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Department of Petroleum Engineering

THE PROJECT TITLE

Three Phases Separator Design of Zelten Field

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Supervised By

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Project Report Submitted as Partial Fulfillment of the Requirements for the Degree of Bachelor in Petroleum Engineering

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ABSTRACT

In the industry world, the necessity for planning and scheduling are required to keep up with both daily production requirements and uncertain future environmental changes. The performance and internal multiphase flow behavior in a three-phase separator was investigated. The separator considered represents an existing surface facility belonging to Sirte Company for Onshore Oil Operations. The importance of these activities is to develop optimization strategies to find the optimal capacity Gas, Oil and water values for an onshore three phases separation train.

In currently operation processwe use three phase horizontal separators in the gas oil separation plant to separate the well fluids arriving from outlying production fields.

Generally, a vessel of this type is used to separate Gas, Oil and Water.

This project covers the principles of separation process, type of separators and main functions with illustrative diagrams of internal construction in addition applying data obtained from Zelten field in the equations to determine the separator capacity of each phase.

ACKNOWLEDGEMENTS

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I would like to thank all my university fellows, near and far away friends, my friend Ibrahim Algn, uncles, aunts and cousins for their support during the development of my bachelor degree and the help through my path in these four years.

Especially and above all deep thanks from the bottom of my heart goes to my family; Father, Mother , Brothers and my Sisters.

Thank you all for the love and support, It's truly heartening. you have influenced my life in such a positive way words cannot express my appreciation. You are truly an inspiration.

APPROVAL

This project report is submitted to the Faculty of Technical Engineering, Bright Star University – Brega, and has been accepted as partial fulfillment of the requirement for the degree of bachelor in Petroleum Engineering. The members of the Examination Committee are as follows:

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Supervisor

Department of Petroleum Engineering

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Examiner 1

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Examiner 2

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Faculty of Technical Engineering

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DECLARATION

I hereby declare that the project report is my original work except for quotations and citations, which have been duly acknowledged. I also declare that it has not been previously, and is not concurrently, submitted for any other degree at Bright Star University – Brega or at any other institution.

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Ahmed Hussein Mohammed Abdullah

21141123

Date:

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NOMENCLATURES

Symbol	Description	Unit
q	Oil capacity	Ft^3/min
Vo	oil volume	min/ft^3
Tr	retention Time	min
Di	Inside diameter	ft
H	high of column	ft
C	drag coefficient	
Pg	density of gas	ib/ft
U	velocity	ft/sec
separation coefficient	K	
P	operating pressure	psia
Z	compressibility factor	
A	Area	Ft^2

Abbreviation	Description
LPG	liquefied petroleum gas
ATF	aviation turbine fuel
HSD	high speed diesel
GOR	gas oil ratio
GOSP	gas oil separation plant
ASTM	American society for testing and Materials
API	American petroleum institute

Chapter I

CRUDE OIL

1-CRUDE OIL:

1.1 INTRODUCTION:

Raw petroleum is known as crude oil or mineral oil. It is a mixture of various organic substances and is the source of hydrocarbons, such as methane, ethane, propane, butane, pentane, and various other paraffinic, naphthenic, and aromatic hydrocarbons. Various petroleum products, such as gaseous and liquid fuels, lubricating oil, solvents, asphalts, waxes, and coke, are derived from refining crude oil. Many lighter hydrocarbons and other organic chemicals are synthesized by thermal and catalytic treatments of these hydrocarbons.

The hydrocarbon processing industry is basically divided into three distinct activities petroleum production, petroleum refining, and petrochemical manufacture. Refineries produce cooking gas (liquefied petroleum gas or LPG), motor spirit (also known as petrol or gasoline), naphtha, kerosene, aviation turbine fuel (ATF), high speed diesel (HSD), lubricating base oils, wax, coke, bitumen (or asphalt), *etc.*, which are mostly a mixture of various hydrocarbons (the organic compounds made of carbon and hydrogen as the major constituent elements). In a petrochemical plant (where one or more petrochemicals are produced) or in a petrochemical complex (where many petrochemical products are produced), pure hydrocarbons or other organic chemicals with a definite number and type of constituent element or compound are produced from the products in refineries.

Thus, petrochemicals are derived from petroleum products obtained from refineries. Products from a petrochemical complex are plastics, rubbers, synthetic fibers, raw materials for soap and detergents, alcohols, paints, pharmaceuticals, etc.

Since petroleum is the mixture of hundreds of thousands of hydrocarbon compounds, there is a possibility of synthesizing many new compounds. In fact, due to the advancement of new technology, new petrochemicals are being invented and will continue to be added to this industry in the near future. Hence, the petrochemical industry is still a growing industry.

The manufacture of valuable petrochemicals from low-valued petroleum products has been the main attractive option for the refining industry investing in the petrochemical industry. Thus, modern refineries are, in fact, refinery cum petrochemical complexes.

1.2 COMPOSITION OF CRUDE OIL

The compounds in crude petroleum oil are essentially hydrocarbons or substituted hydrocarbons in which the major elements are carbon at 85%-90% and hydrogen at 10%–14%, and the rest with non-hydrocarbon elements sulfur (0.2%–3%), nitrogen (< 0.1–2%), oxygen (1%–1.5%), and organ metallic compounds of nickel, vanadium, arsenic, lead, and othermetals in traces (in parts per million or parts per billion concentration).

Inorganic salts of magnesium chloride, sodium chlorides, and other mineral salts are also accompanied with crude oil from the well either because of water from formation or water and chemicals injected during drilling and production.

1.2.1 PARAFFIN'S

Paraffin's, also known as alkanes, are a saturated compound that have the general formula $C_nH_2n+_2$, where n is the number of carbon atoms.

The simplest alkane is methane (CH_4), which is also represented as C1. Normal paraffin's (n-paraffin's or n-alkanes) are unbranched straight- chain molecules.

Each member of these paraffin's differs from the next higher and the next lower member by a –CH_2– group called a methylene group.

They have similar chemical and physical properties, which change gradually as carbon atoms are added to the chain.

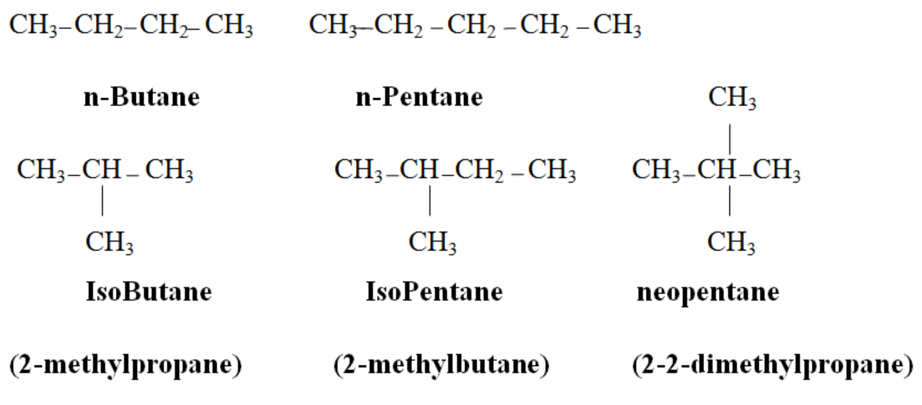


Figure 1.1 Paraffin's structure.

1.2.2 NAPHTHENES

Naphthenes, also known as cycloalkanes, are saturated hydrocarbons that have at least one ring of carbon atoms. They have the general formula C_nH_{2n}. A common example is cyclohexane (C_6H_{12}).

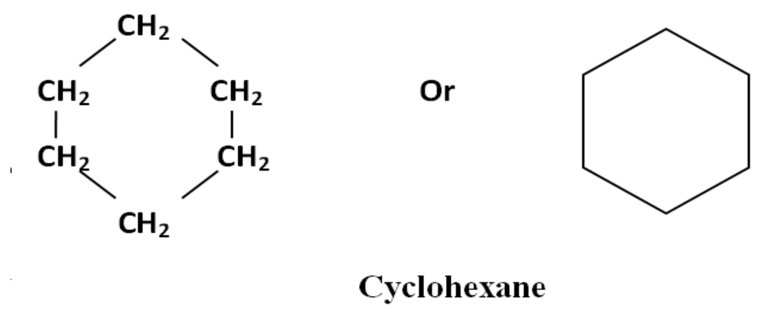


Figure 1.2 Naphthenes structure .

The boiling point and densities of naphthenes are higher than those of alkanes having the same number of carbon atoms. Naphthenes commonly present in crude oil are rings with five or six carbon atoms.

1.2.3 AROMATICS

Aromatics are unsaturated cyclic compounds composed of one or more benzene rings. The benzene ring has three double bonds with unique electron arrangements that make it quite stable.

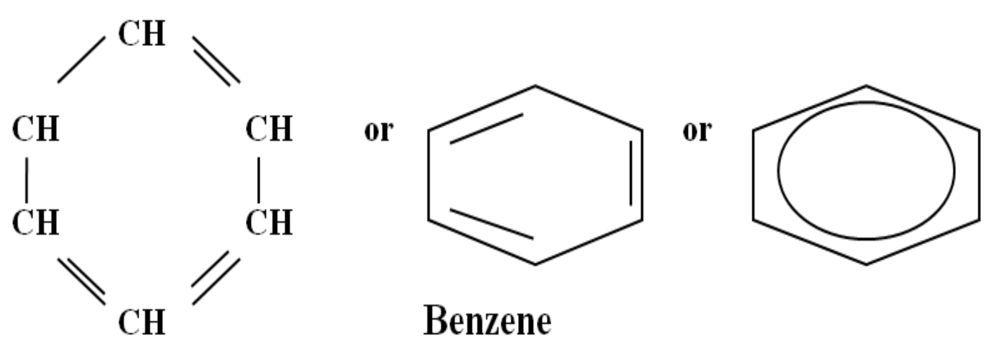


Figure 1.3 Aromatics structure

1.2.4 SULPHUR COMPOUNDS

The Sulphur content of crude oils varies from less than 0.05 to more than 10 wt% but generally falls in the range 1–4 wt%. Crude oil with less than 1 wt % sulphur is referred to as low sulphur or sweet, and that with more than 1 wt% sulphur is referred to as high sulphur or sour.

1.2.5 OXYGEN COMPOUNDS

The oxygen content of crude oil is usually less than 2 wt%. Phenomenally high oxygen content indicates that the oil has suffered prolonged exposure to the atmosphere.

Oxygen in crude oil can occur in a variety of forms. These include alcohols, ethers, carboxylic acids, phenolic compounds, ketones, esters and anhydrides.

The presence of such compounds causes the crude to be acidic with consequent processing problems such as corrosion.

