid control valve is open. [17, 32] The figure 2-8 shows the schematic of vortex breaker.

Sand Jets and Drains

In horizontal separators, the accumulation of sand and solids at the bottom of the vessel will reduce the separation efficiency by occupying vessel volume. To remove the solids, sand drains are opened and then high-pressure water is pumped through the jets to agitate the solids and flush them down the drains. [11, 17]

Coalescers

In a small vessel the coalescers' plate are installed in liquid section. These plates aid in coalescence of oil droplets in the water and water droplet in oil. The coalescing plates increase the water droplets

entrainment in the oil phase to, making gravity settling of these drops to the oil–water interface easier. [11]

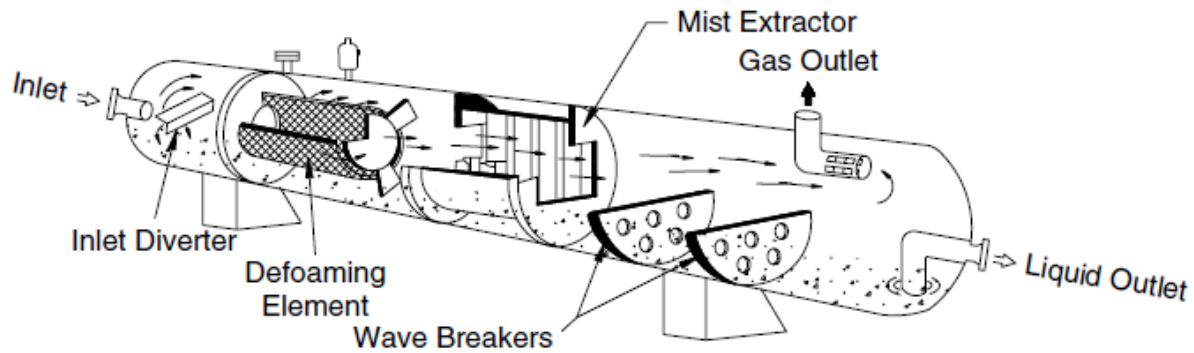


Figure 2-7 : Horizontal separator fitted with an inlet diverter, de-foaming element, mist extractor and wave breaker

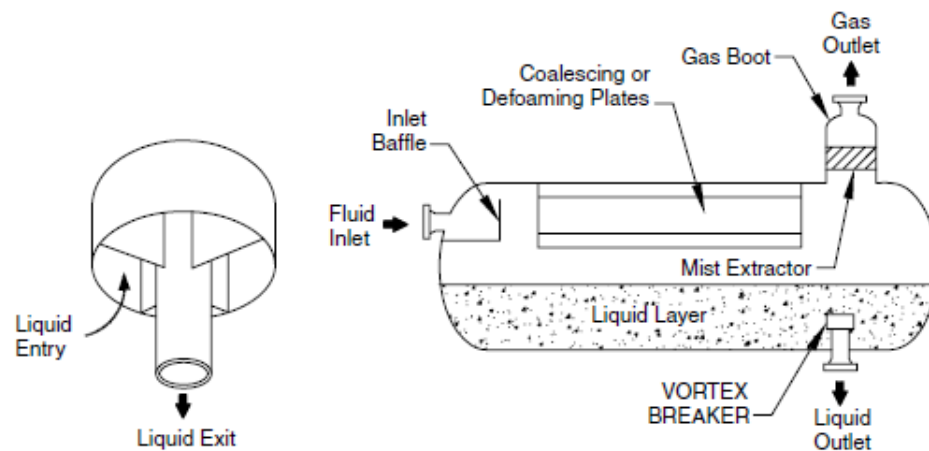


Figure 2-8: Vortex Breaker

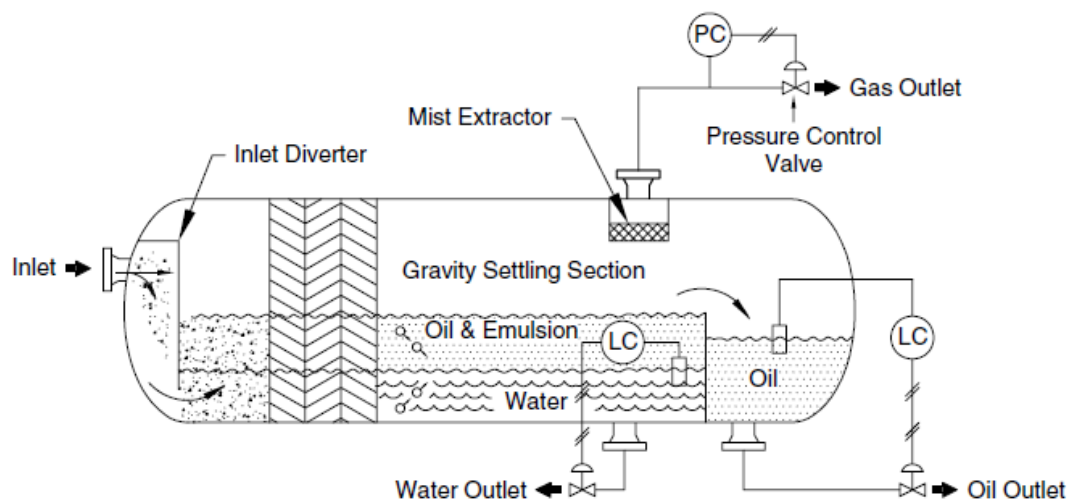


Figure 2-9 : Schematic of horizontal three-phase separator fitted with coalescing plates

3 Emulsions

As described in the unit 2.3.1; stable oil-water dispersion is referred to as emulsions which are formed by the turbulence in the flow. The crude oil emulsion can be categorized into water-in-oil emulsion, oil-in-water emulsions, water-in-oil-in-water emulsions and oil-in-water-in-oil emulsions.

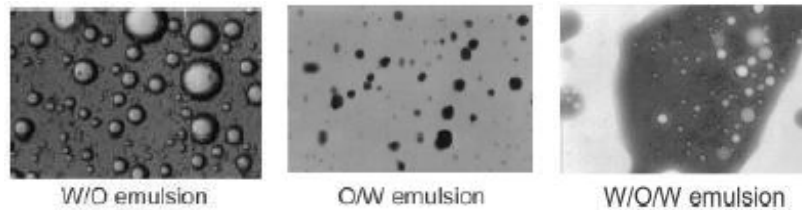


Figure 3-1 : Photomicrographs of emulsions a) W/O emulsion b) O/W emulsion c) W/O/W emulsion. [12]

Stable emulsions are formed when the water droplets are very small and cannot be separated. The emulsions can be stabilized by asphaltenes and organic solids, shear force and reduced temperatures. The emulsions produced by asphaltenes are tight. The higher the asphaltenes' content, the tighter the emulsion. Choking the well increases the shearing effect and causes the formation of tighter emulsions. Higher shear stress results in smaller size of water droplets and the viscosity of the emulsion decreases.

The untreated crude oil has water content from 1 to 90 percent per volume. The high viscosity, low gravity oil tends to emulsify more readily than the low viscosity, high gravity oil since the high viscosity hinders the mobility of the water. Generally, low API crude oil forms stable and tighter emulsions. The majority of emulsifying agents are asphaltenes and paraffins. The asphaltenes tend to emulsify more readily than paraffins. The problem of removing the emulsified water becomes more intense at high water cuts, water-flooding zones, and in production wells which are stimulated by thermal and chemical recovery techniques [13].

The emulsified water affects also the sediment and salt content of the stream. The acceptable range for BS&W varies from 0.2 to 3.0 % [13]. Before applying an appropriate emulsion treatment method, emulsion samples should be tested for their stability and characteristics. The following section describes the sampling, testing and treatment methods

3.1 Emulsion Sampling

Emulsions samples are tested in the laboratory to verify crude specification and to evaluate emulsion treating system. The extracted emulsion sample should be the representative of the liquid from which it is extracted provided the emulsification does not occur when sample is extracted.

Manning and Thompson [14] claim that a good sample should:

- Be representative of stream being treated.
- Be a composite of the production from the individual wells that are being fed to the treater.
- Contain a representative quantity of any chemicals such as demulsifiers, corrosion inhibitors, paraffin etc.

- Be fresh so as to prevent stabilization and/or aging phenomena.

The emulsion sample should not be withdrawn from the wellhead, manifold and separator because emulsification can occur due to the turbulence created. If the sample is removed from the pressure zone to a sample container; this sample might show a high percentage of emulsion that is not representative of the reservoir system. The emulsion sample should not be withdrawn from the bottom or top of the pipe or vessel. At the bottom, free water can accumulate, which may affect basic sediment and water values, while at the top of the vessel is mainly oil. The recommended sampling position in a pipe is on the side, preferably with a quill as shown in figure 3-2. Turbulence and high fluid velocity in the pipe will ensure that the sample is homogenous and representative of the emulsions in the process stream. There are several techniques to extract the emulsion sample; some of them are described below [14].

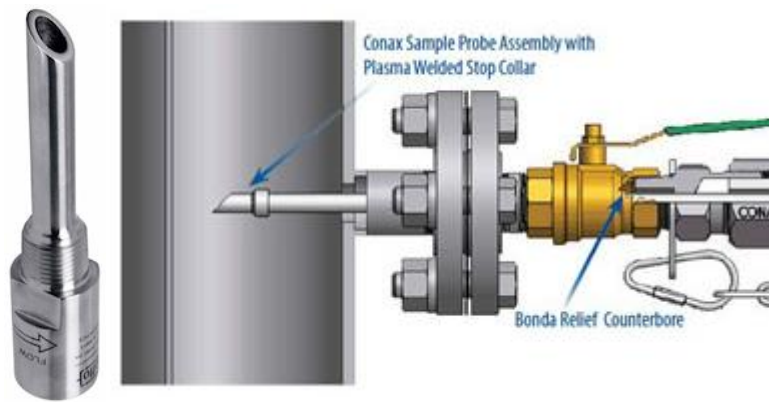


Figure 3-2 : A typical quill and the quill assembly in a pipeline

Samples from a pressurized source should be extracted by the means of quill assembly as shown in figure 3-2. The schematic of high-pressure emulsion sampling is shown in figure 3-3. It should be extracted such that the emulsification does not occur due to sampling. The cylinder is evacuated and filled with pressurized fluid (such as glycol or synthetic oil) on the bottom side and the top is connected to the sampling source so the sample can be extracted. The bottom valve is closed and the top valve is opened slowly to pressurize the fluid in the cylinder. Once the top valve is completely open, the bottom valve is opened very slowly to drain the pressurizing liquid while allowing the sample liquid to be taken in from the top and into the cylinder. This procedure is carried out slowly to obtain the sample with almost no pressure drop. Once the sample is captured the cylinder is depressurized very slowly to ambient pressure.

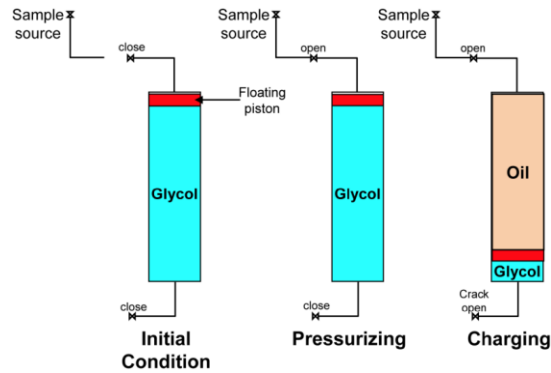


Figure 3-3 : Sampling of a high-pressure emulsion

In pressurized zones, the velocity of discharging liquid during sampling is normally too high. Samples from a pressure zone can be taken without further emulsification of the liquids if the velocity of the discharging liquid is controlled. One method is to use a piece of small-diameter tubing that is 10 to 15 ft long. One end of the tubing is connected to a bleeder valve on the line or vessel from which the sample is to be extracted, and the other end is connected to the sample container. The bleeder valve is opened fully, and the sample is allowed to flow through the small-diameter tubing into the container. Emulsification caused by pressure differential may be largely eliminated by flow through small-diameter tubing; however, contact with the tubing walls might produce coalescence, or perturbations to the flow caused by the passage of solids or large water drops might produce emulsification.

3.2 Emulsion testing

3.2.1 Emulsion bottle test

Various testing procedures are available to select appropriate emulsion treating methods. These tests include bottle tests, dynamic simulators and actual plant tests. The laboratory bottle tests provide the estimate of emulsion treating temperatures and retention times for design and operations. They evaluate emulsions for their tightness, prospective demulsifier and effect of conditions on emulsion resolution. The emulsion samples are obtained from the main production header and the sample extraction point is before demulsifier injection point.

The emulsion separation index ESI test is used to select and screen demulsifier. It quantifies the effect of various factors that affect oil water separation including temperature, shear, and asphaltenes content, water cut, demulsifier dosage and mixing different crudes.

The emulsion separation index is a method to measure tightness of an emulsion, developed at Saudi Aramco. In this method, the total water separated (in BS&W percent value) at a given demulsifier dosage is averaged to determine the separation index for the emulsion. The ESI is calculated from the measured oil/water separation data using following equation.

$$I = \frac{\sum W}{\sum n} \quad \text{Equation 3-1}$$

Where I = emulsion separation index, W = water separation at a given demulsifier concentration/time as a percentage of BS&W, and n = number of experiments.

As the separation index provides a measure of emulsion tightness, lower the index, stable is the emulsion. The index is quoted at the temperature of the test, the demulsifier used and range of demulsifier doses tested. The procedure may vary from laboratory to laboratory. The complete testing procedure is described by (Sunil, Martin) [3].

Bottle test can not estimate the dynamic effects of the water droplet dispersion and coalescence as it does not take in to account control valves, pipes, inlet diverters, baffles and water wash sections [12]. The laboratory test provides results for static conditions where as the field usage is dynamic, so the demulsifier dosage described by laboratory test is higher than that of a field. The ESI tests in laboratory are carried out on dead crudes while field usage test are done on live crudes so there is an aging effect on crude oil too. Moreover, in lab experiments there may be systematic, random and personal errors in the experiments.

3.2.2 High-pressure separation rig

Since depressurized crude oils are used for the bottle tests. The samples used in the laboratory are not true representative of the field crude oils because the bottle tests are upgraded to real separation conditions and there is a time delay in acquiring samples from a field consisting of several wells, there is a deviation in the crude oil characteristics of the sample. Ideally the test should be conducted on pressurized samples in order to overcome the above difficulties. The separation rig is used to mix water and oil at elevated temperature and pressure. In separation rig the water and oil meet at elevated pressure in a pipeline and flow through a choke valve into the separation cell. The separation cell is filled with a constant liquid flow for a given time. The amount of the different phases (foam, oil, emulsion layer, and water) is recorded as a function of time. The separation rig offers the advantage of preventing the crude oils from contacting with the air. Also the mixing conditions can be adjusted to real process conditions. The complete testing procedure is described by (Schramm) [16]

3.2.3 Emulsion Plant test

The performance of a demulsifier can be checked through a plant test. The duration for this test varies between 1 day and 2 weeks. The Plant test takes place whenever a new chemical additive is injected into the system. The dosage of the new additive gradually increases until the previously injected chemical is entirely removed from the treatment process. The performance of the new chemical is monitored. The frequency of data collection is correlated with the retention time. For example, if a system provides a 12 hrs retention time, it should be checked every 2 hrs. A system with a retention time of 15 min should be monitored continuously e.g. every minute etc. The complete testing procedure is described by (Schramm) [16].

3.3 Emulsion Treatment

The oil emulsions must be separated before the transportation and further oil processing. The judgment of emulsion treating techniques either using treating equipment or demulsifier is based on experience and engineering judgment. Each production stream is unique and the separation strategy for each is evaluated individually to adopt the best strategy. The planning for future emulsion treating equipment is carried out design phase.

The emulsion treating methods are selected after investigation of the physical characteristics of oil and water. The pilot and plant test are carried out to determine the actual treating equipment and the bottle test are used to quantify the demulsifier type and dosage. In an established process facility, the demulsifier dosage, production rate, water cuts, temperatures and costs over time are recorded to analyze the demulsifier performance. Sometimes the crude oil specification determines the treating procedure. The treatment can be complex due to the wide variety of crude oils, separation equipment, and chemical demulsifier, product specifications, and aging of the emulsion and change of production conditions over time. The emulsions can be separated into water and oil by chemical treatment, thermal treatment, electrical methods and mechanical treatment.

3.3.1 Crude oil treating equipments

Crude oil treating equipment is designed to break emulsions by coalescing the water droplets and then using gravity separation to separate the water from the oil [16]. It follows three basic steps: destabilization (coagulation), coalescence (flocculation), and gravity separation (sedimentation). The water droplets must have sufficient time for coalescence. It is important when designing a crude oil treating system to take into account parameters like: temperature, time, viscosity of oil and physical dimensions of the treating vessel [13].

The mechanical separation devices cannot achieve a 100 % separation of the hydrocarbons from the produced water. The separated water will contain 0.1 – 10 vol. % of dispersed and dissolved hydrocarbons [13]. Oil-water separation can be enhanced by heating, emulsion breaking chemicals, coalescing media and electrostatic fields. Emulsion should be treated immediately after it is separated from its associated gas.

3.3.1.1 Heating

Heating the crude oil emulsion reduces viscosity and helps water to settle more rapidly, it increases droplets by coalescence, dissolves paraffin crystals and causes the injected chemicals to react more rapidly. Heating breaks the film around the droplets of the dispersed phase and deactivates the emulsifying agent such as paraffin crystals and asphaltenes, allowing the dispersed water droplets to collide and eventually to coalesce. As the droplets grow in size they begin to settle, causing the water to settle at the bottom of the treating vessel.

For High gas oil ratio wells or those produced by artificial lift, heater treater is installed downstream of the separator. For high water to oil ratio, heater treater is installed downstream of the free water knock out drum. The free water is separated in the free-water knockout vessel before the emulsion is treated.

The normal treating temperature ranges from 100-160 F for black oils, above 300F for heavy crudes and below 180F for light oils [11]. The tests determine the lowest practical treating temperature that should be applied so minimum energy is consumed in heating. Heating the crude oil will boil off the volatile hydrocarbons, making the tank oil heavy, with low API and reduce liquid volume in the tank.

Heaters are vessels used to raise the temperature of the liquid before it enters a gunbarrel, wash tank, or horizontal flow treater. Two types of heaters are commonly used in upstream operations. These are the indirect fired heaters and the direct fired heaters. Both types have a shell and a fire tube.

In Indirect fire heater, Oil flows through tubes that are immersed in water, which in turn is heated by a fire tube. The fire tube contains hot exhaust gases from combustion of a mixture of air and fuel. The hot external surface of the fire tube heats the bath of the liquid in which it is immersed. Alternatively, heat may be supplied to the water bath by a heating fluid medium, steam, or electric immersed heaters instead of a fire tube. Indirect heaters maintain a constant temperature over a long period of time and are safer than direct heaters. The indirect heaters can re-circulate air, which saves fuel; the discharge duct can deliver hot air to different job sites to use the hot air.

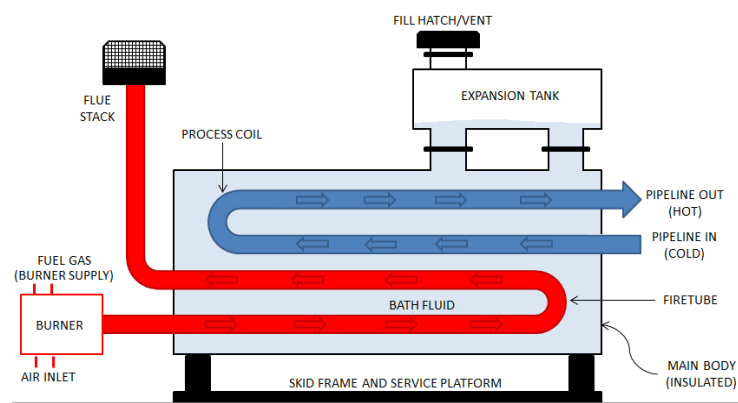


Figure 3-4 : Indirect fired heaters

In direct fired heater; a burner provides hot gasses that transfer their heat energy to process oil flowing directly through coils installed inside the heater vessel as shown in figure 3-5. Direct fired heaters reach the desired temperature quickly; they are efficient (75 to 90%) and have a lower initial cost, making them more efficient than indirect-fired heaters. Direct fired heaters are typically used where fuel gas is available and treatment of high volumes of oil is required. Direct-fired heaters require special safety equipment and cannot be used in tightly sealed spaces or near flammable materials because of the exhaust and fumes produced.

