THE ECONOMICS OF CRUDE OIL STABILIZATION

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CERTIFICATION

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DEDICATION

This work is dedicated to GOD Almighty for his multitude of mercies and grace upon me.

To my loving wife Mrs. Faith Ude and our children, Patrick jr., Fidelia, Samuel, Cordelia and Joseph for their sacrifices, love and understanding.

To my brothers Francis, Charles and my only sister Francisca

And to all, who believe in honest effort and hard work to improve their lot.

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I use this opportunity to appreciate God Almighty in so many ways, for health, strength, humility and determination, to see this goal materializing.

I also appreciate Engr. Prof B. Obah, Engr. Dr. R.M. Aguta, our HOD Engr. Dr. M.S. Nwakaudu, Mr. Andrew Okorocha, Engr. Okechukwu, Ikokwu and all the other academic staff too numerous to mention for their encouragement.

I also acknowledge the prayer of friends and ministers who stood by me through thick and thin.

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I thank you all, and I pray that the good Lord will reward you all. Amen!

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NOMENCLATURE

AGST	Above Ground Storage Tanks
API	American Petroleum Institute
BOPD	Barrels of Oil Per Day
BS&W	Basic Sediments And Water
BTU	British Thermal Unit
EFRT	External Floating Roof Tanks
EPA	Environmental Protection Agency
ETV	Environmental Technology Verification
EVRU	Environmental Vapour Recovery Unit
FRT	Fixed Roof Tanks
GOR	Gas Oil Ratio
HAP	Hazardous Air Pollutants
IFRT	Internal Floating Roof Tanks
KPA	Kilo Pascal
L.P.C.S	Liquid Petroleum Confinement System
M^3	Meter Cube
MCFGPD	Million Cubic Feet Gross Per Day
PPMW	Parts Per Million By Weight
Psig	Pounds Per Square Inch Gauge
Psia	Pounds Per Square Inch Absolute
PTB	Pounds Per Barrel

PVT	Pressure Vapour Temperature
RVP	Reid Vapour Pressure
SCF	Standard Cubic Feet
THC	Total Hydrocarbon
TPY	Tonnes Per Year
TVP	True Vapour Pressure
VBE	Vasquez and Beggs Equation
VOC	Volatile Organic Compounds
VP	Vapour Pressure
VRU	Vapour Recovery Units
WTI	West Texas Intermediate

ABSTRACT

Estimating the gas/VOC emissions from oil and gas producing equipments has been a goal which the industry and regulatory agencies have spent a great deal of study and effort to contend with. This research estimated the flashing losses of gas/VOC emission from conventional atmospheric storage tanks to the atmosphere using Vasquez-Beggs Equation (VBE). Using VBE confirmed observed losses experienced in the industry as is represented in a graph showing the losses. It went further to quantify the revenue losses as a result of these flashing losses. It also investigated measures that can drastically reduce the emission to it's barest minimum. Some of the measures found to recover these VOC/gas emissions include viz; Optimizing separator operating pressures, Vapor recovery system, Liquid petroleum confinement system and Optimizing stage flashing separation for optimum recovery of reservoir fluid. The significance of this research is such that if the above measures are implemented, it will reduce drastically the hazardous air pollutants (HAP) to catchment area and boost revenue to the industry players and revenue earners.

CHAPTER ONE

INTRODUCTION

1.1 Preamble

Most of the oil produced in Nigeria is from the Niger Delta part of the country. This oil the "Bonny Light" blend has an aggregate of 37° API and the Forcados blend is 31° API. About 65% of the crude produced is light, 35° API or more.

One could see at a glance that a lot of losses of light ends are vulnerable at very slight increases in ambient temperature. The light ends if adequately harnessed, will reduce emission to the barest minimum and would mean so much to the world in terms of:

a. The economic value of these light ends so much sought after, which has the potentials to improve economies of refineries/countries.
b. Reduction in the chain of events that would lead to global warming.
c. Reduction in health hazards to the work environment and catchment area.
d. Nigeria also stand to gain economically from the earnings of these hitherto lost light ends that would boost her much needed foreign exchange required to improve her economy and
e. It would reduce the embarrassment of not meeting production forecast on hotter days with day time vessel temperatures ranging from 40°C to about 59°C for the hours between 10:00HRS and 16:00HRS, for the months of January through May and from about October to December.

These same vessel temperatures get as low as from 31°C to about 43°C within the same time interval with its attendant higher fluid recovery rate in the months of June to October. Nigeria has two broad distinct seasons;

("Dry" and "Rainy") which are supposed to be for equal periods of six months. However with the increased effect of global warming, the hotter days are increasing above the rainy season days.

1.2 Statement of the Problem

This research work therefore has its goal as how to "achieve the prevention of this loss of produced crude oil through emission to the atmosphere, by retention and storage, in a system that can conserve or drastically reduce this loss to its barest minimum" thus reduce the revenue lost through emission

Emissions from tanks result from the "Flash" and "differential" vaporization and weathering of vapours from crude oil tanks. Sources for tank emissions include all oil and condensate storage tanks.

1.3 Objective of Research

1. To estimate the flashing losses/VOC (volatile organic compounds) emissions from atmospheric storage tanks using Vasquez and Beggs Equation (VBE)
2. To quantify the revenue losses as a result of these vented gases
3. To enumerate measures to reduce these flashing losses

1.4 Scope of the Research

This research work is centered on the economic evaluation of crude oil losses from stabilized crude oil in atmospheric storage tanks in tank farms. Flashing losses from two atmospheric storage tanks were considered.

1.5 Significance of Research

If the crude oil is adequately stabilized and stored in corresponding adequate atmospheric storage tanks, flashing losses will be minimized or probably eliminated.

This study which deals with the review, estimation and economic analysis of stabilized crude oil losses; is purposed to alert all industry players in the Niger Delta to wake up to these losses. The crude oil from this region has API^o ranges of 21 to 56 API^o. The consequence is such that if not properly handled, entire fluid production from very high API^o reservoirs could be lost completely in atmospheric storage tanks. Generally in the Niger Delta region of Nigeria, the petroleum industry uses conventional surface atmospheric storage tanks in various flow stations or tank farms. These tanks are constructed of either bolted or welded steel sheets and are fitted with various appurtenances according to design codes or end user's requirement.

If this work is heeded to, will increase revenue to industry players and royalty owners, also reduce or eliminate flash and differential/VOC emissions thus ensuring a healthy working environment for the industry workers and natives of catchment area.

CHAPTER TWO

LITERATURE REVIEW

2.1 Previous related studies

Several research efforts have been directed towards 'Optimizing separator operating pressure' with the view to reduce or eliminate flashing losses. Boyer and O'Connel (2005) presented that Devon Energy Production Company, L.P. surveyed its G.A. Ray No.93 oil and gas production facility and increased profits approximately $7000 per year by optimizing their operating pressures of low pressure three-phase separators, at no extra cost to the facility. The primary goal of the optimization was to increase profits for the facility by putting more gas into the sales pipeline and to reduce emissions of methane with minimal costs to the facility. In the oil and gas production, processing and transmission operations, processes that involve crude oil and condensate undergoing pressure drops result in the separation of natural gas from the oil fraction. This liberation of natural gas is commonly referred to as "flashing" of natural gas from the oil.

They further observed that flashing losses from crude oil and condensate storage are routinely vented to the atmosphere. By minimizing operating pressure of low-pressure separators, the amount of flashing losses can be reduced, resulting in increased profits at a minimal cost of implementation and an immediate payback. Storage losses include working and breathing emissions. Working emissions are generally defined as the sum of displacement and withdrawal emissions caused by product movements; breathing emissions are caused by changing meteorological conditions.

Pontiff and Boyer (2005) suggested that a survey of the operating parameters of a facility can reveal opportunities to reduce flash losses and increase profits by increasing gas sent to sales. Such a survey may reveal opportunities that warrant

a vapour recovery unit to recover the remaining flash gas that is vented to the atmosphere before or after optimization. These flash gas savings result in a reduction in the emissions of methane, a greenhouse gas. Installing vapour recovery units on crude oil storage tanks gives information on the sizing and economics of vapour recovery units for oil storage tanks. Note that for storage tanks, emissions from flashing are in addition to tank working losses, breathing losses and loading losses from tank trucks and barges.

Flashing emissions can be several orders of magnitude greater than the combined working, breathing and loading losses, depending on the pressure drop and the volatility of the oil or condensate.

Mark et al (2003) pointed out that there are approximately 250,000 tank batteries in the United States. These tanks store oil and condensate prior to transportation to sales via pipeline or trucking. The sources of the vent gases in tanks are from flash, standing and working losses. There are approximately 8,000 to 10,000 mechanical vapour recovery units (VRUs) installed at production sites with four tanks typically connected to each VRU. Most of these tanks are fixed-roof storage tanks, the type we have here in the Niger Delta region of Nigeria. Upon rushing in under pressure of the oil into the storage tanks, lower molecular weight hydrocarbons dissolved in the crude oil emerge out of solution or "FLASHES" when the pressure drops as the oil enters the tank. The storage tanks are typically down stream of a low-pressure vessel such as a two or three phase separator or heater treater. The hydrocarbons that flash include methane, ethane volatile organic compounds and hazardous air pollutants. These gases collect in the plenum of the fixed roof storage tanks that are typically used in oil and gas productions. Working losses occur from plenum vapours released during filling of the tank and agitation of tank contents when fresh oil mixes in the storage tanks.

Atmospheric Fixed-roof tanks typically have a pressure relief valve that vents gas when the tank pressure exceeds 0.25 psig. Vapour recovery systems for crude oil storage tanks are installed for several reasons. (www.epa.gov/gasstar/install.htm) accessed June 2010

(1) Capturing vent gas for use in the system (e.g., fuel gas, gas lift) or injection into the sales pipeline, this result in improved efficiency, increased profits and conservation of natural resources.

(2) Regulatory issues arise because tank vent gases contain "Volatile Organic Compounds" VOC (propane plus fraction) that are the precursors to the formation of ozone. Regulatory authorities require the limiting of emissions of vent gases that contain high concentrations of hydrogen sulphide (H_2S) gas and hazardous air pollutants (HAP) such as n-hexane, benzene, toluene, methylbenzene, and xylenes.

(3) In addition, the greater concern over global warming has resulted in scrutiny of methane emissions, an identified greenhouse gas.

Mark et al (2003) used Vapour Recovery Units (Venturi Jets) to capture flashed gas from atmospheric storage tanks. Gundolf (1990) carried out studies on how to reduce VOC emission in West Germany using internal floating covers and vapour collection system. Shaver et al (2001) did a study on emission control using "Liquid Petroleum Confinement System" (L.P.C.S.). John, (2008) used "separator stages flashing" separation to maximize reservoir fluid recovery

2.2 The Main Economic losses

These flash gases typically have a higher BTU value than the inlet gas and thus have more economic value. These gases from crude oil and condensate

(oil) storage tanks are generally vented to the atmosphere (although sometimes they are recovered for use as fuel gas, gas lift gas, sent to the sales pipeline or burned in a flare). For facilities that do not have a low-pressure gathering system or do not operate a low-pressure booster compressor, the low-pressure separators and/or heater treaters may vent to the atmosphere or burn the gas in a flare.

2.3 Various techniques applied to reduce these economic losses

Companies can optimize the process by reducing operating pressures of low-pressure separators and heater treaters such that less flash gas is vented to the atmosphere. For example, less flash gas will be generated from an oil storage tank provided the facility reduces the operating pressure of the low-pressure separator or heater treater just upstream of the oil storage tank and the flash gas from the low-pressure separator or heater treater is routed back into the system (e.g., suction of compressor, fuel gas system, etc.) Boyer and O'Connel(2005) . This may require a lower operating pressure for the booster compressor's first stage suction or for the fuel gas system. These optimizations can be accomplished by adjusting operating pressures with minimal capital or at no operational costs.

The optimization technique is to operate the low-pressure separators or heater treaters at the lowest possible pressures such that less flash gas is generated from the pressure drop between the separator or heater and the downstream vessels that vent to the atmosphere or burned in flare. For this technique to be successful, the operating pressure of the upstream vessel (low-pressure separator to be optimized) must be of greater pressure than the downstream vessel (compressor) that receives the flash gas. For example, a low-pressure separator operated at 85 psig, sends its natural gas to the suction of an onsite booster compressor with a suction pressure of 80 psig. If the operator

reduced the operating pressure of the low-pressure separator to about 50 psig, then the suction pressure of the compressor must be less than 50 psig to ensure the low-pressure gas is recovered by the compressor.

Gundolf (1990) presented that there are several emission control techniques. Breathing emissions can be effectively reduced by introducing a gas balancing system across a group of storage tanks. Such a system enables almost total recovery of hydrocarbons which can be returned to the gasoline pool. With the aid of internal floating covers for fixed-roof tanks, the hydrocarbon emission can be lowered at least by 90%. Emissions from pressure relief and blow-down systems can be avoided by vapour collection systems. In West Germany, prior to 1980, internal floating covers with an efficiency of some 90% had to be installed into fixed-roof tanks with more than 10000 m^3 capacity. Fixed-roof tanks in small depots are equipped with pressure/vacuum valves. Some refining companies fitted rim-mounted secondary seals on floating-roof tanks to further reduce the already relatively low emissions from equipment with primary seals. In 1990, installed vapour return systems resulted in a hydrocarbon recovery of about 31% and reduced the hydrocarbon emissions in the western German gasoline distribution system accordingly.

Mark, et al (2003) presented that Bernoulli's equation shows that, if no work is done on or by a flowing frictionless fluid, its energy due to pressure and velocity remains constant at all points along the streamline. As a result an increase of velocity is always accompanied by a decrease in pressure. This principle can be used to collect a low pressure natural gas stream with a high pressure motive gas stream for entrainment and compression to an intermediate pressure. A jet venturi ejector is a mixing and pressure increasing device which consists of a nozzle and venturi. The nozzle receives the motive fluid (e. g., natural gas) from a high pressure source. As the motive fluid passes through the jet, velocity increases and pressure decreases. The increased velocity, plus the

decreased pressure, causes suction around the nozzle. Low pressure around the nozzle is drawn into the motive stream and mixed with it. The venturi consists of a section of piping whose diameter narrows at the throat and then widens at its terminal end. This increased diameter at the terminal end causes the mixed fluid velocity to decrease and the pressure to increase. The venturi converts the high velocity jet stream into an intermediate pressure for delivery to a system for this intermediate pressure.

Antonio and Adriano (2006) observed that the process of efficiently degassing and dewatering of crude oil is a permanent concern in the industry from both, economical and environmental perspective. Oil and gas separators are utilized to achieve this purpose and are an integrant part of the surface separation equipment designed to handle the fluids produced from oil and gas wells and segregate it into oil/water and gas. They are installed either at the central processing plants or near the production wells.

The oil and gas separators consist normally in two families; the two stage- oil/gas and the three stage-water/oil/gas separators. Their efficiency, translated by the quantity of gas separated from the oil is dependent upon:-

1. Physical, chemical and electrochemical characteristics of the crude
2. Process operating temperature
3. Process operating pressure
4. Equipment rate throughput
5. Size and configuration of the separator
6. Other factors

If the crude degassing process is not complete, then, at some point in the distribution circle, for example in the atmospheric storage tanks at the refinery or while loading tankers, substantial amount of associated gas will be released

into the atmosphere, causing environmental damage (VOC emissions) a primary cause for the global warming, direct economic loss as part of the saleable product is lost and in some cases upset in the client's process due to high 'Reid vapour pressure' (RVP). Recognizing escalating concerns, namely the potential increase in sea levels and flooding in coastal areas due to global warming, the actual market conditions of efficient utilization of hydrocarbon resources associated with zero flaring and venting targets, are clearly sending the message that the development of complimentary technologies targeting the enhancement of actual process conditions has become an obligation of all players involved world wide.

Pontiff and Boyer (2005) explained that there are many areas in the production, gas processing and transmission processes where flash gases are generated and vented to the atmosphere. These include:-

1. **Intermediate Flash:** High/intermediate pressure separators that send crude oil and condensate to a low-pressure separator. This low-pressure separator operates at a pressure greater than atmospheric pressure and may vent directly to the atmosphere. A heater treater may also be used.

2. **Fixed Roof Storage Tanks:** High/low-pressure crude oil and condensate are flashed into tanks operating at atmospheric pressure. (See Fig.2.2)

3. **Pipelines:** Gas lines that are "pigged" or physically purged of condensate have the potential to vent natural gas to the atmosphere.
4. **Inlet Separators:** Gas plant inlet separators that dump into storage tanks operating at atmospheric pressure.

