A PROJECT REPORT ON

PROBLEMS OF OFFSHORE PRODUCTION OPERATION

A report submitted in partial fulfillment for the award of the requirements for the Degree of

Masters of Technology

IN

Gas Engineering

(Academic Session 2005-2007)

By

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May 2007.

CERTIFICATE

This is to certify that the project work entitled on **"Problems of Offshore Production Operation"** submitted by **Amol Nilkanth Bodhale** in partial fulfillment of the requirement for the award of degree of Masters of Technology (Gas Engineering), at College of Engineering, University of Petroleum & Energy Studies, Dehradun is a record of the work carried out by him under my supervision and guidance.

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This is to certify that Mr. Amol Nilkanth Bodhale, S/o Mr. Nilkanth B. Bodhale has successfully worked on his project, at GSPC NIKO Resources Limited Hazira Oil and Gas Facility, Surat, Gujarat, during the period from 5/3/07 to 15/4/07.

He worked on the project Offshore Production Handling System, for that he was in GSPC NIKO offshore, Hazira, ALFA-BOB platform for two weeks.

He also worked on the troubleshooting assignment given to him, during this period. We found him to be sincere, hardworking and eager to learn the processes.

We wish him all the best for his future endeavors.

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ABSTRACT

Water injection is effective method to enhance oil recovery, it improves oil recovery rate efficiently. At Niko offshore seawater is used for injection purpose, it improved oil recovery by 46%. As seawater is using for injection, it is necessary to maintain quality of an injection water to protect reservoir, production facilities and stimulate production. The problem-identified as, whenever water injection stopped for any reason reservoir pressure decreases suddenly. It result in reduction of oil recovery, production loss and may result in shut in of well. Problem indicates that injected water quality is not good enough to protect reservoir and requires improvement in injected water quality. From observation and injection water quality test it is cleared that, there is scope to improve treated water quality by proper chemical dosing, by injecting additional chemical like biocide, and by time-to-time check of water quality parameters.

With effective injection water treatment oil production can be enhance, recovery rate can improve and reservoir pressure loss can be save. Good quality of injection water will increase well life and ultimately will make profit for the company.

Another problem discussed in case study is of oil separator of dew point control unit, of gas processing plant. Sometimes Liquid propane condenses and settled down at bottom of oil separator, when compressor is in stand by mode. And when compressor lube oil pump starts the propane liquid goes first, results in loss of propane and may result in bearing failure, compressor tripping if propane phase is carried into the compressor. From observation and study, probable cause of problem and its solution is find out, which will be helpful to prevent loss of propane and bearing failure and ultimately save she cost and time for the company.

Chapter-1

1. Introduction

Offshore platforms are critical components of the offshore infrastructure, supporting drilling and production operations, and playing a key role in the overall development of offshore oil and natural gas reserves.

Platforms are used to:

- Connect the offshore pipeline grid;
- Provide an efficient means to perform pipeline maintenance;
- Locate compression, separation, production handling and other facilities;
- & Conduct drilling operations during the initial development phase of an oil and natural gas reserve and workover operation.

Platform structure as,

Main Deck- supports living quarters, helideck, drilling area and platform crane.

Cellar Deck- supports wellheads, wellhead control panel and control room, manifolds, test separator, pig launchers, fuel gas scrubber, instrument/utility air system, flare system and survival craft.

Bellow Cellar Deck- supports open and closed drain tanks and pumps; access to boat loading is through stairs from below cellar deck.

Offshore production consists of a number of operations that allow the safe and efficient production of Hydrocarbons from the flowing wells. The key operations conducted at the offshore platform include: - Produced hydrocarbon separation, Gas processing, Oil and Gas transport; Well testing, Produced water treatment and injection, Seawater lift for cooling duty and injection, and Utilities to support these processes.

All the details of facilities and operations are specifically about the GSPC NIKO hazira offshore, ALFA BOB platform. Platform located in cambay basin at about 2 km from the shoreline, near Hazira, Surat. Platform current production is nearly about 11-lakh m^3 of Gas, 1050 bbl of oil, 18 bbl of condensate and 500 bbl of water per day. Platform production is from ten wells; seven gas well and three oil well.

Problem of Niko offshore seawater injection and problem of oil separator in further processing of gas are considered as case study.

As reservoir pressure is decreasing, out of three, one oil well converted for water injection, to build up reservoir pressure. Water injection increase the reservoir pressure and thereby stimulate production. Wellhead pressure of 520 psi is maintained on injection well. Sea water is used for injection purpose processed through clarifier, settling tank, multimedia filtration, cartridge and bag filters and finally to storage tank from where it is injected to resererservoir. Chemicals used for seawater treatment is from baker oil tools. The problem-observed as, whenever water injection stopped for any reason reservoir pressure decreases suddenly. It result in reduction of oil recovery, production loss and may result in shut in of well. Main objective of the project work is to find out problems with the existing seawater treatment process system and finding out the remedial solution for the problem to save the production loss, reservoir pressure loss and to make seawater topside treatment effective, for the company.

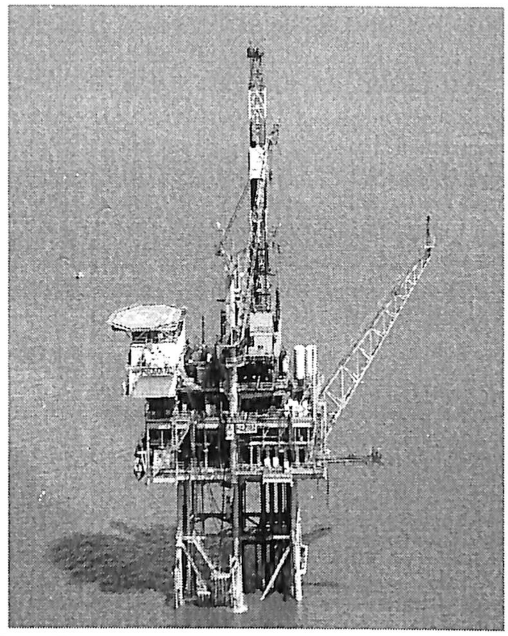


Fig. 1. Niko Offshore (Tension leg platform)

Hydrocarbon fluids transferred from offshore to onshore for further processing through two 12", 2 km offshore pipeline, as high pressure pipeline and low pressure pipeline. Gas transferred through high-pressure pipeline and oil transferred through low-pressure pipeline. To maintain oil flow above pour point, pour point depressant is injected inline. Gas is processed at gas plant before sale to meet sale gas requirements. Various maintenance and operational problems of gas processing plant need to sort out effectively to prevent further loss and damage of assets. One operational problem is considered as case study and sorted out effectively.