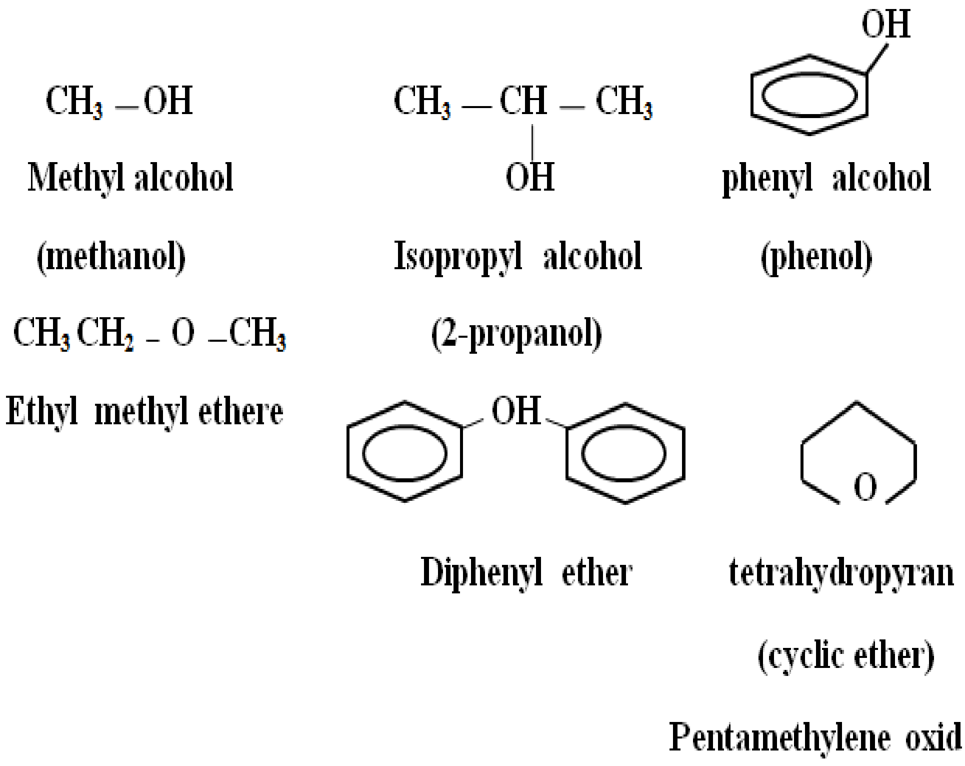
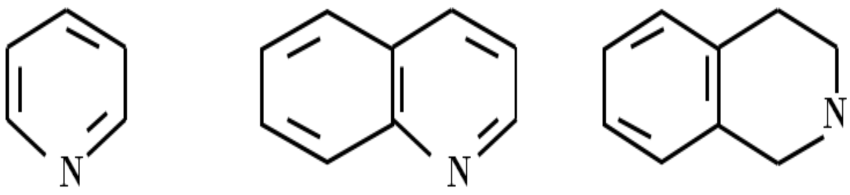


Figure 1.4 Alcohols, ethers, carboxylic acids, phenolic compounds, ketones

1.2.6 NITROGEN COMPOUNDS

Crude oils contain very low amounts of nitrogen compounds. In general, the more asphaltic the oil, the higher its nitrogen content Nitrogen compounds are more stable than Sulphur compounds and therefore are harder to remove. Even though they are present at very low concentrations, nitrogen compounds have great significance in refinery operations. They can be responsible for the poisoning of a cracking catalyst, and they also contribute to gum formation in finished products. The nitrogen compounds in crude oils may be classified as basic or non-basic. Basic nitrogen compounds consist of pyridines. The greater part of the nitrogen in crude oils is the non-basic nitrogen compounds, which are generally of pyrrole types. Pyridines are six-membered hetero-aromatic compounds containing one nitrogen atom.

When fused with benzene rings, pyridines are converted to the polycyclicheteroaromatic compounds quinolines and isoquinolines.



Pyridine (C_2H_5N) quinoline (C_9H_7N) isoquinoline (C_9H_7N)

Figure 1.5Nitrogen Compounds with organic compounds.

1.2.7 METALLIC COMPOUNDS

Metallic compounds exist in all crude oil types in very small amounts. Their concentration must be reduced to avoid operational problems and to prevent them from contaminating the products. Metals affect many upgrade-ing processes. They cause poisoning to the catalysts used for hydroprocessing and cracking.

Even minute amounts of metals (iron, nickel and vanadium) in the feedstock to the catalytic cracker affect the activity of the catalyst and result in increased gas and coke formation and reduced gasolineyields. For high-temperature power generators, the presence of vanadium in the fuel may lead to ash deposits on turbine blades and cause severe corrosion, and the deterioration of refractory furnace linings.

1.2.8 ASPHALTENES

Resins Asphaltenes are dark brown friable solids that have no definite melting point and usually leave carbonaceous residue on heating. They are made up of condensed polynuclear aromatic layers linked by saturated links.

These layers are folded, creating a solid structure known as a micelle. Their molecular weights span a wide range, from a few hundred to several million. Asphaltenes are separated from petroleum in the laboratory using non-polar solvents such as pentane and n-heptane/

1.3 CRUDE OIL ASSAY

A crude oil assay is essentially the chemical evaluation of crude oil feedstocks by petroleum testing laboratories. Each crude oil type has unique molecular, chemical characteristics. No crude oil type is identical and there are crucial differences in crude oil quality. The results of crude oil assay testing provide extensive detailed hydrocarbon analysis data for refiners, oil traders and producers.

Various parameters used for Storage & Handling of crude oil are as follows:

1.3.1 API GRAVITY

This is the most common measurement performed on petroleum products; density is expressed in terms of API gravity. This measurement determines the weight of a crude oil per unit volume at 60 °F, normally measured by the Hydrometer method..

$$API\ Gravity = \frac{141.5}{sp.gr\ at\ 60°F} - 131.5$$

1.3.2 VISCOSITY

Viscosity is a measurement of a fluid resistance to flow. Most measurements use the force of gravity to produce the flow through a small capillary tube called a viscometer; thus the measurement is known as kinematic viscosity having a unit of centistokes (C.st).

1.3.3 REID VAPOR PRESSURE (RVP)

RVP is measurement of the volatility of a liquid hydrocarbon. Normally this is performed by ASTM D 323. This measurement is normally used to predict gasoline performance, normally expressed in pounds per square inch (psi). This is normally an inspection that is performed on Whole Crudes having relatively high API's.

1.3.4 FLASH POINT

Flash point is the lowest temperature at which application of the test flame causes the vapour and air mixture above the sample to ignite.

1.3.5 SALT CONTENT

The salt content is measured by ASTM D 3230 to determine the corrosiveness of a Crude oil.

It is this conductivity method that measures a sample of crude oil dissolved in water and compares that to reference solutions of salt.

1.3.6 WATER & SEDIMENT

Sediment and water values in crude oils are critical parameters as to whether problems will occur in the processing in the refinery.

In many cases, desalting equipment may be required in order to handle agiven crude slate.

1.3.7 METALS

The metals concentration in crude can range from a few to several thousand ppms.Low values of certain elements such as nickel / vanadium can severely affect catalyst activity.

1.3.8 SULFUR CONTENT.

The sulfur content of crude oils is normally in the range of 0.1-5.0-wt %. Sulfur is normally measured by an x-ray technique such as ASTM D 4294 or D 5291.These methods have large dynamic ranges and allow analysis to be completed in about 3-5 minutes.

Samples having sulfur contents greater than 5.0 % are measured by methods such as ASTM D 1552, a combustion technique. For extremely low levels an ultraviolet fluorescence technique is employed (ASTM D 5453) Again most of these methods are very robust, but can be influenced by not having a representative sample. Crudes are determined to be sweet or sour based on the amount of dissolved hydrogen sulfide All of previous assays are used in Zelten field that prepared by Libyan Petroleum Institute, in addition of these assays, there are several tests that can be conducted with Test separator.

Chapter II
TYPE OF SEPARATORS

2-TYPE OF SEPARATORS

2.1 INTRODUCTION

Produced wellhead fluids are complex mixtures of different compounds of hydrogen and carbon, all with different densities, vapor pressures, and other physical characteristics

As a well stream flows from the hot, high-pressure petroleum reservoir, it experiences pressure and temperature reductions. Gases evolve from the liquids and the well stream changes in character.

The velocity of the gas carries liquid droplets, and the liquid carries gas bubbles. The physical separation of these phases is one of the basic operations in the production, processing, and treatment of oil and gas.

2.2 FACTORS AFFECTING SEPARATION

Characteristics of the flow stream will greatly affect the design and operation of a separator.

The following factors must be determined before separator design:

• Gas and liquid flow rates (minimum, average, and peak)

• Operating and design pressures and temperatures.

• Surging or slugging tendencies of the feed streams.

•Physical properties of the fluids such as density 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.

2.3 THE MAIN FUNCTIONS OF A SEPARATOR ARE:

1. To cause primary phase separation of the liquids from the gases.

2. To contain this process by removing the entrained gas from the liquid.

3. To provide controls that stops the possibility of gas escaping with the liquid.

4. To allow sufficient time in the separator to promote the separation of oil and water.

5. To discharge the separated fluids from the vessel in such a manner that remixing of any of them is impossible.

2.4 EQUIPMENT DESCRIPTION

2.4.1 HORIZONTAL SEPARATORS .

In the (Figure 2-1) is a schematic of a horizontal separator. The fluid enters the separator and hits an inlet diverter causing a sudden change in momentum.

The initial gross separation of liquid and vapor occurs at the inlet diverter. The force of gravity causes the liquid droplets to fall out of the gas stream to the bottom of the vessel where it is collected.

This liquid collection section provides the retention time required to let entrained gas evolve out of the oil and rise to the vapor space

It also provides a surge volume, if necessary, to handle intermittent slugs of liquid. The liquid then leaves the vessel through the liquid dump valve.

The liquid dump valve is regulated by a level controller.

The level controller senses changes in liquid level and controls the dump valve accordingly

The gas flows over the inlet diverter and then horizontally through the gravity settling section above the liquid.

As the gas flows through this section, small drops of liquid that were entrained in the gas and not separated by the inlet diverter are separated out by gravity and fall to the gasliquid interface. 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

This section uses elements of vanes, wire mesh, or plates to coalesce and remove the very small droplets of liquid in one final separation before the gas leaves the vessel.

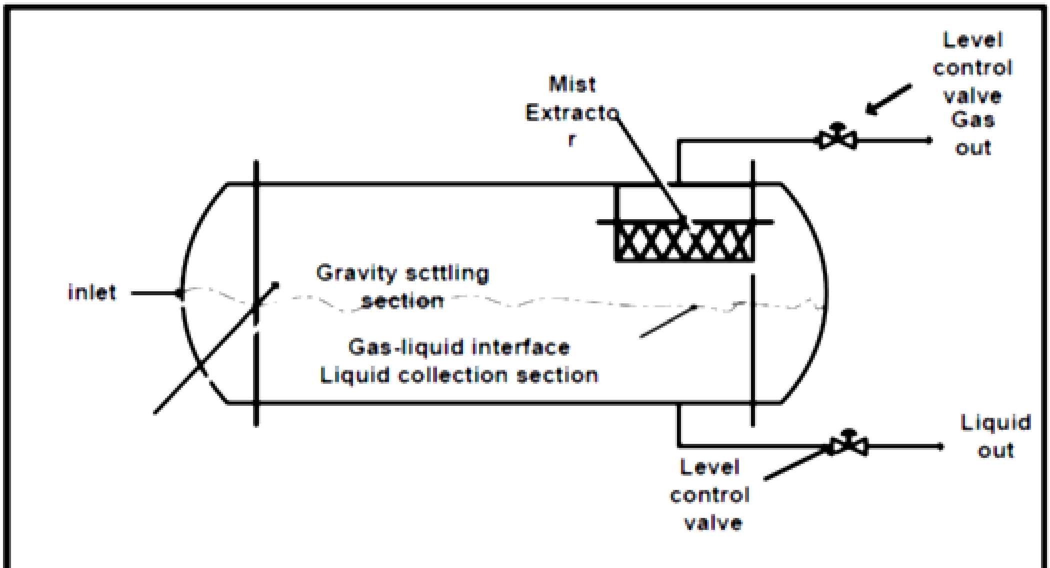


Figure 2.1 Horizontal separator schematic.

The pressure in the separator is maintained by a pressure controller. 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.

2.4.2 VERTICAL SEPARATORS

(Figure 2-2) is a schematic of a vertical separator. In this configuration the inlet flow enters the vessel through the side.

As in the horizontal separator, 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 level controller and liquid dump valve operate the same as in a horizontal separator

The gas flows over the inlet diverter and then vertically upward toward the gas outlet. In the gravity settling section the liquid drops fall vertically downward counter to the gas flow.

Gas goes through the mist extractor section before it leaves the vessel. Pressure and level are maintained as in a horizontal separator.