Note that for storage tanks, emissions from flashing are in addition to tank working losses, breathing losses and loading losses from tank trucks and

barges. Flashing emissions can be several orders of magnitude greater than the combined working, breathing and loading losses, depending on the pressure drop and the volatility of the oil or condensation of an intermediate flash situation. (See Figure 2.1)

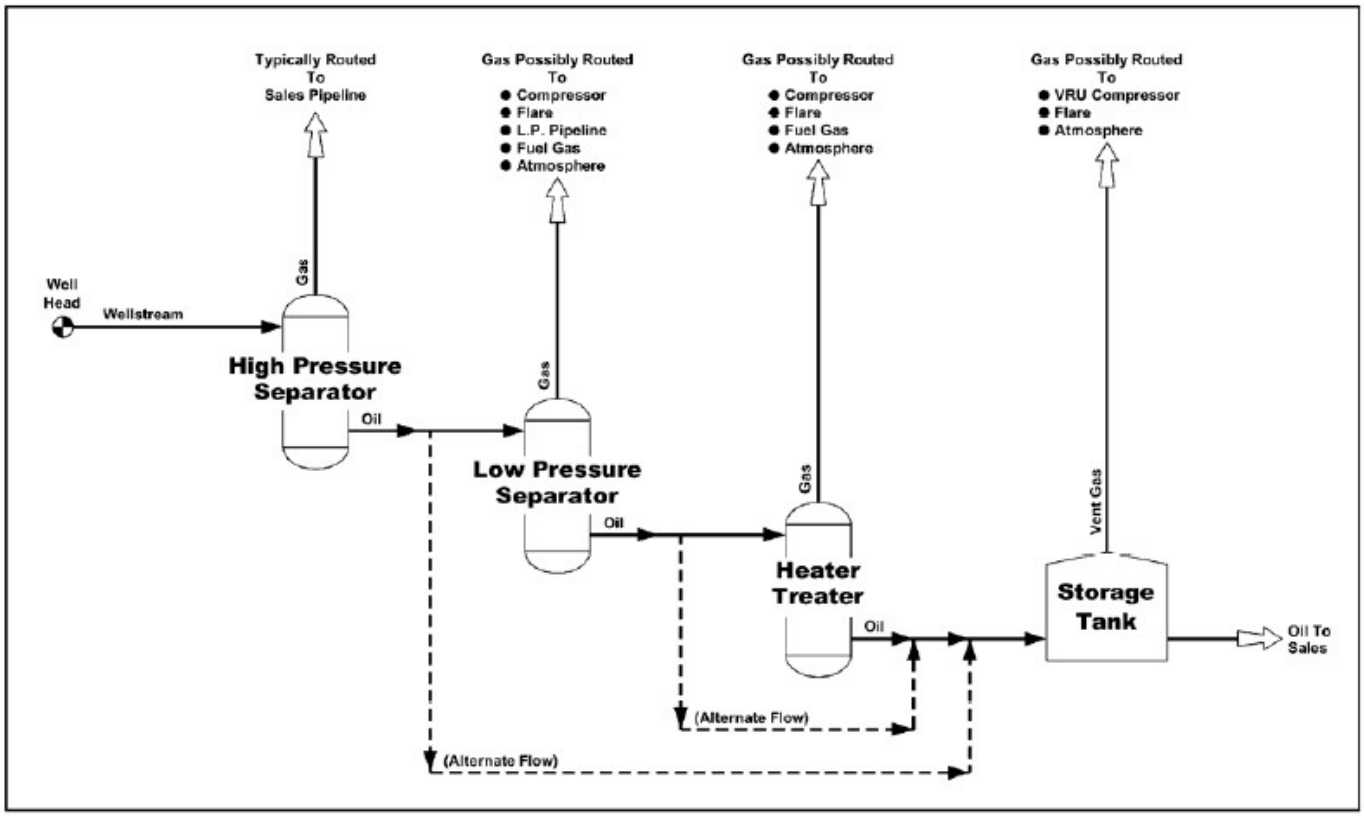

Figure 2.1-Process flow and possible destination of flash gas

Delahunt, J. F. (1987) presented that there are linings applied to the shells and roof of above ground storage tanks in the petroleum and petrochemical industry. Their history of use began before WWII and continued into the 1950's where testing and evaluation of the first modern coatings was initiated. In the early 1950's, the protective coatings in use included gunite, inorganic zinc rich silicates, and maintenance type of protective coatings. In the 1960's, epoxies began to be used as well as copolymers such as coal tar epoxy and epoxy-phenolics. Their use continues today as well as the newer protective coatings such as epoxy, novolacs and others. Storage tank linings may be used for several purposes. The first of these is corrosion control; a second is protection of product quality, third, to minimize evaporation of light

hydrocarbon products and components, which results in environmental protection, and lastly, to reduce tank roof seal wear. Internal storage tank corrosion depends upon many variables including: type of hydrocarbon stored; type of tank i.e., cone roof, floating roof or internal floating roof, working of the tank, and environmental conditions. He further presented that there are three primary designs of AGST (Above Ground Storage Tanks) in use today; they are Fixed Roof Tanks (FRT), which are frequently addressed as Cone Roof Tanks, External Floating Roof Tanks (EFRT) and the newer Internal Floating Roof Tanks (IFRT). Open top tanks or reservoirs were used up until the 1950's but are no longer in use today.

Fixed Roof Tank (FRT) - The fixed roof or cone roof storage tank was developed in order to overcome the disadvantages of open top tanks. Open top tanks are no longer in use but were in service up through the 1950s or later. FRT provides for superior containment of the evaporative vapours but still does not suppress evaporation from the complete exposure of the stored hydrocarbon.

External Floating Roof Tank (EFRT) - This type of tank with an External Floating Roof came into service about the 1920's. It was designed to significantly reduce evaporation losses common to FRT. It does this, as the name implies, with a roof that floats up and down as the liquid level within the tank rises and falls. This eliminates the vapour space. However, its disadvantages include the possibility of aggressive internal shell corrosion because of exposure to the weather and abrasion of the tank roof as it moves up and down during working of the tank. Another major concern is that the roof

itself is exposed to ice, snow and rain, which usually results in severe damage and sinking of the roof.

Internal Floating Roof Tank (IFRT) - Developed in the late 1950s and early 1960s, an external roof protects the Internal Floating Roof from the elements (weather) and prevents lightening strikes. The external roof is a geodesic dome of mechanical construction. This type of construction minimizes evaporation losses and also, limits the exposure of the shell to the weather and that may reduce internal shell corrosion compared to an EFRT. Such data however, is not yet available.

Figure 2.3 shows a common seal design used for both EFRT and IFRT tanks. These seals provide product conservation by minimizing evaporative product or light blending component losses. It consists of a metal shoe that rides against the shell of the tank. There is both a primary and secondary seal - the first is frequently an elastomeric fabric seal and a secondary elastomeric seal. Both can be changed because of abrasive wear and deterioration during working of the tank. During the early 1950's, evaluations were initiated to determine the effectiveness of linings applied to the shells of floating roof tanks. It was felt that several advantages might be achieved as follows:

Reduced evaporation losses from "cling" of product up the shell

- Reduced evaporation losses from "creep" of product up the shell.

- Increased life of floating roof seals.
- Increased tank life because of reduced shell corrosion.

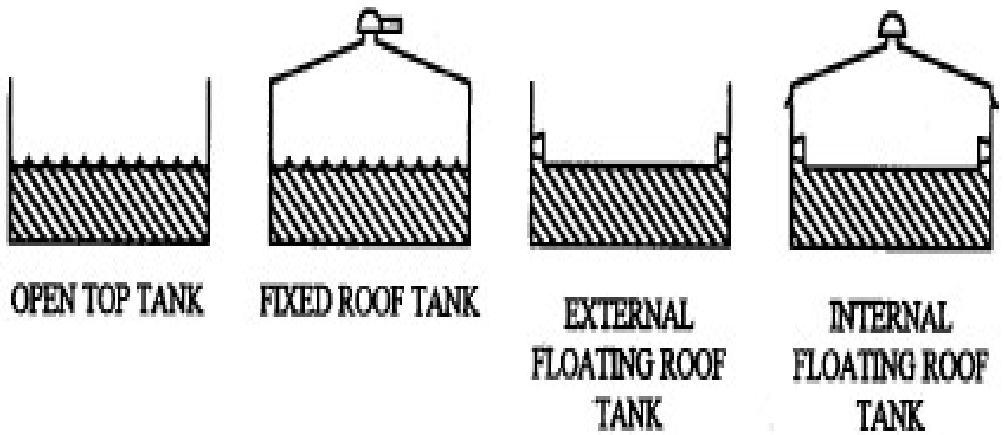

Figure 2.2
Various types of above ground storage tank.

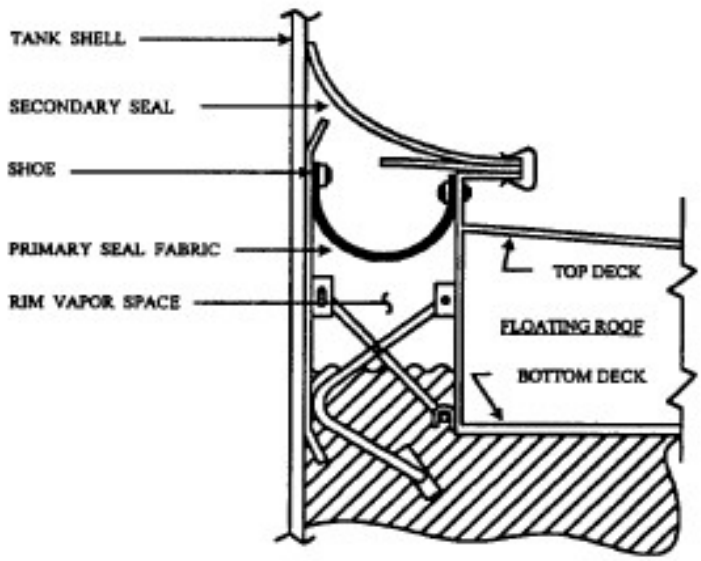

Figure 2.3
A schematic drawing of one type of seal used on floating roof tanks.

Shaver et al (2001) observed that the crude oil in its condition in atmospheric storage tank is observed in the form of gas and undergoes certain physical changes, due to the vapour pressures of escaping major constituents of

the crude oil being greater than that of the atmospheric pressure, causing 'differential' and 'flash' vaporization. The crude oil being observed as gas, can best be described by applying 'Charles' and 'Boyles' laws, in the form of 'Ideal Gas' equation

$$PV = nRT. \quad \text{----------} 2.1$$

where
P is the pressure of the gas,
V is the volume,
T is its absolute temperature,
n is the number of moles of the gas, and
R is a constant.

This implies that any changes in pressure, volume or temperature with respect to the stored crude oil, at constantly changing physical and atmospheric conditions under which it is stored, causes a loss of the crude oil to the atmosphere. This loss can be as high as 50% or more of the daily produced crude oil volume in atmospheric pollution and contamination as well as lost revenues to both the working interest and royalty owners.

They presented that the primary sources of vented vapours from an atmospheric tank system are:

Displacement during filling operations

1. Filling losses are those vapours that are expelled from the tank when the crude oil is introduced into the system. The filling causes the vapors to be compressed until they are equal in pressure to the mechanical backpressure relief and then they are vented. As the system is emptied, the crude flashes into vapour to occupy the void space above the fluid-vapour interface.

2. Losses can also occur due to the expansion of the crude oil after it enters the system.

Vaporization of the crude oil: The crude oil that is now at atmospheric conditions within the system undergoes a series of vaporization phases until they are vented.

Breathing: The temperature differences between day and night cause the vapours to be expelled. The economics of the expelled vapours can be quantified using Vasquez, M. and Beggs, H. D. correlation for fluid physical property predictions.

John M. presented that a separator divides the combined liquid-gas stream into individual phase components that are relatively free of each other for subsequent processing.

Separation in production operations is necessary for several reasons:

- Downstream equipments can not handle gas-liquid mixtures. Pumps require gas free liquid, while compressors and dehydration equipment require liquid-free gas.
- Product specifications set limits on impurities. Oil generally can not contain greater than 1% BS&W (Basic Sediments and Water, a term that describes both water and solid impurities) at the time of custody transfer to the pipeline. Gas sales contracts generally require that the gas contain no free liquids.
- Measurement devices for gases or liquids are highly inaccurate when another phase is present.
- The liquid portion from a well stream mixture may be maximized by multiple stages of separation.
- The full well stream is sensitive to the inlet, first stage pressure.

Maximizing the lighter hydrocarbons in the liquid phase also increases the volatility of the crude. Storage in the field and transport by tanker limit the liquid product true vapour pressure to atmospheric pressure at maximum storage temperature. The exception is when pressure crude is shipped via pipeline to receiving facilities that are designed to conserve the flash gas with vapour recovery systems.

Maximizing the light hydrocarbons in the liquid phase may also maximize the sulphur content of the crude. Specifications limit the hydrogen sulphide content to concentrations which reduce toxicity, and corrosion, during processing at the refinery.

De-sulphurizing to slipping specification may be required in the field processing scheme Crude oils vary widely in composition and physical properties. Some are almost gaslike materials of 65° API gravity, whereas others are semi-solid asphaltic materials with API gravities less than 10°. Light crudes are generally more valuable to refineries and are easier to handle and produce than heavy crudes. Conversely, heavy crudes, being more difficult to process, sell for less than light crudes.

The crude oil gravity can be varied by adjusting the quantity of pentane and lighter fractions retained in the stock--tank liquid. Although major changes in crude oil gravity are not feasible at the production facilities, these facilities can adjust other crude oil properties, including vapour pressure, H_2S concentration, BS&W content, and salt content. Typical specification ranges for these properties are as follows:

- Maximum vapour pressure: 5 to 20 psia RVP (Reid Vapour Pressure)
- Maximum Hydrogen Sulphide: 10 to 100 ppmw (parts per million by weight)

- Maximum BS&W: 0.2% to 3.0%
- Maximum salt concentration: 10 to 25 ptb (pounds per barrel)

Crude oil specifications for production facilities are sometimes determined by the refinery and at other times by the pipeline or tanker that transports the crude from the production facility to the refinery. A low vapour pressure (VP) is important for the stability of the crude during storage and transport. A high VP results in a loss of volatile components in storage tanks or in the tanker.

High VP also becomes a safety issue. Gases from unstable crude are heavier than air and are difficult to disperse. Consequently, the risk of explosion is greater. To prevent the release of gas during storage or transport, the VP specification is usually from 5- to 20-psia RVP. **Reid vapour pressure** is reported as pounds per square inch at 100°f and is always less than the true vapour pressure. Crudes may exhibit a true vapour pressure (TVP) which is one to six psi higher than the measured Reid vapour pressure.

Refineries are capable of processing crude oil with an RVP of 20 psia, but tankers can only accept a product with a maximum RVP of 10 to 14 psia. In the United States, the Environmental Protection Agency (EPA), dictates that a crude have a maximum VP of approximately 11-psia RVP for atmospheric storage. The RVP is selected according to the ambient temperature, the place of delivery, and the transport route.

Hydrogen sulphide in the well stream can also impose constraints. Personnel safety and corrosion considerations require that H_2S concentrations be lowered to a safe level. The specification is generally set in the range of 60 to 100 ppmw, but can be as low as 10 ppmw. For example, most tankers are capable of handling sour crude with a maximum H_2S concentration of 100

ppmw, but some refineries are unable to process crude containing more than 10 ppmw of Hydrogen sulphide. Ultimately, the product specification for any production facility must be individually determined to derive maximum profits from the operation of the facility.

CHAPTER THREE

METHODOLOGY

3.1 OPTIMIZATION OF SEPARATOR'S OPERATING PRESSURE

Procedure:

In optimizing separator's operating pressure as a means of checking hydrocarbon emissions from low pressure separator flowing into storage tanks, below are the five steps that company ABC used to optimize operating pressures of the low-pressure separators flowing to oil storage tank battery:-

1. Choose a flash gas volume estimation method.
2. Collect needed process data.
3. Determine existing gas-to-oil ratio (GOR) and gas volume of flash gas lost.
4. Determine the optimal operating pressures and implement.
5. Determine the new GOR and volume of flash gas lost after lowering operating pressures and calculate the monetary volume of recovered methane.

Description of the Separator's Operating Pressure Optimization Process

Multiple oil and gas production wells flow to their respective high-pressure separators (see figure 3.1). System No. 1 wells flowed to High-Pressure Separator No. 1 operating at 425 psig at 86°F, and System No. 2 wells are sent to High-Pressure Separator No. 2 operating at 295 psig at 85°F (see figure5). The booster compressor collected flash gas from the high-pressure separators for compression to the sales pipeline pressure of 800 psig. Oil from

the high-pressure separators usually flows to their respective low-pressure separators (Nos. 1 and 2) for further separation of gas, oil and water. Gas from the low-pressure separators flow to the suction of the booster compressor, where ultimate compression to the gas sales pipeline pressure of 800 psig takes place. The low-pressure separators operate at 40 psig. The booster compressor first stage suction was set at 35 psig.