Chapter-2

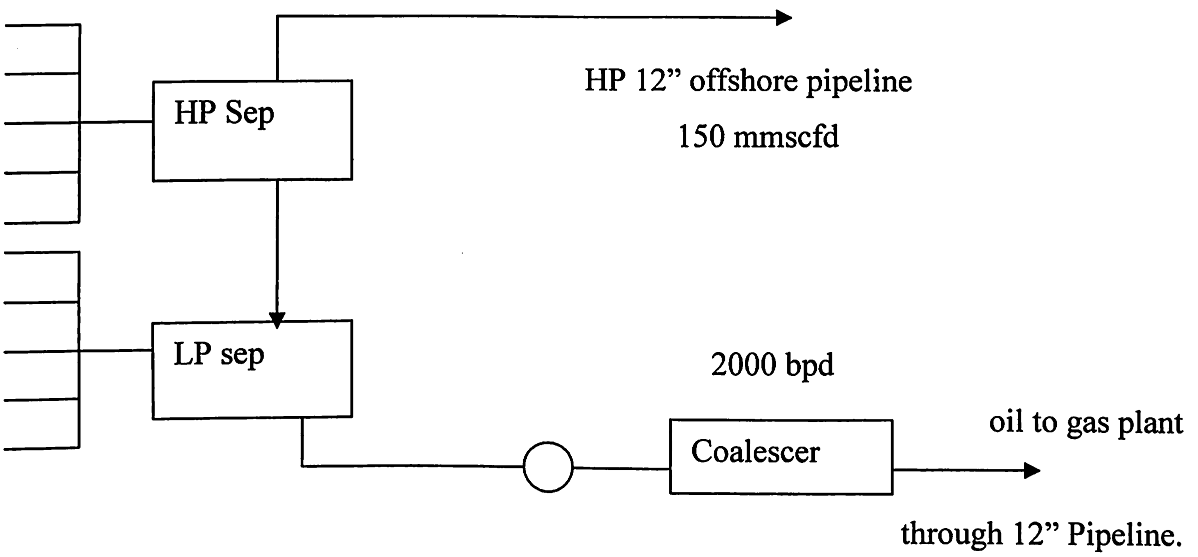
2. Offshore Production Facilities

2.1 Simple Process Flow

Hydrocarbon flow from the producing wells received at either the high pressure or low-pressure production manifolds on the platform and transferred to separation unit for separation into oil, gas, and water phases. Wells on test runs via an additional test manifold and separator.

Figure 2: - offshore production process

Manifolds



2.2 Wellhead control panel (WHCP)

The wellhead area consists of all 20 wellheads including the wellhead hydraulic safety and control panel. As well fluids are produced from wellheads; they are separated into HP/LP production, test, drain and vent manifolds.

The function of WHCP is to monitor, control and close the wing valves EV, upper master valve (UMV) and sub surface safety valve (SSSV) in safe and sequential manner. In the event of any abnormal process condition EV, UMV and SSSV closes in a safe and sequential manner and opens EV, UMV and SSSV in a safe and sequential manner when the process returns to normal condition.

Shut in of wing valve and UMV will take place when any process abnormal condition (from platform control/ shutdown system) occurs.

2.3 Wellhead facilities and inlet manifolds

Well flow line transports Hydrocarbons from wellhead to production (HP/LP/oil) or testing manifolds. The inlet manifold is comprised of HP/LP and oil production manifolds and a test manifold. Purpose of inlet manifold is to collect well fluid and send it to pipeline via production manifold or test manifolds. Valving is provided to allow flow from individual wells to be diverted to either the production manifolds or test manifolds.

2.4 Test separator

The purpose of testing is to measure the production rates of each well. Well testing activities are regularly carried out at well platform. Testing is carried out for one well at a time. Remote on-off actuated valves are provided for each well at the well flow line to route well fluid either to production or test manifold.

2.5 Pig Launching Facilities

The pig launcher (L-101/102) is designed to launch conventional pig into the export gas pipeline to the shore. Normally the pig launcher is pressurized with N2 and isolated from main system. It should be ensured that the launcher is positively in safe state before opening its door. This is achieved by repeating the depressurization of launcher before opening the door.

2.6 Instrument /Utility Air System

The instrument and utility air system provides dry air for instrument use and wet air for general uses such as for pneumatically operated tool, air cleaning, or vessel purging. Two air compressors (one lead and one lag) supply compressed air at max pressure of 860 kpag. Lead compressor started either locally or from control room via dedicated panel. Lag compressor is automatically started if the pressure at instrument air receiver falls below 600 kpag. After moisture separators, compressed air flows to the instrument air prefilter to separate free water from compressed air.

2.7 Flare system

The purpose of flare system on platform is to gather all HC releases, flare and disperse them to atmosphere at Safe location. The flare system consists of flare header, flare knock out drum (KOD), flare KOD booster pump and injection pump, boom, ignition control panel and tip. Vents from PSV relief blow down etc. are routed to flare KOD. Condensate is drawn from the KOD by KOD booster and injection pumps and is routed to HP/ LP production manifold. The gas is discharged through the flare stack. The flare ignition panel is provided for the flare tip. The system is continuously purged by fuel gas to

Flare KOD: -

The flare KOD is fed by a flare header. The main sources are relief valves and blow down valve from the test separator, the HP and LP production manifold and fuel gas scrubber. The flare KOD operates at about 10 kpag at under normal operating conditions. The flare KOD is designed as a two-phase separator removing liquid from gas in order to protect liquid carry over.

2.8 Closed drain system

The closed drainage system is designed to permit safe and efficient disposal of HC fluids drained out from the vessels and flow lines from the various processes and utility areas.