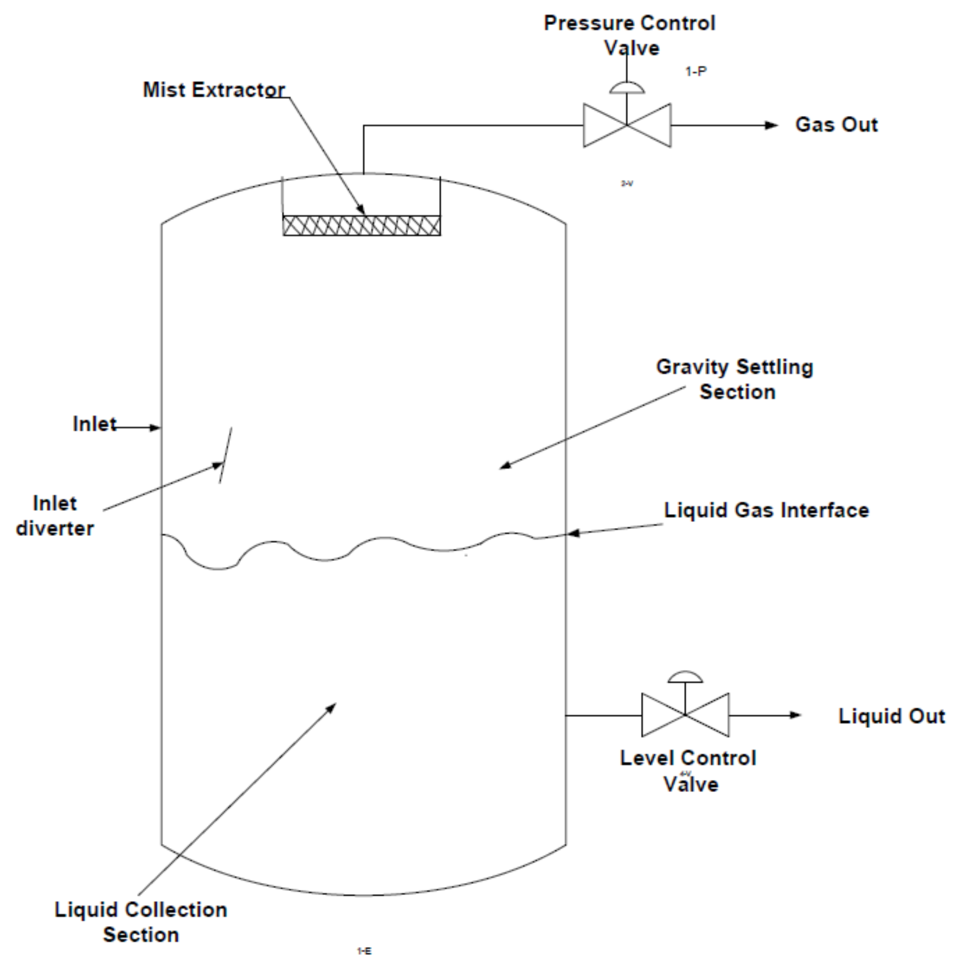


Figure2.2. Vertical separator schematic.

2.4.3 SPHERICAL SEPARATORS

A typical spherical separator is shown in (Figure 2.3) The same four sections can be found in this vessel.

Spherical separators are a specia case of a vertical separator where there is no cylindrical shell between the two heads. They may be very efficient from a pressure containment standpoint but because they have limited liquid surge capability and they exhibit fabrication difficulties, they are not usually used in oil field facilities. For this reason we will not be discussing spherical separators any further.

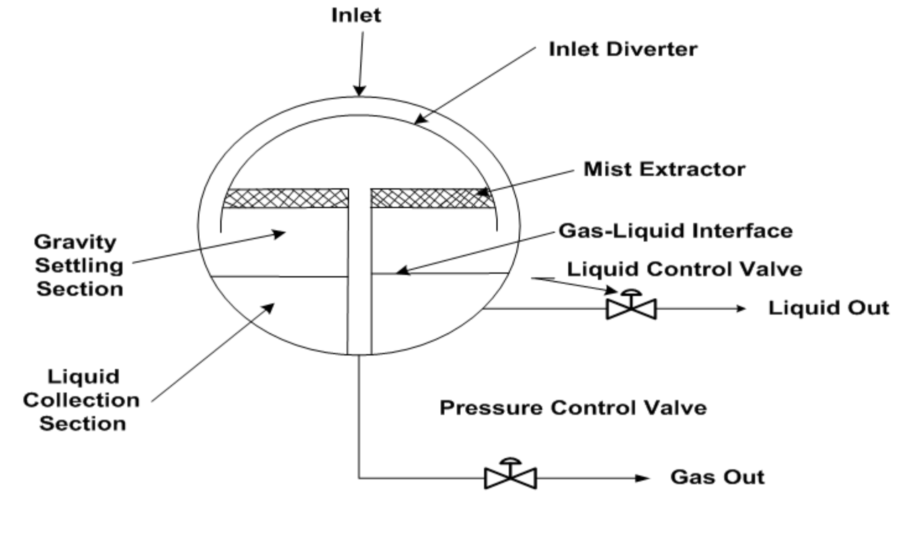


Figure2.3. Spherical separator schematic

2.4.4. CYCLONE SEPARATORS

Other Configurations are designed to operate by centrifugal force. These designs are best suited for fairly clean gas streams. The swirling action of the gas stream as it enters the scrubber separates the droplets and dust from the gas stream by centrifugal force

Although such designs can result in significantly smaller sizes, they are not commonly used in production operations because (1) Their design is rather sensitive to flow rate and (2) They require greater pressure drop than the standard configurations previously described.

Since separation efficiency decreases as velocity decreases, cyclone separators are not suitable for widely varying flow rates.

These units are commonly used to recover glycol carryover downstream of a dehydration tower. In recent years, demand for using cyclone separators on floating facilities has increased because space and weight considerations are overriding on such facilities.

2.4.5 TWO-BARREL SEPARATORS

are common where there is a very low liquid flow rate. In these designs the gas and liquid chambers are separated as shown in (Figure 2.4)

The flow stream enters the vessel in the upper barrel and strikes the inlet diverter. The free liquids fall to the lower barrel through a flow pipe. The gas flows through the gravity settling section and encounters a mist extractor enroots to the gas outlet.

The liquids drain through a flow pipe into the lower barrel.

Small amounts of gas entrained in the liquid are liberated in the liquid collection barrel and flow up through the flow pipes.

In this manner the liquid accumulation is separated from the gas stream so that there is no chance of high gas velocities re-entraining liquid as it flows over the interface. Because of their additional cost, and the absence of problems with single vessel separators, they are not widely used in oil field systems.

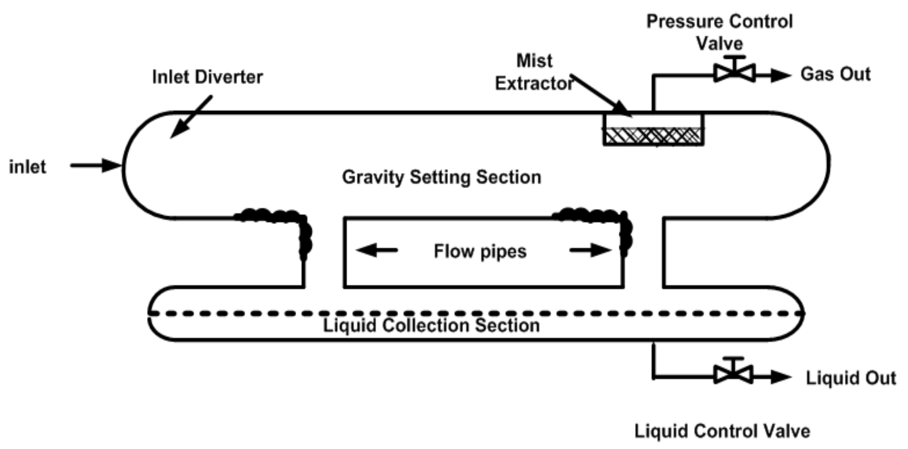


Figure2.4. Double-barrel separator.

2.4.6 FILTER SEPARATOR

Another type of separator that is frequently used in some high-gas/low-liquid flow applications.

These can be either horizontal or vertical in configuration. Figure 2.5 shows a horizontal two-barrel design.

Filter tubes in the initial separation section cause coalescence of any liquid mist into larger droplets as the gas passes through the tubes. A secondary section of vanes or other mist extractor elements.

removes these coalesced droplets. This vessel can remove 100% of all particles larger than about 2 microns and 99% of those down to about 1A micron

Filter separators are commonly used:

-on compressor inlets in field compressor stations.

-Final scrubbers upstream of glycol contact towers.

and instrument/fuel gas applications.

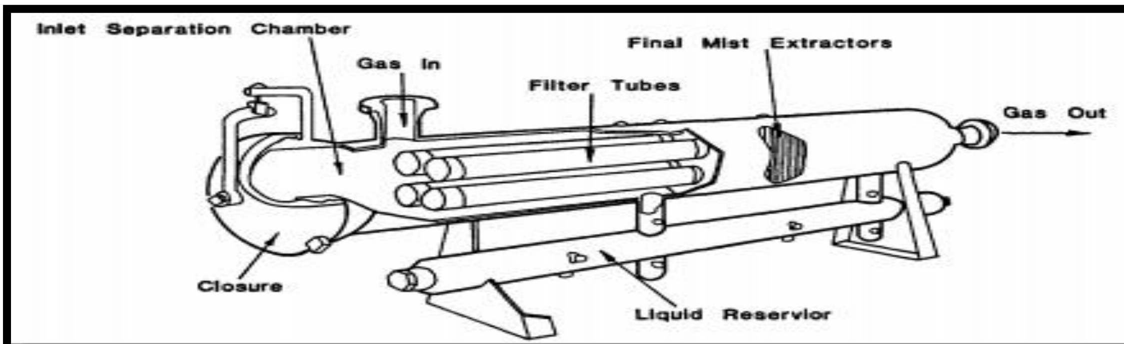


Figure 2.5. Typical Filter Separator

The design of filter separators is proprietary and dependent upon the type of filter element employed.

In applications where there is very little liquid flow, often a horizontal separator will be designed with a liquid sump on the outlet end to provide the required liquid retention time. This results in an overall smaller diameter for the vessel.

2.4.7 SCRUBBERS

A scrubber is a two-phase separator that is designed to recover liquids carried over from the gas outlets of production separators or to catch liquids condensed due to cooling or pressure drops.

Liquid loading in a scrubber is much lower than that in a separator. Typical applications include: upstream of mechanical equipment such as compressors that could be damaged, destroyed or rendered ineffective by free liquid; downstream of equipment that can cause liquids to condense from a gas stream (such as coolers); upstream of gas dehydration equipment that would lose efficiency, be damaged, or be destroyed if contaminated with liquid hydrocarbons; and upstream of a vent or flare outlet. Vertical scrubbers are most commonly used.

Horizontal scrubbers can be used, but space limitations usually dictate the use of a vertical configuration.

2.5 HORIZONTAL Verses VERTICAL VESSEL SELECTION.

Horizontal separators are smaller and less expensive than vertical separators for a given gas capacity. In the gravity settling section of a horizontal vessel, the liquid droplets fall perpendicular to the gas flow and thus are more easily settled out of the gas continuous phase. Also, since the interface area is larger in a horizontal separator than a vertical separator, it is easier for the gas bubbles, which come out of solution as the liquid approaches equilibrium, to reach the vapor space. Horizontal separators offer greater liquid capacity and are best suited for liquid-liquid separation and foaming crudes. Thus, from a pure gas/liquid separation process, horizontal separators would be preferred. However, they do have the following drawbacks, which could lead to a preference for a vertical separator in certain situations:

1. Horizontal separators are not as good as vertical separators in handling solids. The liquid dump of a vertical separator can be placed at the center of the bottom head so that solids will not build up in the separator but continue to the next vessel in the process.

As an alternative, a drain could be placed at this location so that solids could be disposed of periodically while liquid leaves the vessel at a slightly higher elevation

In a horizontal vessel, it is necessary to place several drains along the length of the vessel. Since the solids will have an angle of repose of 45° to 60°, the drains must be spaced at very close intervals. Attempts to lengthen the distance between drains, by providing sand jets in the vicinity of each drain to fluidize the solids while the drains are in operation, are expensive and have been only marginally successful in field operations.