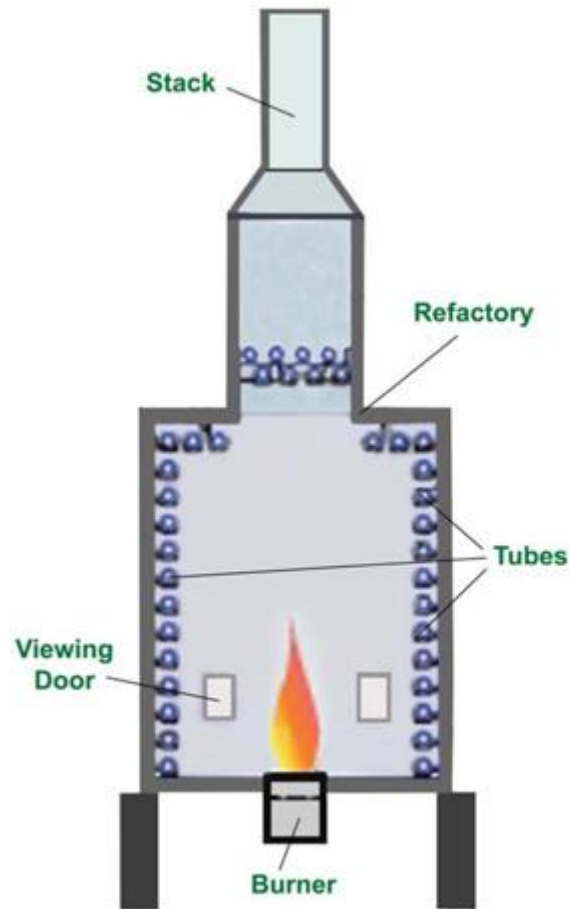


Figure 3-5 : direct fired heaters

3.3.1.2 *Electrostatic coalescers*

Electrostatic coalescers are used to coalesce the small droplets dispersed in crude oil by supplying high-voltage electric field to water in oil emulsions. The electrostatic coalescence method is beneficial for reducing the water content to very low levels (less than 0.5%). The water-in-oil is subjected to electrostatic field in which the oil is non-conducting and water is conducting. According to Stewart and Arnold [13]:

1. The droplets become polarized. The positive and negative poles of the droplets are brought adjacent to each other. Due to electrical attraction the droplets come together and coalesce.
2. Droplets are attracted to an electrode due to the induced charge. In an AC (alternating current) field, due to inertia, small droplets vibrate over a larger distance than larger droplets thus promoting coalescence. In a DC (direct current) field the droplets tend to collect on the electrodes, forming larger drops until eventually they settle due to gravity.
3. The electric field tends to distort and thus weaken the film of the emulsifier surrounding the water droplets. Water droplets dispersed in oil and subjected to a sinusoidal alternating current

field will be elongated along the lines of force during the first half cycle. As they are relaxed during the low-voltage portion, the surface tension will pull the droplets back toward the spherical shape. The same effect is obtained in the next half of the alternating cycle. The weakened film is thus more easily broken when droplets collide; making coalescence more likely. Greater the voltage, higher will be the collision and then greater coalescing.

The electrostatic coalescence is suitable for small quantity of water in oil. If oil contains large quantity of water; a chain of charged water particles is formed, which might link the two electrodes and short the circuit.

3.3.1.3 Storage Tanks

If the oil contains only small percentage of water or if the water and oil are loosely emulsified, then the water can settle to the bottom of the oil-storage tank and get removed before the oil shipment.

When the tank is full of liquid, then the influx is stopped or switched to another tank and the tank remains idle while water settles out of the oil. When the water is separated, it is drained from the bottom of the tank and the oil is gauged, sampled, and pumped or drained to a truck or pipeline.

This practice is generally recommended only for small volumes of free or loosely emulsified water on small leases or for low-production wells.

3.3.1.4 Water washing in settling tanks

In some emulsion-treating vessels, separation of liquids and vapors takes place in the inlet diverter, flume, or gas boot that is located at the top of the vessel. The liquids flow by gravity through a large downcomer to the bottom of the vessel. A spreader plate on the lower end of the downcomer spreads the emulsion into many rivulets that move upward through the water, accomplishing a water wash. After passing through the water wash, the emulsion flows to the upper portion of the vessel, where the coalesced water droplets settle out of the oil.

When an emulsion stream flows through water, the water droplets tend to coalesce with the water phase and thus they leave the oil phase. This is the principle on which a water wash operates. The water wash is more beneficial if the emulsion has been previously destabilized by a demulsifier or if the water is heated. After passing through the water wash, the emulsion flows to the upper portion of the vessel, where the coalesced water droplets settle out of the oil. The effectiveness of a water wash greatly depends on the ability of the spreader plate or distributor to divide the emulsion into rivulets, causing the emulsion to have maximum intimate contact with the water bath, so that its small drops of water can coalesce with the bulk water.

Most large tanks minimize short-circuiting by using a spreader to distribute the flow over the entire cross section of the tank. By separating it into many small streams, the spreader increases the emulsion's intimate contact with the water and so promotes coalescence in the water-wash section. The

flow from the spreader controls the agitation and the water outlet collector controls the vortexing and horizontal flow of water, so more emulsion spreads out in an upward-flow.

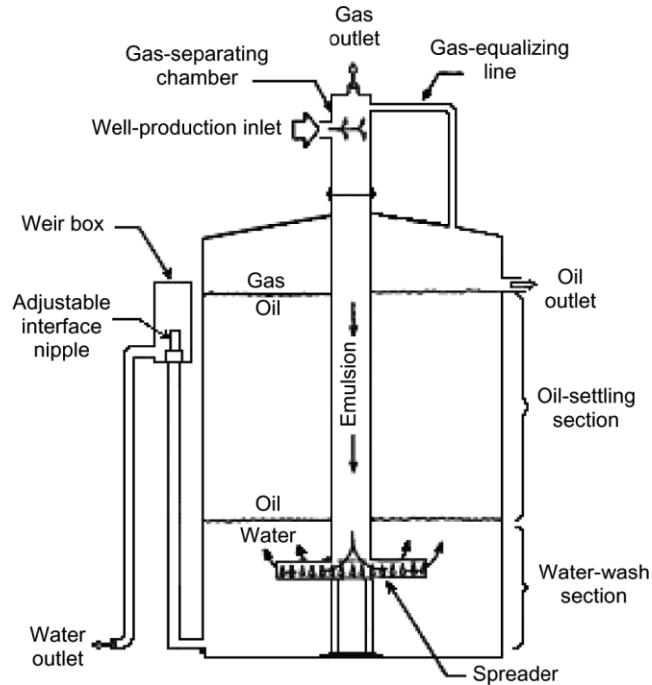


Figure 3-6 : Typical settling tank with internal downcomer (central flume) and emulsion spreader.

The agitation, vortexing and horizontal movement of water should be avoided as it will prevent the de-emulsification. Heating the influx upstream of tank or in the tank, together with a moderate agitation helps water droplets to coalesce and gas to be removed. The Gun-Barrel tanks can be heated by fire tube or plate type heating elements which work on the same principle of horizontal and vertical treater.

3.3.1.5 Vertical Emulsion Treater

The vertical units are preferred for one well lease. In vertical unit, the initial separation is done at inlet separator where gas is separated and flows to the mist extractor in the upper section while liquid flows towards the bottom section which serves as the FWKO. The oil and emulsion flows upward around the fire tubes, treating oil flow outwards to the oil outlet and gas are flashed to the upper part or the vessel. The bottom section is sized so as to allow free water to settle as this will reduce the heating energy. [19]

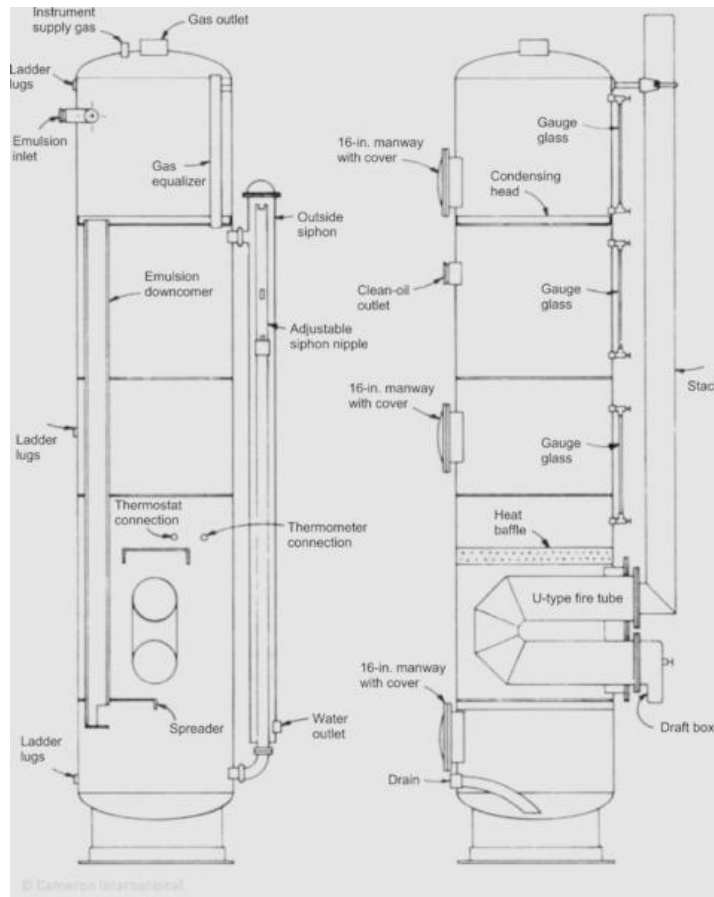


Figure 3-7 : Vertical Emulsion Treater

3.3.1.6 Horizontal Emulsion Treater

The horizontal units are preferred for multi well lease. In horizontal unit, after flashing of the gas, the liquid flows downwards to the oil-water interface, where it is water-washed and free water is separated. Oil and emulsion rise past the fire tube and flow into oil-surge chamber. The oil and emulsion flow through the coalescing section, the spreader distributes the flow uniformly through the length of the section and treated oil is collected through the collecting device while the coalesced water droplets flow through the rising oil. The inlet section must be sized to handle separation of the free water and the heating of the oil. The coalescing section must be sized to provide adequate retention time for coalescence to occur and for the coalescing water droplets to settle through the upward-flowing oil. The coalescence section is designed for the adequate retention time for coalescence and for the coalescing water to settle through the upward flowing oil. [19]

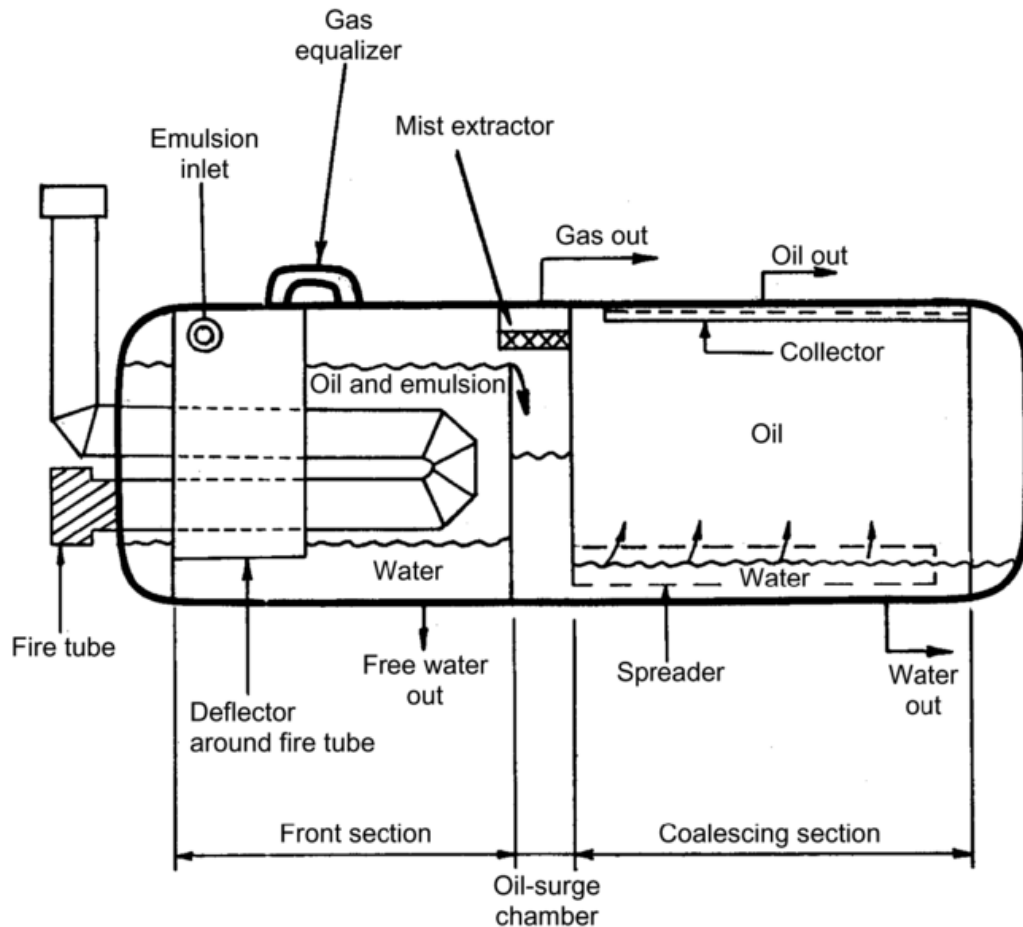


Figure 3-9: Horizontal Emulsion Treater

3.3.1.7 Demulsification equipment

In a Vessel, the emulsions can be treated by baffle plates. The baffle plates evenly distribute the emulsions in the vessel and the gentle agitation coalesce the droplets. The corrugated plate pack can be installed which can assist in coalescence. These plates change the direction of flow when the flow is laminar, to enable the water droplets to contact the plates and coalesce with the film on the surface of the plates. The corrugated plate pack cannot be used with high paraffin deposit as it can plug the flow.

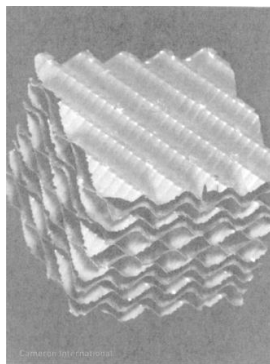


Figure 3-8 : Corrugated-plate pack, a special coalescing medium for crude-oil emulsions. (Courtesy of Natco Group Inc.)

The emulsified oil stream can be passed through the filters. A filtering material with fine pores can filter out the dispersed water droplets of a crude-oil emulsion when the filtering material is submerged in oil. Filtering is not a widely used crude-oil-emulsion treatment method, because of the difficulty in obtaining and maintaining the desired filtering effect and because filtering materials become easily plugged.

Distillation can be used to remove water from crude-oil emulsions. Along with lighter oil fractions, the water can be distilled by heating and then separated by appropriate means. The lighter oil fractions usually are returned to the crude oil. Flash systems use the excess heat in the oil that is received from the treater or treating system and convert it to latent heat at or near atmospheric pressure. A surface condenser condenses the flashed steam in the cooler, incoming stream of raw crude, thus scavenging the excess heat that ordinarily would be wasted.

3.3.2 Demulsifier

If the stream has high asphaltenes content, surfactants and wetting agents are added as demulsifiers. The surfactants are elongated molecules that have a polar part with an affinity to water and a non-polar part with an affinity to oil (figure 3-9) [17]. When they are adsorbed at the oil-water interface they are oriented so as the polar part is immersed in water and the non-polar part in oil.

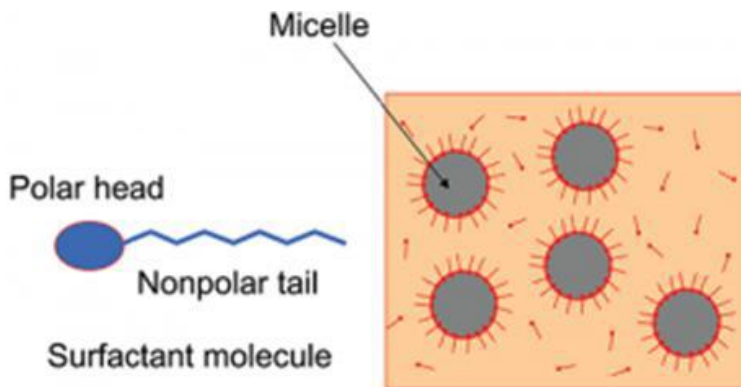


Figure 3-9 : A surfactant molecule and formation of micelles in a W/O emulsion.[15]

Demulsifier can be used to destabilize the stabilizing components of the interfacial film surrounding the emulsion droplets by the adsorption of the demulsifier at the interface and thus assist in coalescence of crude oil emulsions. The demulsifier is able to reach droplet interface, combine water droplets together in a cluster and counteract against emulsifying agent.

The figure 3-10 shows demulsifier and natural surfactant approaching each other. Since demulsifier are highly surface active agent as compare to natural surfactants, the demulsifiers can replace the natural surfactants at the interface. Moreover, the length of the hydrophobic tails of the demulsifiers is larger than that of the natural emulsifiers. The adsorption of the demulsifier molecules enhances the film drainage and therefore reduces the interfacial tension. As a result, the interfacial film becomes very thin and collapses and droplet coalescence occurs. Weakly adsorbed surfactants like asphaltenes can easily be displaced by the demulsifiers. [15] Demulsifier decreases the surface tension of water droplets which

promotes the separation of oil and water or by rupturing of the droplet interface film and promote the water droplet coalescence [12].

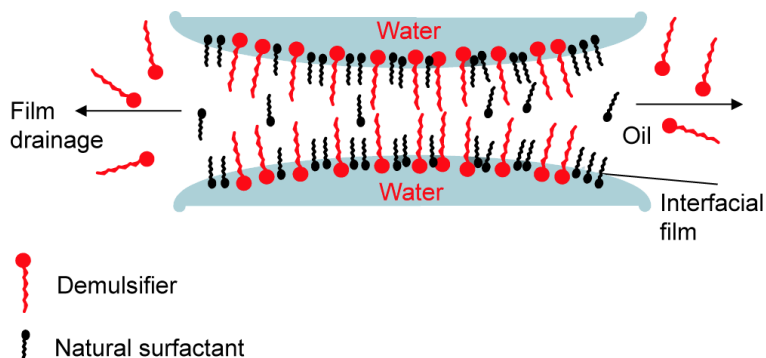


Figure 3-10 : the demulsifier displaces the indigenous surfactants in the interfacial film.

According to Kokal [12] demulsifier neutralize the effect of emulsifiers as follows:

- They migrate rapidly through the continuous oil phase to the water droplet interface where the emulsifiers are concentrated.
- They diffuse the oil/water interface when the concentration of the demulsifier is high enough. However, it should not be higher than the critical concentration.
- They occupy a high rate of adsorption at the interface.
- They accelerate the rate of film drainage and promoting coalescence on the basis that the interfacial activity is high enough.