Oil from the low-pressure separators flows to the oil storage tanks. ABC conducted sampling, chemical analyses and computer simulations for several operating scenarios for separators and tanks operating at its Production Facility. The sampling consisted of a pressurized oil sample taken from each of the two high-pressure separators operating at the facility. A specialized company conducted a laboratory analysis of each pressurized oil sample to determine the gas-to-oil ratio (GOR) and chemical make-up of the flash gas. The analyses were conducted for the intermediate flash between each high-pressure separator's operating conditions and the low-pressure separator conditions of 20 psig and 80 psig for a total of four intermediate flash analyses. The samples from each separator were also analyzed to determine the GOR and the chemical makeup for flash losses from 20 psig to storage tanks conditions and from 80 psig to storage tank conditions for a total of four final flash analyses.

The GOR and chemical makeup of flash gas for several other operating conditions were also simulated using WinProp 2004. The simulations used the Soave-Redlich Kwong Equations of State tuned to actual laboratory analyses from the field samples. The results of the testing and analyses for various operating conditions are summarized in Table 3.1. To optimize the operations, ABC adjusted the operating pressures of the low–pressure separator booster compression suction to 20 psig. This reduced the pressure drop by 20 psig. The average oil production to each of the separators was 100 barrels of oil per day (BOPD).

Table 3.1 Results for ABC's flashes from low-pressure separator conditions to atmospheric storage tank conditions

Flash Analysis for Gas-to-Oil Ratio (GOR)	Pressure drop (psig)	Total GOR (scf/bbl)	Flash Gas BTU Value (BTU/scf)	Total Flash Volume[A] (scf/year)	Flash Gas Value per year[B]	Methane GOR Ratio (scf/bbl)	Methane Flash Volume[C] (scf/year)
Sample for LP (Low Pressure Separator) No. 1 to storage tanks	20	20	2303	730,000	$8,406	4.5	164,000
Sample for LP No. 2 to storage tanks	20	29	2548	1,059,000	$13,492	4.2	153,000
			TOTALS	1,789,000	$21,898		317,000
Simulation for LP No. 1 to atmospheric tank	40	30.4	2079	1,110,000	$11,538	8.6	314,000
Simulation for LP No. 2 to storage tanks	40	42.2	2241	1,540,000	$17,256	9.3	339,000
			TOTALS	2,650,000	$28,794		653,000
Simulation for LP No. 1 to storage tanks	60	47.7	2083	1,741,000	$18,133	13.5	493,000
Simulation for LP No. 2 to storage tanks	60	63.5	2225	2,318,000	$25,788	14.7	537,000
			TOTALS	4,059,000	$43,921		1,030,000
Sample for LP No. 1 to storage tanks	80	75	2172	2,738,000	$29,734	19.9	726,000
Sample for LP No. 2 to storage tanks	80	90	2384	3,285,000	$39,157	19.2	701,000
			TOTALS	6,023,000	$68,891		1,427,000

[A]Estimate based on average production rate of 100 barrels of oil per day.
[B]Estimate based on average production rate of 100 barrels of oil per day and flash gas valued at $5.00 per 1,000,000 BTU/scf.

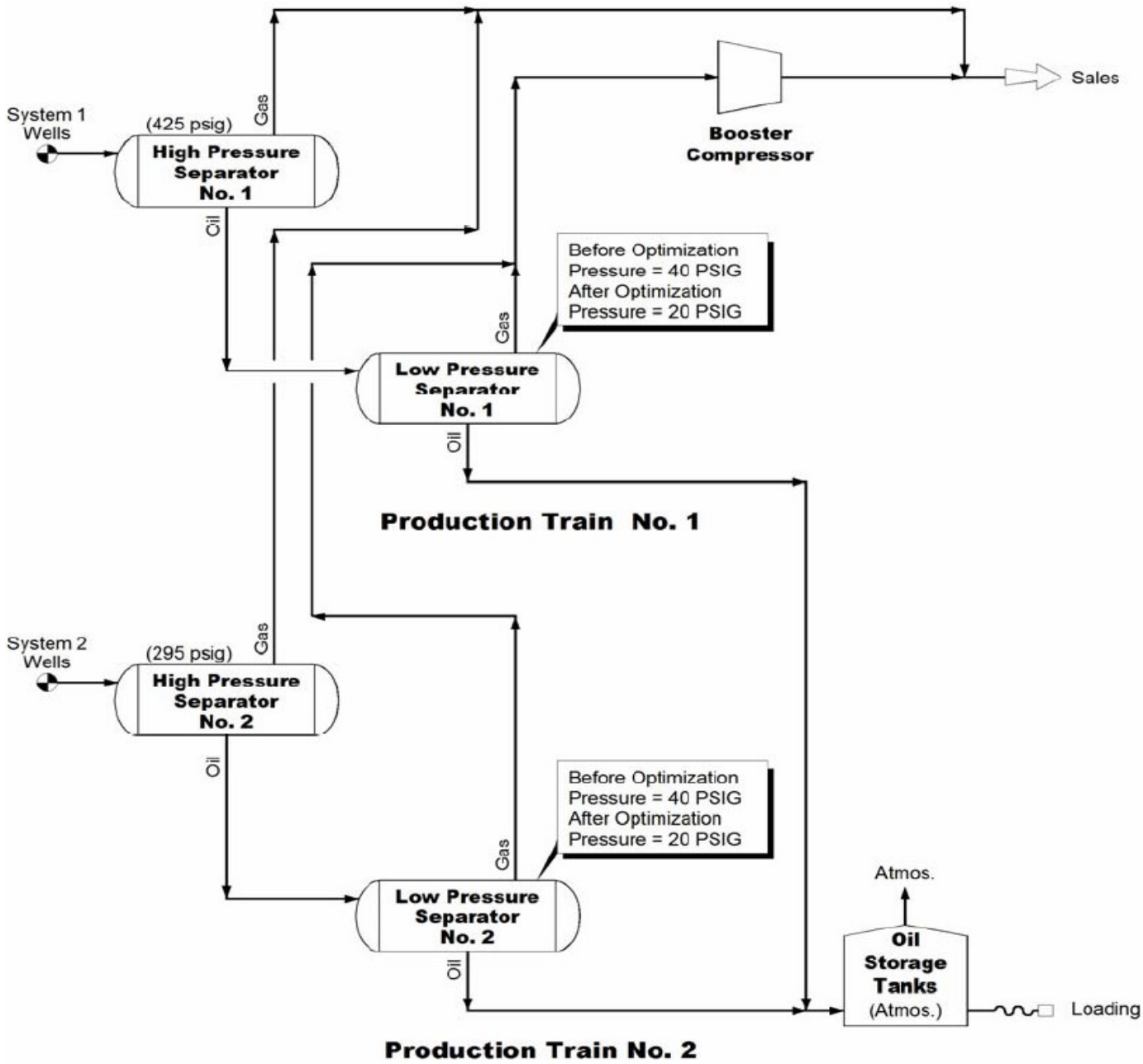

Figure 3.1 Process Flow before and after optimization

3.2 USING NON-MECHANICAL TECHNOLOGY TO RECOVER NATURAL GAS VAPOR

PROCEDURE: Vapour recovery systems for crude oil storage tanks are installed for several reasons. Capturing vent gas for use in the system (e.g., fuel gas, gas lift or injection) into the sales pipeline results in improved efficiency, increased profits, and conservation of natural resources. According to Bernoulli's equation, if no work is done on or by a flowing frictionless fluid, its energy due to pressure and velocity remains constant at all points along streamline. As a result an increase in velocity is always accompanied by a decrease in pressure. This principle can be used to collect a low pressure natural gas stream with a high pressure motive gas stream for entrainment and compression to an intermediate pressure.

The Company QRS' Facility is an oil and gas production facility. The facility had an existing mechanical vapour recovery unit that collected stock tank gas, increased the gas pressure and send it to the onsite booster compressor. The booster compressor sent its gas to the sales pipeline. This facility was required to operate a vapour recovery system on their storage tanks by an Environmental Protection Agency. Initially, an electric driven vane compressor was installed to handle the vapours. Its efficiency was 90% of the time. Due to reliability issue and cost of maintenance, QRS researched new options. They choose a specialized company's Venturi jet ejector, called the EVRU (Environmental Vapour Recovery Unit) as a viable and feasible option. The EVRU uses a venturi jet ejector to collect gas from vents, storage tanks and pressure vessels and re-injects the gas back into the system.

Prior to designing the venturi jet ejector, a walkdown of the site was conducted on the 21st of August, 2001, to determine the operating parameters of the process, obtain an equipment inventory and to identify all sources of vent gas at the location. The data required for the venturi jet ejector design are viz:-

- Operating pressure of pressure system (e.g., suction pressure of each of stage of on site booster compressor).
- Sources of high pressure gas (e.g., compressor discharge, high pressure gas to and from glycol dehydration unit contactor tower).
- Operating pressure of high pressure gas system.
- Present and future estimated volume of gas that would be compressed in booster compressor (needed to ensure available horsepower to compress intermediate pressure gas from venture jet ejector).
- Amount of spare horsepower available to booster compressor for compressing intermediate pressure gas from venturi jet ejector.
- Tank dimensions, tank operating pressure, location and dimensions of venting piping.
- Volume of gas recovered by existing mechanical vapour recovery.

Method of Operation

Venturi jet ejectors use the kinetic energy in a high-pressure motive gas to create a vacuum that can entrain and mix another source gas stream. The motive gas and the source gas are mixed in the venturi jet ejector, increased to an intermediate pressure with gas mixture and sent to a low-pressure system. The resultant gas mixture can be injected into the suction of a compressor, low-pressure separator, fuel gas system or flare. Thus making the unit a closed-loop system, that reduces or eliminates vent gas emissions. The facility storage consisted of five, fixed roof storage tanks (each 400-barrel capacity) and two gun barrel tanks (each 750 barrel capacity). The settings for the pressure relief

valves for the tanks were 0.3 psig of pressure and 0.3 psig of vacuum. The facility was configured with the vent from each tank routed to a common 6-inch header pipe for collection by the mechanical vapour recovery unit. The mechanical recovery unit increased the vent gas pressure for injection into the first stage of the existing booster onsite booster compressor. The onsite booster compressor received from other onsite low-pressure separators prior to injection into the sales pipeline.

Consequently, while conducting the walk down, the 'specialized company' measured the flow rate of gas vented from the tanks using ultrasonic meter. The meter used was an ultrasonic gas flow transmitter. The meter used was equipped with a 2-inch spool piece that contained the transducers, a pressure sensor and a temperature sensor. Gas flowed from a common header through the spool piece for measurement. Flow rate readings were taken at 10-second intervals over a 24-hour period. This gave a complete profile of the gas flowrate over 24-hour period. The inline spool piece has no flow obstruction, caused no pressure drop and could be used for pressures less than 0.3psig. While measuring the flowrate, a sample of the vent gas was collected using a vacuum bottle. This sample was chemically analysed for methane through decane plus components using a commercial laboratory facility.

During the flowrate measurement, the facility's oil production was approximately 700 BOPD of 62° API gravity oil. The pressure of the separator upstream of the storage tanks was approximately 80 psig. The measured flowrate over the 24-hour period was 202,000 SCF with an average flowrate of 140.3SCF/minute. The flow ranged from 90 to 160 SCF/minute. The laboratory analysis of the vent gas yielded an energy content of 1850 BTU/SCF. Based on this energy content, 373.7 MMBTU/day of gas was available for collection. Using the onsite facility process information and the measured flowrate data, the 'specialized company' designed a venturi jet ejector for the process. To

ensure that adequate capacity was available for future increased production, two venture jet ejectors in parallel were proposed for the application. Venturi jet ejector 1 was designed to collect 200 MSCFD and Venturi jet ejector 2 was designed to collect 100 MSCFD for a combined design capacity of 300 MSCFD. The EVRU was designed to maintain tank pressures in the range of 0.10 to 0.3psig. Ejector 1 was designed to maintain tank pressures between 0.10 to 0.20 psig; Ejector 2 operates when tank pressures exceeded 0.20 psig. Both ejectors send vent gas to the first stage of the onsite booster compressor for ultimate injection into the sales pipeline. The source of the motive gas for the venturi jet ejectors was gas from the onsite glycol dehydrator's contact tower. The motive gas to the venturi jet ejectors was controlled with a pressure regulator and flow controller to maintain a designed pressure of 850 psig. The discharge pressure from the venturi jet ejectors was approximately 25 psig.

The pressure and vacuum settings for the tanks' pressure relief devices were not changed from their original settings in place when the mechanical vapour recovery unit was operational. To ensure that positive pressure was maintained in each tank, the EVRU's programmable logic controller was programmed to maintain a positive pressure of 0.1psig. The EVRU is designed to shut off the motive gas and shut down the unit if the pressure exceeded this set point. To ensure that air did not enter the system an oxygen sensor was installed upstream of the vacuum jet ejectors. The oxygen sensor was designed to shut down the system if oxygen concentration in the vent gas exceeded 2.5 % by volume.

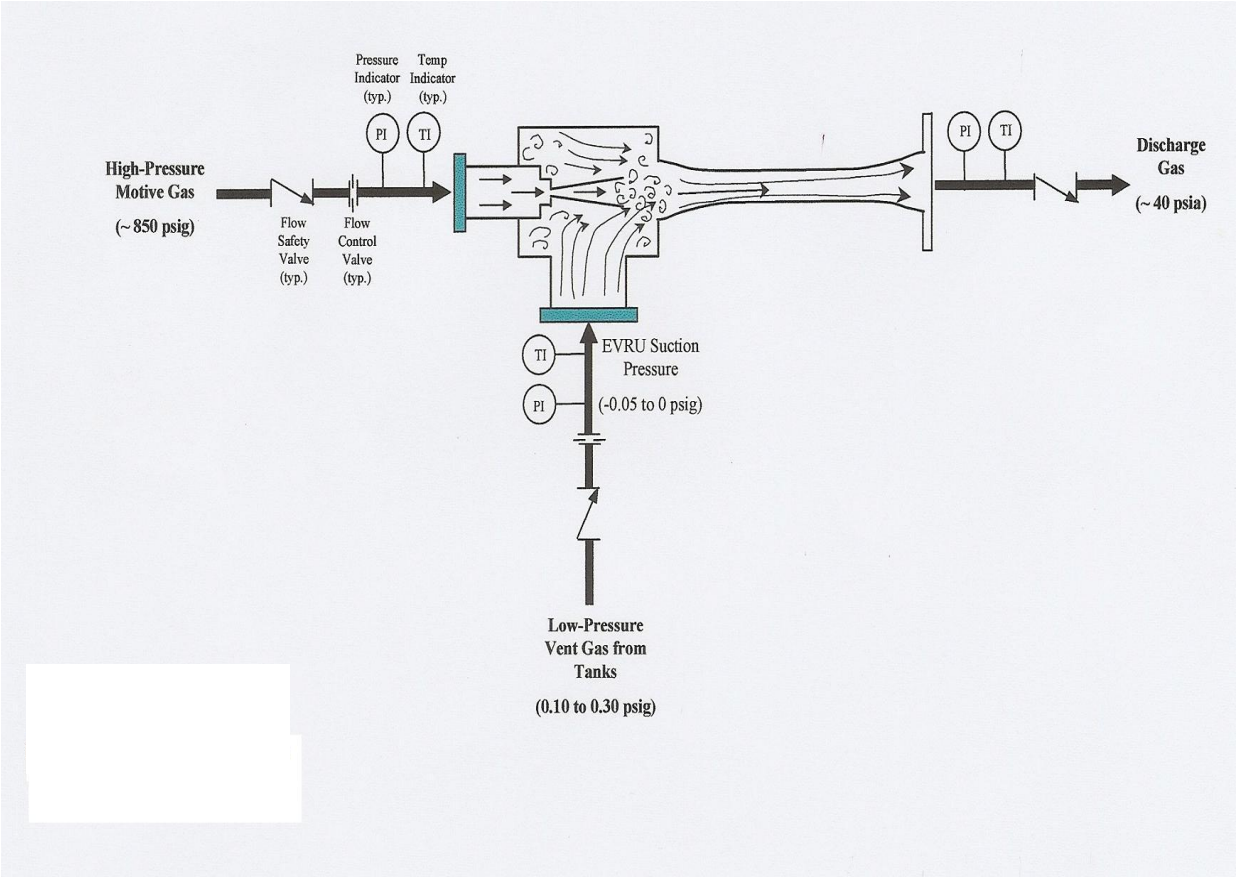

Figure 3.2 A venturi system

3.3 LIQUID PETROLEUM CONFINEMENT SYSTEM

The standard well site storage system in the United States is the conventional atmospheric storage tank, the type we have here in the Niger Delta of Nigeria. The standard atmospheric tank is constructed of either bolted or welded steal and then fitted with various appurtenances according to design codes or end user requirements. Of great consideration is the historic manner in which the tank is vented to atmosphere.

The primary sources of vented vapours from an atmospheric tank system are:

Displacement during filling operations

1. Filling losses are those vapours that are expelled from the tank when the crude oil is introduced into the system. The filling causes the vapours to be

compressed until they are equal in pressure to the mechanical backpressure relief and then they are vented. As the system is emptied, the crude flashes into vapour to occupy the void space above the fluid-vapour interface.

2. Losses can also occur due to the expansion of the crude oil after it enters the system.

Vaporization of the crude oil: The crude oil that is now at atmospheric conditions within the system undergoes a series of vaporization phases until they are vented.