2. Horizontal vessels require more plan area to perform the same separation as vertical vessels. While this may not be of importance at a land location, it could be very important offshore.

3. Smaller, horizontal vessels can have less liquid surge capacity than vertical vessels sized for the same steady-state flow rate. For a given change in liquid surface elevation, there is typically a larger increase in liquid volume for a horizontal separator than for a vertical separator sized for the same flow rate. However, the geometry of a horizontal vessel causes any high level shut-down device to be located.

TWO-PASE OIL AND GAS SEPERATION

Close to the normal operating level. In a vertical vessel the shutdown could be placed much higher, allowing the level controller and dump valve more time to react to the surge. In addition, surges in horizontal vessels could create internal waves that could activate a high level sensor. It should be pointed out that vertical vessels also have some drawbacks that are not process related and must be considered in making a selection. These are:

1. The relief valve and some of the controls may be difficult to service without special ladders and platforms.

2. The vessel may have to be removed from a skid for trucking due to height restrictions. Overall, horizontal vessels are the most economical for normal oil-gas separation, particularly where there may be problems with emulsions, foam, or high gas-oil ratios (GOR).

Vertical vessels work most effectively in low GOR applications.

They are also used in some very high GOR applications, such as scrubbers where only fluid mists are being removed from the gas.

2.5.1 OPERATIONAL COMPARISON BETWEEN HORIZONTAL AND VERTICAL VESSELS

Operational Function	Horizontal Vessel	Vertical Vessel
Usage	High Gas - Liquid Ratio	Low Gas - Liquid Ratio
Capacity/Efficiency	Large fluid-flow capacity	Limited fluid-flow capacity
Emulsion Breaking	Convenient, high residence time	Difficult, due to limited space for phase separation
Sand and Foreign Material	Difficult, due to longitudinal distance. Multiple outlets are required. De-sanding nozzles are essential	Easy outlet at the bottom of the vessel- sand drain off nozzles
Separation Efficiency	Good due to addition horizontal space	Efficiency limited for highly emulsified liquid
Liquid Surge	Sudden liquid surge results difficulty in the operation of interface level controller	Less susceptible to liquid surge
Maintenance and Operation	Difficult due to space limitation- special access platform for instruments and valves	No problem with access due to addition spaceMultiple instruments/valves can be installed
Cost per unit capacity	Expensive	Average
Installation	Average-depending on the access area	Difficult-due to height limitation
Location	On-shore facilities	Off-shore Installation

Chapter III
Zelten field

3. ZELTEN FIELD

3.1 INTRODUCTION

The Zelten oil field (now known as the Nasser field) is located at the foot of the Zelten Mountains, about 169 kilometers south of Brega in Concession 6. Zelten holds the title as the largest oil field in the Gulf of Sidra. The 229 wells in Zelten use a gas lifting system. The Zelten oil field is not associated with the town Zelten, which is located in the North-West of Libya. field is one of the biggest fields that subsidiary of Sirte Oil Company that based in Brega, Libya, engaged in crude oil and natural gas exploration, production and refining, and it was subsidiary of the state owned National Oil Corporation (NOC).

The field was discovered in 1956 Zelten was Libya's first major oil well, producing about 17,500 bbl./day

The Zelten gas-lift system was installed during the period from 1969 to 1971 and represented one of the first uses of gas lift on a field wide basis to produce the high volume wells typical of Middle East Oil fields.

There are five gathering centers in Zelten field GOSP1, GOSP2, GOSP3, GOSP4, GOSP51 each gathering center contain manifold and separation equipment necessary to receive oil from the wells to remove gas and water and to direct the separated oil and gas to central processing station for further treatment.

Each gathering center have first separation unit that contain Manifold , one test separator, two production separators, control room and oil & gas trunk lines to transport oil and gas to GC9 which contain Gas Oil Separation Plant (GOSP) that contain the necessary equipment for separating and treatment gas and oil to reach to desirable product quality and designed production rate at 60°F and 14.7psi and salt content not greater than 10 PTD, with basic sediment and water content (BS & W) not greater than 0.2% by weight.

3.1.1 FIELD PRODUCTION OPERATING AREAS

This consists of the South Field production wells, and Ralah, Waha, Wadi and Jebel field production. These fields produce crude oil with associated gas which is piped to the main ZeltenGosp for separation of the oil, gas and water. The water, after separation is dumped to the Zelten lakes. The oil is metered and pumped to Brega via a 36" transmission line. The separated gas at various pressure levels is compressed and separated from produced condensate. The gas is dehydrated by contact with Tri-Ethylene Glycol (TEG) and enters a 36" pipeline to Brega LNG plant.

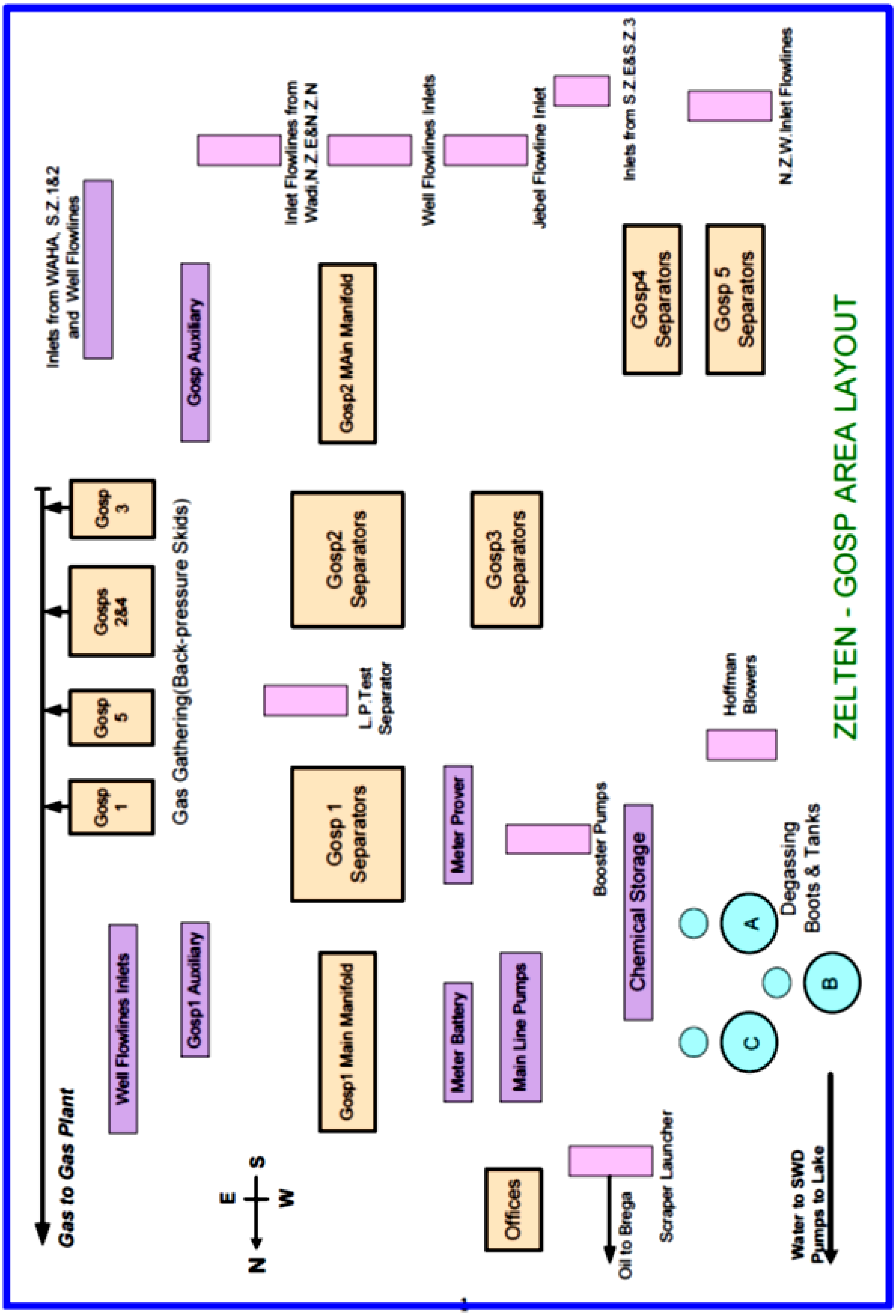
Condensate produced in Zelten is metered and joins the gas in the 36" line to Brega. A 30" line is also used for condensate storage when operating conditions are abnormal.

Gas and condensate are also received in Zelten from the Waha Company. The gas is mainly used for plant fuel and gas lift operations. The condensate is piped to the 36" gas transmission line to Brega. Zelten areas also include the North Field operations.

These consist of Meghil, Sorra and Lehib fields. Gas Lift and Wireline operations are also conducted in the Zelten production fields.

In the South field many natural flow and gas lifted wells are piped to FIELD MANIFOLDS and then to the Gosps via single flow -lines, as listed below:-

SOUTH ZELTEN I:	SOUTH ZELTEN II:
SOUTH ZELTEN III:	SOUTH ZELTEN EAST:
NORTH ZELTEN NORTH:	NORTH ZELTEN WEST:
NORTH ZELTEN EAST:	WADI FIELD:
WAHA FIELD:	JEBEL & RALAH FIELDS:


ZELTEN - GOSP AREA LAYOUT
Gas to Gas Plant
Gas Gathering(Back-pressure Skids)
Gosp 1
Gosp 5
Gosps 2&4
Gosp 3
Inlets from WAHA, S.Z.1&2 and Well Flowlines
Gosp Auxiliary
Gosp2 MAin Manifold
Inlet Flowlines from Wadi,N.Z.E&N.Z.N
Well Flowlines Inlets
Jebel Flowline Inlet
Inlets from S.Z.E&S.Z.3
N.Z.W.Inlet Flowlines
Gosp4 Separators
Gosp 5 Separators
Gosp2 Separators
Gosp3 Separators
L.P.Test Separator
Hoffman Blowers
Gosp 1 Separators
Meter Prover
Booster Pumps
Chemical Storage
Degassing Boots & Tanks
A
B
C
Well Flowlines Inlets
Gosp1 Auxiliary
Gosp1 Main Manifold
Meter Battery
Main Line Pumps
Offices
Oil to Brega
Scraper Launcher
Water to SWD Pumps to Lake
N
E
S
W