When demulsifier is added to emulsions, there must be an initial period of continuous and moderate agitation of the treated emulsion in order to produce contact between the demulsifier and interfacial area and coalescence of the dispersed droplets, followed by a settling period. Demulsifier can be added to the oil in tank in small proportions, the tank contents are agitated or circulated and sufficient time is allowed for water to settle in the tank. The demulsifier volume added to the emulsion continuous stream is direct proportional to the volume of the emulsion and if it is mixed evenly. Demulsifiers are easy to use and are inexpensive chemicals that minimize the required amount of heat and settling time.

Emulsion breaking can be characterized by a properly chemical selection for the given emulsion, by the quantity of this chemical, by the mixing of this chemical in the emulsion and finally by the retention time in separators in order the dispersed water droplets to settle down [17]. The type and quantity of demulsifier is determined by the emulsion sample test.

In case of a water-in-oil emulsion a demulsifier must be used that is almost insoluble in water and highly soluble in oil. So the demulsifier can diffuse rapidly through the continuous phase and reach the droplet interface. [18] According to the Chandran, Krishnan, Sinnathambi [18], oil soluble demulsifier are the best for water-in-oil emulsions because the surfactant will absorb directly into the continuous phase. Oil soluble demulsifier are usually formulated by organic solvents, such as toluene, xylene, dioxane, or even in co-solvents comprising of organic solvents and water, where the organic solvent usually consists of ethylene diamine, diethylene triamine or ethanolamines.

3.3.3 Optimal Treating Crude oil emulsion

The combination of emulsion treating methods with equipment can optimize the initial project and operating costs. The optimal and cheapest options in the oil processing are to prevent the formation of additional emulsion where ever is feasible. The steps to prevent emulsion formation are to eliminate water production and preserve oil loss wherever possible by using adequately sized three phase separator at appropriate operating conditions. The oil-in-water emulsion can be prevented by using optimum treating temperature, cooling the oil before discharging it to the storage and using vapor recovery units on vessel and tanks.

To achieve the optimum operation of emulsion-treating equipment; proper records of operating temperatures, pressures, fuel and/or power consumption, chemical usage, performance is required. These records are maintained and reviewed on a daily, weekly, or monthly basis.

Some crude oils are adequately treated by use of chemical injection with coalescence and/or settling without heat; but, some emulsions require an increased temperature during the coalescing and settling period. A proper balance of chemical and heat helps to provide the most economical and efficient treating system.

3.4 Industrial practice for Emulsion treatment

As mentioned in unit 3.3.1; the separation for water-oil dispersion can be accomplished by employing long residence time. A typical residence time of such a vessel would be 5-10 minutes while for heavy oil the time may exceed the 30 minutes [38]. The residence time of LP separator is 5 minutes and furthermore; water-oil mixture can be allowed to settle for a long time in storage tank until the oil-water dispersions are separated and the final product is within the specifications according to lab analyses.

When a process plant is designed, an appropriated procedure to handle emulsion is selected beforehand. The suitable procedure for emulsion treatment can be selected by lab tests or any available data similar oil/gas sources. The emulsion testing methods are described in chapter 3.2

In a process Unit, there are several sampling points that can be used to obtain a sample for the lab analyses. Depending on the conditions of the process and the type of the fluid, the appropriate sampling configuration is selected and strict sampling procedures are followed .There are several sampling points in a process unit that are especially designed for the sampling purpose. There is certainly a sampling point in the unit feed to analyze the mixture that is about to be processed. There are some key locations within the process unit for sampling; they can be intermediate sampling points or the product sampling points that leaves the process Unit. Usually process analyzers are installed on final product lines to analyze the composition and physical properties .Process analyzers are on-line sensing tools used to determine the properties of substances involved in industrial processes. It is a usual practice by operators to extract sample from the drain and vent of equipment or piping. Some of the sampling techniques and sampling equipments are described in section 3.1

For an already established facility; the internal packing's can be installed inside the separator or suitable demulsifying chemical is injected at the upstream of the feed separator. The optimal demulsifying mixture can be selected beforehand, after lab analysis of the fluid and consulting with chemical vendors. A typical installation for chemicals injection system would include a vessel containing the chemical and a set of small pumps for the pressure injection. The most economical and widely practiced method is to treat emulsion by means of chemical demulsifier rather than installing an emulsion treating equipment.

4 Process Simulation

4.1 History

The period between 1970 and 1980 is known as the golden age for the scientific computation, while in the same period of 1970-80's the major engineering bureaus, as well as some large manufacturing companies in refining and petrochemical industries developed in-house flow-sheet programs. The advent of high-speed computation systems boosted the business of small companies specialized in modeling and simulation. The expansion of the refining and petrochemical industries motivated the advent of computer packages and soon scientific computation evolved from individual programs to large packages designed as industrial products. [24]

In 1976, US Department of Energy and MIT launched jointly the ASPEN project, which was later continued by ASPEN PLUS at ASPEN TECH. The first simulation began in 1996, when simulation science which is precursor of PRO II, a small company in Los Angeles, USA came up with the idea of commercializing a process simulator on computers for distillation column. Three years later ChemShare in Houston, USA released DESIGN 2 which continued with DESIGN II and WINSIM, a capable flow sheeting program for gas & oil applications. Nowadays process simulation is highly demanded by industrial users as compare to those supplied by generic software capabilities. On the other hand, the needs in modeling of industrial users are much larger than those supplied by generic software capabilities. The solution to this contradiction involves a large cooperation between specialized software firms and the community of Computer Aided Process Engineering (CAPE) users. This should exploit the Internet technology. [24]

4.2 Process Simulation

Simulation is a procedure of manipulating the model of a system, conducting virtual experiments to analyze the behavior of the system or evaluate several strategies for the development and operation of the system with certain limit of accuracy. [24]The simulation helps predicting the behavior of a process, in which some preliminary data of the equipment that constitute the process are known. It introduces systematic investigation of different alternatives that can be developed for a design problem.

Process simulation is a tool for process and chemical engineers that can be used in the execution of repetitive tasks or in activities of high complexity that must be solved in relatively short times. Chemical process simulation represents the process of chemical or physical transformation through a mathematic model that involves the calculation of mass and energy balances coupled with phase equilibrium and with transport and chemical kinetics equations. Mathematical models are employed in process simulation which uses the linear, nonlinear and differential algebraic equations to represent equipment or process operations, physical–chemical properties, connections between the equipment and operations and their specifications. Various mathematical models are used for the simulation to calculate and analyze the optimal operating point. The models allow the description of properties over wide range of temperatures and pressures and they can introduce approximations and assumptions to interpolate or extrapolate within the range of properties to find the parameters for unknown properties.

The simulator generates the comprehensive report of material and energy stream, it analyses the co relation between the reaction and separation system, it can demonstrate the formation and separation systems and their byproducts, study the environmental impact, and evaluate process plant flexibility to changes in feed or product. The material and energy streams are balanced throughout the process flow to find the stable operation conditions. It performs sizing and costing calculation for a chemical process. It can also enhance process safety and control, update process documents and optimize the economic performance of the plant.[1]

4.2.1 Steady state and dynamic process simulation

A steady-state model performs a mass and energy balance of a process independent of time. It supports both operation and design for revamping and debottlenecking. It can be used to optimize the process by reducing capital and equipment costs and maximize the production. Dynamic simulation is time-dependent, it is built into the models via derivative terms i.e. accumulation of mass and energy. This includes the description of starting up and shutting down a plant, changes of conditions during a reaction, holdups, thermal changes, design of process control system, operator training and real time optimization.[3]

4.3 Process Simulator

A process simulator is software used for the modeling of the behavior of a chemical process in steady state, by means of the determination of pressures, temperatures, and flows. Nowadays, the computer programs employed in process simulation have broad in the study to the dynamic behavior of processes, as well as to the control systems and their response to perturbations inherent to the operation.

Process simulators are used for the design, development of chemical plants and processes. It can perform equipment sizing, cost estimation, properties estimation and analysis, operability analysis and process optimization. The Process simulator allows predicting the behavior of a process by changing the values of main operating variables and analyzing different cases is a simultaneous way and then optimizing the operating conditions of new or existing plants. It is can also track a chemical plant during its whole useful life, in order to foresee extensions on process improvements. Various applications in process simulators determines the better use of the energy resources, improve the process controllability to minimize the operating costs to Increase the yield and process efficiency.

The graphical user interface of process simulator allows developing a well-defined flow sheet. The process flow diagrams are the language of chemical processes. The process flow diagrams are developed in flow sheet mode. In flow sheet, the material and energy streams are defined with the scope of designing a new plant or performance of an existing plant or modification on operational plant. After the complete description of the flow sheet, the simulator then conducts the virtual experiment or simulation of the process.

The two fundamental strategies used in the solution of simulation problems are the sequential strategy and the simultaneous strategy.

4.3.1 Sequential Modular Simulators

The sequential computing of units is mostly used in steady state conditions. The concept of sequential simulation comes from the concept of independent modules. The modules are totally independent from each other and the information flow for the calculation in the simulation coincides with the physical flow in the plant. The advantage of using modules is that each equations system is solved using its own methodology and that way a sequential order of calculation is established to solve one-by-one all the units of the process.

The principal features of a sequential modular simulator are the following[26]:

- It contains calculation libraries and routines¹.
- The iteration variables are in the recycle² streams. The individual models are solved in an efficient way.
- It is easily understandable for engineers that are not simulation specialists due to the existing correspondence between the mass flow and the calculation sequence.
- It involves complex convergence methods. In convergence methods the calculations are based on the assumed information. The initial values are assumed for a stream and each of the following units is solved obtaining new values for the parameters of the assumed stream. Subsequently, the new values help to repeat these calculations again and again, until the difference between the initial and the calculated values fulfill a given tolerance; that point is known as convergence.
- The information entered by the user for the related streams and equipment is easily verifiable
- The design problems are easier to solve

4.3.2 Simultaneous or Equation Oriented Simulators

Simultaneous or equation oriented simulators use the mathematical models that represents the process built on a large algebraic equations system. Here modules representing process units or subsystems may also exist. These modules do not contain numerical methods for the calculation of output values but they provide the required information to run the calculations that represent the mathematical model. The process model is made of the sum of the models of all the units that comprise the process or plant in the simulation. Due to the compilation and clustering philosophy of all the equations that build the process, this type of simulators are known as Equation oriented. The concept of modules is maintained here in order to facilitate the interaction with the user and to allow the specification of the required information for the problem.

¹ routines are initially supplied programs

² The recycles owe their existence to all those processes in which reversible reactions and competitive phenomena take place. In the simulators there are specific subroutines for the calculation of recycles and the pursuit of convergence.

The equation oriented simulators are not suitable for highly non-ideal systems that correspond to chemical plants as they can produce multiple solutions. The numeric solution of problems consisting of large systems of equations requires proper initialization.

The principal features of an equation oriented simulator are following [26]:

- Each unit is represented by the equations that model it. The model is the integration of all the subsystems
- The distinction between process variable and operative parameters disappears. In consequence the design problems are simplified
- Simultaneous solution of the system of (nonlinear) algebraic equations
- Higher convergence velocity
- They need a better initialization (the higher the complexity of the problem to solve the better the initialization that should be provided)
- The higher the complexity, the less the reliability of the results and the more the convergence issues (solutions without physical meaning)
- Easier to use for non-specialists

The hybrid simulators use a strategy mixture of the sequential and simultaneous ones. The first model solution employs a sequential strategy and then upgrading the linear coefficients to find a solution with a simultaneous strategy. The simulation begins with a sequential step in which the output variables are determined from input information and parameters in an initial scanning of the flow diagram. Then a simultaneous step starts for the solution of linearized models in a second scanning of the process. Some simulators of high industrial application appeal to a hybrid strategy to ensure convergence, even in the worst cases.

The most widely known commercial and academic process simulators are: DESIGN II, CHEMCAD, PRO II, UNISIM, ASPEN PLUS, and ASPEN HYSYS.

4.4 Design II

Design II was developed by WinSim in 1991 for windows. It offers both dynamic and steady state simulation. DESIGN II is a comprehensive process simulation computational engine, with easy to use interface which performs complete heat and material balance calculations for a wide variety of pipeline and processing applications. All results are transferred to Excel, which will be properly formatted and placed on appropriate pages. [27]

WinSim's simulator offers advanced features, such as sizing and rating of heat exchangers and separators, within the flow sheet. The DESIGN II has database of 1,200+ pure components, and others can also be added. It includes a crude library with 38 world crudes.

DESIGN II has a custom set of binary interaction parameters built in it for use with the Modified Peng-Robinson thermodynamic k-value method. These binary interaction parameters (BIPs) modify the thermodynamic flash calculations so that the TEG to hydrocarbon component interactions is modeled correctly. DESIGN II can be used to predict the natural gas hydrate inhibition effects of injection of ethylene glycol (EG), di-ethylene glycol (DEG), triethylene glycol (TEG) or methanol (MeOH) and formation of natural gas hydrates for any stream in the flow sheet. [27]

DESIGN II supports almost any data regression methodology. Its regression methods include binary, ternary, quaternary, etc. Regression methods estimate the thermo-physical properties of the most common varieties of equilibrium data. These methods handle V-L-E, L-L-E, V-L-L-E, and V-L-L-L-E data. [27]

4.5 Chemcad

Chemcad is commercial software developed by Chemstations Inc. The CHEMCAD Suite is present in the market since 1984. It has the library of more than 2000 components, thermodynamic methods, and unit operations to allow steady-state and dynamic simulation of continuous chemical processes from lab scale to full scale. [28]

It simulates steady state process for gaseous, liquid and solid processes, gas washing, and absorption and desorption in columns, chemical reactions, heat exchange of fluids with condensation and vaporization, mixed phases in pipes with pump, compressor, valves for pressure drop calculation, and separation according to particle sizes and electrolyte reactions. It simulates dynamic processes for operability check-out; PID loop tuning, operator training, online process control and soft sensor functionality.

It uses thermodynamic properties to calculate bubble points and dew points. The program is equipped with a large databank for physical properties and components and extensive facilities for mixture property calculations. It can regress for the pure components and binary interaction parameters on user data. [28]

It uses international standards for designing and sizing heat exchanger, vessels, piping, valves, pumps, column trays. It includes piping networks, two phase relief systems and pressure drop calculations. It can generate the equipment and process costing, process safety analyses and generated full reports on heat and material balance. [28]

Unlike other process simulation programs, CHEMCAD has number of valuable features included in the standard software and the user doesn't need to buy additional features separately.

4.6 PRO/II

PRO/II is the main product of the Process Engineering Suite (PES) providing the general flow sheet and process design capabilities. PES (from Invensys) is a consistent set of tools for engineering design and operational analysis. This integrated suite of software readily interfaces with other applications commonly used by process engineers, thus enhancing productivity in the plant life cycle. PES has several comprehensive modules such as: The PRO/II is a general purpose process flow sheet simulator and optimization tool. HEXTRAN is a comprehensive heat transfer simulation and pinch analysis tool, DATACON is used for plant gross error detection and data reconciliation, INPLANT is a multiphase fluid flow simulation for plant piping networks and VISUAL FLOW is used for design and modeling of safety systems and pressure relief networks.

PRO/II is commercial software developed by Schneider Electric, SimSci. The PRO/II was released in the market in 2004. PRO/II simulates a wide range of processes for steady state, from refining to chemicals. It has 1,700+ pure component library and 1900+ components/species electrolyte databank, non-library and pseudo components and assay characterization, multiple assay blends. [29]

PRO/II has comprehensive thermodynamics and physical property data which allow the creation and management of custom components, data regression and managing custom libraries. The excel ad-on model allows the customizable process modeling and for customized reporting.

PRO/II is integrated with third party industry-standard licensors including HTRI for heat exchanger modeling, OLI for Electrolyte models, & Koch-Glitsch for distillation modeling, Spiral CrudeSuite for assay information .PRO/II Process Engineering can be used via cloud in addition to the on-premise access method. The user access control allows the administrator to add & delete users or edit privileges as needed. The IT overhead uses the product on pure on demand cloud machines via a secure URL so installations are not needed. The price of PRO/II package is based on usage subscription and flexible, incremental usage credits.

4.7 UniSim

UniSim is commercial software developed by Honeywell. The UniSim was released in the market in 2004. UniSim is process modeling software that for steady-state and dynamic simulation. It models for plant design, performance monitoring, troubleshooting, business planning, and asset management. UniSim is used to design, optimize and operate chemical process or refining plant. [25]

In UniSim, the physical operations are governed by thermodynamics and mass/energy balances and can be specified by operation relations. UniSim Design includes over fifty unit operations that represent process equipment (i.e. separators, heat exchangers, distillation columns, reactors), process controls (i.e. instrumentation, PID and multi-variable controllers, process switches) and logic functions (i.e. mathematical functions, boolean operations). In addition, users may build and use their own extensions in the UniSim simulation environment, leveraging and protecting their IP.

UniSim allows individual property view, the process flow diagrams, graphical performance profiles, data book, workbook and tabular summaries. UniSim has a collection of utilities which can be attached to process streams and unit operation to provide additional information. UniSim has built-in tools for equipment sizing and rating. It is integrated with cost reporting in the UniSim Design environment which allows efficient working on economics of the process to meet feasibility and profitability criteria.

UniSim Design links to the specialist third-party software for unit operation design such as HTRI Exchanger Suite for heat-exchanger design and rating; Schlumberger OLGAS-2P/3P, Pipesys, Pipesim, and OLGA for detailed pipeline design and simulation; Petex IPM Suite (GAP/RESOLVE) for well-head management; MySEP for separator design; and Pro-M for compressor design.

4.8 Aspen Plus

The process simulation capabilities of Aspen Plus enables engineers to predict the behavior of a process using basic engineering relationships such as mass and energy balances, phase and chemical equilibrium, and reaction kinetics. The thermodynamic data, operating conditions and the rigorous Aspen Plus equipment models can simulate actual plant behavior. Aspen Plus contains data, physical properties, and unit operation models, built-in defaults, reports and other features and capabilities developed for specific industrial applications.

Aspen Plus uses the extensive physical property models, data and estimation methods available in Aspen Properties, which covers a wide range of processes from simple ideal behavior to strongly non-ideal mixtures and electrolytes. The built-in database contains parameters for more than 8,500 components, covering organic, inorganic, aqueous, and salt species and more than 37,000 sets of binary interaction parameters for 4,000 binary mixtures. [30]

Aspen Plus is located between the group of simulators using the sequential strategy, in the same way as other simulators such as PRO II and CHEMCAD. However, it is important to mention that in the last versions of this simulator the possibility to work with the simultaneous or equation oriented strategy has been included, allowing the modeling of systems and processes much more complex, highly integrated and with a high number of recycles. [25] It is composed by group of simulation or program units represented through blocks and icons. These blocks are a unit in which the pertinent information must be provided to solve the mass and energy balances. The model uses the simultaneous or equation oriented strategy to solve the complex and highly integrated models systems and process.

The steady-state models can be imported to dynamic modeling to develop custom unit operations. The Aspen plus Dynamics modeling allows to run emergency scenarios, evaluate startup and shutdown procedures, test control schemes, design batch processes, and more.

4.9 HYSYS

HYSYS was first conceived and created by the Canadian company Hyprotech, founded by researchers from the University of Calgary.[4][5] The HYSYS Version1.1 Reference Volume was published in

1996. Aspen HYSYS is widely used process industry for conceptual design and detailed engineering, control, optimization and process monitoring stages in a project. [31]

Aspen HYSYS has a user friendly interface which makes the process modeling easier for the casual users in plant and production operations. Aspen HYSYS have the workflow automation that links process models to Microsoft Excel using Aspen Simulation Workbook.

Aspen HYSYS modeling addresses a wide range of models including distillation, reactions, heat transfer operations, rotating equipment, and controller and logical operations in both steady-state and dynamic environments which are widely used in oil and gas processing, refineries, and some air separation industries. This modeling integrates the steady state and dynamic models in one unit. The integration of steady and dynamic model enables to simulate at the stages of process design with the rigorous analysis analyses of dynamic behavior and their control. Aspen HYSYS has collection of utilities which can be attached to process streams and unit operation to provide additional information, so the process engineer is able to decide the detail designs on the basis of dynamics.