Breathing: The temperature differences between day and night cause the vapours to be expelled.

Pressure-Volume-Temperature Relationships

The series of physical changes causing the vaporization of the crude oil within the atmospheric tank system can be best described using the "ideal-gas" law. The ideal gas equation,

$$PV = nRT \text{ ---------- } 3.1$$

expresses a quantitative relationship between all four of the variables in describing the state of a gas. When the crude oil is placed in a storage system under atmospheric conditions, it readily escapes into the gas phase. For certain types of crude oil, the system will eventually be emptied if left unchecked. This physical change is known as "vaporization" or "evaporation". This phenomenon can be explained in terms of the kinetic-molecular model as follows.

Kinetic Molecular Model

Vaporization: A particle at or near the liquid surface can escape, or vaporize, into the gas phase when it acquires sufficient kinetic energy through

collisions to overcome its attraction to other surrounding particles within the liquid. The lesser the attractive forces, the more readily vaporization occurs. One of the two particles is actually more volatile. The rate of vaporization increases with temperature due to the increase of kinetic energy. The vaporization of particles having high kinetic energy causes particles of lower kinetic energy, remaining in the liquid, to decrease in energy; the temperature of the remaining liquid is thereby lowered because the temperature reflects the average kinetic energy of all the particles. In conventional storage tanks, the liquid acquires energy from its surroundings and essentially remains at the same temperature during the vaporization processes.

When a particle of gas escapes from the liquid surface, it collides with other particles already in vapour form as well as with the interior walls of the tank. The random motion of the particle may bring it back in contact with the liquid surface and it becomes captured or condensed. The overall net rate of vaporization is the rate at which the particles vaporize minus the rate at which they are condensed. One significant problem with an atmospheric storage tank system is that the vent line carries away the escaped particles thereby eliminating any chance for them to be recaptured by random motion and this result in an increase in the net rate of vaporization. Yet another problem with the atmospheric tank is that they are constructed as a vertical cylinder, which allows the available surface area of the gas - liquid interface to remain constant regardless of the volume.

The following conditions enhance vapour losses:-

Heat of Vaporization: The quantity of heat that is required to convert a liquid to a gas at constant temperature is the heat of vaporization.

Flash Vaporization: When the vapour particles are caught in the upward drift of the venting process, then the pressure drop causes flash vaporization to occur and these particles will not remain in the tank.

Vapour Pressure: If crude oil is placed in a confined container, such as the L.P.C.S. System, then the particles entering the vapour phase cannot escape. Particles in random motion are condensed or recaptured when they strike the surface of the liquid. The internal pressure of the system is caused by the random motion of the particles and is termed the vapour pressure. The rate of condensation increases as the rate of particles in the vapour phase increases. When the two processes become equal, the pressure will stabilize. In an atmospheric tank, the vapour pressure is constantly at a pressure that is 4 ounces (or less) greater than atmospheric pressure.

Dynamic Equilibrium: When the two rates of vaporization and condensation become equal, the number of particles in the vapour phase becomes stabilized. This results in a steady state and is termed dynamic equilibrium. The rates of the two opposing processes take place at the same rate as a function of time. When equilibrium is reached, no additional particles enter the vapour phase. If the pressure within the system were to be monitored, as a function of time, it would be observed to increase until equilibrium is attained and thereafter it would remain constant. The resulting equilibrium vapour pressure is dependent upon the attractive forces between particles of the liquid and their temperature.

Boiling Points: A liquid is observed to boil when vapour bubbles appear in the interior of a liquid. This occurs when the vapour pressure equals the external pressure acting on the liquid's surface. The boiling point of any hydrocarbon depends on pressure. Water boils at 1 atmosphere of pressure and 100° Celsius. The boiling point of any liquid at 1 atmosphere of pressure is called its normal

boiling point. By contrast, the normal boiling point of gasoline and many crude oil condensates is 13 degrees Celsius.

All of the above pressure-volume-temperature relationships directly cause and affect the rate of vapour losses from crude oil at the well site during its time in storage. A visual model of the processes taking place within a conventional atmospheric storage system is presented in Figure 3.4.

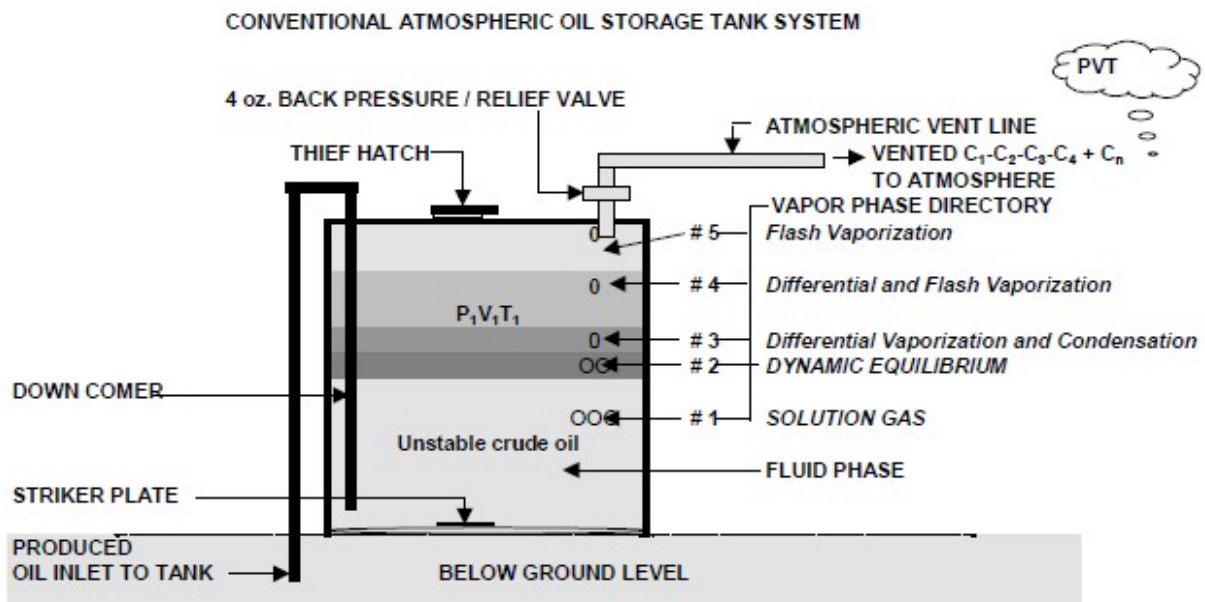

Figure 3.3- Conventional atmospheric storage tank depicting vaporization processes of the crude oil in progress.

As can be observed, the ever-changing physical conditions within the tank are an attempt to become stable with the atmospheric conditions. Because the atmosphere has a different pressure, volume and temperature than the volatile hydrocarbon vapours within the tank, the pressure-volume-temperature relationships are not equal. This dynamic difference will continue because the atmospheric tank cannot bring the two into dynamic equilibrium. The use of Boyle's law states that the product of pressure and volume at constant temperature is a constant. Using subscript 1 to denote the pressure, volume and temperature, $P_1V_1T_1$ within the tank and no subscripts after the crude oil products are vented to the atmospheric PVT, it can be observed that

$$P_1V_1T_1 \neq PVT. \quad \text{----------} \quad 3.2$$

The following statement can therefore be made:

[[The summation of the quantity of the various vented products represents the total volume of the recoverable product.]]

Volatile Hydrocarbons

Many of the constituents of crude oil are not stable at atmospheric temperatures and pressures and are considered to be volatile products. The boiling points are lower and vapour pressures of these products are greater than most atmospheric conditions, i.e. 14.696 psia and 100 ^{o}F. As observed in Figure 7,

Table 3.2- showing some typical volatile hydrocarbons found in crude oil.

Physical Properties of Some Volatile Hydrocarbons

Volatile Hydrocarbon	Boiling Point @ 14.696 psia. Degf.	Vapor Pressure @ 100 degf. Psia.
Methane	-358.74	(5000.)
Ethane	-127.44	(800.)
Propane	-43.73	188.000
Iso-Butane	10.74	72.390
n-Butane	31.12	51.540
55 API^{0} Gasoline	55.00	7.000
Iso-Butane	82.11	20.444
n- Pentane	96.91	15.575
n-Hexane	155.73	4.960
n-Heptane	209.16	1.6201
Kerosene	257.00	1.0000
Diesel	399.20	0.7000

The volatile hydrocarbons listed, beginning with Methane down through n-Pentane, will boil at temperatures below 100 ^{o}F. And will have vapour pressures greater than 14.696 psia. These unstable volatile products will enter

the vapour phase within an atmospheric storage tank and escape to the atmosphere. Additionally, it can be observed that even heavier products such as n-Hexane down through Diesel will also vaporize under the same conditions, although at slower rates.

Of special interest are the properties of Gasoline. These are included because they closely represent the boiling points and vapour pressures of the many types of condensate crude oils associated with high GOR wells. High gravity crude oils having boiling points and vapour pressures greater than atmospheric cannot be contained and will readily vaporize from an atmospheric storage tank system. A graph depicting the range of the boiling points and vapour pressures of the volatile hydrocarbons can be observed in Figure 8.

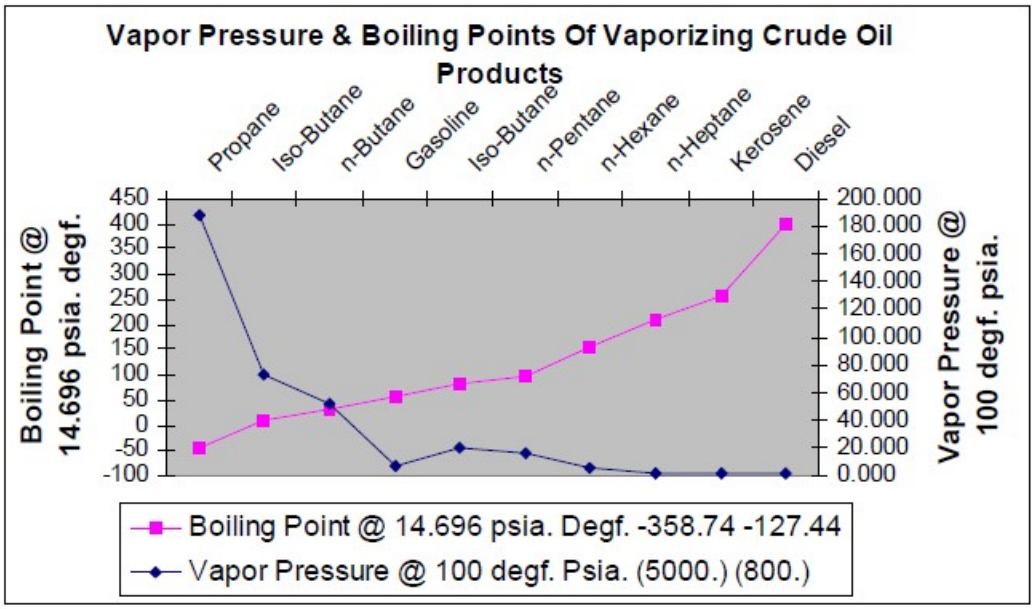

Figure 3.4- Graph of volatile hydrocarbon boiling points and vapour pressures.

The Liquid Petroleum Confinement System

This new well site crude oil storage method offers an innovative and viable solution to the problem of losing crude oil to the atmosphere in vapour form. In this system, when the crude oil molecules enter the vapour phase, they

cannot escape to the atmosphere. In random motion, the molecules strike the surface of the liquid and are recaptured. Thus two processes occur simultaneously:

(1.) Vaporization or entry of particles into the vapour phase, and

(2.) Condensation or entry of particles into the liquid phase.

Because of the confined nature of the crude oil, the rate of vaporization and condensation become equal and stabilized at pressures on the order of 10-20 psi or higher depending on the design. "Dynamic Equilibrium" is obtained. Since the system is constructed to be a confined energy system, there is only one pressure-volume-temperature relationship considered $P_1V_1T_1$ = PVT. The left side of the equation is the first L.P.C.S. compartment and the right side of the equation is the second compartment, or vice versa. The processes are isolated from atmospheric conditions.

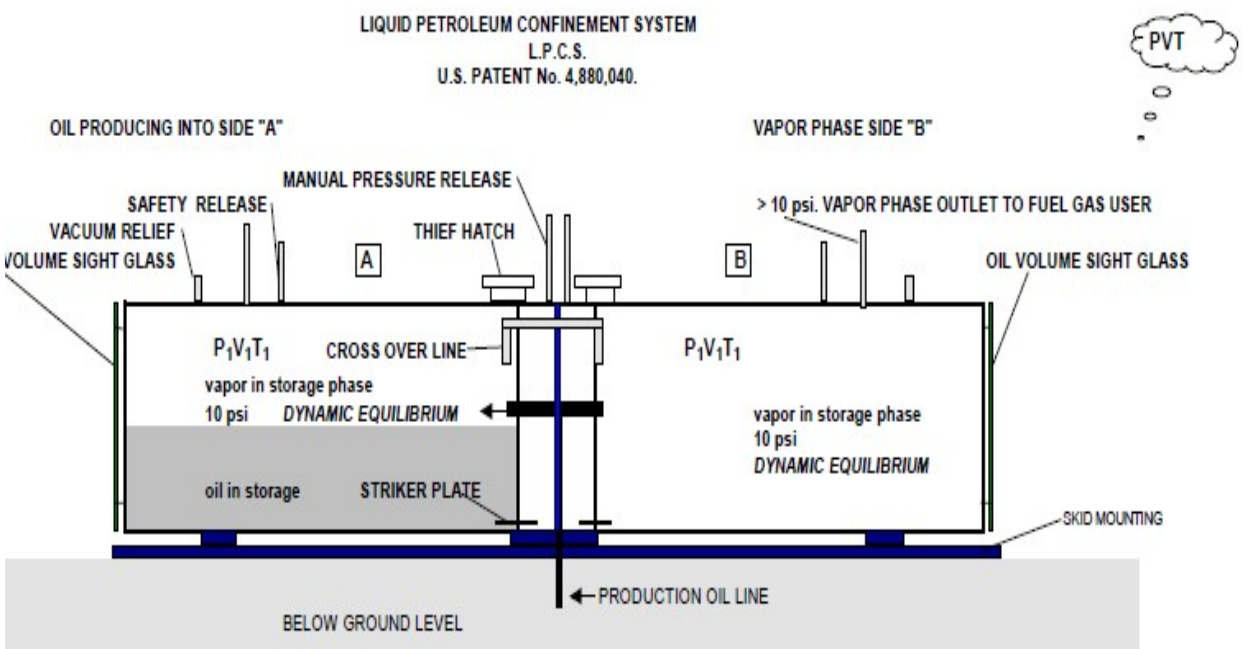

Figure 3.5- L.P.C.S. System with oil production directed into compartment "A".

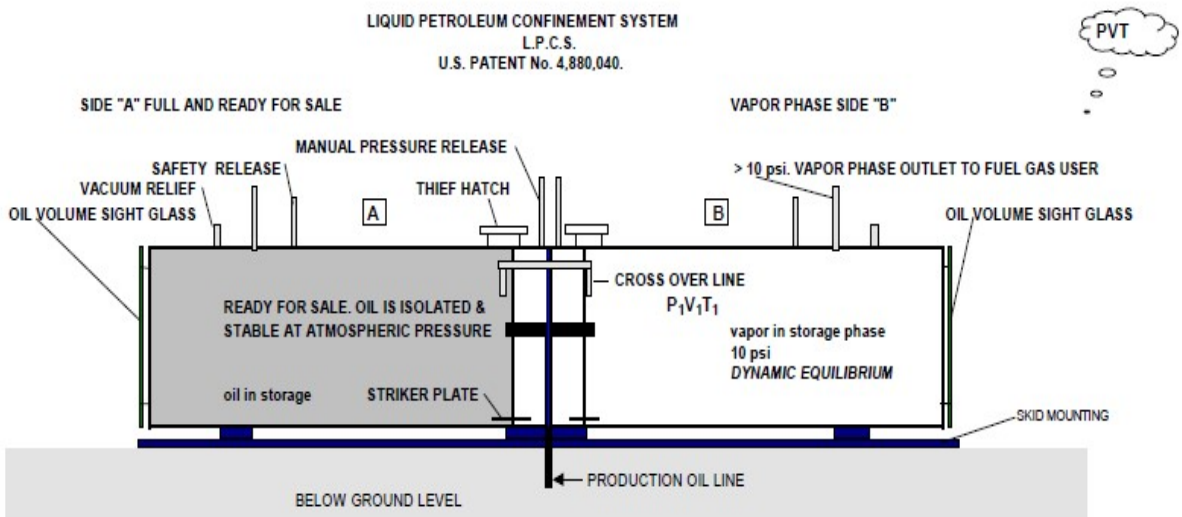

Figure 3.6-L.P.C.S. System with full oil storage in compartment “A”.