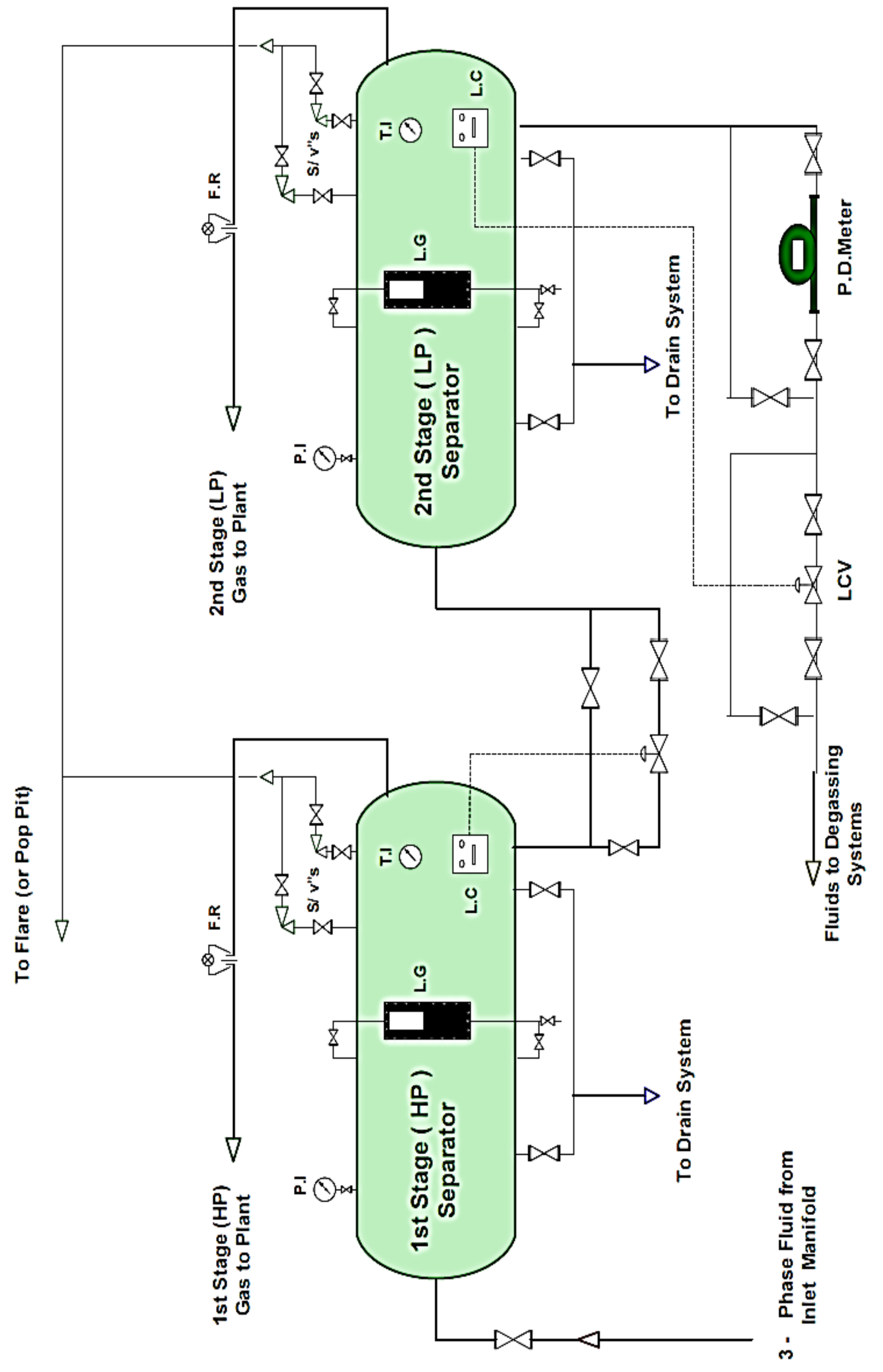


FIGURE 3.2 TYPICAL TWO - STAGE SEPARATION PLANT (GOSP)

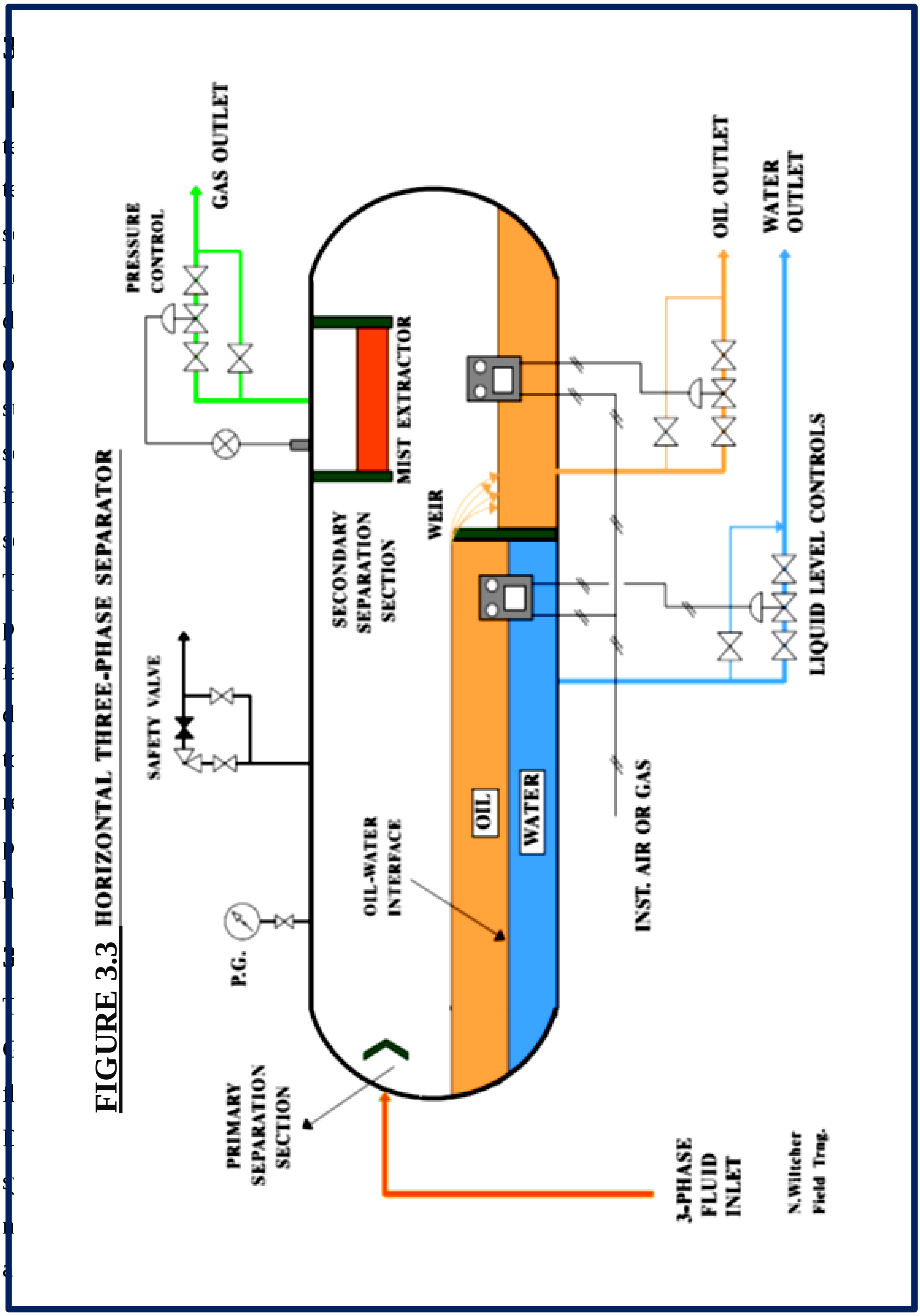


FIGURE 3.3 HORIZONTAL THREE-PHASE SEPARATOR

3.2.2 SLUG CATCHER

This is a buried, three branched piping arrangement which serves to remove any water or hydrocarbon condensate which may form in the gas trunk lines.

The gas flow from all gathering centers are distributed between branches, any liquid droplets or slugs accumulate at the low end of the catcher, where level control removes excess liquid and allows it to pass to the degassing boot. From the slug catcher, gas may be sent to Fuel gas compressors or High pressure flare system.

3.2.3 SECOND STAGE PRODUCTION SEPARATORS

The second stage separators are another level of pressure reduction designed to operate at normal pressure of 75 psig with capacity of 493barral for each separator. As on the case of first stage production separators at low pressure, the residual water is drawn off on level control to disposal pit, while the gas from this stage will be flared until the gas plant is in operation, or used as make-up for fuel gas compression system if needed. The oil leaves this stage free of water and gas is joined with oil from sump tank and condensates from slug catcher and fuel gas compressors into the Degassing Boot. The separator provided with drain valves in and two relief valves designed at 150 psig, and eject the excessive into high pressure flare system.

3.2.4 DEGASSING BOOT

The degassing boots are two vertical vessels located in the GOSP with capacity 792 barral and 56ft height and operation pressure 4 psig and temperature of 105°F. The function of the degassing boot is to strip more gas from the oil coming from second stage separators by the reduction in pressure that occur by the height of the vessel permit gases to liberate and leaves the vessel from the top via pressure control valve to the gas compressor station or to low pressure flare system. The liquid phase in the degassing boot occupied the lower portion of the vessel, the water level controlled via level control valve and sent to water disposal pit, where oil is controlled via level control valve and goes into crude oil surge tank. There is relief valve in the top of the vessel open at 50 psig to the high flare system.

3.2.5 CRUDE OIL SURGE TANKS

The surge tanks are two fixed roof tanks with height 40ft and capacity 40,000 barrel for each tank at the operating pressure 0.6 psig, the tank receive the crude from degassing boot in the bottom of tank and distributed by distributed pipe, the water is rejected to the water disposal pit via level control valve, and the gas is sent to low pressure flare system, at this point, however, it still has an unacceptable salt content and must undergo the desalting process. The surge tank provided by firefighting system, band hole around it, drain system, relief valves, and sample points to check product quality by laboratory.

3.2.6 DE SALTER FEED PUMPS

The crude oil from surge tank is flow by static pressure to the desalted feed pumps which is four vertical centrifugal pumps, that pump crude oil to the DE salters at rate of 3800 GPM per pump and pressure about 130 psig, each pump provided with strainers to clean the oil before inter a pump, the outlet of pumps is combined in one header driven to Desalters.

3.2.7 DE SALTERS/ELECTRIC COALESCER

The desalting process in necessary to meet crude oil shipping requirement, and it's should remove salt down to a level of 10 PTB and the BS&W to below 0.2% by weight. The salts that dissolved in residual water droplets that associated with oil must be settled and removed in the desalter.

3.2.8 CRUDE OIL STORAGE TANK

Once the crude oil desalted, it flows to the crude oil storage tank. The tank has a 250,000 barrel capacity and is fitted with a floating roof and fire fighting system. The tank operated at atmospheric pressure and there is pipe exit from the tank and pumped by oil heating pumps to the heater, and then back to the tank for Dewaxing, any water in tank is drained into the water disposal pit.

3.2.9 BOOSTER PUMPS BOOSTER PUMPS

are two vertical centrifugal pumps driven by electrical motor with 275 H.P these pumps provided mainline pumps with 65 psig, the pump capacity is 7,300 GPM with 130 ft total discharge head at 80% efficiency.

3.2.10 METERS AND PROVER SYSTEM

There are four positive displacement meters in pump station for counting the pumping rate from Messla field per day. Prover is device that has known volume with sphere inside it used for calibrating the reading of meters and check if its right, by comparing reading between meter and prover.

3.2.11 MAINLINE PUMPS

The pump station consists of four 2000 H.P electric motor driven horizontal centrifugal pumps connected in series, the crude from meters is pumped to about 300 psig and flow through throttle valve, then mixed with SARIR line and goes to the AMAL field via Launcher 42 inch then to RasLanuf Terminal. There is a pig send every month to clean a pipe from sludge.

3.3 SUPPORT SYSTEMS

The GOSP support systems are assisting and aid the operation of GC9 as follows:

3.3.1 FUEL GAS SYSTEM

A gas compression system supplied 25 MMSCFD of fuel at 200 psig for the turbine generators and other users, e.g., heaters, flare pilots, purge gas, *etc*. There are four centrifugal compressors, two for low pressures from surge tank and degassing boot and then joined with high pressure gas that come from slug catcher to entering to the two compressors to compress it to desirable pressure for Turbine.

3.3.2 HOT OIL SYSTEM

The crude oil heater is of the forced-draft convection type supplied with combustion air fan, soot blowing apparatus, flame safety system, and control panel. The crude oil from storage tank at 100°F enters the heater at convection section and leaves at 300°F, the temperature controlled via flow control valve in inlet line of fuel gas to the system, the hot oil then leaves heater to return into storage tank to prevent wax.

3.3.3 HOT WATER SYSTEM

The water heater is of the forced-draft convection type supplied with combustion air fan, soot blowing apparatus, flame safety system, and control panel. The water from water tanks at 80°F heated to 180°F to enter desalters for break emulsions.

3.3.4 FLARE SYSTEM

All high pressure reliefs are flows through high pressure knockout drum to recover condensates and gases flows to flare nozzle, the same thing with low pressure reliefs are flows through low pressure knockout drum to recover condensates and gases flows to another flare nozzle.

3.3.5 INSTRUMENT AIR SYSTEM

There are two piston compressors provide instrumentation and other uses in system by Air with 250 SCFM of 150 psig with after coolers and two refrigerated dryers.