It has a number of optional add-on applications such as Aspen HYSYS Dynamics, Aspen HYSYS Crude, Aspen HYSYS Amines, Aspen HYSYS OLGAS, Aspen HYSYS PIPESYS, Aspen RefSYS and Aspen HYSYS Upstream. Aspen HYSYS Upstream provides an E&P-specific solution for integrated asset modeling, In HYSYS Upstream the production field data is input to create an asset-wide model from the reservoir to the back end of the facility. [31]

5 HYSYS Simulation

Aspen HYSYS Process simulation software was used for carrying out all the necessary calculations and development the model. The access to the Aspen HYSYS license and technical support was provided by ASPROFOS Engineering S.A. The problem statement for the simulation is extracted from MSc thesis titled Basic design of oil process train in upstream facilities by Klothakis Andreas, 2016 [33]. The data was extracted from SPE Journal and CMG examples.

The combined effluent from three oil reservoirs was selected as inflow conditions to the upstream production facility. The fluid and production characteristics from each reservoir are provided in Tables 5-1. The oil 1 represents the heavy oil, oil 2 represents the intermediate and oil 3 represents the light oil. The simulation with three types of oil shows the reasonable simulation results with respect to field oil. Table 5-2 shows the water cut increase with the period of time. Production 1 refers to the initial production rate of oil and water; production 2, 3 and 4 shows the consecutive increase of water cut and decrease in oil production; production 5 refers to the end of production with maximum water cut.

Component	Oil 1	Oil 2	Oil 3
Nitrogen	0,57	0,34	1,67
Carbon Dioxide	2,46	0,02	2,18
Methane	36,37	34,62	60,51
Ethane	3,47	4,11	7,52
Propane	4,05	1,01	4,74
i-Butane	0,59	0,76	0
n-Butane	1,34	0,49	4,12
i-Pentane	0,74	0,43	0
n-Pentane	0,83	0,21	2,97
Hexanes	1,62	1,16	1,38
Heptanes plus	47,96	56,85	14,91
Total	100	100	100
C7+ molecular weight	329	274	181
C7+ specific gravity	0,9594	0,92	0,799
Live oil molecular weight	171,4		46.69
Stock tank oil API gravity	19	23,6	47
Asphaltene content in stock tank oil, wt%	16,8		
Reservoir temperature, °F	212	203	246
Saturation pressure, psia	2950	2810	4677
GOR (SCF/STB)		300	2,909
initial oil FVF (RB/STB)		1.16	2.704

Table 5-1 : Composition and properties of oil

	Production (BBL/D)	State 1	State 2	State 3	State 4	State 5
--	-----------------------	---------	---------	---------	---------	---------

Oil 1	Oil	3000	2800	2300	2000	1800
	Water	100	180	320	560	720
	Watercut	0,032258	0,060403	0,122137	0,21875	0,285714
Oil 2	Oil	6000	5700	5300	4800	4200
	Water	10	400	1000	1500	2000
	Watercut	0,001664	0,065574	0,15873	0,238095	0,322581
Oil 3	Oil	5000	4800	4500	4100	3600
	Water	0	100	400	800	1200
	Watercut	0	0,020408	0,081633	0,163265	0,25
Total	Watercut	0,007796	0,048641	0,124457	0,207849	0,289941

Table 5-2 : Oil and water flow rate

Details of the production fluids and of the flow rates for each reservoir were combined with crude oil product specifications, in order to define the boundary conditions of an efficient oil separation process train. The main specification was a final product Reid Vapor Pressure of 10-12 psia and tank oil water content 0.5% (v/v). The design included mass/energy balance calculations, vessel details (sizing, fluid rates and conditions), compressor details, heating/cooling requirements. Internal configurations of any separation / treating vessel were also included in the study.

5.1 Properties Environment

The HYSYS simulation begins with property initialization. This includes first choosing all individual components that will exist in the overall system and then choosing a fluid package that will accurately simulate all components in the range of expected temperatures and pressures. In Properties environment components lists are generated and combine with property packages to form fluid packages.

As shown in table 5-1; the well streams contains light group (methane and ethane), Intermediate group (propane, butane, pentane, hexane) and heavy group (heptane and heptane plus). The components from these groups are assembled in the properties environment for simulation of separation. Components that are not available in HYSYS library can be defined as hypothetical components. The user defined hypothetical component can be defined by molecular weight and ideal liquid density. HYSYS will estimate the properties required to calculate vapor pressure for the hypothetical components. These properties are Molecular Weight, Temperature, Normal Boiling Point, Pressure, Liquid Density, Volume and Acentricity. The components used for the simulation are given in figure 5-1

Component List View: Component List - 1 [HYSYS Databanks]

Source Databank: HYSYS

Component	Type	Group
Methane	Pure Component	
Ethane	Pure Component	
Propane	Pure Component	
i-Butane	Pure Component	
n-Butane	Pure Component	
n-Pentane	Pure Component	
i-Pentane	Pure Component	
n-Hexane	Pure Component	
Hydrogen	Pure Component	
H2O	Pure Component	
Nitrogen	Pure Component	
CO	Pure Component	
CO2	Pure Component	
H2S	Pure Component	
C7+(1)*	User Defined Hypothe...	HypoGroup1
C7+(2)*	User Defined Hypothe...	HypoGroup1
C7+(3)*	User Defined Hypothe...	HypoGroup1
C6-C10*	User Defined Hypothe...	HypoGroup2
C10-C15*	User Defined Hypothe...	HypoGroup2
C15-C20*	User Defined Hypothe...	HypoGroup2
C20-C25*	User Defined Hypothe...	HypoGroup2
C25-C30*	User Defined Hypothe...	HypoGroup2
C30-C35*	User Defined Hypothe...	HypoGroup2
C35-C40*	User Defined Hypothe...	HypoGroup2
C40+*	User Defined Hypothe...	HypoGroup2

Status: OK

Figure 5-1 : Component List

When component list is defined, the list is combined with the property package. Property packages are specialized collections of methods for calculating the properties of components at particular temperature, pressure and composition of interest within the simulation. The combination of the component list and the property package comprise the HYSYS fluid package. The fluid package defines the material being operated in the unit operations, including component lists, component properties, property package, and reactors. The fluid package then becomes basis for simulating material streams.

Fluid Package consists of all necessary information pertaining to pure component flash and physical property defined in a single location allowing for easy creation and modification. HYSYS uses fluid package to contain all necessary information for performing flash and physical property calculation. The property package, pure components, hypothetical components, electrolytic component, interaction parameters reactions tabular data can be defined inside a single entity.

An Appropriate property package is selected for successful process simulation. The selection of properties is based on component of the process stream and the operating conditions. Equations of state models are reliable in predicting the properties of most hydrocarbon based fluids over a wide range of operating conditions.

In the property package selection group there is the access to the list of property packages. For oil, gas, and petrochemical applications, the Peng-Robinson equation of state is generally the recommended property package. It rigorously solves most single-phase, two-phase, and three-phase systems with a high degree of efficiency, accuracy and reliability. The Peng-Robinson (PR) model is ideal for Vapor-Liquid Equilibrium (VLE) calculations as well as for calculating liquid densities for hydrocarbon systems. The Peng-Robinson (PR) model can calculate properties for non-polar or slightly polar components, Polar or non-ideal chemical systems. For non-library or hydrocarbon pseudo-component, HC-HC interaction parameters are generated automatically by HYSYS. Key components such as He, H₂, N₂, CO₂, H₂S, H₂O, CH₃OH, EG, DEG, and TEG require case specific interaction parameters. The Peng-Robinson (PR) model is applicable for the temperature Range greater than -456°F and Pressure Range less than 15,000 psia.

The Lee-Kesler method is used for the calculation of enthalpies. This option results in a combined property Package, employing the appropriate equation of state for vapor-liquid equilibrium calculations and the Lee-Kesler equation for the calculation of enthalpies and entropies. This method yields comparable results to Aspen HYSYS' standard equations of state and has identical ranges of applicability. Lee-Kesler enthalpies may be slightly more accurate for heavy hydrocarbon systems.

The combined Property Package employs the appropriate equation of state (PR) for vapor-liquid equilibrium calculations and the Lee-Kesler equation for the calculation of enthalpies and entropies.

Package Type: HYSYS Component List Selection: Component List - 1 [HYSYS Databanks]

Property Package Selection:

- IAPWS-IF97
- Kabadi-Danner
- Lee-Kesler-Plöcker
- MBWR
- NBS Steam
- NRTL
- Peng-Robinson**
- PR-Twu
- PRSV
- Sour PR
- Sour SRK
- SRK
- SRK-Twu
- Sulsim (Sulfur Recovery)
- Twu-Sim-Tassone
- UNIQUAC
- Wilson
- Zudkevitch-Joffe

Options:

Enthalpy	Lee-Kesler
Density	Costald
Modify T _c , P _c for H ₂ , He	Modify T _c , P _c for H ₂ , He
Indexed Viscosity	HYSYS Viscosity
Peng-Robinson Options	HYSYS
EOS Solution Methods	Numerical Method
Phase Identification	Default
Surface Tension Method	HYSYS Method
Thermal Conductivity	API 12A3.2-1 Method

Parameters:

Figure 5-2 : Fluid Package

Density Calculation Method: COSTALD combined with “The Smooth Liquid Density option” is selected so that Aspen HYSYS interpolates the liquid densities from Tr=0.95 to Tr=1.0, giving a smooth transition. It is recommended for petroleum and hydrocarbon liquid mixtures at low and moderate pressure. The

densities differ if the option is not selected. COSTALD provides better results for liquid densities and smoothing near $T_r=1$ where there is sometimes a risk for discontinuities. COSTALD model includes both temperature and pressure dependence. Viscosity Calculation Method: Aspen HYSYS default method was selected which provides an estimate of the apparent liquid viscosity of an immiscible hydrocarbon liquid-aqueous mixture using only the viscosity and the volume fraction of the hydrocarbon phase.

The number of pseudo components is needed to accurately model oil stream changes. The component lumping refers to the process of converting a large number of pure and hypothetical components to a smaller reduced slate of components required by other applications, to improve performance or match known stream characteristics. The component delumper converts a small set of lumped components back to a complete list of components when the extra fidelity is required, or an allocation back to individual source or well flow composition is required.

The delumper allows the attachment of one or more feed streams with different components using one or more different fluid packages. It recovers the original constituent components from a hypothetical component. As a result the outlet component list may include the individual components from the input list and recovered components.

Options	
Enthalpy	Property Package EOS
Density	Costald
Modify Tc, Pc for H2, He	Modify Tc, Pc for H2, He
Indexed Viscosity	HYSYS Viscosity
Peng-Robinson Options	HYSYS
EOS Solution Methods	Cubic EOS Analytical Method
Phase Identification	Default
Surface Tension Method	HYSYS Method
Thermal Conductivity	API 12A3.2-1 Method

Figure 5-3 : Delumper Fluid Package

Peng-Robinson EOS property package and T-P flash calculation method were used. HYSYS Oil char was the delumping method set, which defined a hypothetical group based on temperature ranges specified automatically. Methane to hexane components were lumped while the heavy were delumped to eight hypothetical cuts as shown in figure 5-4. The concentration of methane in the lumped mixture is much higher compared to rest of the light components so that it permits the use of the combined behavior of lumped components.

Delumping Method

☐ Component Recovery ☒ HYSYS Oil Char

Inlet

Sort By

☒ None

☐ Boiling Point

☐ Molecular Weight

☐ Molar Flow (Rev)

C6-C10*

C10-C15*

C15-C20*

C20-C25*

C25-C30*

C30-C35*

C35-C40*

C40+*

C7+(1)*

C7+(2)*

C7+(3)*

Outlet

Kept Components

Methane

Ethane

Propane

i-Butane

n-Butane

i-Pentane

n-Pentane

Hydrogen

H2O

Nitrogen

CO

CO2

H2S

n-Hexane

Hypo Options

Generated Hypos

HYP(1)366*

HYP(1)434*

HYP(1)490*

HYP(1)582*

HYP(1)641*

HYP(1)709*

HYP(1)747*

HYP(1)818*

Cut Method

User Num of Cuts

No. of hypo cuts: 8

Figure 5-4 : Hypothetical cuts

5.2 Simulation Environment

In simulation environment the flow sheets are developed. The flow sheet environment is ready to be used after introducing fluid packages. Here the bulk of model is created and then the simulation begins by defining input streams and associated unit operations. The feed stream that will be separated in a process is introduced with its composition, flow rate, temperature and pressure of the stream. After the parameters are defined, the feed is connected to the equipment and simulation runs. The HYSYS solves the simulation problem using vapor liquid equilibrium equations using available parameters

In flow sheet there are many simulation options such as dynamics and control, external model, heat transfer units, manipulators, piping and hydraulics, pressure changers, reactors and separators. The desired unit operation is added to the process flow diagram as per simulation goals. The chemical components are defined and thermodynamic modeling issues are analyzed. The simulation model is analyzed with addition or removal of each unit operation. The calculation results for the simulation are stored in workbook format.

The main target is to separate gas from oil and then maximize the revenue from hydrocarbon production. The following assumptions were made for the present simulation in order to estimate the preliminary performance of the processing facility:

- It is simulated for Steady State

- The feed pressure to the facility is assumed to have constant pressure and flow rate.
- Stanley M. Walas, 1990 [32]; suggested that a heat exchanger requires at least 3-9 psia pressure drop and a control valve requires at least 10 psia pressure drop in order to operate.
- The heat loss in the process equipment is considered to be negligible.
- The separator operations on HYSYS are based on perfect thermodynamic separation. The Ideal separator simulation was used only for preliminary estimations of separator's performance, size and costing.

5.3 Flow Sheet Development

5.3.1 Feed

The production system begins at the well head. The flow rate from the wellhead is controlled by a choke unless the well has an artificial lift system. The wellhead fluids are complex mixtures of different hydrocarbon compounds and water. As the well fluid reach the separation facility its temperature tends to approach the ambient conditions. At ambient condition the viscosity is usually higher and it is difficult to separate the phases. Table 5-3 and 5-4 show the properties and composition of the feed at the inlet of the facility.

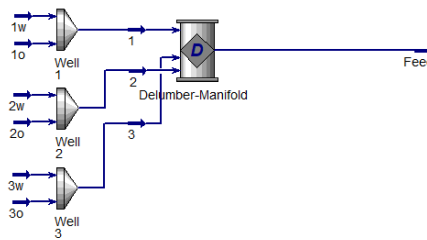


Figure 5-5 : Feed

Feed Properties	
Temperature (F)	60
Pressure (Psia)	1000
Mass Flow (lb/hr)	153603
Liquid Volume Flow (barrel/day)	14110
Std Gas Flow (MMSCFD)	14.453
Petroleum Property (API)	58.14

Table 5-3 : Feed Properties

Feed Composition	
Comp Mole Frac (Methane)	0.465
Comp Mole Frac (Ethane)	0.056
Comp Mole Frac (Propane)	0.033
Comp Mole Frac (i-Butane)	0.003
Comp Mole Frac (n-Butane)	0.025

Comp Mole Frac (i-Pentane)	0.002
Comp Mole Frac (n-Pentane)	0.017
Comp Mole Frac (Hydrogen)	0
Comp Mole Frac (H ₂ O)	0.056
Comp Mole Frac (Nitrogen)	0.01
Comp Mole Frac (CO)	0
Comp Mole Frac (CO ₂)	0.015
Comp Mole Frac (H ₂ S)	0
Comp Mole Frac (n-Hexane)	0.0127
Comp Mole Frac (HYP{1}366*)	0.0213
Comp Mole Frac (HYP{1}434*)	0.0277
Comp Mole Frac (HYP{1}490*)	0.0284
Comp Mole Frac (HYP{1}582*)	0.0031
Comp Mole Frac (HYP{1}641*)	0.0969
Comp Mole Frac (HYP{1}709*)	0.04
Comp Mole Frac (HYP{1}747*)	0.0745
Comp Mole Frac (HYP{1}818*)	0.013

Table 5-4 : Feed Composition

5.3.2 Heater

The separator mechanically separates the liquid and gas on the basis of density difference. A heater is installed upstream of the HP separator to control the separation temperature. The temperature is used to control the vapor pressure of the stabilized product. As temperature increases the separation of viscous or low API gravity oils, water and sand is enhanced. The elevated temperatures also permit lower retention times and therefore reduce the necessary size of the separation equipment. Heating can also prevent wax, hydrate and foam formation and accumulation. HYSYS hydrate prediction feature shows hydrate formation at 60 F and separators are operated at temperature marginally above hydrate formation temperature. The hydrate formation can cause the plugging and block the flow and hence reduce the capacity of separator. The plug may also activate the safety valves and rupture disks.

5.3.3 Multi-stage Separation

The separator design is very important as improper design or non-optimal design can bottleneck and reduce the capacity of the entire facility. The multi stage separation enables efficient separation of production fluids with highest stability of liquid and gas streams. The multi stage separation mainly ensures the stabilization of the resulting phases and recovers highest quantity of liquid hydrocarbon from the well fluid. In multi stage separator, the separation is carried in series of separators in which the pressure decreases gradually. The fluid is discharged from the higher pressure separator to the next lower pressure separator. The highest pressure is the in first separator and lowest pressure is in the final

separator. As the fluid is multi-component, the lighter hydrocarbon molecules are removed at relatively high pressures. During each stage the lighter molecules are removed as soon as they are formed and the partial pressure of the intermediate components is maximized at each stage [11]. The third separator is set near to the atmospheric pressure so oil can be routed to tanks at atmospheric pressure.

5.3.4 Storage Tank

The tanks are used as storage equipment rather than separation equipment in industry because tanks operate at atmospheric pressure and they are installed isolated from the process zones in the industry as the a surge of hot gas from process can suddenly increase tank pressure and damage the tank, so the tank vapors are tuned to obtain minimum flow rate. The progressive reduction in pressure and temperature does not allow any vaporization when delivered into the storage tank and in the event of small variation in stock tank pressure and temperature. An ambient cooler is installed at the upstream of tanks to make the temperature of stock tank oil close to ambient conditions. The figure 5-6 shows the configuration of three-staged separating unit with heater and tank.