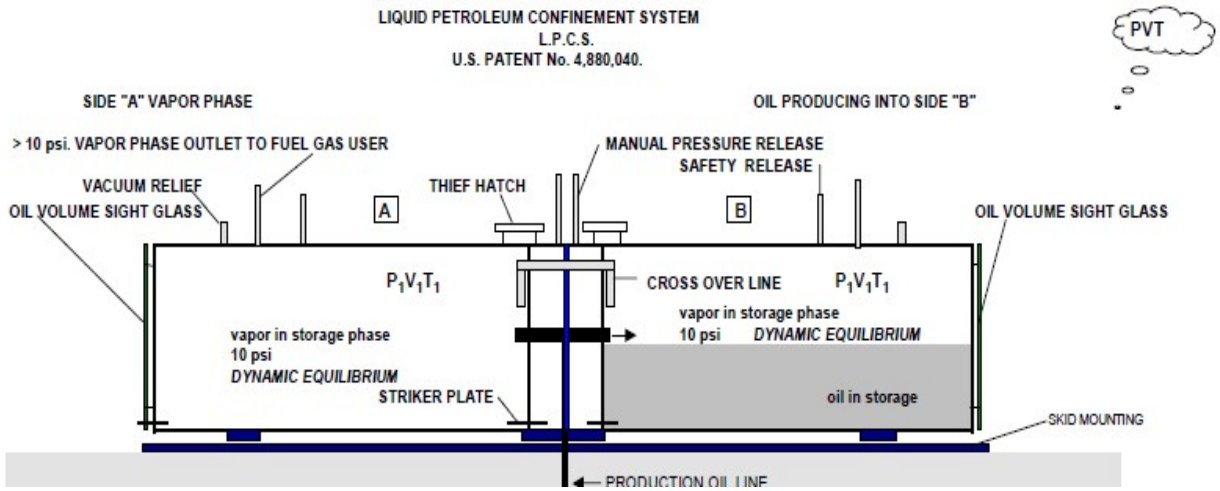

Figure 3.7-L.P.C.S. System with oil production directed to compartment “B”.

The L.P.C.S. System vessel is constructed of rolled and welded steel fabricated in a horizontal, spherical shape with two identical interior compartments. The first compartment is equal in volume to the second. The produced crude oil is

directed into the first compartment where it is allowed to be stored as it is produced. The individual compartments are collectively designed to be a closed system with no atmospheric vent lines. As the volume of the storage crude oil increases with production, “Dynamic Equilibrium” is established at a pressure that is greater than atmospheric but less than the working pressure of the vessel. The vapours are in a communication phase between the two compartments and are considered to be at a constant pressure.

L.P.C.S. Discussion

As the volume of fluid rises vertically within the horizontal cylinder, the surface area of the fluid available for vaporization and condensation changes by first increasing then decreasing. The maximum surface area of the liquid is attained when the vessel is half full. When filling, the vapours are systematically forced into the second compartment.

As the volume reaches maximum, the surface area of the fluid available for vaporization and condensation is at a minimum. The vapour phase of the system is now almost completely contained in the second compartment. Vapours stored in this manner are continually available for on site fuel gas or may be systematically flared. Either way, contamination of the atmosphere is eliminated.

When the compartment containing the crude oil liquid is full, it is isolated from the second compartment. Continued crude oil production is directed to the second compartment only. The remaining minor volumes of vapour in the first compartment are vented and then the compartment is closed. Since the crude oil can no longer undergo vaporization and condensation, then a steady state exits and the crude oil is stable. All potential vapour losses are confined within the system and most are returned to the liquid by the “Dynamic Equilibrium”

process. The surplus vapours are confined within the second vessel. Since the system is a confined energy system, no products are lost to the atmosphere.

All of the pressure-volume-temperature relationships are confined within the system and are not equated with the atmosphere.

Therefore $P_1V_1T_1$ = a constant for any given time.

Dynamic Equilibrium is obtained during all phases of the three production modes of the system. The crude oil is stable when the compartment is full and there is no space available for vaporization. A set of three visual models representing the confined processes which occur within the Liquid Petroleum Confinement System are presented in Figures 3.5, 3.6 and 3.7. Note that the differential and flash vaporization processes, which occur in the atmospheric tank, are eliminated by confinement.

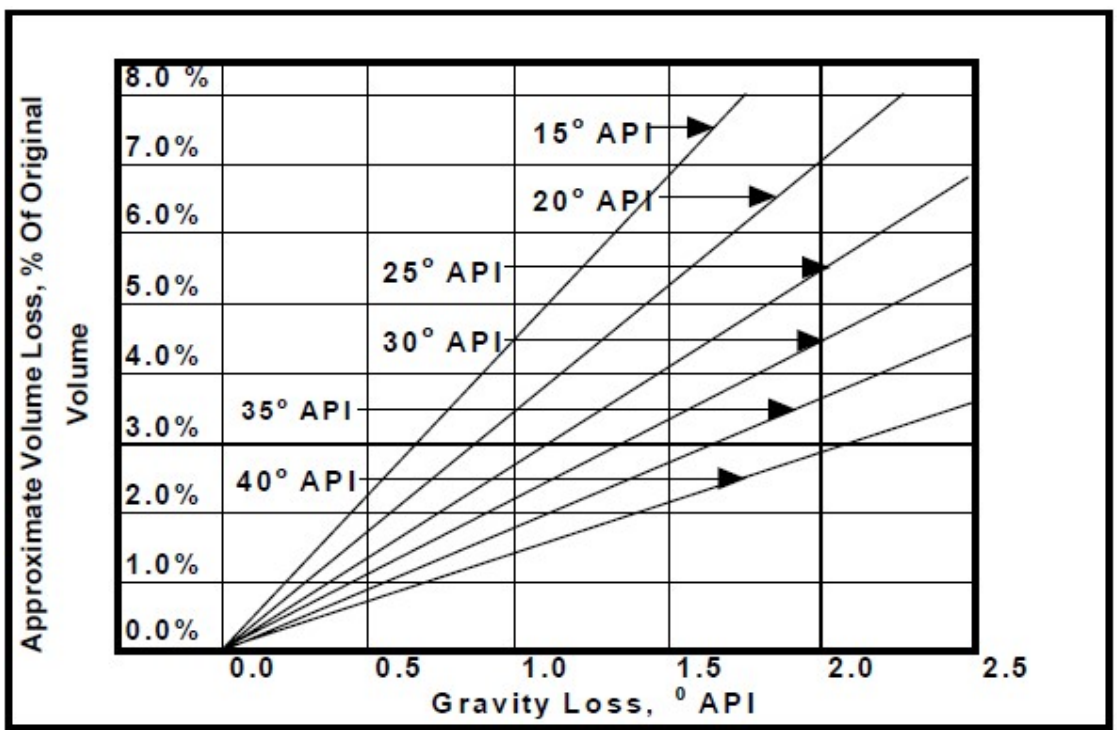

Figure 3.8- Show that volume loss creates API gravity loss. (Modified after Roof, William E.)

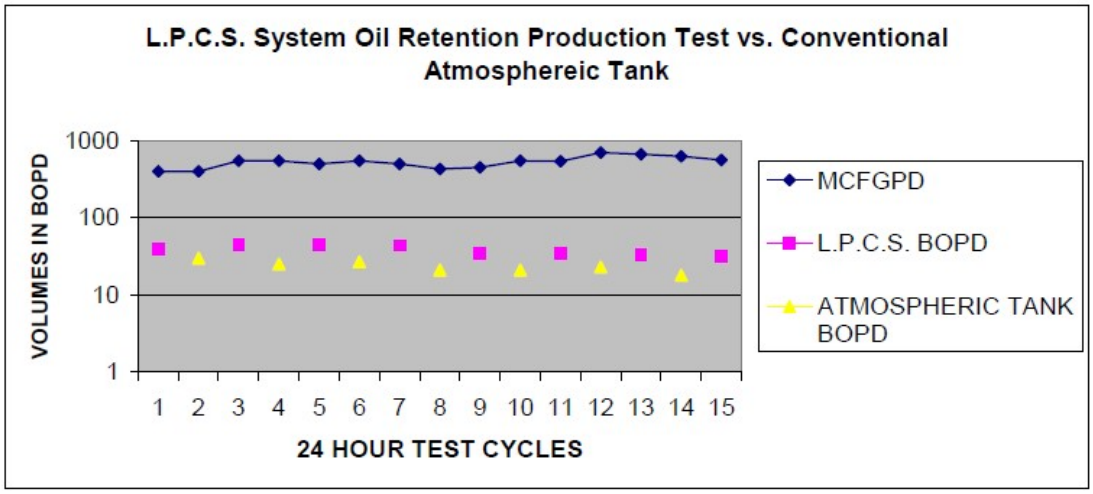

Figure 3.9- Fifteen day production graph indicating metered gas production as well as the oil volume production into L.P.C.S. System and atmospheric tank.

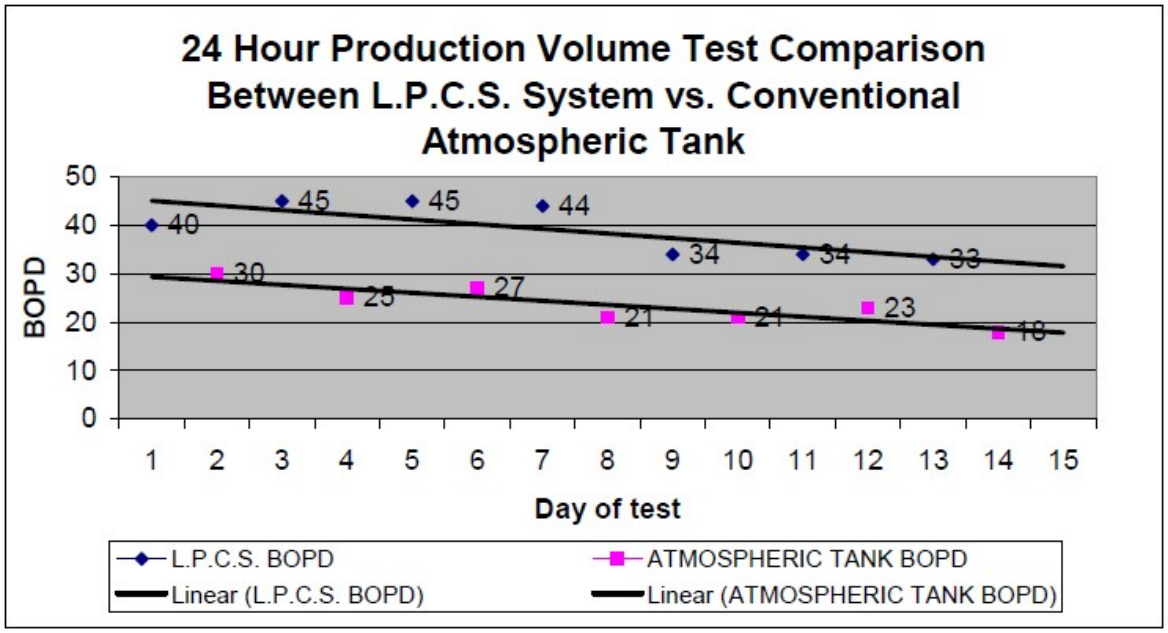

Figure 3.10- Graph of daily production volumes into each type of system.

3.4. USING GRAPH TO ILLUSTRATE THE RATE OF EMISSION FROM A TANK FARM AS A RESULT OF GLOBAL WARMING

In an oilfield, located in the eastern Niger Delta, this research was conducted in their oil centre-- a tank farm.

A study was made of their data between June 2007 and May 2008.

Table 3.3 contains the data of Production forecast for the day under review; the actual oil and gas production for the same day; the difference between the forecast and the actual production for the day; the average ambient temperature for the day also. For the purpose of this research, the values or observations for the 15th day of every month was taken as the average for the month. Having presented the various effects of the other parameters that affect crude oil storage and stabilization such as:-

a. Optimizing separators operating pressures to reduce flash losses at no operating cost.
b. Using Environmental Vapour Recovery Unit (EVRU) e.g. Venturi jet ejector to ensure zero loss of emissions constituents
c. We have also seen the effectiveness of the "Liquid Petroleum Confinement System" (L.P.C.S.), in ensuring that there are no losses of liquid petroleum, even of gaseous product and
d. Optimizing stage flashing separation for optimum recovery of reservoir fluid.

Therefore having presented above facts and figures, it is thus convincing enough for one to accept the report on the table below. Due to the lack of facilities to measure effectively and to the minutest detail, the losses through emission in atmospheric storage tanks here in the Niger Delta, available data

was consulted and consequently used to explain the unknown.

Table 3.3 Oil production forecast, actual oil production, gas produced, GOR, & ambient T^{o} Figures

Month	Production Forecast BOPD	Production into Storage Tank BOPD	Production Deviation from the Forecast BOPD	Gas Produced MMSCFPD	GOR scf	Average Ambient Temperature
June	80,547	83,650	3,103	1,238,020	14,800	74
July	81,350	84,400	3,050	1,266,000	15,000	74
August	80,830	83,835	3,005	1,278,484,	15,250	76
September	80,140	82,150	3,010	1,253,609	15,260	76
October	80,150	82,100	1,950	1,251,204	15,240	76
November	80,600	79,000	-1,600	1,241,880	15,720	79
December	80,950	78,947	-2,003	1,381,573	17,500	82
January	80,500	78,492	-2,008	1,397,158	17,800	82
February	80,680	78,000	-2,680	1,431,300	18,350	83
March	80,150	78,490	-1,660	1,271,538	16,200	82
April	80,105	78,805	-1,300	1,271,538	15,690	79
May	80,056	81,306	1,250	1,227,721	15,100	79

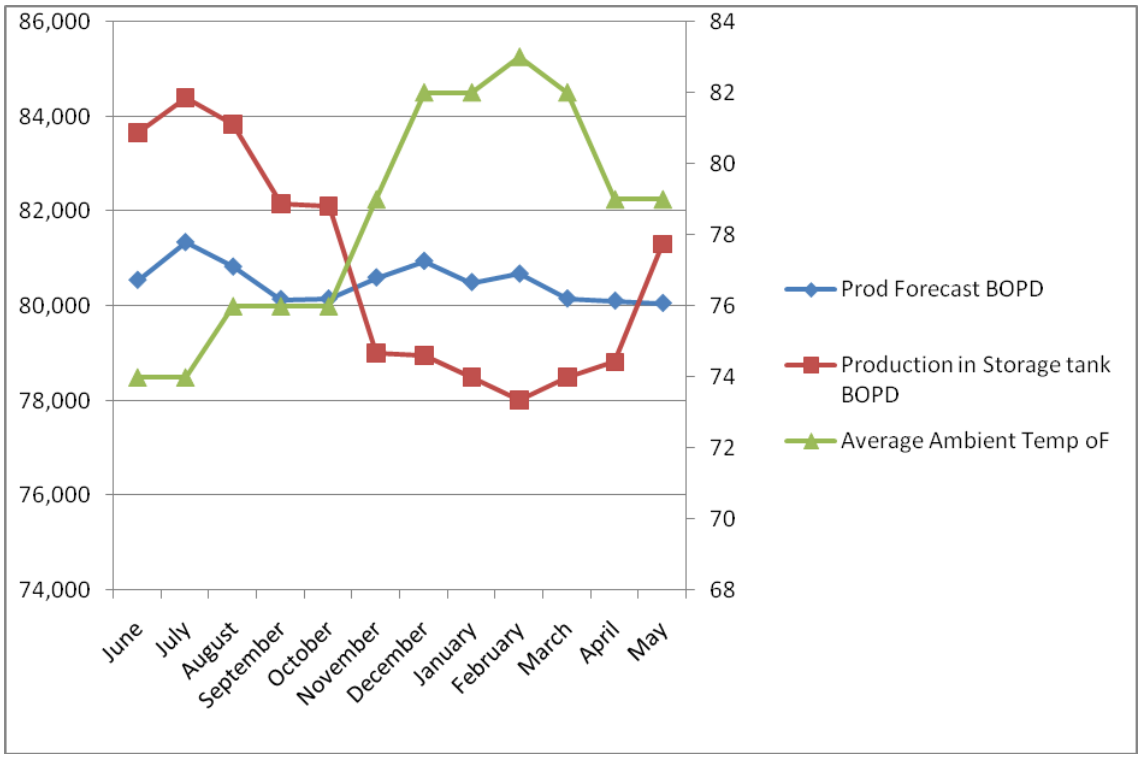

Figure 3.11-Graph of 24 hours production forecast, actual production in the storage tank, and ambient temperature.

A composite graph, comprising three different plots or graphs were merged in one:-

a. The graph of average ambient temperature of the 15th day of each month against the 15th day of the same month.
b. The graph of production forecast for the day (15th of every month) against the same day of the same month and
c. The graph of actual days (15th of every month) production against the same day of the month under review.