3.3.6 CHEMICAL INJECTION SYSTEM

In order to minimize corrosion problems and prevent the formation of inseparable oil-water emulsions, provisions have been made to inject corrosion inhibitor, oxygen scavenger, and demulsifying chemical at various strategic locations within the process. The equipment necessary to accomplish this is presented as follows: Chemical injection at GC-9 inlet Manifold.

–Chemical injection at the Desalters.

–Chemical injection in the raw water system that heated in water heater.

– There are specified tanks for corrosion inhibitor and for demulsifier provided by sight glass and centrifugal pumps for pumping it into the specified locations.

3.3.7 SUMP TANK

There are two sump tanks; one is located at GOSP for collecting the drainage of sample points, sight glasses, desalter sample boxes, the second sump tank located at pump station unit for collecting drainage of mainline pumps, pig launcher drains, meter and prover drains, and sight glass of storage tank. The sump tanks have 60 barrel per tank, and its provided by centrifugal pumps at specific level the pump automatically start and pump liquids into degassing boot at pressure 50 psig.

GAS-OIL RATIO

Test: Gas-Oil Ratio reports are required at periodic intervals for all wells. The test is made to determine the volume of gas produced per barrel of oil so as to ascertain whether or not a well, in making its allowable, is producing gas in excess of the allowable limit. 15 The procedure for making a gas-oil ratio test is the same regardless of whether it is taken from a survey period, or a special test between surveys. Although the equipment used in making gas-oil ratio tests is the same as that used for potential tests, the purpose is different because it is used to establish when the gas-oil ratio exceeds the permissible limit. The volume of gas used in computing gas-oil ratios, and reported as being produced during a test should be the total volume of gas produced from the well during a 24-hour test period as shown in table below..

Well Data			
W.H Pressure	150	PSIG	AGOCO CHOKE
W.H Pressure	305	PSIG	JOWEFE CHOKE
Test W.H Pressure	310	PSIG	(Average)
W.H Temperature	98	°F	
Choke Size	32 / 64"		
Line Pressure	105	PSIG	
Separator Data			
Separator Pressure	150	PSIG	
Gas Temperature	118	°F	
Well Affluent Data			
Gas Density	0.768		
H_2S	0	ppm	

API	38	60°F	
6 Hours Test Rate Data			
Total Gas Produced	0.11265	MM scf	
Total Stock Tank Oil Produced	296	bbls	
Total Water Rate Produced	28	bbls	
Average 24 Hour Production			
Average Total Gas Rate	0.45062	MM scf/d	
Average Corrected Stock Tank Oil Rate	1184	bbl/d	
Average Total Water Rate	110	bbl/d	
Average Total (GOR)	381	scf / bbl	
Average Uncorrected Total Fluid Produced	1.334	bbl/d	
Average Corrected Total Fluid Produced	1.294	bbl/d	
W.C	8.2	%	
Salinity (NaCl)	152,000	ppm	

Table 3.1: WELL TEST SUMMARY IN ZELTEN FIELD

DESCRIPTION	Zelten
API gravity@ 60	36.4
API gravity@ 100	38
Specific gravity @ 100	0.8333
Kinematic viscosity @ 100 , cSt	7.64
Pour point,	+70
Sulphur, wt%	0.14
Wax Content	10.52
Salt content, Lbs/1000BBLS	213.84
BS & W, Vol	0.5
Water by Distillation, Vol	0.1
Hydrogen sulphide, ppm	1
Melting Pt of Wax,	118
Reid vapour pressure @ 100	4.2

Table 3.2 Zelten Oil Composition from the Lab

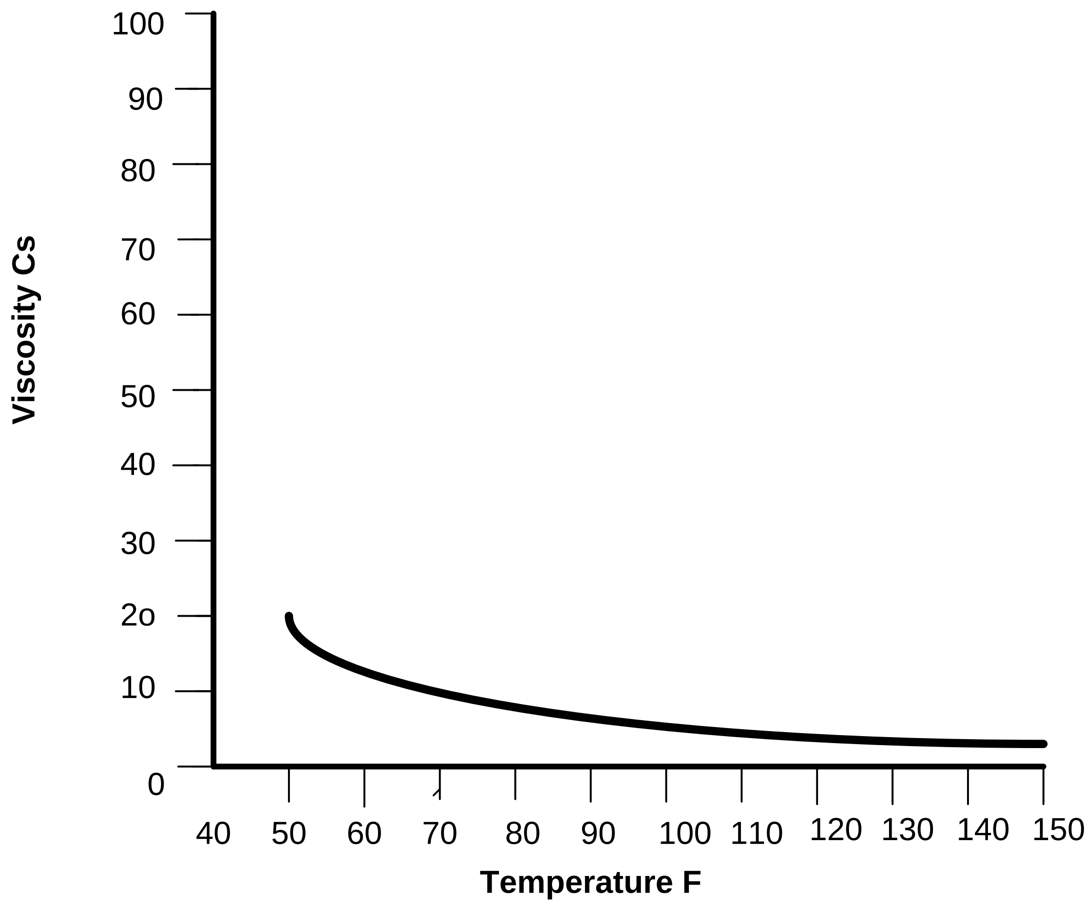


Figure 3.3 Zelten Crude Oil Composition Test By Libyan Oil Institute

DESCRIPTION	METHOD	
Density @ 15 , g/ml	0.833	ASTM D-4052
Specific gravity @ 60/60	0.8363	Calculation
API gravity	37.7	Calculation
Flash point,	<-39	ASTM D-56
Reid vapour pressure, psi	5.5	ASTM D-323
Hydrogen sulphide, ppm	3.22	IP 103
Water and sediment content, vol.%	0.035	ASTM D-4007
sulphur content, wt.%	0.125	ASTM D-4294
Pour point,	9	ASTM D-97
Kinematic viscosity @ 100 , cSt	8.1222	ASTM D-445
Asphaltenes content, wt.%	0.3	IP 143
Conradson carbon residue, wt.%	2.791	ASTM D-189
Ash content, wt.%	0.006	ASTM D-482
Characterization factor	12.2	UOP 375
Salt content (as NaCl) mg/l	3	IP 77
Vanadium, ppm	0.197	ASTM D-5708
Nickel, ppm	2.982	ASTM D-5708

Table3.3 Zelten Crude Oil Composition Test By Libyan Oil Institute

Chapter IV

RESULTS AND DISCUSSION

4.DETERMINING SEPARATOR CAPACITY

4.1 ANALYTICAL METHOD FOR DETERMINING SEPARATOR CAPACITY

4.1.1: OIL CAPACITY

A separator's oil capacity (q) is based on the relationship between the normal oil volume
(V_o) and the retention time (t_r) in the separator, which is usually one minute to allow gas and water to separate from the oil:

$$q = \frac{V_o}{t_r} \text{ ft}^3/\text{min} \qquad (4.1)$$

$$\text{or} \quad q = 257 \frac{V_o}{t_r} \text{ bbl/day} \qquad (4.2)$$

The rated oil capacity is considered to be one-half the actual capacity, to allow for normal heading flows. **Equation4.2** becomes

$$q_r = 128 \frac{V_o}{t_r} \text{ bbl/day} \qquad (4.3)$$

The oil volume of a vertical separator is:

$$V_o = 0.785 \; D_i^{\,2} \; h \qquad (4.4)$$

Where: D_i = The inside diameter of separator in feet

h = The height of the oil column in feet above the bottom of oil outlet (for a shell height of 5ft., h = 2.5 ft; for a 10 ft. shell, h = 3.25 ft.; and for a 15 ft. shell, h = 4.25 ft).

Substituting **Equation4.4** into**Equation4.3** :

4.1.2: EQUATION OF VERTICAL SEPARATOR

The separator oil capacity in bbl/day is:

$$q_r = 100.5 \frac{D_i^2 h}{t_r} \qquad \textbf{(4.5)}$$

4.2.3: EQUATION OF HORIZONTAL SINGLE-TUBE SEPARATOR

The oil volume is:

$$V_o = 0.785 \; D_i^2 \; \frac{L}{2} \qquad \textbf{(4.6)}$$

Where: L = Shell length in feet

V_o= Oil volume in ft^3

And hence, substituting **Equation 4.6** into **Equation 4.3**:

$$q_r = 50.24 \frac{D_i^2 L}{t_r} \qquad \textbf{(4.7)}$$

For a Horizontal Double-Tube Separator

The oil volume is:

$$V_o = 0.785 \; D_i^2 \; L \qquad \textbf{(4.8)}$$

And substituting in **Equation 4.3**, the rated oil capacity is:

$$q_r = 100.5 \frac{D_i^2 L}{t_r} \qquad \mathbf{(4.9)}$$

4.2:GAS CAPACITY

4.2.1:VERTICAL AND HORIZONTAL SEPARATORS

A separator's gas capacity is related to the entrainment (or suspending) velocity. The upward velocity of a gas stream required for suspension of a particle is determined from the particle's resistance to the moving gas and the force on the particle due to gravity. The resistance of a sphere in a moving gas, neglecting the viscosity of the gas which is small, is given by Souders and Brown as:

$$F_a = \frac{C \rho_g \pi D_p^2 U^2}{8} \qquad \mathbf{(4.10)}$$

Where: F_a = Total force on the particle

C = Drag coefficient on the particle

D_p = Diameter of particle, (ft)

ρ_g = Density of the gas,(lb/ft^3)

U = Linear velocity of gas relative to the particle, (ft/sec)

The force due to gravity on a spherical particle, less buoyance, is:

$$F_g = \frac{\pi D_p^{\,3}}{6} (\rho_o - \rho_g) g \qquad \textbf{(4.11)}$$

Where: ρ_o = Density of the oil particle

When the gravitational force equals the resistance to the moving gas, the particle remains suspended:

$$F_a = F_g = \frac{C \rho_g \pi D_p^{\,2} U^2}{8} = \frac{\pi D_p^{\,3}}{6} (\rho_o - \rho_g) g \qquad \textbf{(4.12)}$$

and the theoretical suspending velocity is:

$$U = \left[\frac{4 g D_p (\rho_o - \rho_g)}{3 C \rho_g} \right]^{1/2} \qquad \textbf{(4.13)}$$

If D_p and C are constant in **Equation** 4.13 ,

$$U_t = K \left[\frac{\rho_o - \rho_g}{\rho_g} \right]^{1/2} \qquad \textbf{(4.14)}$$

Where: U_t = Entrainment velocity, ft/sec

K = Separation coefficient $= \sqrt{4 g D_p / 3C}$

ρ_o = Density of oil under separator conditions, lb/ft^3

ρ_g = Density of gas under separator conditions, lb/ft^3

The volume of gas flowing, Q, in ft^3/sec is:

$$Q = \frac{Q_{sc}}{86{,}400} \times \frac{\rho_{gsc}}{\rho_g} \qquad \textbf{(4.15)}$$

Where:

Q_{sc} = Gas flow rate in scf/day

ρ_{gsc} = Gas density at standard condition lb/ ft^3

ρ_g = Gas density at flowing conditions in lb/ ft^3

The flow area A in square feet is related to the gas flow rate and the allowable gas velocity by:

$$A = \frac{Q}{U_a} = \frac{\pi D_i^2}{4} \qquad \textbf{(4.16)}$$

Where D_i is the inside diameter of the separator in ft.