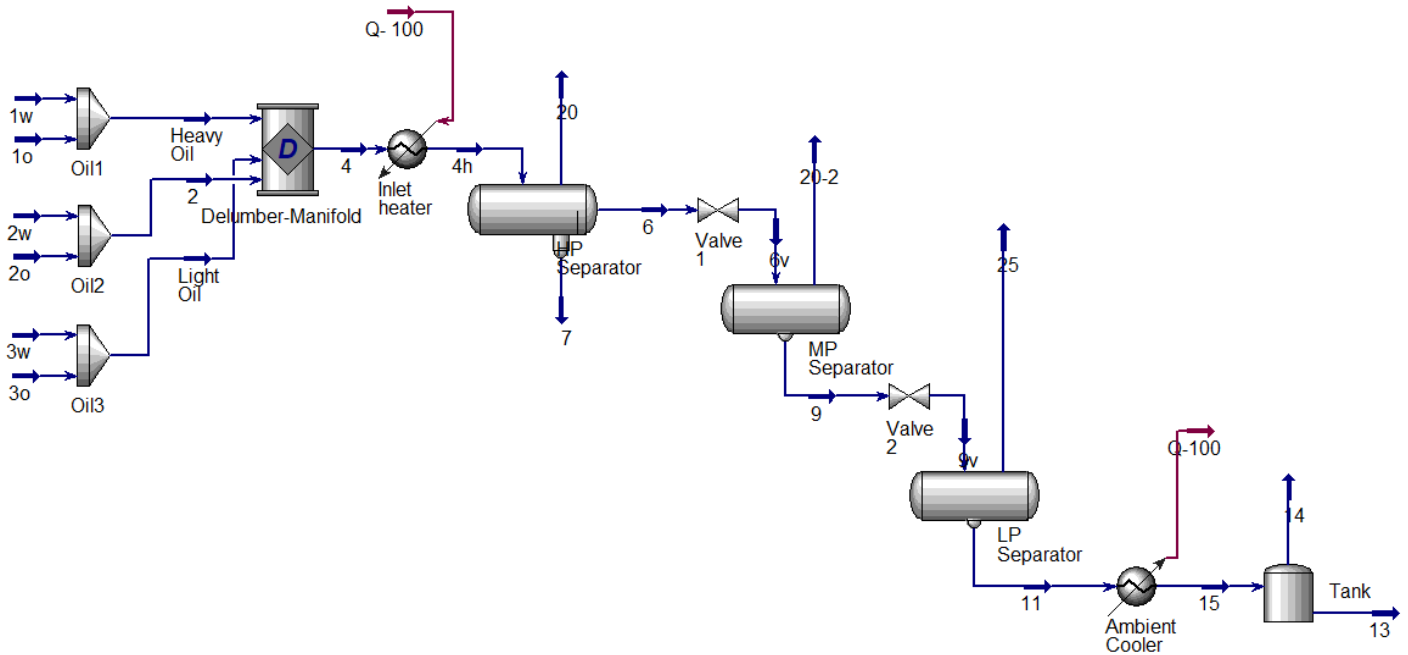


Figure 5-6 : Three-staged separating unit

5.4 Simulation strategy

As the thesis objective suggests increasing the oil recovery, the strategy is to obtain maximum liquid oil at tank and minimize tank vapor. The temperatures and pressure at the inlet of the separators and tank are tuned to achieve gas zero mass flow at tank gas.

5.4.1 Optimum Pressure

The number of stages normally ranges between two and four, which depends on gas oil ratio and the well stream pressure. The two stage separation is usually used for the medium to low GOR and low well stream pressure, three stage separations are used for the medium to high GOR and high pressure well streams [11]. According to Campbell [22] the number of stages n can be estimated by

$$R = \sqrt[n]{\frac{P_1}{P}} \quad \text{Equation 5-1}$$

Where: R =pressure ratio; P_1 =pressure in stage 1 (high-pressure end) in psia; P =stock tank pressure in psia and n =number of stages excluding tank. This implies an assumption of equal pressure ratios between the stages, which has been found to be the optimum operating condition for maximizing liquid recovery. The maximum ratio per stage will normally be in the range of 3.6 to 4.0 in order to minimize inter-stage temperatures. [22] Table 5-1 shows the calculated number of stages using the equation 5-1. The numbers of stages are found to be 3.

$P_1 = 1000$ psia			$P = 14.7$ psia		
R	3.6	3.7	3.8	3.9	4.0
n	3	3	3	3	3

Table 5-5

The High pressure separator units can handle pressures of 975 to 1500 psi, Medium-pressure separators operate from 230 to 700 psi, and Low-pressure units handle pressures of 10 to 180 psi. According to Arnold [11] the minimum pressure for the lowest pressure stage would be 25 to 50 psig as this pressure corresponds to the stock tank pressure. It allows the oil to be dumped to a treater or a tank. The pressure at any intermediate stage can then be determined using the following equation:

$$P_r = \frac{P_{r-1}}{R} \quad \text{Equation 5-2}$$

Where: p_r = pressure at stage r , psia; and R = pressure ratio.

The HP separator pressure is 1000 psia and stock tank pressure is 14.7 psia, based on the pressure and temperature tuning in HYSYS simulation and the formula above, the MP and LP separator pressures are approximated to be 247 psia and 58 psia respectively. The temperatures and pressure tuned at the inlet of the separators and tank to achieve gas zero mass flow at tank gas are shown in table 5-6.

	Temperature (F)	Pressure (Psia)
HP Separator	374	1000
MP Separator	374.6	247
LP Separator	373.5	58

Tank	60	14.7
------	----	------

Table 5-6

The temperature is increased at the inlet of each separator. It should be mentioned that the temperature change occurs in a gas as a result of a sudden pressure change over a valve known as the Joule-Thomson effect. This tuning strategy produces the tank oil as shown in table 5-7

Tank Oil	
Oil Production [bbl/day]	9717
API	25.52
RVP	3.192
Tank - Water content in Oil (v/v)	0.0001

Table 5-7

The vapor loss from each separator is shown in table 5-8. The Vapor recovery unit needs to be added to recover any liquid from the vapors.

	Mass Flow
HP Separator Vapor loss	21266 lb/hr
MP Separator Vapor loss	3035 lb/hr
LP Separator Vapor loss	1554 lb/hr
Combined Vapor Loss	25855 lb/hr

Table 5-8

Before proceeding to Vapor recovery unit, the heating effects need to be analyzed so that suitable temperature range can be simulated for the equipment in the vapor recovery unit

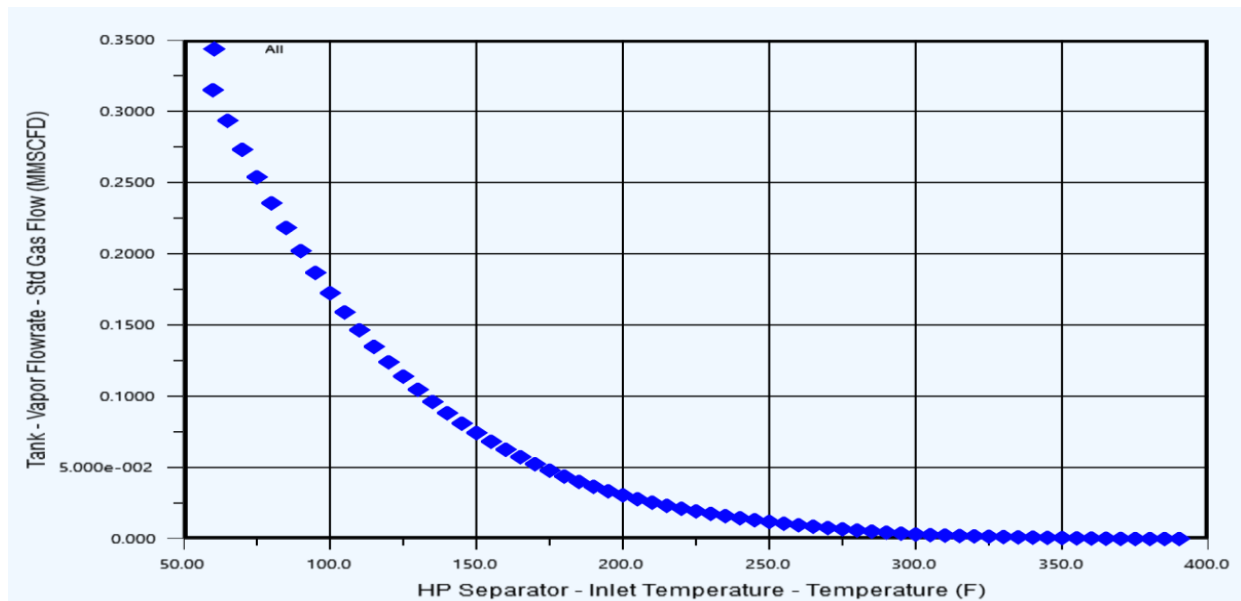
5.4.2 Heating Effect

The liquid and gas are separated mechanically from hydrocarbon stream at specific temperature and pressure by means of a separator. The phase equilibrium is the condition where the liquids and vapors have reached certain pressure and temperature conditions at which they can separate. The high temperature at separator inlet would lead to excess vaporization and the lower temperatures would trigger flow assurance issues such as paraffin, hydrates and foam. Heating decreases the oil viscosity making it easier for the gas to escape from the oil. The temperature increase the also increase the amount of gas which evolves from the oil. These analyses affect the oil production flow, tank Vapor Flow rate, oil product RVP, API, to compression power and water content in oil.

5.4.2.1 Tank Vapor Flow rate

As the temperature is increased, more gas is liberated in the separators and so more stabilized oil is produced at downstream separators and tank. Since the more volatile components are removed in the

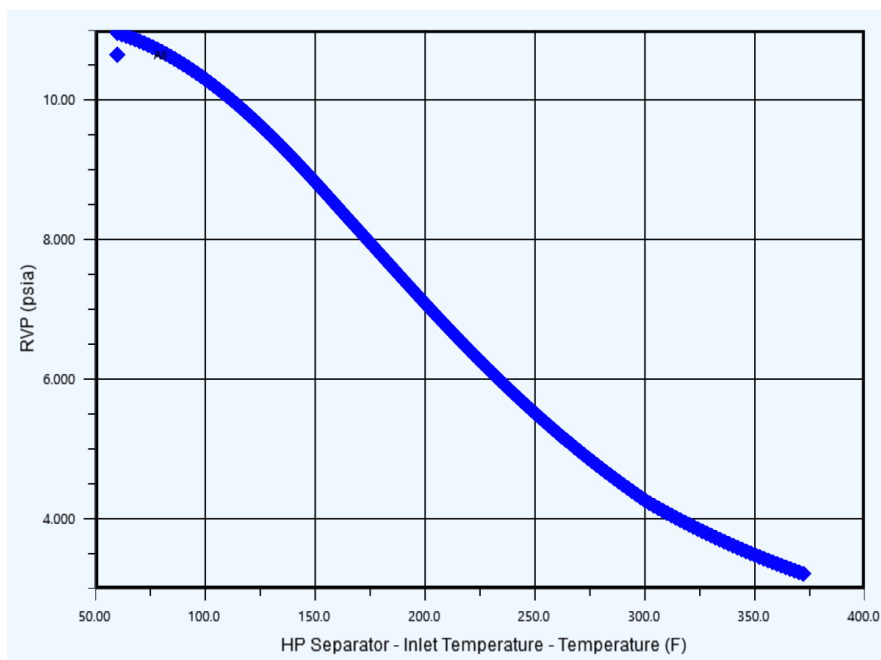
HP Separator, the gas contents in MP, LP separator, tank are less. The decreasing vapor flow rate at the tank is shown on graph 5-1.



Graph 5-1

5.4.2.2 RVP

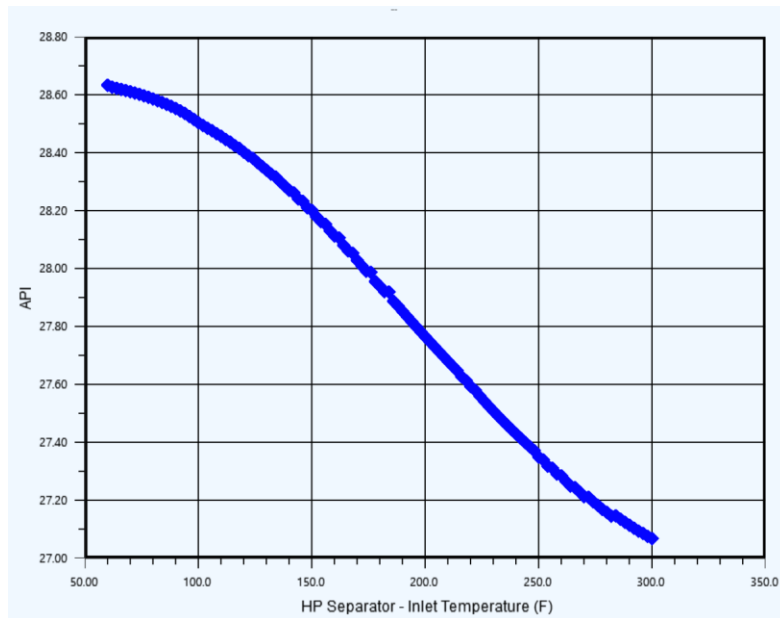
As shown in graph 5-2; RVP is steadily decreasing with the increase of inlet temperature leading to more stabilized tank oil as in graph below. The more volatile components are removed in HP Separator, so the contents of the MP and LP separator are more stabilized and there is lower gas liberation in MP and HP Separator.



Graph 5-2

5.4.2.3 API

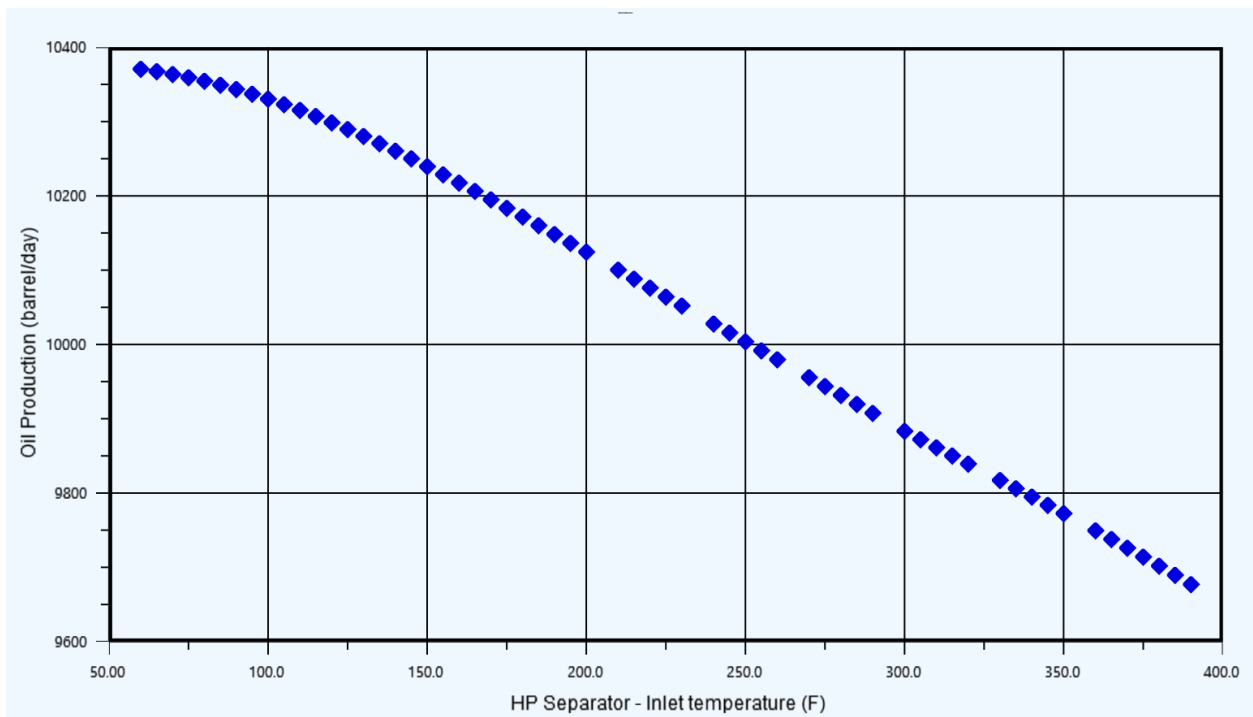
As shown in graph 5-3; Increasing the temperature reduces the API that is lighter components are removed and heavy oil is produced.



Graph 5-3

5.4.2.4 Oil Production

The lower temperatures show the higher liquid recovery as shown in graph 5-4 but at the cost of RVP (graph 5-2). The lowest possible temperatures are selected to conserve energy.

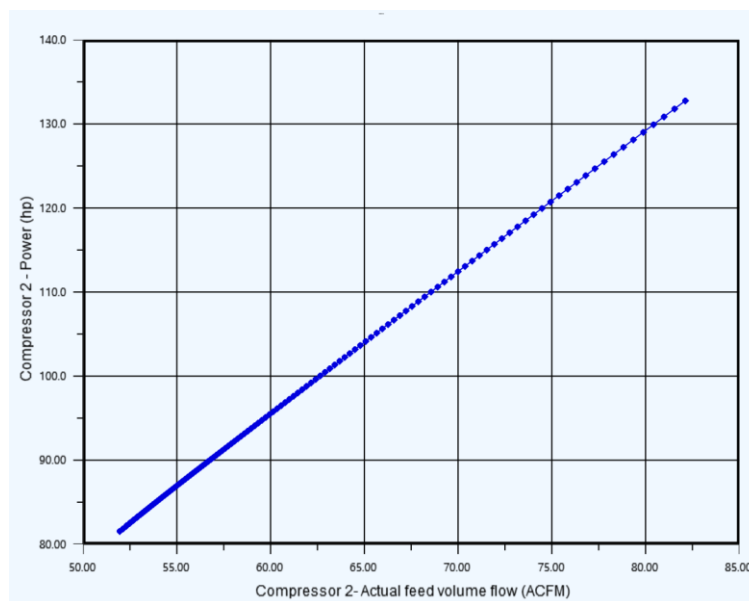


Graph 5-4

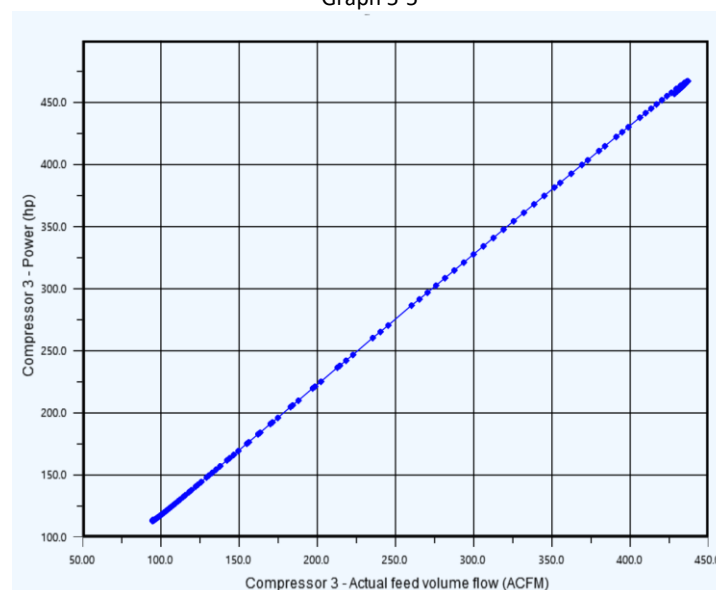
5.4.2.5 Compressor Power

Since the feed at MP separator is more than that of the LP separator, more vapors are produced from the outlet of the MP separator as compare to the LP separator. These vapors from MP and LP separators are feed for compressor 2 and compressor 3 after passing the knock out drums KOD 2A and KOD 3A.

As the actual feed volume flow for compressor 2 and compressor 3 increases, their brake horse power increases as it is demonstrated in the graph below. Moreover the pressure difference produced at compressor 3 is greater than compressor 2 and so the brake horse power of compressor 3 is greater than that of compressor 2.