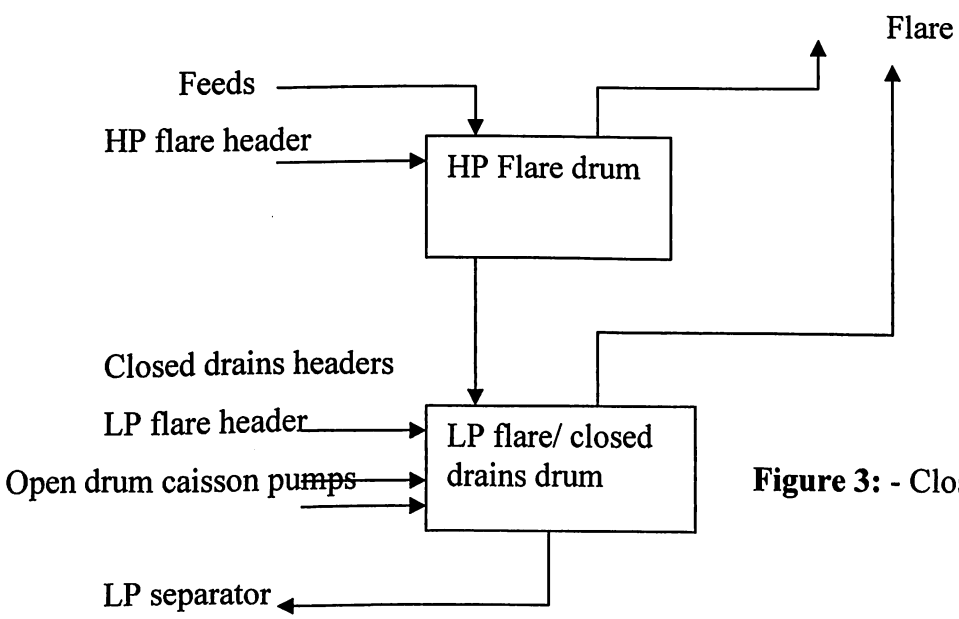


Figure 3: - Closed drain system

The main components of the closed drain system are the HC drain drum and HC drain drum pump. The HC drain drum is located below celler deck.

HC drain drum V-190 is designed as a three-phase separator with a weir. Oily drain is flashed at 10 kpag and the resulting gas is sent to the flare system. V-190 is continuously purged by fuel gas to prevent air ingress. The accumulated water is discharged under on /off control level control LT-190 to the sump caisson V-195.

2.9 Open Drain System

The platform deck drainage system is designed to avoid discharging HC or other chemical into sea. Drain collection boxes are provided on the deck. These are two sets of collection. One is located at lower elevation for collecting HC spillage and other is located at higher elevation for collecting higher flow of drainage. e.g. fire water.

The HC spillage will be routed to the sump caisson and the drains flow will deluge / rainfall will be routed overboard.

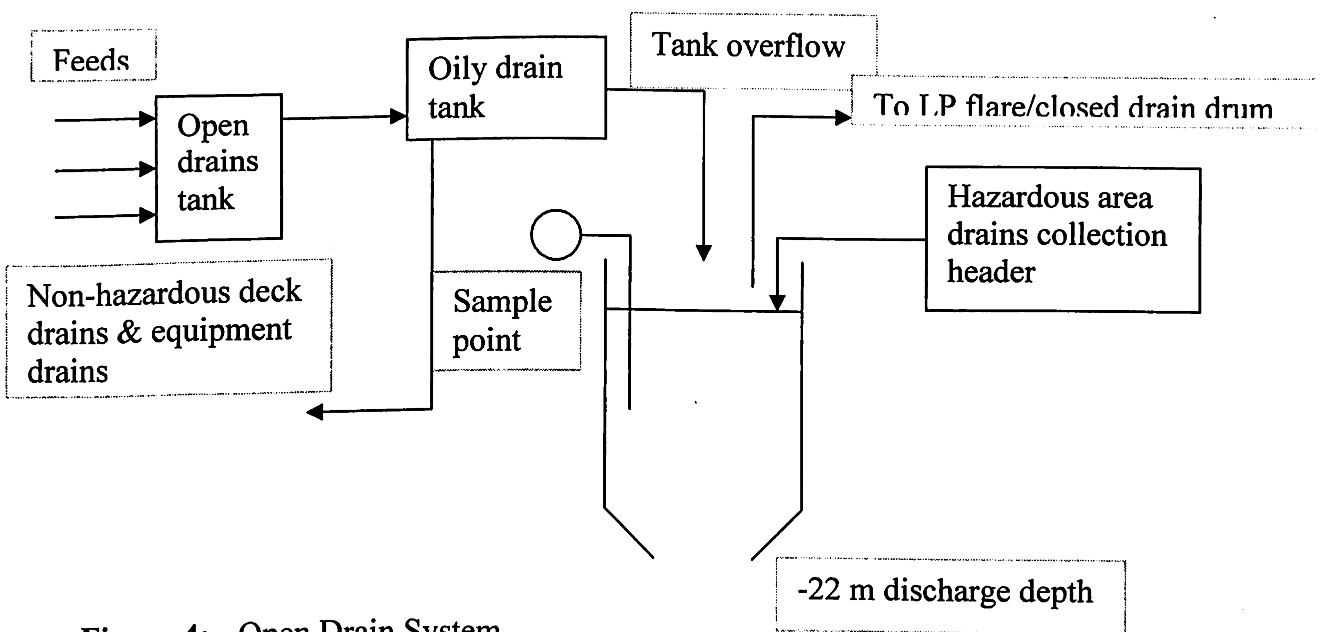


Figure 4: - Open Drain System

2.10 Diesel fuel system

The diesel system is provided to supply fuel to the following users:-

- Two fire water pumps.
- Emergency or standby electrical generator.
- 55MT deck crane and 15 MT deck crane.

Drilling rig: - The drilling contractor shall provide diesel distribution for drilling rig diesel consumer such as rig generators, cementing unit and e-logging unit.

2.11 Fuel gas system

Fuel gas system has been provided to supply fuel gas to the main electric generator. The flare system purge and pilot gas, and the closed HC drain down purge. Fuel gas is also required for drilling rig. A connection with the shutdown valve is provided from the fuel gas user's header. The fuel gas system consists of a fuel gas scrubber, self-contained pressure reduction valves and piping network to connect all the fuel gas consumers.

2.12 Firewater system

The firewater system consists of following equipments: -

(i) Diesel firewater pumps (2 *100 % one duty, one stand by) 375-m3/ hr each, will supply the firewater to the platform both pumps are diesel engine driven.

(ii) Deluge valves one at each deluge zone total 5 zones.

Zone 1- Process equipment on celler deck and HC drain drum on sub celler deck including escape routes.

Zone 2- Wellhead area including escape route

Zone 3- Helideck area

Zone 4- Main deck and drilling rig

Zone 5- Leaving quarters

(iii) Fire hydrants monitor and hose seals are located on each drain.

Local seawater may be very turbid with a large amount of suspended solids. Biocides (hypochlorite) injection is provided to control marine growth. Sprinklers are provided for HC containing equipment escape routes, wellhead and helideck area.