Substituting **Equations 4.14** & **4.15** into **Equation 4.16**,

$$\frac{\pi D_i^2}{4} = \frac{Q_{sc}}{86{,}400} \times \frac{\rho_{gsc}}{\rho_g}\left[\frac{\rho_g}{\rho_o - \rho_g}\right]^{1/2}\frac{1}{K} \qquad \textbf{(4.17)}$$

The gas density at flowing conditions is found with the following **Equation**:

$$\rho_g = \rho_{gsc} \times \frac{P}{P_{sc}} \times \frac{\theta_{sc} + 460}{\theta + 460} \times \frac{1}{Z} \qquad (4.18)$$

or:

$$\frac{\rho_{gsc}}{\rho_g} = \frac{P_{sc}}{P_g} \times Z \times \frac{\theta + 460}{\theta_{sc} + 460} \qquad (4.19)$$

Where:

P = The operating pressure in Psia,

P_{sc}= The base pressure in Psia, and

Z = The compressibility factor.

Substituting **Equation** 4.19 into 4.17:

$$\frac{\pi D_i^2}{4} = \frac{Q_{sc}\, Z}{86{,}400} \times \frac{P_{sc}}{P} \times \frac{\theta + 460}{\theta_{sc} + 460}\left[\frac{\rho_g}{\rho_o - \rho_g}\right]^{1/2} \frac{1}{K}$$

Solving for Q_{sc} ,

$$Q_{sc} = \frac{67{,}824\, K D_i^2}{Z} \times \frac{P}{P_{sc}} \times \frac{\theta_{sc} + 460}{\theta + 460}\left[\frac{\rho_o - \rho_g}{\rho_g}\right]^{1/2} \qquad (4.20)$$

4.3 CORRECTION FOR WALL THICKNESS

Some manufacturers base separator sizes on the outside diameter of the vessel. When this is done, a correction for the wall thickness is necessary. From **Equation 4.20**, Q_{sc} is proportional to D_i for a given well stream.

$$Q_1 = Q_2 \left(D_{i1}^{\ 2} \big/ D_{i2}^{\ 2} \right) \tag{4.21}$$

Where: Q_1 = The desired capacity for a separator with inside diameter D_{i1}

Q_2 = The known capacity for a separator with inside diameter of D_{i2}

4.4 Separator Diameters required for various operating conditions

Equations 4.14 through **4.20** can be rearranged to yield solutions for the diameter of separator or mist extractor required for various operating conditions. The gas density in pounds per cubic foot at operating conditions based on gas gravity is given by:

$$\rho_g = \frac{\rho_{asc}\, G\, \theta_{sc}\, P}{Z\, \theta\, P_{sc}} \tag{4.22}$$

Where: ρ_{asc} = Density of air at std. conditions

For standard conditions of 14.7 psia and 520 °R,

ρ_{asc} = 0.0764 lb/ft^3 and **Equation 4.22** reduced to:

$$\rho_g = \frac{2.70\ G\,P}{Z\,\theta} \qquad (4.23)$$

Where: G = Gas gravity (for air, equal to 1)

P = Operating pressure, psia

Z = Compressibility factor, dimensionless

θ = Operating temperature, °R

The allowable velocity is:

$$U_a = K \left[\frac{\rho_o - \rho_g}{\rho_g}\right]^{1/2} \text{ ft/sec}$$

and the gas volume at operating conditions is:

$$Q_g = \left[\frac{Z \times Q_{sc} \times 10.73 \times \theta \times 10^6}{379.4 \times 86{,}400 \times P}\right] \text{ft}^3\text{/sec} \qquad (4.24)$$

clearing, $$Q_g = \left[\frac{0.3273 \times Z \times Q_{sc} \times \theta}{P}\right] \qquad (4.25)$$

Where Q_{sc} is the number of million standard cubic feet of gas per day at 14.7 psia and 60°F.

The separator or mist extractor area is:

$$A_s = \frac{Q_g}{U_a} \quad \text{ft}^2 \qquad (4.26)$$

and the diameter is:

$$D_S = 13.53\sqrt{A_S} \qquad (4.27)$$

Where D_s = Diameter, inches

A_s = Area, ft^2

4.5 OTER FACTORS CONSIDRRD IN SIZING

In **Equation4.20**, for vertical separators without a mist extractor the allowable velocity constant (K) is 0.117, and with a mist extractor it is 0.167. In the case of horizontal separators with a mist extractor, (K) is 0.382. In calculating the gas capacity of single-tube horizontal separators, the cross-sectional area of that portion of the vessel occupied by liquid is subtracted from the total area, to find an equivalent diameter. When this equivalent diameter is used in **Equation 4.20**, the gas capacities of horizontal separators are obtained by multiplying the value obtained from this Equation by the factor $(L / 10)^{0.56}$, where L is the shell length in feet.

In vertical separators the distance from the oil inlet to the bottom of the mist extractor should be at least one diameter, and the distance from the oil inlet to the normal liquid level should be at least 24in. Since these requirements cannot be satisfied in 5-ft and 7.5-ft separators, a correction factor of 0.80 is applied to the gas capacity of these separators.

4.6 Calculating HORIZONTAL OIL & GAS SEPERATOR

Data given:

Separator length	= 10 ft
Operating pressure	= 15opsia
Operating Temperature	= 90° F
Gas specific gravity	= 0.64
Compressibility factor	= 0.881
Liquid gravity	= 10° API at 60°F
Gas capacity	= 70 MMscf / day

Using the following Equation for determining the specific gravity of the well fluid at Operating temperature.

$$G_t = G_{60} \left[1 - \beta \left(\theta - 60\right)\right] \qquad \textbf{(4.28)}$$

Where G_{60} = Specific gravity of fluid at 60° F

β = The thermal coefficient of expansion of the fluid in API standard 2500

θ = Operating temperature $\quad \therefore \quad G_{60} = \dfrac{141.5}{131.5 + 10} = 1.0$

β = 0.00035

G_t = 1.00 [1 - 0.00035 (90 - 60)]

= 0.9895 at 90° F

ρ_o = 0.9895 ×62.4 = 61.75 lb / ft^3 at 90° F

$$\rho_g = \frac{(0.0764)\ 0.64 \times 520 \times 774}{0.881 \times 550 \times 14.7} = 2.77 \text{ lb / ft}^3$$

Using a constant of 0.382 in Equation 4.14 , we find the allowable velocity to be:

$$U_a = 0.382 \left[\frac{61.75 - 2.77}{2.77}\right]^{1/2}$$

$$= \quad 0.382 \times 4.61 = 1.761 \text{ ft / sec}$$

The operating rate is calculated using Equation 4.25

$$Q_g = \frac{Z \times Q_{sc} \times 10.73 \times \theta}{379.4 \times 86{,}400 \times P} \text{ ft}^3/\text{sec} = \frac{0.3273\, Z\, Q_{sc}\, \theta}{P}$$

$$Q_g = \frac{0.3273 \times 0.881 \times 70 \times 550}{775} = 14.32 \text{ ft}^3/\text{sec}$$

and thus: $$A_g = \frac{Q_g}{U_a} = \frac{14.32}{1.761} = 8.132 \text{ ft}^2$$

If the area of the gas space, A_g, is equal to the area of the liquid space, A_L, then:

$$\pi D_i^2 / 4 = 2 \times 8.132 = 16.26$$

$$D_i = 4.0 \text{ ft I.D}$$

The oil volume

$$V_o = 0.785 \quad D_i^2 \quad \frac{L}{2}$$

And hence, substituting **Equation 4.6** into **Equation 4.3**:

$$q_r = 50.24 \frac{D_i^2 L}{t_r}$$

Chapter V

HEALTH AND SAFETY

5: HEALTH AND SAFETY

5.1 INTRODUCTION

Security and safety is something that is important and a major state in the world of work, especially when Jobs are executed at high risk for the safety of workers and the environment. Danger (hazard) which can lead to endangerment of safety of life and the environment can occur on things unpredictable even underestimated. According to the OHSAS 18001: 2007.

The danger (hazard) is all sources, situation or activity that has the potential to cause injury (accident) and occupational diseases, therefore it is necessary to audit the work environment in order to predict the hazard that can occur and the subsequent risk management planning (risk management) for the handling of such hazards danger may occur due to the nature and content of various chemicals contained in crude oil which is the result of the drilling, one of the elements is H_2S, is a substance that is most prone to fire and gas leakage H_2S as toxic gas and potential hazard could cause accidents.

The purpose of the investigations guaranteed for the safety of the workers with the most severe consequence is death. Potential work accidents are caused by the toxic properties of H_2S gas and crude oil properties itself flammable.

Potential accidents that can involve citizens more widely around the plant. That is because the H_2S gas is carried by the wind and the volume of crude oil very much, quite capable of burning the plant.

5.2 RISK ASSESSMENT

Risk assessment is a careful examination of consequences resulting from the undesired events that could cause harm to people or property, so that sufficient precautions can be taken. Workers and others have a right to be protected from harm caused by a failure to take reasonable control measures.

Hydrocarbon operations are generally hazardous in nature by virtue of intrinsic chemical properties of hydrocarbons or their temperature or pressure of operation or a combination of these. Fire, explosion, hazardous release or a combination of these are the hazards associated with hydrocarbon operations.

These elements have resulted in the development of more comprehensive, systematic and sophisticated methods of Safety Engineering, such as, hazard analysis and risk assessment to improve upon the integrity, reliability and safety of hydrocarbon operations.

The objectives of the risk assessment as per the requirements stated in the terms of reference of the EIA study, the risk assessment study has been undertaken to address the following aspects:

- To identify and assess those fire and explosion hazards arising from production of oil and gas in order to comply with regulatory requirements, company policy and business requirements.
- To eliminate or reduce to as low as reasonably practical (ALARP) in terms of risk to human health, risk of injury, risk of damage to plant, equipment and environment, business interruption or loss etc.

5.3 IDENTIFICATION OF HAZARDS IN PRODUCTION OF OIL AND GAS FROM FACILITY

Any industry plays a major role in world's economy, such as oil and gas, petrochemical, chemical and manufacturing facilities.

Huge investments are made to keep the upkeep of the facilities in order as well as to increase the production capacity, even marginally.

Any accident like blowout, oil spill, operational problems etc. shall cause heavy economical loss to the industry which might include loss of equipment, assets and human life. various hazards associated with production of oil and gas is briefly described as below:

5.3.1 MINOR CRUDE OIL SPILL

A minor oil spill is confined within the well site area. The conditions which can result in minor oil spill are as follows:

- Spillage in crude oil separation system crude oil, spillage from leaking valves, lines and separator vessel.
- Spillage while crude oil production with during the well production operation, there exists a possibility of hydrocarbon gases being released and spillage of crude oil

may result from a failure of pipe, lines valves, separator at production facility. Spilled oil should be immediately cleaned once the leakage is controlled.

5.3.2 MAJOR OIL SPILL

Spillage can only happen in case of major leaks from storage tanks, separators or uncontrolled flow from wells, Since the reservoir does not have the pressure which will allow the wells to self-flow, an artificial lift method (artificial gas lift) is proposed to bring the oil to the surface for commercial production. Therefore possibility of uncontrolled flow from well during production is remote.