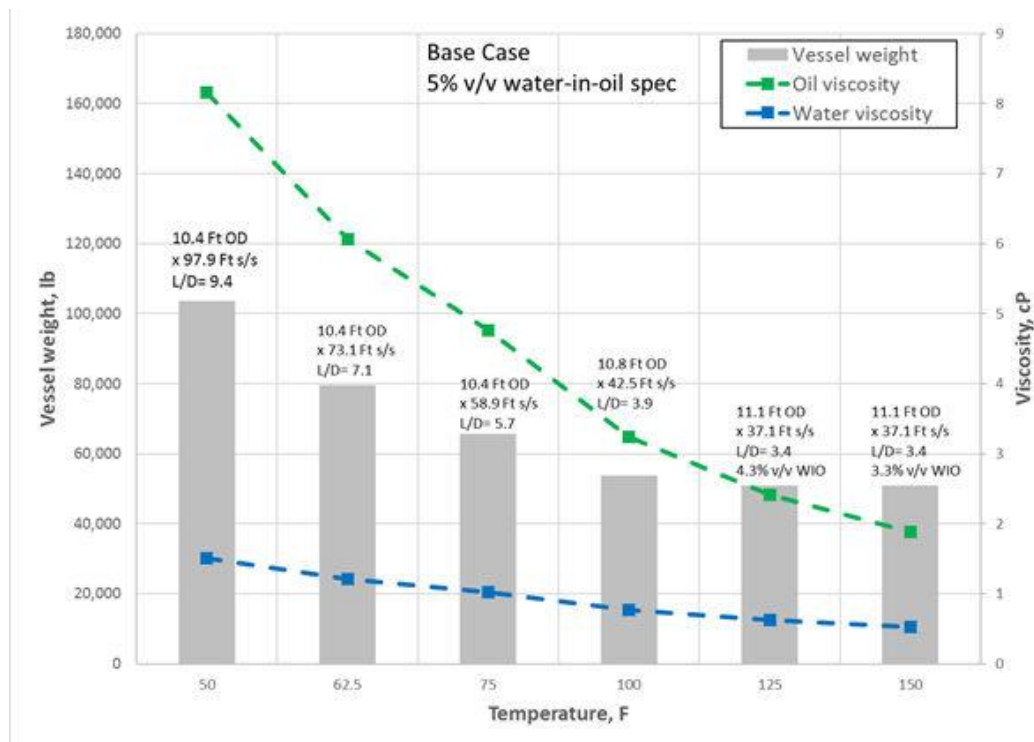
Graph 5-5



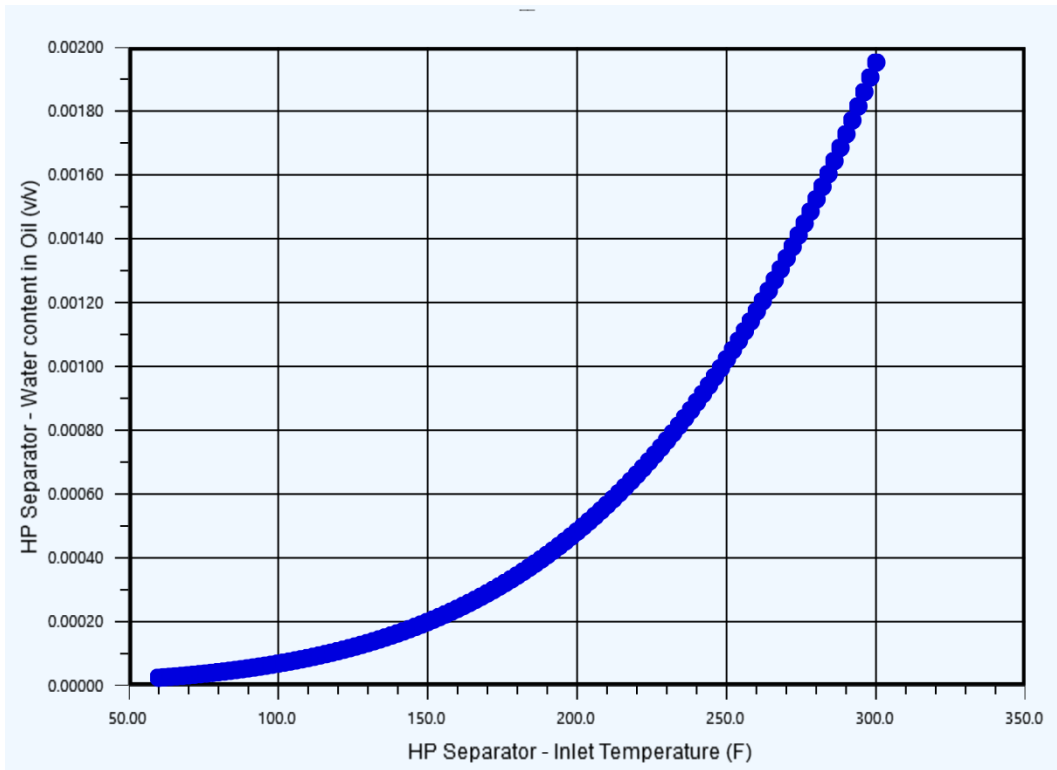
Graph 5-6

5.4.2.6 Water content in Oil

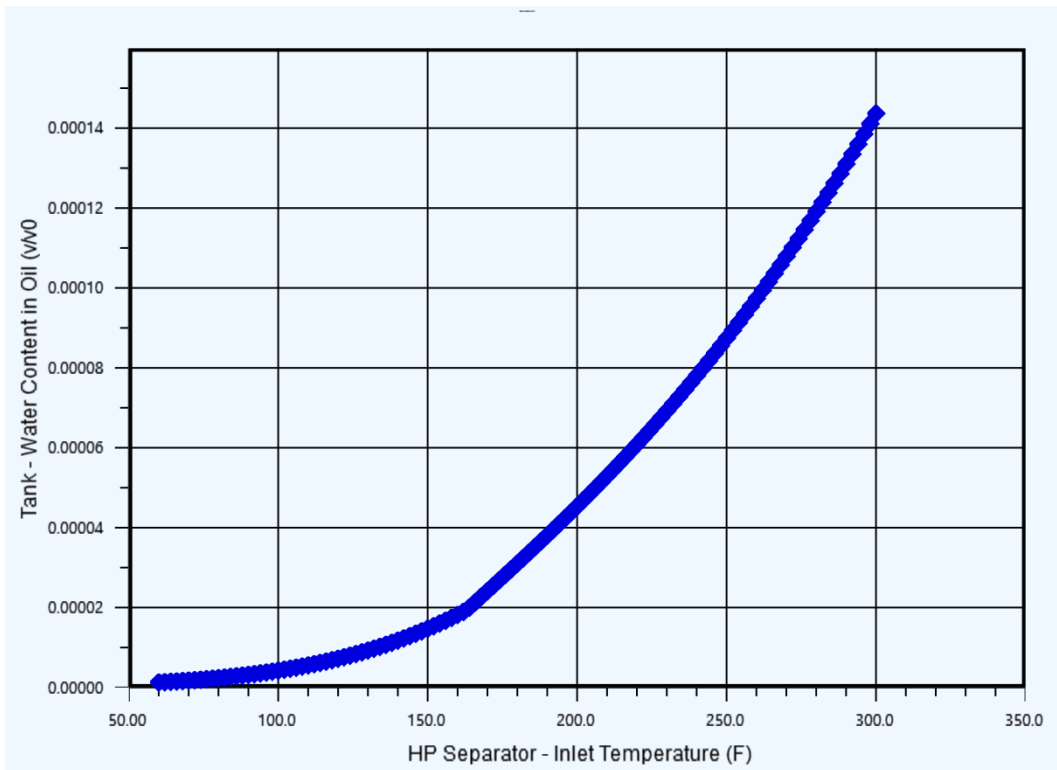
The higher temperature makes phase separation easier for both continuous phases. The graph 5-7 shows that; as the temperature increases the oil and water viscosity decreases which increases the phase separation. The graph shows that the oil viscosity declines rapidly as compare to water viscosity, which means that the increase in temperature will release more water content in product as compare to oil content product, so high water content is produced at tank and HP-separator-light-liquid-outlet as shown in graph 5-8 and 5-9, since the higher temperature separates releases more oil as compare to water, it can be constrained by water-in-oil product limit.



Graph 5-7



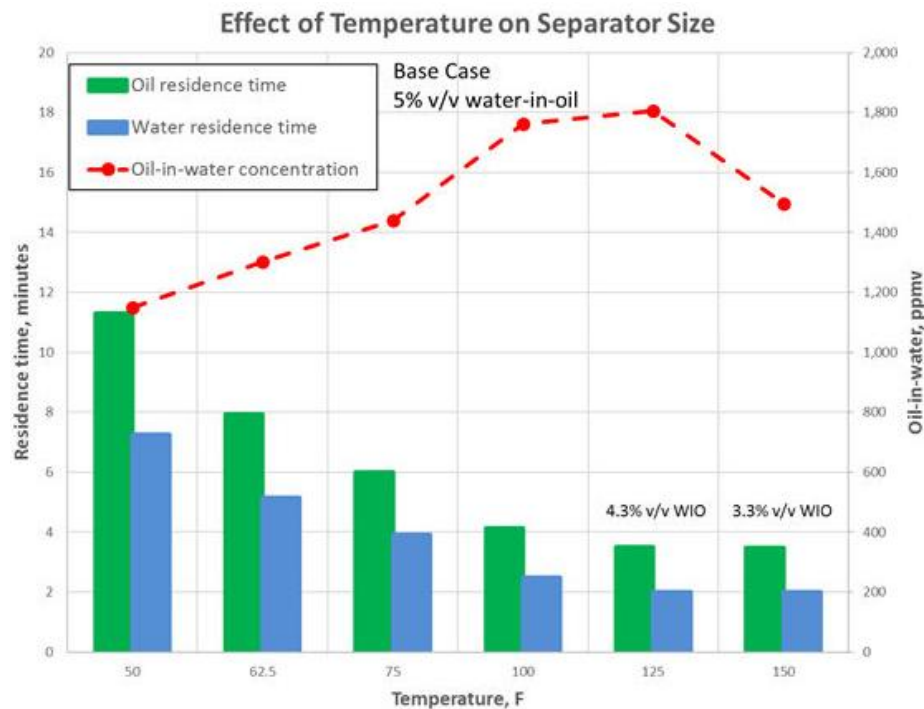
Graph 5-8



Graph 5-9

5.4.2.7 Separator size

As shown in graph 5-10; as temperature increases, the separator size decreases mainly because of the rapid decrease in oil viscosity. It can be verified by graph 5-10; which shows that as the temperature increases the liquid residence time decrease, which reduces the size of separator particularly its length.



Graph 5-10

The temperature analysis demonstrates that the higher temperature has the following advantages and disadvantages:

Advantages

- The higher temperature produces less tank vapors
- The higher temperature produces more stabilized oil
- The higher temperature produces low vapors at the MP Separators and LP Separators, so the compressors power requirement decreases

Disadvantages

- The higher temperature produces less tank oil
- The higher temperature produces low API oil i-e heavy oil
- The higher temperature produces higher water content in oil at separators and tank
- Temperature above 204 C or 400 F is undesirable for carbon steel piping and equipment. Above 204 C, under dry conditions, the carbon steel equipment and piping will suffer from High temperature hydrogen attack (HTHA). Hydrogen disassociates into nascent (atomic) hydrogen,

During the simulation it was noted that the temperature at the outlet of the compressor 2 and compressor 3 exceeded 400 C, so high-temperature-hydrogen-attack was an issue for the equipment and piping metallurgy. There are three options to resolve this issue, either to install stainless steel piping and equipment downstream of the compressors or to use multi stage compressors with intermediate cooling or to cool the flow upstream of the compressors to lower temperatures so as the temperature does not exceed 400 C at the outlet. Stainless steel is an expensive material for procurement and fabrication, while multistage compressor will also induce higher capital, installation, operational and maintenance costs. So the option of heat exchangers, Cooler 2A and Cooler 3A, were selected and installed at the upstream of Compressors 2 and 3.

	Temperature (F)	Pressure (Psia)
HP Separator	250	1000
MP Separator	245.8	240
LP Separator	239.5	58
Tank	60	14.7
KOD 1	93	997
KOD 2A	190	240
KOD 2B	93	617
KOD 3A	93	58
KOD 3B	150	887

Table 5-9

The gas released from each of the separators is sent to the gas treatment unit. The addition of gas treating unit resulted in the recovery of additional 458bbls/day of crude oil, as it is shown in table 5-10.

Tank Oil	
Oil Production [bbl/day]	10175
API	27.22
RVP	6.832
Tank - Water content in Oil	0.0045

Table 5-10

The Crude Oil after the separators is routed towards the oil treatment unit for the removal of the remaining water and salts and then to the refinery plant or storage tanks. The oil is then sent to the export pumping section where it is pumped for the export.

The cumulative vapor from Knock out drums (KOD 1, KOD 2A, KOD 2B, KOD 3A, KOD 3B) and tank can be used as fuel to heat the feed or as a product to enter the fuel gas network. The high pressure gas is sent to the reinjection in to reservoir and the low pressure gas is sent for recompression re-injection to the reservoir. The water is sent to the water treatment unit to make it suitable for disposal to the environment.

6 Performance Analysis

6.1 The Production states

With respect to the production rates stated in table 5-2; the operating parameters in table 5-9 are used to analyze the effect of well production rate on tank oil production, API, RVP, compressors, and water-content-in-oil as shown in table 6-1.

	Production state 1	Production state 2	Production state 3	Production state 4	Production state 5
Compressor 2 [hp]	62.66	59.61	54.49	49.21	43.27
Compressor 3 [hp]	118.4	114.9	104.5	94.52	83.36
Oil Production [bbl/day]	10175	9647	8725	7842	6911
API	27.22	27.32	27.67	27.79	27.74
RVP	6.832	6.83	6.78	6.717	6.647
Tank - Water content in Oil	0.0045	0.0046	0.0047	0.0047	0.0047

Table 6-1

The above table shows the increase in the water cut between consecutive production states, the reduction of the oil product and of the compressor power. The API and RVP remain approximately constant.

6.2 Well Shut Downs

Well 1 produces a heavy crude oil and Well 3 a light one. Heavy crude oil has low API gravity that is less than 20° [18]. Heavy crude oil has higher viscosity, specific gravity and molecular weight than the light crude oil. The light crude oil normally receives a higher price than the heavy crude oil because it produces a higher percentage of gasoline and diesel fuel in an oil refinery.

The production state 1 is the beginning of production and has the least water cut while production state 5 is the end of production period and has the highest water cut. Wells 1 and 3 were closed in our simulation runs in order to investigate the effect of heavy and light oil on production process. Using the temperature and pressure of table 5-9 resulted in the following output in table 6-2 for the productions states 1 to 5 when the Wells 1 and 3 were closed.

	Production state 1		Production state 2		Production state 3		Production state 4		Production state 5	
	Well 1 closed	Well 3 closed	Well 1 closed	Well 3 closed	Well 1 closed	Well 3 closed	Well 1 closed	Well 3 closed	Well 1 closed	Well 3 closed
Compressor 2 [hp]	52.13	37.16	49.7	35.12	46.39	31.48	42.04	28.17	36.84	24.84
Compressor 3 [hp]	100.9	36.31	94.92	34.26	88.81	30.35	80.74	27.06	70.94	23.93
Oil Production	7565	7862	7240	7426	6749	6644	6123	5946	5364	5246
API	30.87	21.21	30.83	21.23	23.81	21.38	21.71	21.43	30.93	21.4
RVP	7.286	3.811	7.225	3.374	7.134	3.617	7.054	3.555	6.978	3.529
Tank - Water content in Oil	0.001	0.002	0.005	0.002	0.005	0.002	0.005	0.002	0.005	0.002

Table 6-2

The table 6-2 shows increase in the water cut in all production states and reduction in the oil production and compressor power. The API and RVP remain approximately constant, while the water content tends to increase.

Shutting Well 1 removes the heavy oil. As expected the table above shows that shutting Well 1 will increase the RVP and API for all production states.

Since, the oil flow rate of well 2 and well 3 is approximately twice the oil flow rate of well 1. The API and RVP are not increased significantly due to relative low flow ratio of well 1 with respect to other wells. The produced oil gets lighter but the behavior did not change rapidly.

Shutting Well 3 will remove the light oil. As expected, the table above shows that RVP and API will be decreased for all production states. The API and RVP are decreased significantly due to the relative high flow ratio of well 3 with respect to the other wells. The produced oil gets heavier.

6.3 Pressure adjustment for of Well 1 & Well 3 shut down under high and low water cut

As previously stated in table 5-2; the Production state 1 represents least water cut, production state 5 represent maximum water cut and Well 1 produces a heavy crude oil and Well 3 a light one. To simulate for the light oil, well 1 is shut down and well 3 is shut down to simulate heavy oil.

With variation in production states and shut down of wells, the process train can be adjusted for efficient production. The pressure in the process train need to be adjusted to achieve the maximum flow rate and stabilized RVP. The optimization for each case is achieved by adjusting pressure by either control valve or compressors.

The optimization of the production process during well 1 shut down is achieved by reducing the pressure of HP Separator, KOD 1, KOD 2B. Since pressures and flow rates are reduced, the compressors' power is also significantly reduced as they have to handle lower flow rates.

	Production state 1		Production state 5	
	Well 1 Shut Down	Well 3 Shut Down	Well 1 Shut Down	Well 3 Shut Down
HP Separator [psia]	650	350	1000	350
MP Separator [psia]	240	247	240	247
LP Separator [psia]	58	190	58	190
KOD 1 [psia]	537	347	997	347
KOD 2A [psia]	242	247	240	247
KOD 2B [psia]	584	NA	617	NA
KOD 3A [psia]	58	190	58	190
KOD 3B [psia]	997	NA	887	NA

Table 6-3

As shown in table 6-3; The optimization of the production process during well 3 shut down is achieved by reducing the pressure of HP Separator, KOD 1, KOD 2B, KOD 3B, while the MP Separator and LP separator pressures are increased. Since pressures and flow rates are reduced and the fluid is of lower volatility, the compressors' power is also significantly reduced. Due to the very low volatility of this oil, KOD 2A, Compressor 2, Cooler 2A and KOD 3A, Compressor 3, Cooler 3A can be bypassed.

Using the operating parameters in table 6-3; resulted in the following output in table 6-4 on tank oil production, API, RVP, compressors, and water-content-in-oil.

	Production state 1		Production state 5	
	Well 1 Shut Down	Well 3 Shut Down	Well 1 Shut Down	Well 3 Shut Down
Compressor 2 [hp]	26.6	0.0	36.8	0.0
Compressor 3 [hp]	91.0	0.0	70.9	0.0
Oil Production	7543.0	7882.0	5364.0	5259.0
API	30.73	21.17	30.93	21.36
RVP	6.955	3.880	6.978	3.613
Tank - Water content in Oil	0.001	0.0048	0.005	0.005

Table 6-4

7 HYSYS carry over calculation

The carry over in a separator can be simulated on HYSYS by modeling imperfect separation. The carry over calculations are added to the separation model to match process mass balance and to analyze the separation specification for the real separator. It predicts the effect of feed phase dispersion, feed conditions, vessel geometry, and inlet/exit devices on carry over.

In order to properly analyze the particle size distribution in a system, the engineer must characterize these particles by collecting particle size measurements. The default values provided in HYSYS can be used but great care should then be taken in interpreting the results.

The carry over estimation is based on droplet size distribution. The separation is based on critical droplet size. The droplet removal efficiency is the ability to remove smaller droplets; that is less carryover of liquid in the separated gas. The required removal efficiency and acceptable amount of carry-over is determined by the sensitivity of the downstream process or equipment, such as compressors, to the liquid content of the gas. The quantity of gas entrained in the liquid stream and the bubble size distribution is difficult to analyze, but the entrained gas is minor in comparison to the total gas flow so that it does not affect separation performance significantly.