Helideck area is provided with an automatic foam injection system. The details will be provided by other it can be operated either automatically through a deluge valve or manually. A common tie in pt has been provided from rig main to supply firewater to drilling rigs, helideck and living quarters. The foam system/ sprinklers/ monitors etc are required for these areas will be provided by others.

2.13 Control Shutdown

The control / shutdown system TCS/ SDS to be used at offshore platform to carry out the monitoring control shutdown safety function at the offshore wellhead platform. The design of PCS/SDS is based on the full remote operability with no requirement of operator presence at the wellhead platform for day-to-day operation of the platform. Beside monitoring and controlling function PCS and SDS shall perform the following shutdown functions: -

- Emergency Shutdown (ESD).
- Pressure Shutdown (PSD).
- Unit Shutdown (USD).

Emergency Shutdown (ESD): - ESD when initiated shall stop all the process activities at the platform close all the wells, close UMV, wing valve (EV), SSSV and stops all pump, close the export ESD valve and all other shutdown valve. The Emergency Shutdown (ESD) is initiated by abnormal situation like fire detection, confirmed HC gas detection on the platform, manual action from the field ESD push buttons, manual action from platform PCS/ SDS and from DCS at onshore gas plant control room.

Pressure Shutdown (PSD): - When initiated shall stop process activities of the platform, closes UMV, wing valve of all the wells, stop the process pumps and all other shutdown valve including the export ESD valve.

Unit Shutdown (USD): - USD when initiated will close the upper master valve (UMV), wing valve (EV), of a particular well in case of a well head area, trip of particular package in case of any abnormality with the package etc. The unit shutdown is automatically initiated by devices sensing abnormal condition at the well flow lines, at the package units, by PSD, by manual action from the platform PCS / SDS and from DCS at onshore gas plant control room.

Chapter-3

3. Enhanced Oil Recovery Techniques

The potential for enhanced recovery by advanced injection techniques has been known for many decades, but unstable economic climate and the complex nature of the reservoir processes often involved in enhanced recovery have hindered implementation of many projects. Due to improved drilling methods, better production technologies, improved reservoir knowledge, and higher oil prices, these methods are more attractive today.

Underground oil resources of India are limited, therefore maximum efforts should be made to maximize oil recovery by adopting enhanced oil - recovery processes. Various enhanced oil recovery techniques used generally are, gas injection, down–dip water injection water flooding injection, polymer flooding have been implemented in several reservoirs. Results are encouraging and the average recovery factor expected to rise to about 35 to 40%.

More sophisticated techniques such as miscible drive, surfactant flooding, etc. are needed if recovery factors are to improve further. Inputs for these techniques are costly, however, and suitable chemicals presently not available indigenously.

3.1 Introduction

Oil occurs in nature in various ways in different reservoirs. Broadly speaking, these are;

1. Depletion drive, in which the oil zone has no associated bottom/edge water or gas cap.
2. Gas-cap expansion drive, in which the oil zone has no associated bottom/edge water but does have an overlying gas cap.
3. Water drive, in which the oil zone has an associated bottom/edge water, but no overlying gas cap.
4. Combination drive, in which the oil zone is sandwiched between the water-bearing part of the reservoir and the overlying gas cap.

Oil reservoirs are classified according to the type of drive mechanism prevailing. In a depletion-drive reservoir the dissolved gas provides the driving force for moving the oil into the well when production starts. With continual oil production, the reservoir pressure declines, adversely affecting production in two ways. Firstly, the force which drives the oil into the well diminishes, and secondly, the diminution in reservoir pressure causes the release of liquid gas in the form of discrete gas bubbles in the reservoir pore spaces, leading to impairment of oil flow towards the well.

Contrarily, in an active bottom water-drive reservoir the amount of oil withdrawn is replaced by an equivalent volume of reservoir water. Hence no drop in overall reservoir pressure occurs with oil production. But if the water drive is weak, some decline in reservoir pressure is seen with the production of oil. Such an operating mechanism is commonly known as a partial water drive.

In general, oil recovery by means of the primary energy in an underground system varies widely. In a depletion-drive reservoir the recovery factor is about 15 to 18%. It is higher in other types of reservoirs, with the highest occurring in active water-drive ones (30 to 35%). However, oil recovery can be substantially increased with the adoption of enhanced oil-recovery (EOR) techniques. Basically these involve injection of fluid into one part of the reservoir and production of oil through wells in another part.

3.2 Overview of Various EOR Methods

Various *EOR* techniques presently in use are briefly described below.

3.2.1 Pressure Maintenance by Gas Injection

Reservoir pressure can be maintained by the injection of compressed hydrocarbon gas into the gas cap. Gas injection is particularly important in combination-drive reservoirs in which the bottoms water drive or a down-dip water injection tends to push the oil column up into the depleting gas cap, which results in a loss of recoverable oil.

3.2.2 Pressure Maintenance by Water Injection

In partial water-drive reservoirs, with or without a gas cap, additional oil recovery is possible by supplementing the water drive through an injection of water into the aquifer. In such cases water injection is usually done in down-dip wells, as this helps to maintain reservoir pressure at a higher level.

3.2.3 Water Flooding

A very widely used technique in EOR, water flooding means injection of water into the oil zone itself to push the reservoir oil towards the producing wells. Water is pumped into the productive stratum through injection wells in a volume equal to, or sometimes greater than, the volume of oil extracted.
Water injection is usually done in a pattern particularly suitable for each reservoir.

The efficiency of water flooding is impeded by two major limitations. Firstly, all the oil in the pore spaces cannot be flushed out by the water due to the high interfacial tension between water and oil. Secondly, the advancing waterfront quite often bypasses the oil, due mainly to the high viscosity ratio between oil and water, but also to the heterogeneous nature of the reservoir. By and large, 50 to 70 % of the original oil-in-place is left unrecovered after water flooding.