3.5. OPTIMIZING STAGE FLASHING SEPARATION FOR OPTIMUM RECOVERY OF RESERVOIR FLUID.

Conventional stage flash separation is the means of separating the gas from the full well stream. The stages should be selected to maximize retention of liquids. Maximum retention of liquids occurs with differential liberation of gas, i.e., an infinite number of stages. Economics will favour a practical number of stages, perhaps as few as two. Simulation of stage flashing yields liquid retentions that are useful for making economic analyses. A synopsis of a typical staging evaluation is given as follows:

A series of equilibrium flash computations are run on a (reservoir) crude composition at a series of pressure stages. The pressure of the initial separator is varied from 15, 100, 200, 400, and 500 psia (103, 690, 1379, 2759, and 3448 kpa). The number of stages in series is varied from one to six. The intermediate stage pressures for 3, 4, 5, and 6 stages are calculated using equal pressure ratios between stages. The stage pressure ratio is calculated using the following formula:

$$R_{stage} = (R_{overall})^{1/(n-1)} \quad \text{----------3.3}$$

Where n = number of stages

The process simulator is used to calculate data which are then plotted, figs 3.11 to 3.13. The units on the ordinate (y-axis) of some of the figures use only a portion of the scale to accentuate variations.

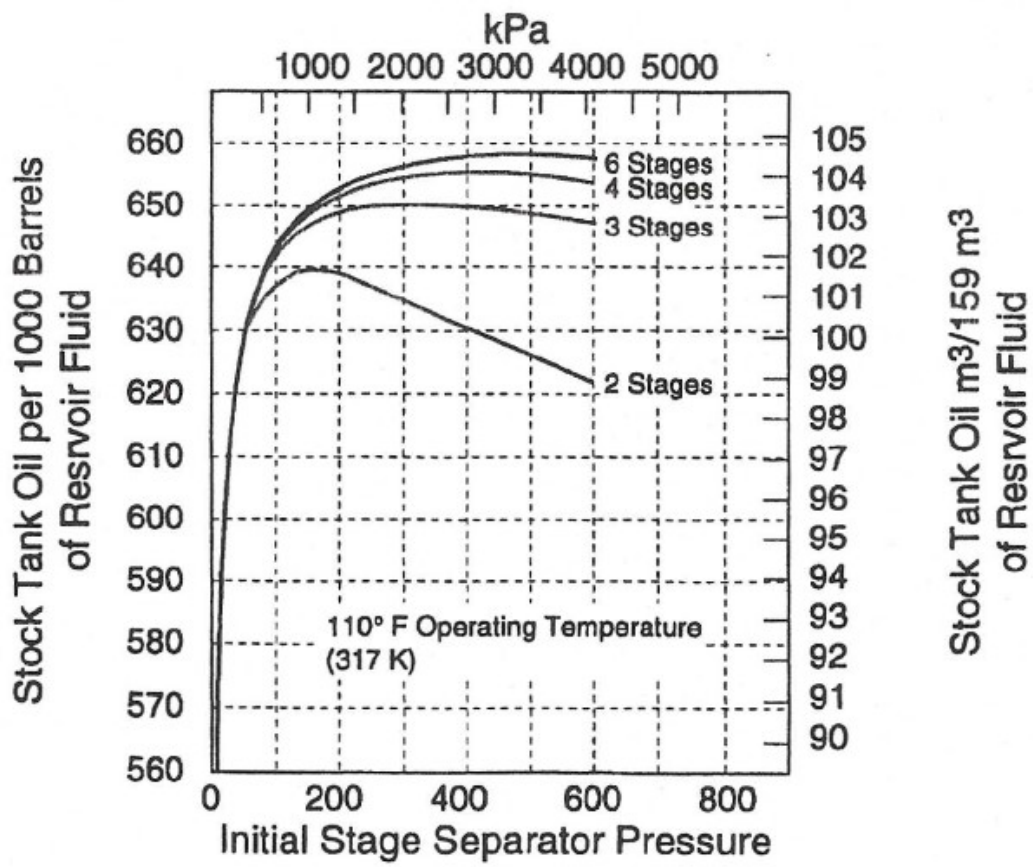

Figure 3.12 Recovery variations against stage pattern pressure

In figure 3.12 the recovery of stock-tank oil is shown for various first stage separator pressures. All recoveries are based upon 1000 barrels (159 m^3) of reservoir fluid at operating temperature of 110°f (317 k).The maximum recovery from each curve is tabulated as follows:

Table 3.4 Recovery Of Stock Tank Oil

	Number of stages				
	6	4	3	2	1
Optimum 1st-stage pressure,					
Psia	500	400	250	150	15
kPa	3448	2759	1724	1034	103
Recovery					
Barrels	657	655	651	640	541
m^3	104	104	103	102	91
Percent gain over 1 stage	21.4	21.0	20.1	18.1	
Percent gain over 2 stages	2.8	2.5	1.7		
Percent gain over 3 stages	1.1	0.8			
Percent gain over 4 stages	0.3				

Note that after one stage of separation the incremental increase for each added stage diminishes. Thus three stages of separation are the most practical. The figure 3.12 curves for three, four, or six show only a small change in recovery as first stage separation pressure is adjusted away from the optimum. Therefore, the first stage may be operated economically at any pressure between 200 and 600 psig. This wide variation in pressures allows the reservoir engineer to optimize wellbore deliverability rates.

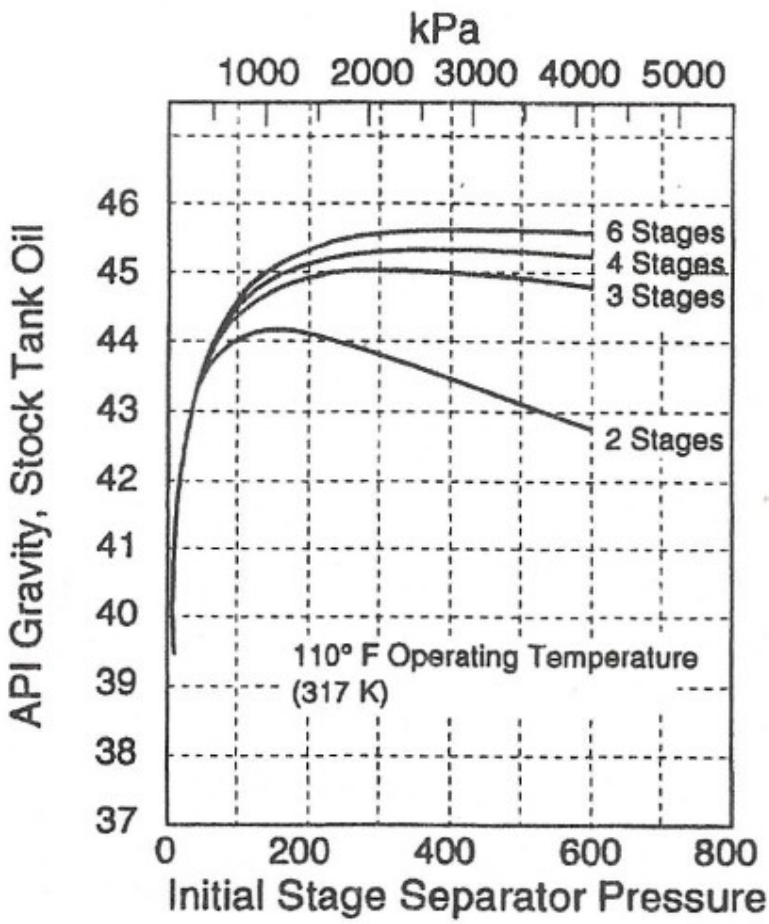

Figure 3.13 API gravity variations against stage pattern pressure

Figure 3.13 is a plot of the relationship of crude API gravity as a function of initial stage pressure for 2-, 3-, 4-, and 6- stage patterns. Oil API gravities in excess of 40° can be expected from two-stage operation. The material benefit (in terms of API gravity) anticipated from additional stages is in the direction of ever-increased proportion of light material. API gravity data at the optimum points is tabulated in table 3.5

Table 3.5 API Gravity Versus Number of Stages

	Number of stages				
	6	4	3	2	1
Optimum 1st-stage pressure,					
Psia	500	400	250	150	15
kPa	3448	2760	1724	690	103
API gravity at optimum	45.6	45.3	45.0	44.2	39.6
Percent API gain over 1 stage flash	15.2	14.3	13.6	11.6	

Figure 3.14 is a plot of the total gas-oil ratios for different initial stage pressures of various staging patterns. The gas-oil ratios at the optimum points of the first stage for various staging patterns of one through six in figure 3.14 are tabulated in table 3.6

Table 3.6 GOR Versus Number of Stages

	Number of stages				
	6	4	3	2	1
Optimum 1st-stage pressure,					
Psia	500	400	250	150	15
kPa	3448	2759	1724	1034	103
GOR at optimum,					
std cu ft/bbl	1167	1180	1194	1236	1566
std m^3 gas/m^3 sto	208	210	213	220	264

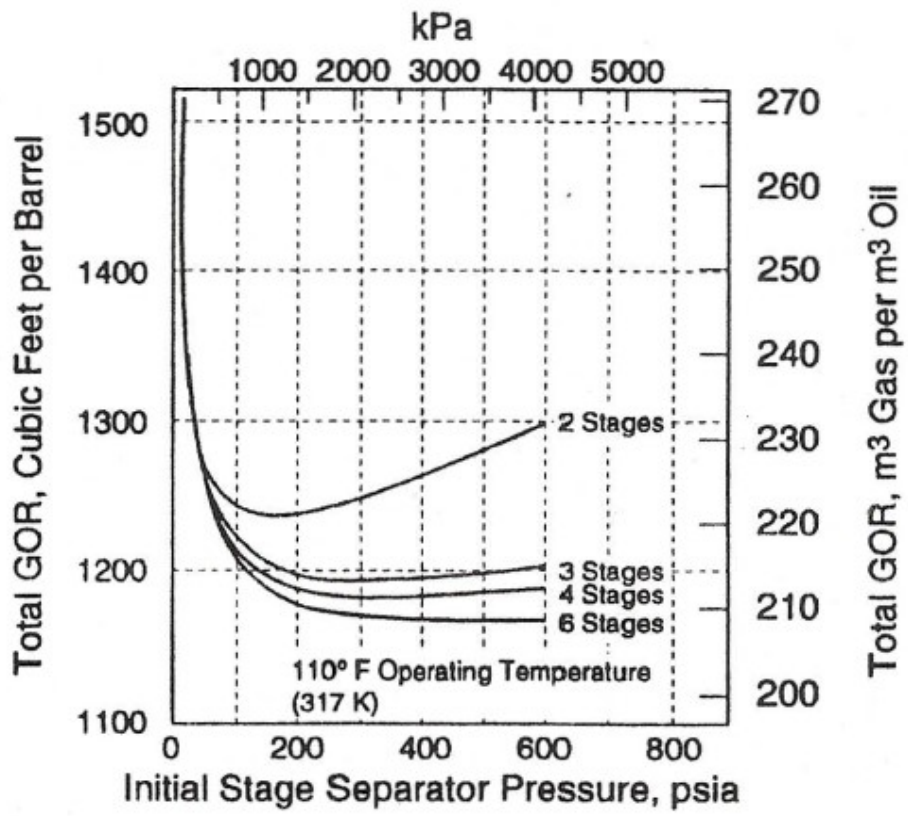

Figure 3.14 Gas-oil ratio variations against stage pattern pressure

3.5.1. Estimation of Emission from Atmospheric Storage Tanks in Tank Farms using VBE correlation (Vasquez-Beggs Equation)

Calculation for emission evaluation was done using a spread sheet xls program – "Volatile Organic Compound emission calculation for flashing"; a Vasquez- Beggs gas/oil ratio correlation method. The beauty of this correlation is that about 6000 crude oil samples from various oil fields all over the world were analysed in the course of deriving this correlation spread sheet program.

In the tank farm under study, economic evaluations of emissions from two tanks (A & B) were estimated. The last stage separator flash pressures were different; for tank A's train it was 18 and 20 psig and for tank B it was 20, 41 and 47 psig respectively.

Table 3.7 shows the production facilities data for atmospheric storage tank A's production train. The operating pressure and temperature of the tank was 14.7 psig and 70°F respectively; the operating pressure and temperature of the last stage separator to the tank was 18 psig and 88°F. The oil production into the tank within the 24 hours during research, simultaneously with tank B, was 5220 barrels and its oil's API° was 45.6.

Table 3.7: Production facilities data for atmospheric storage Tank A

	High pressure separator	Low pressure separator	Storage vessel
W.pressure (psi)	283	18	14.7
W. temperature (°F)	90	88	70
API°	45.6		
Total Oil Prod.(STB)	5220		

Table 3.8 shows the production facilities data for atmospheric storage tank A's production train on a slightly different parameter. The operating pressure and temperature of the tank was 14.7 psig and 70°F respectively; the operating pressure and temperature of the last stage separator to the tank was 20 psig and 88°F. The oil production into the tank within the 24 hours during research, simultaneously with tank B, was 5220 barrels and its oil's API° was 45.6.

Table 3.8 Production facility data for atmospheric storage tank A (a)

	High pressure separator	Low pressure separator	Storage vessel
W.pressure (psi)	283	20	14.7
W. temperature (°F)	90	88	70
API°	45.6		
Total Oil Prod.(STB)	5220		

Tables 3.9 to 3.10 show tank A's economic evaluation of the flashing losses at Constant temperature and various pressures.

Table 3.9 Flashing losses from atmospheric storage tank A at 18 psig separator flashing pressure

Flash Analysis for Gas-to-oil ratio (GOR)	R_s GOR at 18 psig, 88°F	Total Gas flashed Scf/day	THC/yr (Total hydrocarbon) Tonnes/year	(a) Flash/ VOC Tons/yr (C_3+ in stock Tank vapour)	(b) Flash/ VOC Bbls/yr (C_3+ in stock Tank vapour)	(c) C_1 to C_3 in Stock Tank vapour tonnes/yr	(d) Flash gas BTU value BTU/scf	(e) Flash gas BTU scf/yr (C_1 to C_3 in stock tank vapour)	(f) Annual value $ (C_3+)	(g) Annual value $ C_1 to C_3
Tank A	23.61	123,244.2	2863.2	2290.57	16,721.16	572.63	1200	22936,751.91	1,612,421.46	137620.51

LEGEND; This applies to all tables on flashing losses in this work (tables 8, 8a, 10, 10a, and 10b). 7.3 bbls= 1 tonne; 5487 scf = 1 bbl of HC; a typical gas value$ = $5.0 per 1MMBTU
(a) Flash/VOC TPY from spread sheet program VBE_Aug2008.xls
(b) (a)*7.3bbls
(c) THC from VBE_Aug2008 minus (a)
(d) A typical BTU value of 1200
(e) (c) *7.3*5487
(f) (b)*$96.43. Estimate based on the average price/ bbl of Nigerian crude oil for the months Aug. 2007 to May 2008 (source; OPEC bulletin of October 2008. Average price per barrel =$96.43)
(g) (((e)*1200)/1MM)*$5

Table 3.10 Flashing losses from atmospheric storage tank A at 20 psig separator flashing pressure

Flash Analysis for Gas-to-oil ratio (GOR)	R_s GOR at 20 psig, 88°F	Total Gas flashed Scf/day	THC/yr(Total hydrocarbon) Tonnes/year	(a) Flash/VOC Tons/yr(C_3+ in stock Tank vapour)	(b) Flash/VOC Bbls/yr (C_3+ in stock Tank vapour)	(c) C_1 to C_3 in Stock Tank vapour tonnes/year	(d) Flash gas BTU value BTU/scf	(e) Flash gas BTU scf/yr (C_1 to C_3 in stock tank vapour)	(f) Annual value $ (C_3+)	(g) Annual value $ C_1 to C_3
Tank A	25.68	134,049.6	3113.5	2490.82	18,182.99	622.68	1200	24,941509.7	1,753,385.73	149,649.06

Tables 3.11 to 3.12 show production facilities data for atmospheric storage tank B's production train. The operating pressure and temperature of the tank, was 14.7 psi and 70°F respectively. The oil production into the tank during

the 24 hours under research, simultaneously with tank A, was 33,374 barrels and the oil's API^o was 45.3. The operating pressures and temperature of the last stage separator to the atmospheric storage tank B was 20, 41 and 47 psig and constant temperature of 104°F respectively.

Tables 3.11 to 3.13 show tank B's economic evaluation of the flashing losses at Constant temperature and various pressures.

Table 3.11 Production facilities data for atmospheric storage tank B

	High pressure separator	Low pressure separator	Storage vessel
W.pressure (psi)	283	20	14.7
W. temperature (^{o}F)	90	104	70
API^o	45.3		
Total Oil Prod.(STB)	33,374		

Table 3.12 Production facilities data for atmospheric storage tank B-a

	High pressure separator	Low pressure separator	Storage vessel
W.pressure (psi)	283	41	14.7
W. temperature (^{o}F)	90	104	70
API^o	45.6		
Total Oil Prod.(STB)	5220		

Table 3.13 Production facilities for atmospheric storage tank B-b

	High pressure separator	Low pressure separator	Storage vessel
W.pressure (psi)	283	47	14.7
W. temperature (^oF)	90	104	70
API^o	45.6		
Total Oil Prod.(STB)	5220		

Tables 3.14 to 3.16 show the economic evaluation of the flashing losses from atmospheric storage tank B.