The droplet settling method aims at removing a preset liquid droplet size and all droplets larger than this size. According to Karabelas (1978), droplet size spectra generated in turbulent pipe flow of dilute liquid /liquid dispersions can be well represented by a Rosin-Rammler type of equation with constant parameters and only one variable, the maximum drop diameter d_{max} or d_{95} . For engineering calculations in particular, the results of this study suggest that the droplet size spectrum can be estimated by using the Rosin-Rammler equation with a constant slope $n=2.5$ and computed d_{95} . Based on Karabelas' work, HYSYS uses a modified Rossin-Rammler function to estimate droplet size distribution. [35] Rossin-Rammler distributions are defined by:

$$F = \exp(-d/dm)^x \quad (\text{Equation 7-1})$$

Where:

- F = fraction of droplets larger than d
- dm is related to d_{95} . It is the commonly occurring diameter (peak of the histogram / frequency curve), as compared to other different measures of central tendency such as mean or median diameters.
- x = RR index
- d_{95} = 95% of droplets are smaller than this diameter for the specified dispersion
- RR Index = exponent used in the RR equation (also known as the "spread parameter"). Spread is a measure of degree of deviation from the central tendency; its value is characteristic of the substance / system being considered

Another way of expressing this is:

$$\ln(F) = (-d/dm)^x$$

or

$$\ln(\ln(1/F)) = B + x \ln(d) \quad \text{Equation 7-2}$$

Where: $B = \text{constant} = \ln(1/dm)$

Therefore plotting $\ln(\ln(1/F))$ against $\ln(d)$ can be used to calculate the R-R parameters. HYSYS correlations ask the user for d95 data rather than dm. If required dm can be relatively simply calculated from d95 as follows:

$$dm = d95 / (-\ln(1 - 0.95))^{(1/x)} \quad \text{Equation 7-3}$$

It must be emphasized that the use of continuous size distribution functions to represent experimental data is almost always a compromise, since measured data rarely fit the models exactly. However, distribution functions have the advantage that they enable the comparison of a large amount of data using a few basic parameters. An important feature is the ability to represent the size distribution in cumulative form as a straight line by means of a scaling that is constructed so as to linearise the cumulative size distribution function.

The carry over calculation begins with the required product parameters. Literature generally indicates the following upper carry over limits for separators. The product fraction for HP separator is shown in figure 7-2:

- free gas can have up to 2% v/v in separated oil ,
- 1000ppm oil in water
- 0.1 gal/ MMscf/D liquid in gas= 1.33×10^{-8} %v/v
- 30-5% v/v water in oil in high pressure, 5% v/v for medium pressure and 0.5% v/v for low pressure separators

Specification By	Fraction	Flow	Basis
Light liquid in gas	0.0000		Liq. Volume
Heavy liquid in gas	0.0000		
Gas in light liquid	0.0200		
Heavy liquid in light liquid	0.1000		
Gas in heavy liquid	0.0000		
Light liquid in heavy liquid	0.0010		

☐ Use 0.0 as product spec if phase feed flow is zero
☐ Use maximum possible carry over for heavy liquid in light liquid if spec is not achievable
☐ Carry over to zero flow streams ☒ Use PH flash for product streams

Figure 7-1

“Proseparator” method of HYSYS was selected to simulate gas/liquid separation in gas gravity section and mist elimination device. “Horizontal vessel” method was selected to simulate water/oil separation in liquid settling section as shown in figure 7-4. HYSYS offers two sets of correlations to calculate carry-over, “Horizontal Vessel” and “ProSeparator”. Both of them require separator dimensions, nozzle setup and pressure drop specification.[36]

Nozzle Diameter / Location		* Distance from feed end or side of vessel			
		4h	5	6	7
Nozzle diameter [ft]		0.1640	0.1640	0.1640	0.1640
Nozzle height [ft]		3.000	3.000	1.500	0.0000
Nozzle location* [ft]		0.6640	0.6640	0.6640	0.6640

☐ Carry over to zero flow streams
 ☒ Use PH flash for product streams

Figure 7-2

Carry Over Model

☐ None
 ☐ Feed Basis
 ☐ Product Basis
 ☒ Correlation Based

☒ Correlation Setup
 ☐ Dimensions Setup
 ☐ DP / Nozzle Setup

Correlation Setup

Correlation Calculation Type

☐ Overall Correlation
 ☒ Sub Calculations

Inlet Device	Horizontal Vessel	View Correlation
Gas/Liq Separation	Protes ProSeparator	
Liq/Liq Separation	Horizontal Vessel	
Vapour Exit Device	Protes ProSeparator	

☐ Carry over to zero flow streams
 ☒ Use PH flash for product streams

Figure 7-3

The Horizontal Vessel correlations are used for a horizontal three-phase separator. The efficiency of the inlet device is assumed and then the horizontal vessel correlations calculate the 6 types of dispersions (i.e. light liquid in gas, heavy liquid in gas, gas in light liquid, heavy liquid in light liquid, gas in heavy liquid, light liquid in heavy liquid) in the feed as per assumed efficiency of the inlet device and the dispersion fraction. The Rosin-Rammler parameters are used to calculate the droplet distribution of the dispersed phase. The inlet droplet d95 and the densities of the two liquid phases are used to calculate the droplet d95 of the liquid-liquid dispersions. [36]

ProSeparator correlations include droplet size distribution calculation in contrast to conventional methods of sizing which set critical droplet sizes. ProSeparator correlations are rigorous but are limited to calculating liquid carry over into gas. The liquid-liquid separation or gas entrainment are set to zero and the liquid-liquid entrainment are calculated separately and then total carry over is the sum of the separate light and heavy liquid carry over calculations. The droplet distribution of light and heavy liquid are calculated using Rosin-Rammler type distribution. The inlet flow conditions such as gas flow rate, gas/liquid physical properties and inlet pipe size determines the minimum and maximum droplet diameter. It must be noted that ProSeparator effectively calculates Rosin-Rammler parameters (droplet diameters), fitting them to match the predetermined minimum and maximum droplet sizes and does not require the user to specify any of these parameters. The maximum droplet size is determined by ProSeparator using empirical correlations (table 2-3). Accurate physical properties of the fluids (particularly surface tension) are very important to this calculation. [36]

The inlet droplet d95 diameter for Rosin –Rammler distribution was set to the conservative value of 0.0315 in. (800 micron).

Inlet Distribution Parameters		
	Droplet d95 [in]	Rossin Rammler Index
Inlet droplet	3.150e-002	N/A
Light liquid in gas	8.858e-003	2.000
Heavy liquid in gas	8.858e-003	2.000
Gas in light liquid	5.906e-003	2.000
Heavy liquid in light liquid	3.150e-002	2.000
Gas in heavy liquid	5.906e-003	2.000
Light liquid in heavy liquid	2.732e-002	2.000

Figure 7-4

It should be mentioned that the highest production state (i-e production state 5) is selected for the carry over, which will have the highest carry over and it will be automatically satisfy carry over calculations for the low water cuts in production state 1,2,3,4. The water phase is assumed to be totally dispersed in the oil phase and the oil product carryover is 0.00443%v/v lower than the final product specification. The inversion point is used in the calculation of appropriate liquid phase viscosity (i-e water in oil and oil in water). The inversion point is the water fraction at which the system changes in behavior from a water-in-oil emulsion to an oil-in water emulsion. In many cases it is observed to occur at 50-70% water; however there is no reliable means of determining the actual point and it must usually be determined experimentally. Due to the absence of experimental data, the inversion point is selected to be 60%, although it is not expected to affect calculation due to the low water content of the emulsion. The Vane type inlet diverter shows the highest efficiency in graph 2-1 and 2-2 and it is selected.

General data	
Liquid phase inversion [%]	60.00
Liquid residence time factor	1.000
Inlet Device Type	
Inlet device type	User Defined
Inlet device efficiency [%]	97.00
Inlet Holdup	
Inlet light liquid in heavy liquid [%]	0.00
Inlet heavy liquid in light liquid [%]	100.00
Inlet gas in light liquid [%]	3.00
Inlet gas in heavy liquid [%]	0.00
Vapour Exit Device	
Exit device type	User Defined
Gas load factor [m3/m2/s]	<empty>
Critical droplet diameter [in]	3.937e-004
OK	

Figure 7-5

The liquid in gas carry over will be maximized with high oil flows when the watercut is lower at the start of the production. Table 7-1 shows the liquid entrainment in vapor for each production state. The production state 2 is selected as it has the highest liquid entrainment in gas.

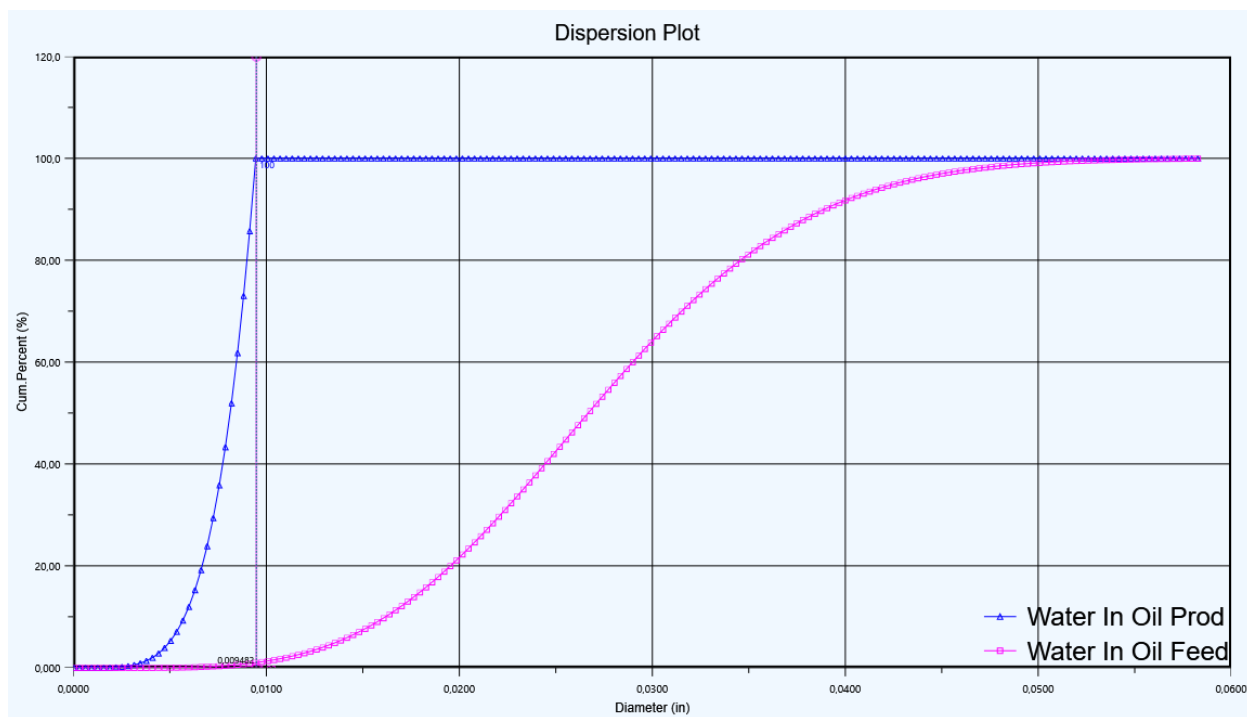
liquid entrainment in vapor (v/v)	
Production state 1	3.04E-08
Production state 2	3.47E-08
Production state 3	3.00E-08
Production state 4	2.41E-08
Production state 5	2.00E-08

Table 7-1

7.1 HYSYS Carry over Results

Water in Oil Carry over

The produced feed and product droplet distribution graph shows that all droplets bigger than 0.0094 in (240 micron < 500 micron) have settled. These results reveal that sizing procedure led to a sufficient but conservative separator size. Furthermore, it proves that the water in oil specifications is satisfied already in the 1st HP Horizontal separator, so the downstream separators were chosen to be two phase separators.



Graph 7-1

Liquid in Gas Carry Over

Using table 2-4 and 2-5; by applying a standard mesh pad demister Otto York 431 with 6 in. thickness in HP separator the carryover was reduced to 9.17E-09 %v/v thus meeting the specifications. Similarly, it was observed that the MP separator requires a higher efficiency mesh-pad demister of 6 in. thickness (Otto York 326, table 2-4 and table 2-5) while LP separator a standard mesh pad of 8in. thickness (Otto York 431, table 2-4 and table 2-5) to satisfy liquid in gas ratio specification (1.33×10^{-8} v/v).

8 Sizing and specification for equipment design

The equipment design section in simulation environment, calculates the size and rating for the equipments based on operating parameters.

8.1 Separators

The separators are sized on the basis of inlet temperature, flow rate, and pressure. Based on the product or equipment requirement one or more variables can be added manually and the size is recalculated on the bases of input. The rating for separators is given in table 8-1, 8-2, 8-3, 8-4, 8-5.

3 Phase Horizontal HP Separator	
Diameter [ft]	2
Total Length [ft]	6
L/D Ratio	3
Max. Allow. Vap. Velocity [ft/s]	0.66
Demister Thickness [in]	6
Liq. Residence Time [seconds]	12.89
Liq. Surge Height [ft]	0.99
Low Level Shut Down Height [ft]	1
Liq. Res. Time at LLSD [seconds]	12.89
Heavy Liq. Residence Time [sec]	12.89
Heavy Liq. Surge Height [ft]	0.03
Total Vapor Height [ft]	0.98

Table 8-1

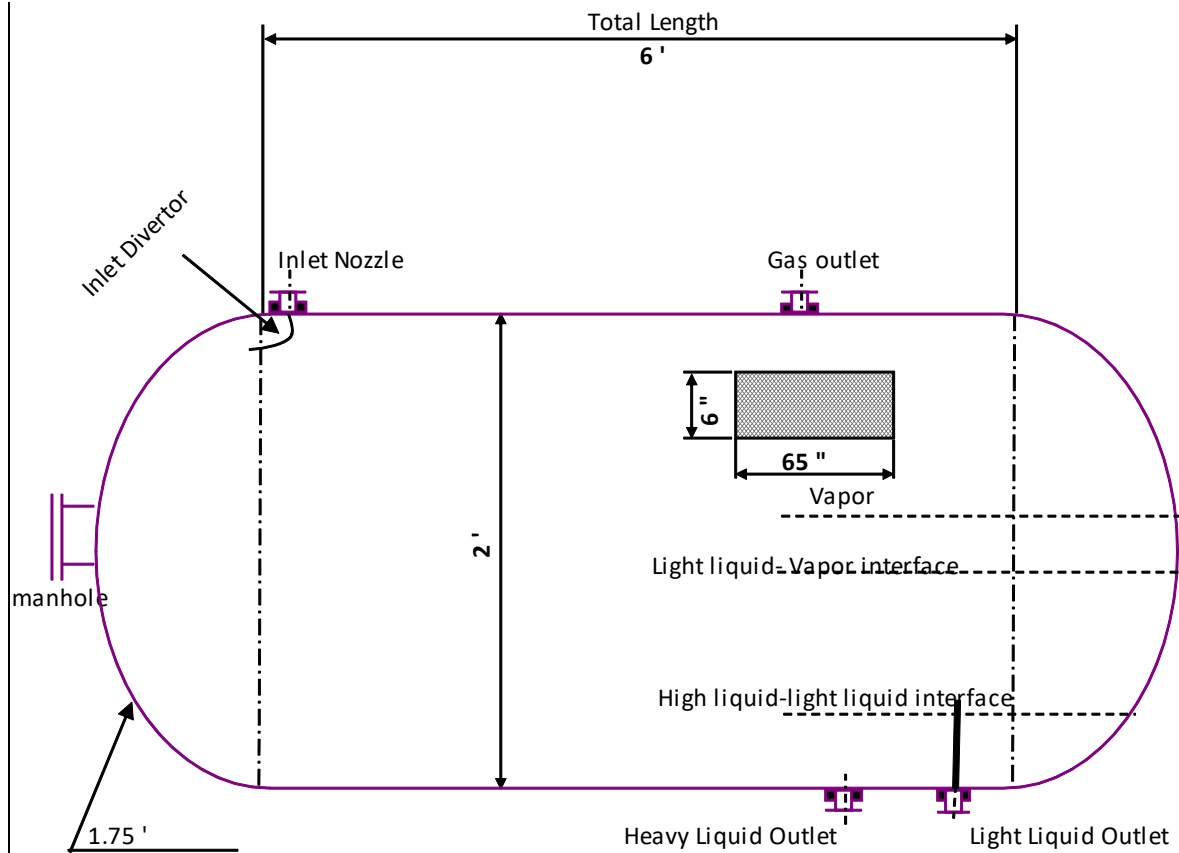


Figure 8-1

2 Phase Horizontal MP Separator	
Diameter [ft]	1.5
Total Length [ft]	4.5
L/D Ratio	3
Max. Allow. Vap. Velocity [ft/s]	1.28
Demister Thickness [in]	6
Liq. Residence Time [seconds]	3.20
Liq. Surge Height [ft]	0.50
Low Level Shut Down Height [ft]	1
Liq. Res. Time at LLSD [seconds]	7.89
Total Vapor Height [ft]	1.00

Table 8-2

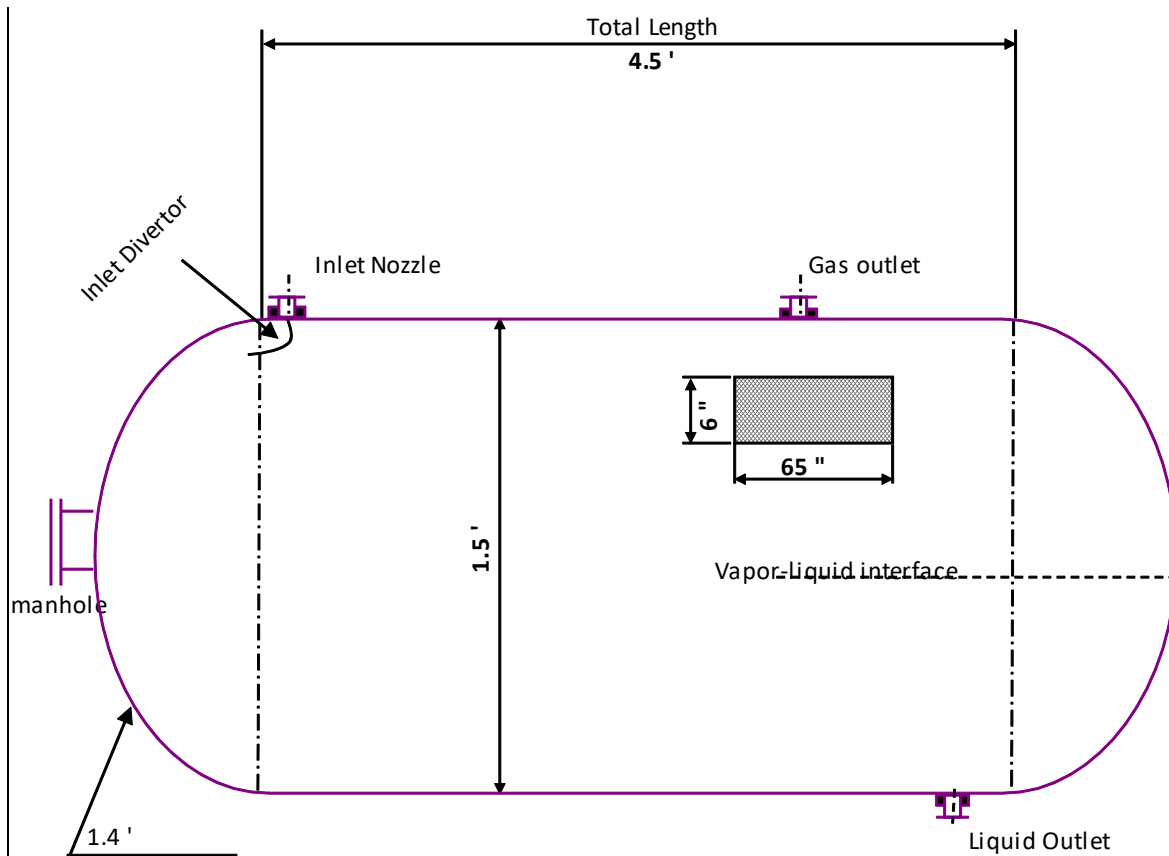


Figure 8-2

2 Phase Horizontal LP Separator	
Diameter [ft]	5.5
Total Length [ft]	19.25
L/D Ratio	3
Max. Allow. Vap. Velocity [ft/s]	1.77
Demister Thickness [in]	5.91
Liq. Residence Time [seconds]	300
Liq. Surge Height [ft]	10.39
Low Level Shut Down Height [ft]	2.5
Liq. Res. Time at LLSD [seconds]	61.70
Inlet Nozzle To Demister [ft]	5.00
Demister Thickness [in]	5.91
Demister To Head [ft]	1
Ellipsoidal Head [ft]	1.37
Total Vapor Height [ft]	8.86