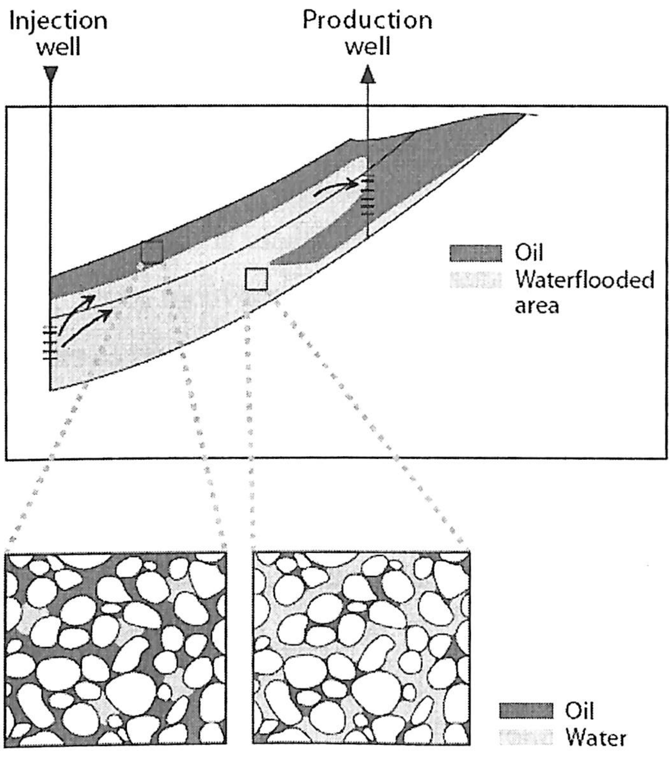


Fig. Section through a reservoir showing an example of the distribution of oil and water following water flooding, and the distribution of the liquids at the pore level

3.2.4 Polymer flooding

Polymer flooding is an augmented water-flooding method where, high molecular weight, water-soluble polymer is added to thicken the injection water, thereby preventing oil bypass. The combined effect of fluid viscosity and reservoir permeability is expressed as mobility. When the ratio of mobility of reservoir oil to mobility of flood water is equalinjection of ised, or made less than unity by injection of water treated with polymer concentrations of 100 ppm to 21000 ppm, recovery of oil is enhanced due to improved water sweep. Polymer flooding involves the injection of a volume of polymer solution (20 to 40% of pore volume or the reservoir) followed by plain water. The concentration of polymer in the solution is initially high and then graaually reduced. Polymers that have proved technoeconomically suitable to ante include partially hydrolysed polyacrylamides anu xanthan gums. A successful polymer flooding can increase recovery by 3.0 to 10% over that achieved by simple water flooding.

3.2.5 Miscible Flooding

When displacement of oil from the reservoir is caused by a fluid that is completely miscible at all times with the crude oil in the zone of intermixing, interfacial tension is totally eliminated and thus capillary retention force develops. Consequently, theoretically the oil-in-place is totally recoverable.

However, 100% recovery of oil from a reservoir is not practicable due to such interference factors as reservoir stratification, reservoir heterogeneity, pattern coverage, gravity segregation, adverse mobility ratio between displaced and displacing fluid, etc. Nevertheless, miscible flooding has the potential for enhancing oil recovery to a significant degree.

Today the following miscible flooding processes are recognized: 1) high pressure, dry hydrocarbon gas process; 2) enriched hydrocarbon gas process; 3) miscible slug process; 4) Water-driven miscible slug process; and 5) Non-hydrocarbon miscible process.

(1) High pressure, dry hydrocarbon, gas process: This process (also known as the "vaporizing gas process") involves injection of lean hydrocarbon gas at a sufficiently high pressure into the reservoir at a certain predetermined pattern.
The reservoir oil should contain sufficient intermediate components so that the injected dry gas will vaporize, leading to a zone of miscibility between the injected gas and reservoir oil.

The high-pressure gas process is applicable only to those reservoirs which contain volatile oil at high pressure. Such reservoirs are generally deep seated. Usually a reservoir pressure in excess of 200 kg/cm^2 is required for a dry gas miscible displacement process to be feasible.

(2) Enriched Hydrocarbon gas process: The pressure requirement for the development of a miscible phase is considerably lowered if the displacing gas is enriched with higher molecular weight hydrocarbon gases, e.g., ethane, propane, butane, etc. In general, reservoirs with a formation pressure of more than 140 kg/cm^2 could be considered candidates. Because-enriching the entire volume of injected gas is sometimes too expensive, a slug or buffer zone of enriched gas is commonly injected between the reservoir oil and a cheaper displacing fluid, usually dry gas. Water, alternate slugs of dry gas and water, and inert gas are also used as displacing fluids. Irrespective of the displacing fluid, determination of the size of the enriched gas slug is very critical to the success of the process. This poses the greatest challenge, given the complexity of reservoir geometry and reservoir heterogeneity.

(3) Miscible slug process: This process involves injection of a solvent slug such as liquid propane or LPG, followed by injection of a cheaper displacing fluid, e.g. dry hydrocarbon gas. It makes miscible flooding possible in reservoirs with a formation pressure as low as 85 kg/cm^2.

The risk of precipitation of asphaltenes after the reservoir oil comes into contact with the solvent slug cannot be ignored. Such a situation lowers reservoir permeability, thereby reducing oil recovery. When the reservoir oil is highly asphaltenic, appropriate laboratory tests should be conducted to ascertain the extent of permeability damage caused by asphaltene precipitation subsequent to displacement of the oil by the solvent slug process. In general, the tendency of a miscible slug to precipitate asphaltene decreases as the molecular weight of the materials in it increases.

The techno-economical viability of the miscible slug process depends greatly on the size of the slug. Use of a large slug volume is uneconomical because of high input cost; contrarily, a very small slug will not maintain miscibility throughout the displacement period. The optimum slug size for a particular reservoir should therefore be designed prior to the initiation of a field project.

(4) Water-driven miscible slug process: One of the major drawbacks of driving a miscible slug with dry gas is poor areal-sweep efficiency. The latter arises from an adverse mobility ratio between the solvent slug and the displacing fluid. In some cases injection of water along with the solvent slug at a certain predetermined ratio has been suggested for overcoming this problem. The water-solvent flooding technique combines the high areal-sweep efficiency of the conventional water flood and the high pore-to-pore sweep efficiency of the miscible displacement process.

(5) Non-hydrocarbon miscible processes: Among the non-hydrocarbon miscible processes, the following are worthy of mention: a) carbon dioxide flooding; and b) alcohol flooding.

Carbon dioxide is not completely miscible with most crude oils, but its solubility in both crude oil and water at reservoir temperatures and pressures is adequate for enhancing oil recovery. On injection, carbon dioxide partially dissolves in the reservoir oil, swells the oil, reduces its viscosity, and often vaporizes it to form a miscible front, which results in a high displacement efficiency of the contacted oil. Four variations in carbon-dioxide miscible flooding are presently employed by the petroleum industry for enhancing oil recovery; a) injection of carbon dioxide as a slug, followed by water or carbonated water; b) injection of carbonated water directly; c) injection of carbon dioxide at high pressure; and d) injection of flue gas or engine exhaust gas, which contains up to 87 % nitrogen and 11 to 13 % carbon.