Table 3.14 Flashing losses from atmospheric storage tank B at 20 psig separator flashing pressure

Flash Analysis for Gas-to-oil ratio (GOR)	R_s GOR at 20 psig, 104°F	Total Gas flashed Scf/day	THC/yr (Total hydrocarbon) Tonnes /year	(a) Flash/VOC Tons/yr (C_3+ in stock Tank vapour)	(b) Flash/VOC Bbls/yr (C_3+ in stock Tank vapour)	(c) C_1 to C_3 in Stock Tank vapour tonnes/ year	(d) Flash gas BTU/ scf	(e) Flash gas BTU scf/yr (C_1 to C_3 in stock tank vapour)	(f) Annual value $ (C_3+)	(g) Annual value $ C_1 to C_3
Tank B	22.18	740,235.32	17195.5	13,756.41	100,421.79	3,439.09	1200	137,753,039.9	9,683,673.21	826,518.56

Table 3.15 Flashing losses from atmospheric storage tank B at 41 psig separator flashing pressure

Flash Analysis for Gas-to-oil ratio (GOR)	R_s GOR at 41 psig, 104°F	Total Gas flashed Scf/day	THC/yr (Total hydrocarbon) Tonnes/yr	(a) Flash/VOC Tons/yr (C_3+ in stock Tank vapour)	(b) Flash/ VOC Bbls/yr (C_3+ in stock Tank vapour)	(c) C_1 to C_3 in Stock Tank vapour tons/yr	(d) Flash gas BTU/ scf	(e) Flash gas BTU scf/yr (C_1 to C_3 in stock tank vapour)	(f) Annual value $ (C_3+)	(g) Annual value $ C_1 to C_3
Tank B	44.01	1,468,789.74	34,114.0	27,291.19	199,225.69	6,822.81	1200	273,288,3336.8	19,211,333.29	224,620.6

Table 3.16 Flashing losses from atmospheric storage tank B at 47 psig separator flashing pressure

Flash Analysis for Gas-to-oil ratio (GOR)	R_s GOR at 47 psig, 104°F	Total Gas flashed Scf/day	THC/yr (Total hydrocarbon) Tonnes /year	(a) Flash/ VOC Tons/yr (C_3+ in stock Tank vapour)	(b) Flash/ VOC Bbls/yr (C_3+ in stock Tank vapour)	(c) C_1 to C_3 in Stock Tank vapour tonnes/ year	(d) Flash gas BTU/ scf	(e) Flash gas BTU scf/yr (C_1 to C_3 in stock tank vapour)	(f) Annual value $ (C_3+)	(g) Annual value $ C_1 to C_3
Tank B	50.94	1,700,071.56	39,484.7	31,587.79	230,590.87	7,896.91	1200	316,311,519.7	22,235,877.59	1,897,869.12

Table 3.17 shows sensitivity analysis of atmospheric storage tank A's flashing losses, averaging 1.01 scf/bbl for every increase of 1 psig in last stage separator' flashing pressures.

At 17 psig separator flashing pressure, the liquid level in the separator was rising above the set point, and hence in a short while will fill up both the space for gas and oil and thus carry over oil to the gas gathering system.

However at 18 psig last stage separators flashing pressure, there was stability within the separator in maintaining the level of liquid at the desired set point and the space for gas in the separator.

Table 3.17 Result of sensitivity analysis for atmospheric storage tank A

TANK A		R_s	THC	VOC
Pressure (psig)	Temperature °F	GOR Scf/bbl	Total HydrocarbonTones/year	Volatile Organic compoundTones/year
17	88	22.60	2740.2	2192.15
18	88	23.61	2863.2	2290.57
19	88	24.64	2987.7	2390.13
20	88	25.68	3113.5	2490.82
24	88	29.94	3630.3	2904.26

Table 3.18 shows sensitivity analysis of atmospheric storage tank B's flashing losses. The average trend of losses is showing 1.08 scf/bbl increases for every 1 psig increase in last stage separator flashing pressures.

At 18 psig, up to 46 psig last stage separator flashing pressure, the liquid level in the separator was rising above the set point, and hence in a short while will fill up both the space for gas and oil and thus carry over oil to the gas gathering system.

However at 47 psig last stage separators flashing pressure, there was stability within the separator in maintaining the level of liquid at the desired set point and the space for gas in the separator.

Table 3.18 Result of sensitivity analysis for atmospheric storage tank B

TANK B		**R_s**	**THC**	**VOC**
Pressure (psig)	Temperature ^oF	GOR Scf/bbl	Total Hydrocarbon Tonnes/year	Volatile Organic compound Tonnes/year
18	104	20.33	15,761.7	12,609.34
20	104	22.18	17,195.5	13,756.5
41	104	44.01	34,114	27,291.19
47	104	50.94	39,484.7	31,587.79
55	104	60.58	46,963.0	37,570.77

The result of the sensitivity analysis carried out on the tanks' emission rate were plotted- last stage separator flashing pressure against GOR

Figure 3.15 shows analysis for tank A and figure 3.16 for tank B

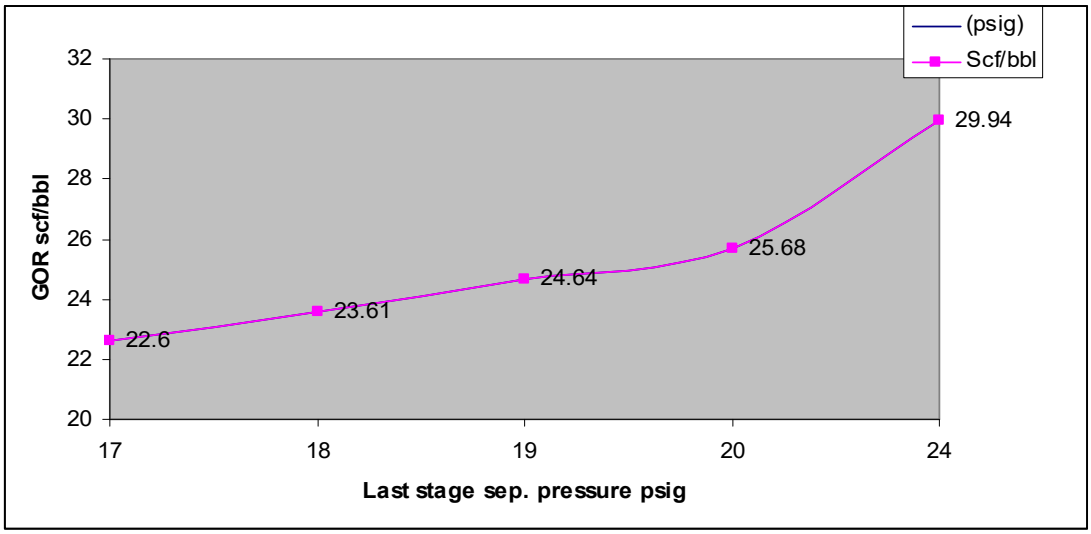

Figure 3.15 The trend of last stage flashing separator pressure vs GOR for atmospheric tank A

Above figure 3.15 confirms the results of table 10 for atmospheric storage tank A.

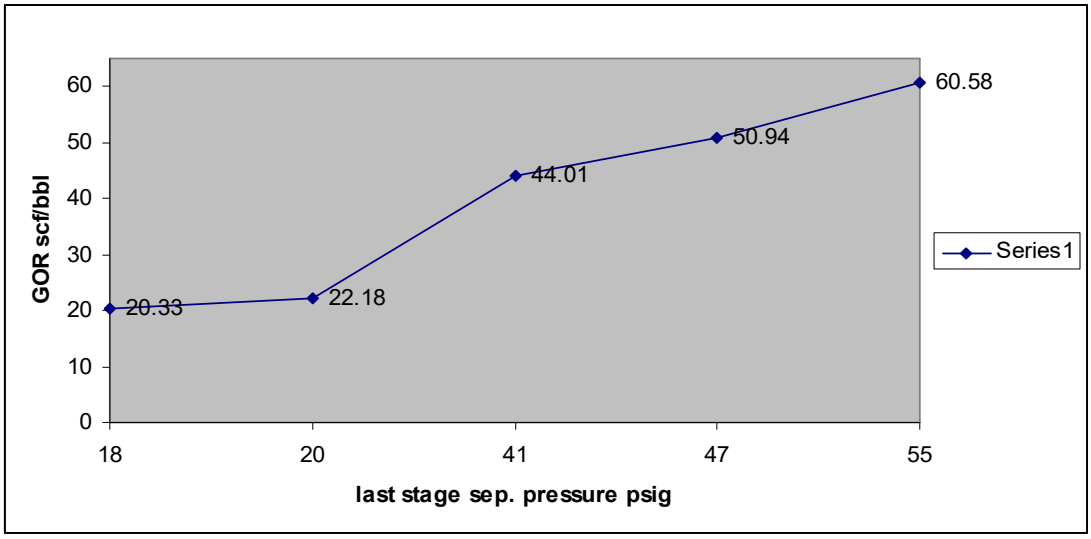

Figure 3.16 The trend of last stage flashing separator pressure vs GOR for atmospheric tank B

The figure 3.16 above confirms the results of table 3.17 for atmospheric storage tank B.

CHAPTER FOUR

4.0 RESULTS AND ANALYSIS

4.1 Optimizing Separators Operating Pressures' Presentation of Data and Results/ the Economics of the System

Estimated flash gas emitted to the atmosphere from the storage tanks of company ABC facility before optimization was 2,650,000 scf/year and total estimated gas flashed emitted to atmosphere after optimization was 1,789,000 scf/year. This resulted in an increase of potential gas to sales of approximately 861,000 scf/year. The gas would be worth $6,896 from 100BOPD per year based on the BTU content of the flash gas and a gas value of $5.00 per MMBTU (Table 3.1). Total estimated methane emitted to the atmosphere from the storage tanks before optimization was 653,000 scf/year and total estimated methane emitted to atmosphere after optimization was 317,000 scf/year. This resulted in an increase of potential methane gas to sales of approximately 336,000 scf/year.

4.2 USING NON-MECHANICAL TECHNOLOGY TO RECOVER NATURAL GAS VAPOR

Presentation of Data and Results/ The Economics of the System

The unit was installed and began operation on May 15th, 2002. Since the startup, the EVRU has been collecting approximately 175,000 SCF per day of 1850 BTU/SCF gas for ultimate injection into the sales pipeline. At that recovery rate, the amount of gas recovered by the EVRU is valued at $336,780 per year based on $2.85/MMBTU. These recovered vapors represent a BTU content of 118,169 MMBTU per year. During June 23rd, 2002, through July 1st,

2002, the Environmental Technology Verification (ETV) conducted verification testing of the EVRU. The verification report showed in September 2002, the results of the testing include the following:-

- Motive to vent gas ratio: 2.2 pounds gas to 1 pound gas with both ejectors operating.
- Volume of gas collected: 121 to 223 MSCFD with an average of 175 MSCFD.
- Potential value of vent gas recovered: $340,318/year based on $2.85/MMBTU.
- Amount of methane recovered: 32.1 MMSCF/year; 678 tons per year.
- Cost of installed unit: $107,958
- Payback: 0.3 year.

Since the beginning of operations in May 15th 2002 to May 14th 2003, the unit has not experienced any downtime.

4.3 The Liquid Petroleum Confinement System

Presentation of Data and Results/the Economics of the System

As previously discussed, when hydrocarbons pass into the vapor phase by vaporization, the volume of the crude oil is also decreased and the API gravity of the crude oil is decreased. There is a definite relationship between the API gravity loss and lost volume. **Figure 3.8** indicates that as the percent of the original volume is lost, the gravity of the crude oil also declines. The current US oil price index for domestic crude oil is benchmarked on 45° API (WTI) West Texas Intermediate crude. Purchasers impose a price reduction of approximately $0.15 per degree of gravity, both above and below the benchmark, on the producer. If the loss of product to the atmosphere resulted in a 2° API gravity loss per barrel below the WTI in storage, then a 200-barrel load would have lost

its value by $60.00. The L.P.C.S. System is designed to curtail this loss by retention.

An onsite production test was conducted to compare the produced oil volume from a flowing gas-condensate well when stored in a conventional atmospheric storage tank as compared to the L.P.C.S. System. The crude oil was 57° API gravity. The procedure for the test was as follows:-

1. The production test period was fifteen days however; the volume in each system was monitored for seven days each to make the test equal.

2. The produced oil was first directed into the L.P.C.S. System for 24 hours and then into the atmospheric tank for 24 hours.

3. The flowing pressure of the well was choke controlled at the three-phase production unit to maintain constant flowing tubing pressure.

4. Tank volumes were strapped at the end of each test period.

5. The L.P.C.S. System was set to operate at 10 psi and the atmospheric tank was set to have 4 ounces of back pressure in the tank.

6. The total of all daily oil production was then averaged to determine the quantity of crude oil lost during production and the storage in the atmospheric tank, or conversely, the volume retained by producing into and storing the crude oil in the L.P.C.S, System.

Results. The average daily oil production retained in the L.P.C.S. System was 38.75 BOPD. The average daily oil production retained in the atmospheric tank was 23.57 BOPD. This equates to a net gain difference of 15.18 BOPD in the L.P.C.S. System. The test results are shown in **Figures 3.8** and **3.9**. At current oil price of $26.98 (dated December 22, 2000) for WTI, the L.P.C.S. System

would have retained an average total dollar value of $409.56 greater than the atmospheric tank on a 24-hour basis. The totals of each seven-day oil production cycle during the test were 275 barrels for the L.P.C.S. System and 165 barrels for the atmospheric tank. The L.P.C.S. System retained 110 barrels more than the atmospheric tank. This would extrapolate to an overall net gain of $2,967.80 of revenue during the 14 days of actual testing. It also represents the revenue value lost from the atmospheric tank. The production ratio indicates that a production gain (retained by dynamic equilibrium) equates to a 40.00 % increase over the atmospheric tank. Conversely, if the well continued to produce into an atmospheric storage tank, the working interest and royalty owners would suffer a 40% loss of oil production and revenues to the atmosphere over the life of the well.

The L.P.C.S. gas vapour volumes having pressures greater than 10 psi are returned to a three-phase production unit separator and are used as fuel gas. Normally, the fuel gas is obtained within the separator from the production gas. This takes away gas that could be sold. As an example, if 30 MCFGPD were returned, having a BTU rating of 1450 per cubic foot, and a value of $10.50 / MMBTU then the gas would have a value of $456.90 per day. (Gas pricing from Henry-Hub December 22, 2000). Since this is recycled gas that would have been vented from the atmospheric tank, it becomes significant in that actual gas sales can be increased while reducing atmospheric contamination. The total revenues for each system are summarized in **Table 4.2**. The economics alone justify the L.P.C.S. System over the conventional atmospheric tank.

[The summation of the quantity of the various vented products represents the total volume of the recoverable product.]

Environmental Attributes

The unique design of the patented Liquid Petroleum Confinement System not only prevents waste and greatly reduces the loss of product to the atmosphere but it met and exceeded current EPA standards. The atmospheric tank does not. Recent **"New Source Performance Standards"** have been set forth in section 111 of the Clean Air Act, 42 U.S.C. The EPA administrator has established NSPS for many of the non-petroleum-related industries, but it has also included all "***petroleum liquid storage vessels***". The overall destructive effects of methane and other hydrocarbons to the Earth's Ozone layer and to the atmosphere are beyond the scope of this Thesis. However, it is extremely important to point out that oil producers must address these environmental issues and that prudence demands that the well site produced crude oil be stored in a manner to prevent waste and contamination. The only viable option to a non-complying standard atmospheric tank (excluding an expensive vapor recovery system) within the petroleum industry today is an L.P.C.S. System. Other issues associated with atmospheric crude oil storage involve the truck transportation of the crude to the refinery.

The truck and trailer are designed to be temporary atmospheric storage facilities and are subject to the same vapor loss processes as those that occur within the interior of the convention well site atmospheric storage tank. The crude oil losses, in vapor form, occurring in route to the refinery can be significant. It is for this reason that discrepancies are noted between the run ticket, which represents the before and after tank gauges, and the amount weighed off at the refinery. This is representative of the problem that first caused oil producers and refiners to agree on the 42 gallon barrel in place of 40 gallon over 140 years ago.