Such situation may occur only if, there is a mechanical damage or failure of emergency shutdown system or combination of both. Oil is produced with associated gas, therefore, an oil spill arising from a failure system will result in the release of hydrocarbon vapors together oil.

5.3.3 BLOWOUT

A blowout is the uncontrolled release of crude oil and/or natural gas from an oil well or gas well after pressure control systems have failed. Modern wells have blowout preventers and control valves for the separators intended to prevent such an occurrence. Formation pressure is very low and with installed Christmas tree, possibilities of well blow out is negligible.

5.3.4 HYDROGEN SULPHIDE (H_2S)

Hydrogen sulfide is the chemical compound with the chemical formula H_2S. It is a colorless gas with the characteristic foul odor of rotten eggs. It is very poisonous, corrosive, and flammable. It can be found at oil and natural gas well sites, at petroleum refineries and in pipelines used to carry crude oil and natural gas, where H_2S is naturally occurring. .As much as 30 percent of natural gas in the world may contain hydrogen sulfide, which is called "sour gas".

5.4 CONTROL MEASURES FOR HAZARDS

Effective controls protect workers from workplace hazards; help avoid injuries, illnesses, and incidents; minimize or eliminate safety and health risks; and help employers provide workers with safe and healthful working conditions.

The processes described in this section will help employers prevent and control hazards identified in the previous section.

5.4.1 CONTROL MEASURES FOR MAJOR SPILLS OF CRUDE OIL FROM, SEPARATORS AND PIPE LINES OF SEPARATOR

Control measures are actions and/or activities that are taken to prevent, eliminate or reduce the occurrence of a hazard that you have identified. To effectively control and prevent hazards, employers should:

- Inspection of separator during fabrication shall be carried out as per the requirements of the applicable codes, specifications, This inspection requires regular checks on the work at various stages as it progresses. During fabrication, a thorough visual check should be undertaken and the separator should be checked for foundation pad and slope, slope of the bottom plates, proper welding sequence and external & internal surfaces *etc*.
- Separator shall be inspected for defects like pin holes, weld cracks, pitting at water accumulation locations and tanks pad shall be visually checked for settlement.
- The separator should be visually examined for external corrosion, seepage, cracks,bulging and deviation from the vertical.
- NDT test for the pipeline of separator and the separator itself.

5.4.2 BASIC PREVENTIVE AND PROTECTIVE FEATURES

- Adequate water supplies for fire protection. The amount/quantity of the water requirement is based on rate of firewater required for the worst possible fire and the time duration for which the fire will last
- Structural design of vessels, piping, structural steel, *etc*.
- Overpressure relief devices.
- Corrosion resistance and/or allowances.
- Segregation of reactive materials in pipelines and equipment.
- Electrical equipment grounding.
- Safe location of auxiliary electrical gear transformers, breakers, *etc*.

- Normal protection against utility loss (alternate electrical feeder, spare instrument air compressor, *etc*.
- Compliance with various applicable codes (ASME, ASTM, ANSI, Building Codes, Fire Codes, *etc*.
- Compliance of OISD-189 for firefighting equipment.
- Fail-safe instrumentation.
- Access to area for emergency vehicles and exits for personal evacuation.
- Drainage to handle probable spills safely plus Firefighting water hose nozzle sprinkler and/or chemicals.
- Hazard area analysis followed by appropriate intrinsically safe electrical equipment wherever required.
- Limitation of glass devices and expansion joints in flammable or hazardous service.
- Protection of pipe racks and instrument cable trays as well as their supports from.
- Protection of fired equipment against accidental explosion and resultant fire.

5.4.3 RISKS AND FAILURE PROBABILITY

The term Risk involves the quantitative evaluation of likelihood of any undesirable event as well as likelihood of harm of damage being caused to life, property and environment. This harm or damage may only occur due to sudden/ accidental release of any hazardous material from the containment.

This sudden accidental release of hazardous material can occur due to failure of component systems. It is difficult to ascertain the failure probability of any system because it will depend on the components of the system. Even if failure occurs, the probability of fire and the extent of damage will depend on many factors like:

- Quantity and physical properties of material released.
- Source of ignition.
- Wind velocity and direction
- Presence of population, properties.

5.5 OCCUPATIONAL HEALTH AND SAFETY

During the project work alot of activities will be involved such as construction, erection, testing, commissioning, operation and maintenance, where the men, materials and machines are the basic inputs. Along with the boons, the industrialization generally brings several problems like occupational health and safety.

The following occupational health and safety issues are specific to proposed plant activities will arise during project work as well as regular operation of plant:

5.1.1 PHYSICAL HAZARDS

Potential physical hazards in proposed plants are related to handling heavy mechanical transport (e.g. trucks) and work at heights (e.g. platforms, ladders, and stairs). Heavy Loads Rolling during construction phase.

Lifting and moving heavy loads at elevated heights using hydraulic platforms and cranes presents a significant occupational safety hazard.

Recommended measures to prevent and control potential worker injury include the following:

- Clear signage in all transport corridors and working areas.
- Appropriate design and layout of facilities to avoid crossover of different activities and flow of processes.
- Implementation of specific load handling and lifting procedures, including description of load to be lifted, specifications of the lifting crane to be used and train the staff in handling of lifting equipment's and driving mechanical transport devices.
- The area of operation of fixed handling equipment (e.g. cranes, elevated platforms) should not cross above worker and pre-assembly areas.
- Material and product handling should remain within restricted zones under supervision.
- Regular maintenance and repair of lifting, electrical, and transport equipment should be conducted.
- Use appropriate PPE (as per GSPC PPE Policy) Implement work rotations providing regular work breaks, access to a cool rest area, and drinking water and under hygienic facilities.

5.5.2 ELECTRICAL HAZARDS

An electrical hazard can be defined as a dangerous condition where a worker could make electrical contact with energized equipment or a conductor, and from which the person may sustain an injury from shock, in addition there is potential for the worker to receive an arc flash burn, thermal burn, or blast injury. Workers may be exposed to electrical hazards due to the presence of heavy-duty electrical equipment in plant.

5.3.3 NOISE

Noise is unwanted sound judged to be unpleasant, loud or disruptive to hearing.

Noise level at operational site shall be up to moderate level.

5.5.4 MANDATORY CLOTHING IN THE INDUSTRIAL AREA

ALL personnel working in or entering the process area for ANY reason MUST wear Safety Shoes, Hard Hat and Ear Protection. Coveralls and gloves should be used where applicable and available.

5.5.5 USE OF CHEMICALS IN THE PROCESS AREA

Corrosion Inhibitor, Caustic, Acids, Glycol *etc* When working with these compounds, gloves, goggles and apron should be worn. Chemicals in contact with the skin can cause burns. In such cases washing with large amounts of water is necessary and medical help obtained. In the case of chemicals in the eyes, to prevent loss of the eye(s), EYE-WASH fountains are located at various points in the plant and MUST be used IMMEDIATELY and CONTINUALLY until medical help arrives.

5.5.6: FIRE HAZARDS

Fire safety is the set of practices intended to reduce the destruction caused by fire. Threats to fire safety are commonly referred to as fire hazards. A fire hazard may include a situation that increases the likelihood of a fire or may impede escape in the event a fire occurs. Firefighting system shell be installed to control the hazard of any damage and extinguish the fire.

5.6 FIRE FIGHTING EQUIPMENT

1. **Fire Hydrants** - These are used for the connection of fire hoses to the Fire-water main to reach the fire area.

2. **Fire Monitors** - Fixed, variable spray nozzles used to keep equipment cool in the vicinity of a fire.
3. **Fire Boxes** - Contain fire hoses, nozzles and foam canisters *etc* for use in a fire situation.
4. **Foam Generators** - For use on LIQUID fires - Oil, Condensate Etc.
5. **Portable Fire Extinguishers** - Various types as below:-

COLOUR CODE	CONTENTS	CLASS OF FIRE	MATERIALS
A. SILVER	WATER	A	Wood, Paper, Rags .etc. (Pressure)
B. RED	POWDER	A & B	Liquids, Low Voltage Elect. Fires
C. CREAM/YELLOW	FOAM	B	Liquids
D. BLACK	CO2	B & C	Liquids, All Electrical Fires

Table 5.1 Type of fire extinguishers

5.6.1 PROCEDURE IN CASE OF FIRE

1.Call your Supervisor or Control Room Operator or Dial the Emergency Number.

2.Briefly give the Type and Location of the Incident/Emergency. This will start the Emergency Response Plan.

3.After making the call, personnel in the area should take steps to :-

- Protect oneself.
- Look after any injured personnel.
- Move injured personnel to a safe location.
- If able, give emergency first-aid.
- Get injured person(s) to Medical or await Medical assistance.
- Utilize available water - monitors etc..to cool the area of the fire.
- Isolate the source of the fuel and depressurize equipment.
- Shut off (or arrange for the shut off) of any electrical circuits in the area.
- Prepare for the arrival of additional equipment and vehicles. Make sure that roads

and access routes are not blocked.

- Remove adjacent material that can be moved to minimize the spread of the fire.
- Keep away from the fire if not actively engaged in the fire fighting but stay in the vicinity in case help is needed.
- Assist the fire fighting crews as needed or requested.

5.7 Activities of Safety Organization

5.7.1 CONSTRUCTION AND ERECTION PHASE

A qualified and experienced safety officer will be appointed. The responsibilities of the safety officer includes identification of the hazardous conditions and unsafe acts of workers and advise on corrective actions, conduct safety audit, organize training programs and provide professional expert advice on various issues related to occupational safety and health. He is also responsible to ensure compliance of safety rules and statutory provisions.

5.7.2 HSE AUDIT AND INSPECTION

Formal inspections can take different forms and you and your representatives will need to agree the best methods for your workplace. Here are some of the ways inspections can take place. HSE audits and Inspections will be carried out at site on bi-monthly basis to:

- To identify any design deficiencies and also any weaknesses which might have cropped up during modifications and additions of facilities.
- To ensure that fire protection facilities and safety systems are well maintained.
- To ensure that operating and maintenance procedures, work practices are as per those stipulated in the manuals and standards, this might have degraded with time.
- To check on security, training, preparedness for handling emergencies and disaster management.
- To check the compliance of statutory regulations, standards, codes.

5.7.3 SAFETY TRAINING

Safety training would be provided by the Safety officers with the assistance corporate HSE department, Professional safety Institutions and Universities. In addition to regular employees, contractor labors would also be provided safety training. To create safety awareness safety films would be shown to workers and leaflets would be distributed.

5.7.4: OCCUPATIONAL HEALTH SURVEILLANCE PLAN

All the potential occupational hazardous work places would be monitored regularly.

The health of employees working in these areas would be monitored periodically for early detection of any ailment due to exposure. For Occupational Health monitoring following plan should be implemented:

A Employee information and training

The industry will provide training program for the employees to aspects; hazards of operations, proper usage of nose mask and earplugs, the importance of engineering controls and work practices associated with job assignment(s).List of Tests to be conducted and recorded:

- Eyes
- Ears and audiogram
- Respirator system
- Circulatory system (Blood Pressure) and abdomen
- Nervous system and locomotor system
- Skin and Urine
- Blood for ESR Rest
- Chest X Ray

B Medical surveillance

All employees and contractors should go through the medical examination once in two years to ascertain the health status of all workers in respect of Occupational Health hazard to which they are exposed. The following medical checkup should be done:

- Comprehensive Pre-employment medical checkup for all employees.
- X-ray of chest to exclude pulmonary TB, *etc.*
- Spirometry test.
- Lung function test.
- Liver function test (LFT).
- Audiometer test to find deafness.
- Vision testing (Near and far as well as color vision).

C Report of schedule medical examination: should be published within the company and also report to higher management with safety & health magazines published within the company. Also workers whose schedule examinations are pending to be intimated through their respective department heads to avoid any worker / employee left out for schedule.

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