With alcohol flooding, both the reservoir oil and the connate water are displaced, it the concentration of alcohol in the slug is sufficiently high. If the alcohol concentration drops below a certain critical level, miscibility is lost and the system then behaves in water flooding (If water is used as the displacing fluid to move the slug through the reservoir). It may be noted here that water is generally used to displace the alcohol slug because of low cost and its favorable affect on areal-sweep efficiency in-pattern flooding.

Several types of alcohol any be used in alcohol flooding e.g., isopropyl alcohol, methyl alcohol, normal amyl alcohol, normal butyl alcohol etc. The type of alcohol to be used in a given field depends on the efficiency with which it displaces oils relative to the alcohol and water volume required.

3.2.6 Surfactant Flooding

Surfactant flooding is usually done after water flooding to recover residual oil by reducing the interfacial tension between the oil and water and interfacial viscosity. The driving fluid containing the surfactant should be able to reduce interfacial tension between oil and water from the level of 20 to 30 dynes/cm to less than 0.001 dyne/cm. These surfactant are characterized by an amphillc molecules, i.e. a molecule with a hydrophilic and an olsophilic end. When a low concentration of surfactant (say 2.0 to 3.0%) is mixed in water, it forms a surfactant solution. But with a concentration of surfactant above the critical point, the surfactant molecules cling together in clusters called micelles. If oil is mixed into this micelles dispersion, the micelles solubilise the microscopic oil droplets to form a micro-emulsion.

Surfactant solutions or micro emulsion are used in surfactant flooding. The first is known as low-tension flooding and the second micellar or micro emulsion flooding. The surfactant used in both types of surfactant flooding is usually a petroleum sulphonate manufactured from hydrocarbons ranging from LPG to crude oil.

Both low-tension surfactant flooding and micro emulsion flooding involve injection of some pore volume of surfactant solution or micro emulsion slug (3 to 20% pore volume) followed by a bank (20 to 50% pore volume) of polymer- thickened water for mobility control and subsequently plain water for driving the reservoir oil towards the producing wells.

The mechanism of displacement of oil in low-tension surfactant flooding is slightly different from that in micro emulsion flooding. In the former the dilute surfactant solution reduces the interfacial tension between the reservoir oil and water thus minimizing capillary oil retention. The polymer-thickened water driven by plain water, then pushes the oil freed from the reservoir pore towards the producing wells. In micro emulsion flooding however, the micro emulsion slug is miscible with oil and as it dissolves forms an oil bank in front; the oil bank and slug are then effectively forced towards the producing wells by the water-driven polymer solution.

Laboratory studies have shown that oil recovery is sustained over a longer period of time by low-tension surfactant flooding, but a higher recovery achieved by micro emulsion flooding. It is difficult to choose between the two since both methods of surfactant flooding offer tremendous scope for future enhanced oil recovery.

3.2.7 Caustic Flooding

Caustic flooding, yet another technique for EOR, involves injection of about 1596 pore volume of 0.05 to 0.50% caustic soda solutions followed by injection of drive water. The slug of caustic soda solution interacts chemically with naturally occurring, surface-active organic acids in the crude oil, leading to a very low caustic/oil interfacial tension (below 0.01 dyne /cm). In-situ, crude-ail-water emulsions result, which acts as mobility control slug, thereby improving oil displacement. To make the water alkaline, sodium carbonate or sodium silicate can be substituted for sodium hydroxide, but the letter has the greater potential.

Caustic flooding is limited to reservoirs with low gravity, high-viscosity crude containing naturally occurring surface -active organic acids. Laboratory tests have shown that caustic flooding does not significantly reduce residual oil saturation in the swept region. Improvement in oil recovery is basically due to better displacement of mobile oil, the end-result of improved sweep efficiency. Hence this method may not be suitable for low-viscosity oil in homogeneous reservoirs where fingering and channeling of drive water are not problematical anyway.

3.2.8 Thermal Techniques

Oil recovery can be increased in some reservoirs with the application of host energy. EOR is due to the affect of one or all of these phenomenon a) reduction of reservoir oil viscosity; b) activation of solution gas drive; c) thermal expansion of reservoir oil.

The most widely used thermal recovery techniques are theses 1) in-situ combustion (also called fire flooding); 2) Steam flooding; and 3) Cyclic steam Injection (also called steam soaking or "huff and puff").

In-situ combustions in this method air are injected into the reservoir which supports combustion of part of the reservoir oil. By controlling the rate of air injection, the amount of oil burned is kept within desired limits. Combustion in the reservoir is either spontaneous or precipitated by an igniter e.g., a downhole heater, gas burner; easily oxid1sed material such as linseed oil, charcoal with an ignition charge, ate. Injection of air through the Injection wells is continued at a controlled rate to propagate the burning front in the reservoir and propel it towards the producing wells. A number of zones exist in a reservoir undergoing fire flooding. Dynamic processes occur in each of these zones, which determine the rate and amount of additional oil recovered.

The burning zone is composed primarily of reservoir sand. Temperatures range from 300 to 650°C in this zone, depending on the physical characteristics of the reservoir and the operating conditions of the project. The coke zone lies just ahead of the burning zone. Coke is produced by the cracking and distillation of the reservoir oil and serves as fuel for propagation of the combustion front. Ahead of the coke zone lie the "steam plateau", hot water zone, and condensate zones successively. These cause miscible displacement of the oil, followed b) hot water/steam drive of the displaced oil towards the producers.

In-situ combustion may be "forward" or "reverse", depending on the direction of air injection vis-à-vis movement of the burning front. Sometimes water slugs and air are alternately injected after initiation of the burning front to improve areal-sweep efficiency. This is called the wet combustion method.

Steam flooding:- Steam flooding involves injection of steam into a group of outlying wells to displace oil towards the producing wells. In steam flooding a steam saturated zone is created in the reservoir, which moves away from the injectors to the producers. The temperature in the steam-saturated zone is about that ofthe injected steam. It is the steam-saturated zone that causes displacement of reservoir oil towards the producers by steam -distillation of the oil, solvent extracting and gas drive. At some distance from the injection wells the steam cools and condenses. This results in a zone of hot water which acts as the displacing fluid for the oil bank towards the producers.

Steam is usually a poor displacing fluid due to its adverse mobility with respect to the steam-affected reservoir oil. The problem is offset by the condensed hot water since its mobility ratio with respect to the displaced oil is relatively favorable.