Table 8-3

2 Phase Vertical Separator – KOD 1	
Diameter [ft]	1.5
Total Length [ft]	5.25
L/D Ratio	3
Max. Allow. Vap. Velocity [ft/s]	1.14
Demister Thickness [in]	5.91
Liq. Residence Time [seconds]	300
Liq. Surge Height [ft]	0.89
Low Level Shut Down Height [ft]	1.5
Liq. Res. Time at LLSD [seconds]	539.21
Inlet Nozzle To Demister [ft]	1.49
Demister Thickness [in]	5.91
Demister To Head [ft]	1
Ellipsoidal Head [ft]	0.37
Total Vapor Height [ft]	4.36

Table 8-4

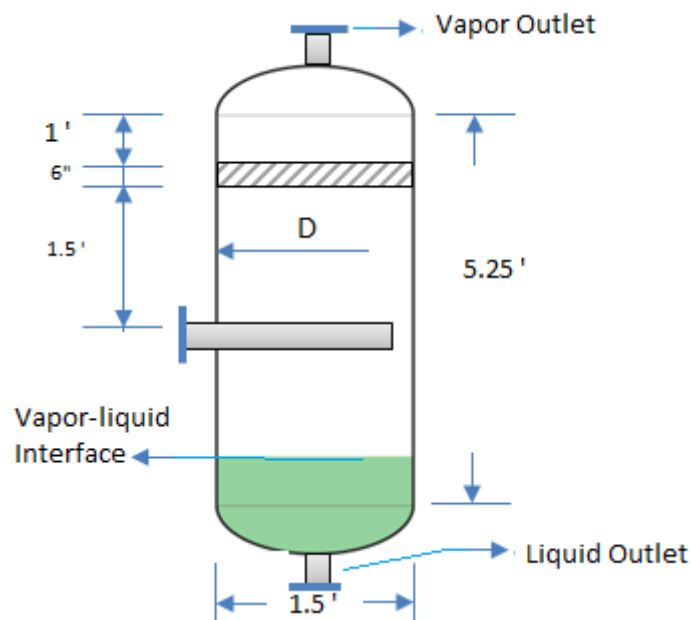


Figure 8-3

2 Phase Vertical Separator	KOD 2A	KOD 3A	KOD 2B	KOD 3B
Diameter [ft]	1.5	1.5	1.5	2
Total Length [ft]	5.25	5.25	5.25	7
L/D Ratio	3	3	3	3
Max. Allow. Vap. Velocity [ft/s]	1.14	2.16	3.27	1.34
Demister Thickness [in]	5.91	5.91	5.91	5.91

Liq. Residence Time [seconds]	300	1047.00	1250.23	925.20
Liq. Surge Height [ft]	0.89	0.88	0.70	0.83
LLSD [ft]	1.5	1.5	1.5	1.5
Liq. Res. Time at LLSD [seconds]	539.21	1918	3004.36	1866.19
Inlet Nozzle To Demister [ft]	1.49	1.51	1.69	3.18
Demister Thickness [in]	5.91	5.91	5.91	5.91
Demister To Head [ft]	1	1	1	1
Ellipsoidal Head [ft]	0.37	0.37	0.37	0.5
Total Vapour Height [ft]	4.36	4.37	4.55	6.17

Table 8-5

8.2 Compressors

The compressors are rated on the basis of inlet temperature, pressure and flow rates and the outlet pressure.

Reciprocating compressor		
	Compressor 2	Compressor 3
Inlet Temperature [F]	93	93
Inlet Pressure [psia]	240	58
Outlet Pressure [psia]	62	890
Pressure Increase [psi]	380	832
Head [ft]	32382	69634
Fluid Head [lbf-ft/lbm]	32382	69634
Capacity [ACFM]	42.46	66.83
Speed [rpm]	50.01	5813576208
Power Consumed [hp]	62.60	118.41
Driver type	Motor	Motor

Table 8-6

8.3 Heat Exchangers

The Heater is used to heat the stream entering the separator. The temperature of 250 F is selected for the separation so shell & tube heat exchanger can be used with hot utility stream at the shell side and process stream on the tube side.

The Ambient Cooler is used to cool the stream entering the tank. The desired influx temperature for the tank is 60 F so shell & tube exchanger can be used with cold utility stream at the tube side and process stream on the shell side.

A list of heating and cooling utilities, with temperature ranges is presented in the Table below [9]. The MP stream is selected for heater and cooling water is used for cooler.

	Utility	Typical operating Range (F)
Hot Utilities— In increasing cost per BTU	Low-pressure steam, 15 to 30 psig	250 to 275 F
	Medium-pressure steam, 100 to 150 psig	325 to 366 F
	High-pressure steam, 400 to 600 psig	448 to 488 F
	Fuel oils	
	Fuel gas	Process waste stream
	Petroleum oils	Below 600 F
	Dowtherms	Below 750 F
Cold Utilities— In increasing cost per BTU	Boiler feed water	Used to raise process steam
	Air cooling	Supply at 85 to 95 F—temperature approach to process 40 F
	River water	Supply at 80 to 90 F (from cooling tower), return at 110 F
	Cooling water	Supply at 80 to 90 F (from cooling tower), return at 115 to 125 F
	Chilled water	45 to 90 F
	Refrigerated brine	0 to 50 F
	Propane refrigerant	40 to 20 F

Table 8-7

Shell & Tube Heat exchanger		
	Inlet Heater	Ambient Cooler
Hot Inlet Temperature [F]	347.00	237
Hot Outlet Temperature [F]	345.20	78
Cold Inlet Temperature [F]	60.10	68
Cold Outlet Temperature [F]	250.00	77
Cold Side Fluid	Process Stream	Cooling Water
Hot Side Fluid	MP Stream	Process Stream

Table 8-8

The Cooler 1, Cooler 2A, Cooler 2B, Cooler 3A, Cooler 3B are Air fin fan coolers. Aerial cooler can be used to cool the process stream entering the Knock out drums.

Air coolers					
	Cooler 1	Cooler 2A	Cooler 2B	Cooler 3A	Cooler 3B
Hot Inlet Temperature [F]	250	250.2	223.9	248.7	377.4
Hot Outlet Temperature [F]	93	93	93	93	150.1
Cold Inlet Temperature [F]	86	86	86	86	86
Cold Outlet Temperature [F]	95	95	95	95	95
Cold Side Fluid	Air	Air	Air	Air	Air
Hot Side Fluid	Process Stream	Process Stream	Process Stream	Process Stream	Process stream

Table 8-9

8.4 Tanks

The fixed roof tank with gas blanketing system can be used against overpressure or vacuum conditions. The tank can be equipped with pressure-vacuum valves and purged with natural gas to eliminate air intake into the vapor space. This system is a safe way to handle vapors from the liquid and to avoid the air mixing in the tank.

When the vapor pressure of the liquid at the inlet of the tank exceeds the atmospheric pressure at normal ambient temperatures, a gas blanketing system is required to maintain a positive tank pressure and minimize the chance of air drawn into the tank vapor space. A gas blanketing system includes the suitable supply of natural gas and pressure regulator that operates to maintain the tank pressure at the predetermined level such to cope up with the atmospheric temperature variations. If the pressure continuously rises the pressure vents releases the pressure by venting blanketing gas and product vapor.

Storage tank	
Vessel diameter [ft]	57.50
Vessel height [ft]	26.00
Design gauge pressure [psig]	15.00
Design temperature [F]	70.00
Number of Holding days	1
Holding hours of day	24
Vapor Free space (% of total storage vessel volume)	5

Table 8-10

9 Project Cost

Aspen Economic Analysis (APEA) is used to estimate the investment or the capital projects at the beginning of a project when only rough preliminary data is available. This analysis can help analyze the economics of the design and assist in the decision making for the project. It also reduces the time and effort required to find optimal designs. Capital and utility cost reduction is of vital importance in the process industry.

The cost analysis can be obtained by simulation or process data for streams and unit operations, identifying the process stream costs, specifying the process utility conditions and prices, mapping the unit operations to the constituent equipment, sizing the equipment based on simulation process data and design standards, evaluating the equipment for cost based on the sizing and so on.

The model for project costing is set up on APEA by specifying process information, mapping the unit operation in the process simulation to sets of equipment, which represent the constituent parts of a unit operation, sizing and customizing the previously defined equipment based on codes/standards and process needs.

The unit operation needs to be mapped accurately to ensure that correct equipment is selected for the particular process. The quoted cost items are estimated by defining a fixed material cost for the base equipment, and then labor hours for the time required to get the equipment installed and running. The combination of the two, allows the economics engine to identify a cost estimate for the quoted equipment.

Aspen Economic Analysis has an interactive sizing expert tool which automatically sizes unit operations based on simplified routines to generate enough parameters to evaluate the cost of the item successfully. Once the mapping, equipment sizing and customization steps are complete, the cost engine can evaluate the cost of the process and its equipment. This will deliver a final process capital and utility cost that can be used to compare relative costs of process case alternatives.

The Aspen Economic Analysis optimizes the design based on feedback from the economics products, simulate different process conditions to see the effects of various changes on important pieces of equipment and unit operations, models stream data directly that has a direct effect on equipment design and cost, directly transfer work done by process engineers on the simulation towards creating the basis for an estimate. This feature uses a comprehensive design-build model by associating appropriate plant bulk materials with specific equipment.

The operating life of plant is selected for 5 years, and the 8766 hours of operation per year. These parameters have effect on the time based cost calculation and capital investment. The economic analysis also includes the raw materials needed for the process feed as well as any product information. Prices for either can be directly linked to simulation streams to get accurate feed stream and product prices over time. The utilities are selected either by user or from the HYSYS defined process utility.

This feature uses distinctive volumetric method for sizing and evaluating process equipment. The volumetric modeling technique accounts for equipment and associated plant and installation bulk materials such as pipes, foundations, supports, controls, etc. that are necessary to install and operate a piece of equipment or the plant. Volumetric modeling builds equipment as a fabricator would, determining equipment requirements like piping, flanges, nozzles, material requirements, instrumentation, bulks, etc. dynamically based on the availability of process stream information and an extensive library of virtual P&IDs for the equipment.

Table 8-1 provides the information required for specifying each piece of the equipment. The materials of construction (MOC), and operating temperature and pressure, are required for all units. The selection of materials for construction, based on strength, corrosivity, and cost of fabrication, is vital to product and process design and economic evaluation. For process design, corrosion and strength data as a function of temperature are needed for the expected chemical compositions within the process. Equipment vendors can also assist in the final selection of materials. In general, carbon steel is used wherever possible because of its low cost and ease of fabrication.


Equipment type	Required specification
Vessel	Height

	Diameter
	Orientation
	Pressure
	Temperature
	Materials of construction
Compressors	Driver type
	Inlet flow
	Suction and discharge pressures
	Temperature
	Shaft power
	Materials of construction
Heat exchangers	Type
	Area
	Duty
	Number of shell and tube passes
	Shell and tubes: operating temperature
	Shell and tubes :pressure
	Shell and tubes :pressure drop
	Shell and tubes: materials of construction

Table 9-1

9.1 Separator Cost Estimation

It uses following equations to calculate the cost of Separators based on volumetric method:

 Costing Equations Help

Thickness

Thickness based on the strength of the long seams

$$B1 = (P * D/2)/(T * Eff - A1 * P) + \text{Corrosion Allowance}$$

Thickness based on the strength of the ends

$$B2 = (P * D/2)/(A2 * T * Eff - A3 * P) + \text{Corrosion Allowance}$$

Shell Mass

$$B = \max(B1, B2)$$

$$\text{Shell Mass} = \pi * D * (L + A4 * D) * B * \text{Mass Density}$$

Base Cost

$$\text{Base Cost} = \text{FMC} * (\text{Index}/252.5) * e^Y$$

$$Y = A5 + A6 * \log(M) + A7 * \log(M^2)$$

Accessories

$$\text{Accessories Cost} = (\text{Index}/252.5) * A8 * D^{A9} * L^{A10}$$

Variables

P = Pressure (Kpag)	D = Diameter (m)
T = Max. Stress (Kpa)	M = Shell Mass (Kg)
FMC = Material of Fab Factor	Index = CE Fab Index
L = Length (m)	Eff = Joint Efficiency

Figure 9-1

Construction Information	
Chemical Eng. Index	252.5
Material Type	Carbon Steel
Mass Density [lb/ft3]	490.8
FMC	1.000
Allowable Stress [psia]	1.370e+004
Shell Thickness [in]	3.250
Corrosion Allowance [in]	0.1250
Efficiency of Joints	1.000

Figure 9-2

The costing and its associated design parameters are as follows:

Horizontal Separators			
	LP Separator	MP Separator	HP Separator
Liquid volume [ft3]	314	314	314
Vessel diameter [ft]	5	5	5
Vessel tangent to tangent length [ft]	16	16	16
Design gauge pressure [psig]	68.3	257.3	1035.3
Design temperature [F]	298.6	300.2	300
Operating temperature [F]	248.6	250.2	250
Equipment Weight [LBS]	5100	9600	26700
Installed Weight [LBS]	21826	25377	51057
Equipment Cost [USD]	23100	30100	65700
Installed Cost [USD]	133900	126700	193400

Table 9-2

Vertical Separators					
	KOD 1	KOD 2B	KOD 3B	KOD 3A	KOD 2A
Liquid volume [ft3]	84.82	84.821	84.82	84.82	84.821
Vessel diameter [ft]	3	3	3	3	3
Vessel tangent to tangent height [ft]	12	12	12	12	12
Design gauge pressure [psig]	1032.3	652.31	922.31	68.30	250.30
Design temperature [F]	250	250	250	250	250
Operating temperature [F]	93	93	150	93	93
Equipment Weight [LBS]	8100	6000	8600	2600	3600
Installed Weight [LBS]	16123	13268	17887	10256	10831
Equipment Cost [USD]	26500	21800	26100	15600	17900
Installed Cost [USD]	105500	93600	109300	96000	89600

Table 9-3

Tank	
Equipment Weight [LBS]	191900
Installed Weight [LBS]	273977
Equipment Cost [USD]	399100
Installed Cost [USD]	712400

Table 9-4

9.2 Utility Cost estimation

The Heating and cooling requires heat optimization of the streams. The criterion to select the optimum energy source is based on multiple factors. Some of the factors are the availability of the source, the cost of the energy stream and the reuse of the energy. Table 9-5 shows unit rate of the utilities required for the project and their cost per hour.

Utility Costing	
Utility	Cost per Hour
Electricity [KW]	\$13.7
MP Steam [BTU/H]	\$32.38
Cooling Water[BTU/H]	\$2.32

Table 9-5 : cost estimation of utilities

9.3 Heat Exchanger Cost estimation

Shell & Tube Heat exchanger		
	Inlet heater	Ambient Cooler
Heat transfer area [ft2]	10339.54	1643.32
Front end TEMA symbol	B	B
Shell TEMA symbol	E	E
Rear end TEMA symbol	M	M
Tube design gauge pressure [psig]	685.30	68.30
Tube design temperature [F]	397	286.44
Tube operating temperature [F]	347	77
Tube outside diameter [ft]	0.08	0.08
Shell design gauge pressure [psig]	1035.31	68.30
Shell design temperature [F]	300	286.44
Shell operating temperature [F]	250	236.44
Tube length extended [ft]	20	20
Tube pitch [ft]	0.10	0.10
Number of tube passes	1	1
Number of shell passes	1	1
Equipment Weight [LBS]	124700	12000
Installed Weight [LBS]	197872	29910
Utility Cost [USD/HR]	32.38	2.32

Equipment Cost [USD]	357700	36700
Installed Cost [USD]	622900	122400

Table 9-6

Air cooler					
	Cooler 1	Cooler 2B	Cooler 3B	Cooler 3A	Cooler 2A
Bare tube area 1st service [ft ²]	628.32	94.25	56.55	56.55	113.10
Design gauge pressure 1st serv. [psig]	1035.31	655.31	925.31	68.30	257.30
Tube outside diameter 1st serv. [ft]	0.08	0.08	0.08	0.08	0.08
Tube length [ft]	8	4	4	4	4
Bay width [ft]	5.5	4	4	4	4
Number of bays	1	1	1	1	1
Fin pitch	11	11	11	11	11
Tube fin height [ft]	0.05	0.05	0.05	0.05	0.05
Tube pitch [ft]	0.20	0.20	0.20	0.20	0.20
Equipment Weight [LBS]	11700	5400	5200	4500	5300
Installed Weight [LBS]	19695	9913	10122	8727	10349
Utility Cost [USD/HR]	0.29	0.12	0.12	0.12	0.12
Equipment Cost [USD]	57100	35900	34300	32600	36000
Installed Cost [USD]	106500	76100	76200	72100	77700

Table 9-7

9.4 Compressor Cost Estimation

Reciprocating gas compressors		
	Compressor 2	Compressor 3
Actual gas flow rate Inlet [ACFM]	42.43	116.85
Design gauge pressure Inlet [psig]	225.3	43.3
Design temperature Inlet [F]	93	93
Design gauge pressure Outlet [psig]	605.3	875.3
Driver power [hp]	60.62	118.45
Molecular weight	24.92	38.85
Specific heat ratio	1.19	1.14
Compressibility factor Inlet	0.92	0.95
Compressibility factor Outlet	0.91	0.82
Driver type	MOTOR	MOTOR
Equipment Weight [LBS]	13600	12300
Total Installed Weight [LBS]	24249	22560
Equipment Cost [USD]	445600	980800
Installed Cost [USD]	522400	1098400

Table 9-8

9.5 Total Project Estimation

Summary	
Total Capital Cost [USD]	9715650
Total Operating Cost [USD/Year]	2134600
Total Utilities Cost [USD/Year]	720255
Desired Rate of Return [Percent/'Year]	20
Equipment Cost [USD]	2187000
Total Installed Cost [USD]	4055500

Table 9-9

10 Conclusion

The simulation of surface separation facility is essential to optimize the production of the oil and minimize the associated cost. The Composition and properties data of the well fluids were introduced to HYSYS process simulator. The optimal number of separators and their operating conditions were analyzed and several sets of equipment configuration and operating conditions were tested. Three-stage separation was selected as the possible scheme to maximize production and increase process train flexibility. The effects of pressure and temperature on produced oil defined the criteria to setup vapor recovery unit.

The effect of various conditions was observed on Oil Production, RVP, API and water-content in oil, and compressors power requirements. The developed model was analyzed for different production states which cover the production conditions from the start to end of the production. Significant effect on the water in oil content was observed. The well shut downs scenarios show the effect of light and heavy oil on API, RVP and water content in oil. For different production states and well shutdown combinations, the process train was optimized by shutting down of compressor and bypassing the knock out drums. The recommended industrial practice for de-emulsification has been discussed in case the laboratory tests indicate significant emulsification tendency.

Carry over calculation was introduced for a realistic equipment design and simulation. Carry over estimation was conducted for the high pressure separator. Droplet size distribution calculations were included. It was figured out that a three phase separator with a boot, in combination with a standard mesh pad demister can meet the final product water in oil specification.

The basic specifications of all equipment were determined at the optimal operating conditions. The utilities were chosen to match the equipment energy requirements, the economic cost and availability. Finally, the cost estimation for the equipment and energy was generated using Aspen economic analyzer tool. The estimated cost was verified on online website¹ developed by Matches and it was found to be reasonable cost analysis. Matches is a certified engineering company which provides cost estimation for development of new products, process and chemical technology by providing basic size, material ,rating etc.

The basic design discussed in the thesis proved to be the step-stone towards the detail design of the process train. It can be said that with the continuous improvement in the modern simulators and availability of technical data; all the experiments and industrial practices in the industry may be simulated at a PC desktop.

¹

<http://www.matche.com/default.html>

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