Table 4.1- Estimated total Revenues from each oil storage system tested

PRODUCT	Atmospheric Tank 7-Day Total Revenues	L.P.C.S. System 7-Day Total Revenues
OIL	$4,451.70	$7,419.50
RECYCLED GAS	$0.00	$3,198.30
TOTAL	$4,451.70	$10,617.80
DIFFERENCE	$0.00	+ $6,166.00

4.4 GRAPHICAL ILLUSTRATION OF EMISSION RATE FROM A TANK FARM AS A RESULT OF GLOBAL WARMING

Presentation of Data and Results/The Economics of the System

A graph illustrating the trend and effects of the ambient temperature on the conventional atmospheric crude oil storage tanks in the Niger Delta of Nigeria is found in figure 3.11

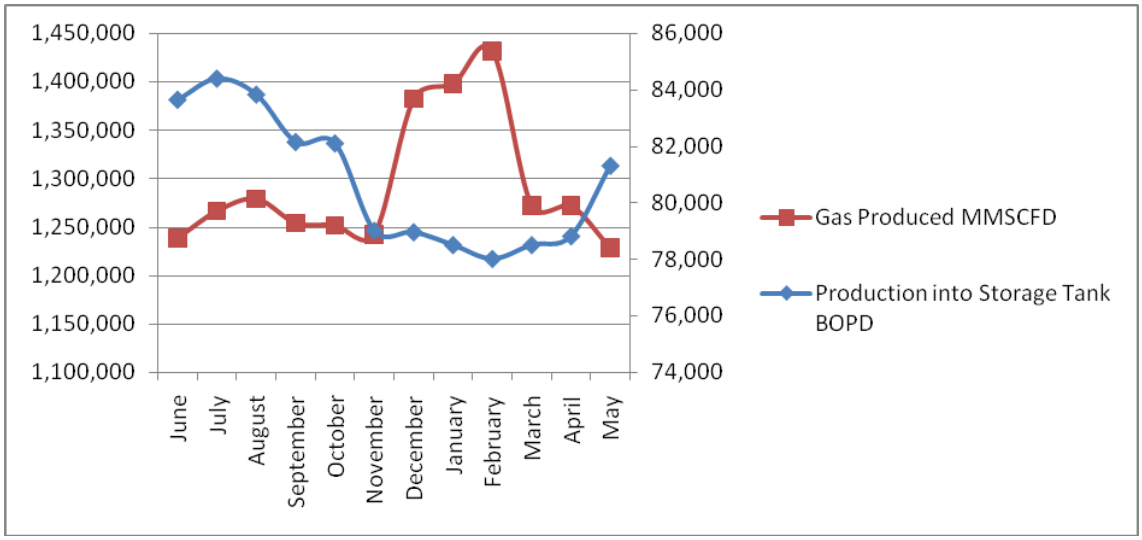

Figure 4.1-Graph of oil and gas produced showing stable reservoir production rate

A composite graph comprising three different plots or graphs were merged in one:-

- ✓ The graph of average ambient temperature against the 15th day of each month of the year
- ✓ The graph of production forecast for the15th day of every month of the year against the day of the same month of the same year
- ✓ The graph of the actual day's (15th day of every month) production against the same day of the month

Table 4.2 shows the economic effect of the ambient temperature on liquid petroleum production and storage in conventional atmospheric tank.

Table 4.2- Shows the economic gains and losses due to ambient temperature changes

Month	**Daily Losses or Gains BBLS**	**Monthly Losses or Gains[A] BBLS**	**Economic Value of Gains[B] $(*1000)**	**Economic Value of Losses[C] $(*1000)**
June	3,103	93,090	8,977.00	
July	3,050	94,550	9,117.00	
August	3,005	93,155	8,983.00	
September	3,010	90,300	8,979.00	
October	1,950	60,450	5,829.00	
November	-1,600	-48,000		4,629.00
December	-2,003	-62,093		5,988.00
January	-2,008	62,248		6,006.00
February	-2,680	-75,040		7,236.00
March	-1,660	-51,460		4,962.00
April	-1,300	-39,000		3,761.00
May	1,250	38,750	3,737.00	
		TOTALS	**$45,622.00**	**$27,192.00**

[A] Estimate based on multiplying the daily loss or gain of the 15th day of the month by the number of days in the month by the average price per barrel

[BC] Estimate based on the average price per barrel of the Nigerian crude oil for the months of August 2007 to May 2008 (Source; OPEC bulletin of October 2008. Average price per barrel = $96.43)

It is worthy of mention here that the deviations above and/or below the forecast arose from the fact that:-

- ➢ The well tests of the individual well strings that made up the forecast figures were conducted in the night hours. During this time the ambient

temperatures are lower than in the day time and liquid petroleum condensation is higher and its' evaporation minimal.

- In the colder days of the rainy season, the day time ambient temperatures are not too far away from the night ambient temperatures
- In hotter days of the dry seasons, the average ambient temperatures of the daytime are higher than the night time ambient temperatures when the tests were carried out.
- It is also worthy to note that emission in the day time hours of the dry season is much more than in the daytime of the rainy season.
- There are also the effects of local high temperatures arising from the radiant heat from the flares which are more pronounced in the dry season.

It becomes very evident that peak recovery or least emission occurred in the month of July when the rains are more consistent, unlike in August to September when occasional break occurred in the rain fall and the sun shined through to raise the ambient temperature a little tiny bit that may not be enough to affect the ambient temperature readings for the day, though the effect will show more on the rate of emission. February is also the month of highest emission or loss of liquid petroleum.

In real economic terms, the loss is colossal, in that on record a profit of $45,622 thousands of US dollars was recovered and the apparent loss below the forecast was $27,192 thousands of US dollar, in effect the real loss was ($45,622 + $27,192) i.e. $72,814 thousands of US dollar. If company ABC celebrated venturi, how much more shall the country and joint venture partners

These losses are as a result of ***"Flash", "differential" and "Standing"*** evaporation.

4.5 OPTIMIZING STAGE FLASH SEPARATION TO OPTIMIZE RECOVERY OF RESERVOIR FLUID

Presentation of Data and Results/The Economics of the System

Three stages of separation are sufficient to reduce the gas to be produced or lost to atmosphere/flare. Crudes with a lower GOR, the effect of the number of stages would be less dramatic. Lower GORs are associated with lower reservoir driving force; therefore, first-stage separator pressures will be less than 600 psig, and two or three stages of separation will be just fine.

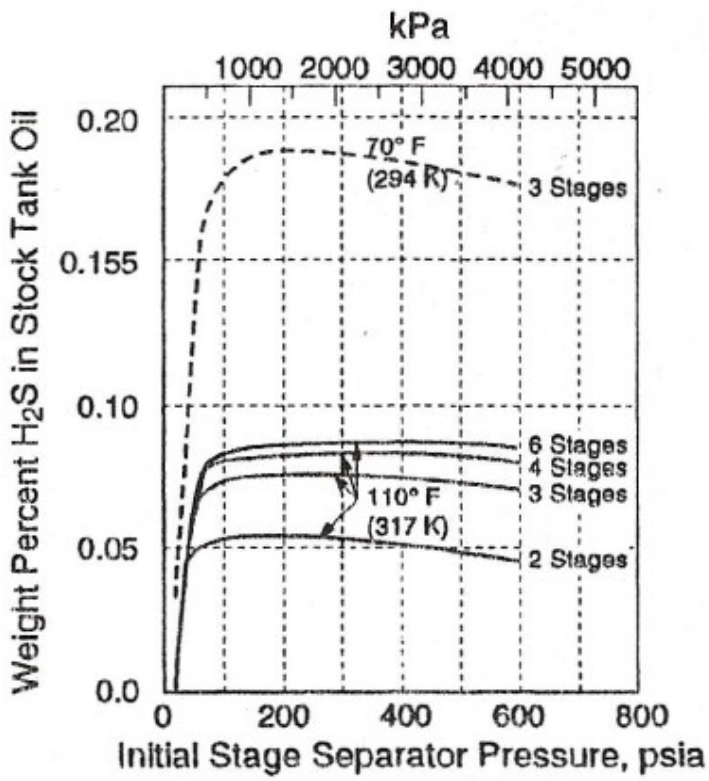

Figure 4.2 H_2S in stock-tank oil variation against stage pattern pressure.

Many types of crude contain sulphur as hydrogen sulphide. Hydrogen sulphide has volatility between that of ethane and propane. Therefore hydrogen sulphide content in the crude is as responsive to an increase in the number of stages as are the hydrocarbons. The hydrogen sulphide individual component

quantity is not masked by the large amount of other hydrocarbon material influencing the equilibrium conditions.

Figure 4.2 is a plot of hydrogen sulphide concentration as it varies with first- stage pressure in staging patterns from two to six. Two operating temperatures of 110°F (317 K) and 70°F (294 K) have been used in the three-stage pattern.

The hydrogen sulphide concentration may be held to a relatively low number if the value of multiple-stage liquid recovery is not emphasized. In this example, even with a single-stage flash, the stock-tank oil exceeds the marketing requirement of 0.007-wt% (70 – ppmw) hydrogen sulphide. Additional stabilization, either by heat or by sweet gas stripping, is required to reach H_2S specification.

The generalizations for crude oil with the properties of the example are:

- ✓ Recovery of crude per unit reservoir withdrawal does not justify more than three stages.

  Going from three to four stages provides a marginal increase of only 0.8% in liquid recovery for this crude.

  Increased stages increases retention of lighter hydrocarbon materials which will be largely lost during processing to remove hydrogen sulphide (unless vapor recovery and sour gas treating are used).

  Added stages increase investment but do not significantly increase income from final processed crude.

- ✓ Three stages of separation permits flexible first-stage operating pressure.

As can be seen in figure 16, the initial-stage pressure may be lowered without severely affecting recovery in a three-stage pattern. It is not so with less than three stages

Improved deliverability at lower wellhead back-pressure does not penalize stage separation recovery.

Initial stage separator pressure selection is a compromise between well deliverability, components in the gas phase, and components in the liquid phase.

4.5.1 Estimation of emission from Atmospheric tanks in Tank Farms using VBE correlation.

Presentation of data/Economics of the system

In the Tank farm under study emission from two tanks (A&B) were studied. The stage separations into these tanks were two trains and a tank. Their first stage separators had the same operating pressures and temperatures of 283 psi and 90°F respectively. However their second stage separators have varied operating pressures and temperatures of 18 psig and 47 psig; 88°F and 104°F respectively for tanks A&B. The oil temperature in the tanks were the same 80°F with the same atmospheric pressures of 14.7 psi, as shown in tables 6 and 8 for tanks A and B respectively.

Table 3.7 for atmospheric storage tank A shows total gas flash/VOC emission for the day from BOPD of 5220 bbls to be 123,244.2 scf/day, an equivalent of 2863.2 tonnes per year (TPY), at 18 psig and 88°F operating condition of the last stage flashing separator, with GOR of 23.61scf/bbl.

Out of these TPY, Flash/VOC (C_3+ in stock tank vapors) was 2290.57 TPY, equivalent to 16,721.66 bbls/year of liquid crude oil emission into the atmosphere, due to flash and differential process, if there were no gas gathering

system like the types mentioned in this research work. C_1 to C_3 fraction in the stock tank vapors amounted to 572.63 TPY.

The annual economic value of the flash/VOC (C_3+) emission stood at US$ 1,612,421.46, while that of C_1 to C_3 was US$ 137,620.51 also. The grand economic value of annual emission stood at US$1,750,041.97. These figures are conservative and cannot take the place of that done by direct measurement. However it has aided in pointing to the colossal loss of revenue and daringly detrimental global consequences.

Considering the sensitivity analysis for tank A system, the operating pressure of 18 psig was chosen because it was the optimal condition; the least operating last stage flash separator pressure that gave lower GOR, though the separator stabilized also at 20 psig.

Table 3.13 for atmospheric storage tank B shows total gas flash/VOC emission for the day from BOPD of 33,374 bbls to be 1,700,071.56 scf/day, an equivalent of 39,484.7 tonnes per year (TPY), at 47 psig and 104°F operating condition of the last stage flashing separator, with GOR of 50.94 scf/bbl.

Out of these TPY, Flash/VOC (C_3+ in stock tank vapors) was 31,587.79 TPY, equivalent to 230,590.87 bbls/year of liquid crude oil emission into the atmosphere, due to flash and differential process, if there were no gas gathering system like the types mentioned in this research work. C_1 to C_3 fraction in the stock tank vapors amounted to 7,896.91 TPY.

The annual economic value of the flash/VOC (C_3+) emission stood at US$ 22,235,877.59, while that of C_1 to C_3 was US$ 1,897,869.12. The grand economic value of annual emission stood at US$24,133,746.71. These figures are conservative and cannot take the place of that done by direct measurement.

Considering tables 3.7 for atmospheric storage tank A and table 3.11 for atmospheric storage tank B, tank A's last stage flashing separator's optimal operating pressure from the sensitivity analysis, which coincided with the practical observation, was 18 psig with GOR of 23.61 scf/bbl.

In table 3.11, the optimal operating pressure for tank B's last stage flashing separators was 20 psig, with a GOR of 22.18 scf/bbl. This represents 1.43scf/bbl (434.89 TPY) lower than that of tank A's system at its optimal operating last stage flashing separator pressure of 18 psig.

The one million dollar question now is; how do we arrive at a last stage flashing separators pressure of 20 psig for tank B system? Introducing a 3rd stage flashing separator is the only viable option since the last stage flashing separator of tank B system at the present rate of production cannot stabilize at any other lower pressure except 47 psig.

If it is possible to operate the last stage flashing separator for tank B system at 20 psig, a handsome profit of US$13,623,554 .94 will be earned annually, which will mean so much to the industry players and royalty earners. Whatever the cost of installing the 3rd stage flashing separator, the payout time will not be long.

CHAPTER FIVE

CONCLUSION AND RECOMMENDATIONS

5.1 Conclusion

It is evidently clear and conclusive that a lot of losses occur in the conventional atmospheric crude oil storage tanks in tank farms. It is also clear that the figures are conservative because during the night hours test, emission still occurs as a result of "Flash and Differential" evaporation in the test tank, which also is a conventional atmospheric tank, though it may not be as much as is seen or noticed during the daytime hours as a result of higher ambient temperatures.

The evidences before us demonstrated that **optimization of operating pressures at facilities and an adequate number of stages flash separation** (two or three stages according to the crude type) can economically recover more products for sales and can reduce the amount of methane gas lost to the atmosphere. This optimization technique can be implemented at negligible or no costs to the facility. The flash gas if recovered will also reduce emissions of volatile organic compounds (VOCs) and hazardous air pollutants (HAP) such as n-hexane, benzene, toluene, ethyl benzene, and xylenes.

The Venturi jet ejectors project using higher pressure natural gas is a viable technology for recovering storage tank vent gases and any entrained liquid petroleum. The venturi ejector as a pressure increasing device can be used to recompress low pressure gas from a variety of sources for injection into the system (e.g. gas lift, fuel gas, sales gas). In addition to atmospheric storage tanks, the technology can be used to recover vent gas from glycol dehydrators, heater treaters and low pressure separators.

` If we take a close look at table 3.11 of "liquid Petroleum Confinement System", we will notice the increased revenue both in the oil and gas. This implies that all the vent gas recovered from conventional atmospheric storage tanks carry along with them some oil due to "differential" evaporation. Tables 3.7, 3.8, 3.11, 3.12 and 3.13 also show the same evidence

It suffices to say here that the conventional atmospheric crude oil storage tanks in tank farms and flow stations are not the answer for the 21st century petroleum industry. If we take a close look at figure 3.9, we will note that volume losses create API gravity loss and thus revenue loss. Volumes of crude oil losses resulting in contamination of the atmosphere during storage and transportation have made it an antiquated technology, which has not basically advanced since the days of "Drakes Folly" in 1859 at Titusville Pennsylvania that led to the addition of 2 gallons for every 40 gallons gauged for losses.

5.2 Recommendations

Producing companies keep on searching for ways to increase profitability while being good stewards of the environment. Managers will want to know how what is suggested to be done affects their bottom line. "How does this add value to my operation?" they will ask.

In order to add value to the operations of tank farms, the following should be done.

a. There should be a conversion of "Fixed (conical) Roof Tank" (FRT) to the newer "Internal Floating Roof Tank" (IFRT). Installing this type of tank will reduce emission losses by about 90%. The company should initiate an engineering study to install "IFRT"

b. Separators operating pressures, should be optimized especially the low pressure separators emptying into atmospheric storage tank. The tank farm under study has some of its low pressure flashing separator operate at between 35 to 47 psig. It is economical to optimize because it will not add anything to their operational cost, only gains. It is worthy of note that "attention to details equals increased profitability". Table 3.1 shows sensitivity analysis or "Flash analysis" for gas-to-oil ratio(GOR)
c. Where it is not possible to optimize as a result of high crude oil production rate, it will suffice here to make provisions to install another stage flashing separator as the need for such was very evident in the conditions that gave rise to figure 3.15.
d. An engineering study should be initiated on how to install "Vapor Recovery Units" EVRU. It costs very little to install and its pay-out time will be less than a year.
e. Alternatively a study should be initiated on how to install a "Liquid Petroleum Confinement System" (L.P.C.S.) storage tank which has no losses or emission. It will also require steps (b) and (d) and its gas will be recompressed for sales line, gas lift or utility
f. A study should be initiated on how to optimize the stage flash separation

Going for "IFRT" will require steps (b) and (d). Optimizing stage flash separation if economically viable is another option. The L.P.C.S. is the most recent and innovative technology. It could well be the answer for the 21st century Petroleum industrial practices.

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