Cyclic steam injection; Cyclic steam injection, also called "huff and puff" or steam stimulation, involves injection of steam directly into the producing wells for a certain length of time (e.g., two or three weeks) and subsequent production of the heated oil from these same wells. Once the heated oil has been produced a now cycle say be initiated. Each cycle may require six to twelve weeks or longer. Condensation and cooling of the injected steam heats the reservoir sock and oil thus reducing oil viscosity around the well bore, which improves mobility and hence production rates. Cyclic steam Injections in production wells are typically conducted in conjunction with steam-flooding projects to ensure higher rates of production of oil at the wellheads.

Chapter-4

4. Dew Point Control Facility

The objective of this principle is to describe the operational procedures and requirements to condition the inlet gas prior to injection into the sales gas pipeline and to ensure;
Safe operation, Minimization of operations manning, maintenance intervention and life cycle costs.

4.1 Hydrocarbon Dew point Control/ Recovery

Natural gas enters the plant from the group header and flows through the inlet separator where free liquids are removed. The gas flow then enters each of the Gas/Gas exchanger tube side inlets, where it is pre-cooled by counter-current heat exchange with the out-going dry sales gas. The gas then receives final cooling on the tube side of the gas chiller/ propane evaporator from the cold vaporizing propane on the shell side. During this cooling process, hydrocarbon liquids are condensed. To prevent freezing in the gas/gas exchangers and gas chiller/propane evaporator glycol is injected at the inlet and of each tube bundle.

The three phase flow of gas, hydrocarbon liquids and glycol proceeds to the low temperature separator where the liquid phases are separated.

Once the liquids have been removed, the dry gas flows through the shell side of the gas/gas exchanger and leaves the plant as dry sales gas. The hydrocarbon liquids leave the low temperature separator, under level control, and flow to the condensate stabilization facilities. The rich glycol flows, also under level control, to the MEG regeneration skid, for reconcentration prior to re-injection at the gas/gas exchangers and gas chiller/ propane evaporator.

4.2 Water Dew point Control

Water dew point control is achieved by injection of glycol into the gas stream. Mono-ethylene glycol is chosen due to its kg to kg advantages over di-ethylene and tri-ethylene glycol. The injected glycol solution forms a non-freezing mixture with the water, which condenses out of the gas upon cooling. The entire principle relies on the solubility

between the glycol and water and therefore the glycol concentration is extremely important.
Ration of rich glycol exiting the low temperature separator is of primary importance and must be maintained at 60-65%. The rich glycol is sent to the MEG regeneration. To maintain the rich concentrations, lean glycol concentration leaving the MEG regeneration should be tat approximately 80%. Glycol concentration outside of these ranges may lead to crystallization at low temperatures, high plant pressure drops, and ultimately freezing – off the gas/gas heat exchangers and gas chiller/propane evaporator.

4.3 Refrigeration system

Propane refrigerant is vaporized in the shell side of the gas/chiller/ propane evaporator where the propane vapors are then drawn into the propane suction scrubber for positive removal of propane liquids prior to compression in the screw compressors. The propane refrigerant, after compression, is discharged into the lube oil separators, where entrained lube oil is removed. The propane is sent through a pressure control valve and to the propane condenser. The pressure control valve maintains the condensing pressure upstream of the condenser. In controlling the condensing pressure, condensing temperature can be effectively control. The liquid propane is gravity fed from the propane condenser to the propane accumulator.
Propane refrigerant leaving the propane accumulator flows through the propane dryers where moisture is removed. The propane proceeds to the propane economizer. The level in the propane economizer. Before propane refrigerant enters the shell side of the gas chiller/propane evaporator, it is passed through level control valve, where pressure is dropped, and the propane is flashed to final operating temperature. The propane is vaporized by heat absorbed from the gas being cooled on the tube side on the gas chiller/ propane evaporator. The vaporized propane flows out of the propane evaporator to the propane suction scrubber, where 5°F of superheating occurs and then flows to the screw compressors. In the suction scrubber, any liquid propane that has carried over the gas chiller is separated from the propane vapor. This ensures no liquid reaches the suction of the compressors.

4.4 Compressor lube oil system

After being discharged from the screw compressors, the propane refrigerant and lube oils are separated in the lube oil separators. The lube oil separator contains five coalescing filter elements that remove lube oil particles 0.3 micron in size and larger. One oil heater controls oil temperature in the reservoir section of the lube oil separator to ensure proper oil temperature exists in shutdown conditions. From lube oil separator, the lube oil is passed through of propane refrigerant. Temperature control of the lube oil is achieved by using a three-way thermostatic valve. This valve mixes hot lube oil from the lube oil separator with the cooled oil from the thermosyphon oil cooler.

After being cooled approximately 60°C, the lube oil travels through a reusable/washable stainless steel 300mesh pre filter. Here the flow split. One half of the lube oil flow is injected into the rotor for cooling of the compressed gas, and the lube oil pumps the remainder through the lube oil filter. Finally the lube oil is injected into the screw compressor, casing to provide lubrication for the compressor bearings and integral gear box.

Chapter-5

Case Study: 1
(Source: Niko Offshore)

Problem:- Poor water quality injection results in loss of well injectivity, fluctuation in production and sudden reservoir pressure loss.

Introduction: -

As reservoir pressure is decreasing, out of three, one oil well is used for water injection, to build up reservoir pressure. Water injection increase the reservoir pressure and thereby stimulate production. Sea water is used for injection purpose processed through clarifier, settling tank, multimedia filtration, cartridge and bag filters and finally to storage tank from where it is injected to resererervoir. Chemicals used for seawater treatment is from baker oil tools. The problem-observed as, there is fluctuation in production as well as pump discharge pressure required for reservoir pressure maintenance is increasing day by day, indicates loss of well injectivity and results in fluctuation of production and sudden reservoir pressure loss.

Process Description: -

Process overview

The floodwater pretreatment processes shall comprise of the following steps: -

(1) Raw water intake
(2) Coagulation
(3) Flocculation settling tank
(4) Multimedia filtration
(5) Micron cartridge filtration
(6) Instrumentation and sampling

Raw seawater treated through clarifier, multimedia filtration, and micron cartridge filtration. Raw water feed pump are installed in the casing fastened to the platform legs and run down into the water surface. Chlorination dose chlorine into the intake pipe directly upstream of the well pumps to inhibit rapid marine growth in the piping. The raw water feed pump is equipped with a variable frequency drive such that the operation have the ability to match flow directly to the clarifier demand.

Coagulant is used to destabilize collides (particles) in the raw water. The destabilized collides result in insoluble precipitate, which is settled in the clarifier. Coagulant is injected inline and is followed by a static mixer to ensure complete and rapid mixing. Generally, coagulant dosages vary between 0 to 40 mg/lit depending on the specific chemical and water quality. Raw water after coagulation flows to a flocculation tank.

Precipitation of the destabilized collides is promoted by the addition of flocculants. Flocculants are higher molecular weight polymers that bridge the destabilized collides together into a lager flocks or particle, thus increasing the amount of settling. The flocculation tank is provided with a mix that operates at a low rpm ensuring gentle but complete mixing. In addition the mix causes smaller flocks to collide with other flocks forming larger particles. The slow mixing and high hydraulic retention time ensure the flow is not broken. The polymer is dosed into the flocculation tank at the entry of the raw water. This ensures optimum retention time for mixing, flocculated water flows by gravity to the downstream tube settler clarifier.

Raw water is pumped into the clarifiers, where the bulk of the solids are removed. The clarification system has been designed with high HRT (hydraulic retention time), constant sludge blow down, tube settlers and a surface skimming system design to take only the very top of the settled water column, evenly across the top of the tank to ensure optimum water quality. Minimal coagulate is used to accelerate the process and improve the water quality. CL2 is also to be dosed upstream of the clarifier to inhibit growth and assist in the oxidization and thus clarification of the raw water. The clarifier has an automated drain valve, which will be automatically closed when the clarifier is not in operation.

Clarified water from the tube settler enters the settled water tank. The tank retention time is designed to decouple clarification and filtration, ensuring a constant flow to the filters and as a result the highest possible filtered water quality.

Three filters feed pumps draw water from the settled water tank and feed multimedia filters operating in parallel. The media in the filter vessel comprise of anthracite and subsequently silica sand layers. Each media is sequentially finer, removing smaller and smaller particulate matter. The filter vessels are equipped with automatic valves to perform operation and maintenance service, backwash, rinse and air scouring operation. Electronic actuated valves are operated through a PLC to provide automatic controls for the operation of the filter, specifically back wash. Operating two filters in parallel allows one filter to remain online while the second one is being backwashed; therefore allowing continuous production. The backwash sequences are controlled by timers, which can be manually adjusted by the operator as based on the turbidity of the filtered water using online turbidity meters.

Micron filtration is provided downstream of the multimedia filters to guarantee a maximum particle size fed into the reservoir, for subsequent injection into the well. An initial 5 micron bag filters are followed by 2or 3 u cartridge filters.

Disposable bag and cartridge filters must be changed regularly as pressure build due to filter exhaustion. Filters are provided in parallel at low loading rates, to ensure longer run times between filter changes.

Flow: - Magnetic flow meters are located on the raw feed water line multimedia filter feed and backwash water line of the system.

Turbidity: - Turbidity meters are on each filtered water line coming out of the multimedia filters. The filtration system is provided with sampling points at Suction of feed pumps.

Chemicals Used: -

Coagulant used are alum and sodium hypochlorite Alum is use to destabilize colloidal particles from the raw seawater, it is dosed at 6 L/hr. Sodium hypochlorite is use as a primary biocide to control the bactrial growth by monitoring the free chlorine level as 1 mg/l. The dose rate should be adjusted by monitoring and maintaining the free chlorine levels at 1 mg/lit.

Coagulant cum flocculant MAGNACLEAR ML-2712 use for suspended solids removal is polyelectrolte MAGNACLEAR ML-2712 (filter aid). The primary method of suspended solids removal is through mechanical means i. e. media filters. The polyelectrolite is used to assit the removal of these suspended solids to meet the water quality requirements.

Oxygen scavenger MAGNATREAT ML-5867 - Mechanical deareation through a deaertor or vacuum tower, will typically reduce the oxygen content to a fractions of a ppm (0.1 to 0.2 ppm). In order to complete the removal of excess O2 a low dosage of scavenger is used the most common scavengers, used are sulphite based.

Corrsion Inhibitor CRONOX ML-2029, cosidering the intermittent problems of residual DO content due to some unexpected fluctuations in the DO content, corrosion inhibitor is use on intermittent basis, as per the requirement, at a dose rate of 20 ppm.

Scale Inhibitor - CALNOX ML-2610 it controls the formation of both sulphate and carbonate scales at a dose rate of 15 ppm.

Identification of Problem: -

Table reading shows there is fluctuation in wellhead pressure of production well. To maintain the reservoir pressure pump discharge pressure required increasing continuously. At the same pump discharge pressure production well wellhead pressure dropped drastically. Pump discharge pressure required for reservoir pressure maintenance is increasing day by day, indicates loss of well injectivity and results in fluctuation of production and sudden reservoir pressure loss. It shows that there is problem with injection water and its treatment process. Therefore there is need to check all injection water quality parameters which may causing damage to reservoir.

Table 1: - Daily Observation of Injection and Production WHP and pump discharge pressure.

Date March- (6 to 17)	Injection well Wellhead Pressure psi	Injection well Pump Discharge pressure psi	Production well wellhead pressure psi
6th	352	380	328
	360	390	334
7th	380	400	342
	396	410	310
8th	404	415	295
	408	420	299
9th	409	425	301
10th	373	430	272
11th	383	400	291
12th	394	410	337
13th	412	420	339
14th	430	450	338
15th	439	455	333
	445	460	329
16th	465	470	323
	482	485	130
17th	475	490	132
	445	450	130
	448	460	336

Probable Causes of Problem: -

(i) Turbidity: -

Turbidity is the measure of the clarity of water. Turbid water caused by suspended and colloidal matter including clay, silt, organic and inorganic matter and microscopic organisms. Turbidity of injection water should be less than 1 NTU. If turbidity of injection water is not under permissible level, it can lead to plugging of reservoir and injectivity of well will get reduce.

Turbidity of treated water observed at outlet of multimedia micron filtration is as follows;

Table 2: - Turbidity observed by online turbidity meter.

TURBIDITY AT MMF O/L (NTU) :A	TURBIDITY AT MMF O/L (NTU) :B	TURBIDITY AT MMF O/L (NTU) :C
0.2 Max	0.2 Max	0.2 Max
0.1	0.09	0.11
0.07	0.06	0.09
0.08	0.09	0.10
0.09	0.10	0.12
0.09	0.09	0.11
0.15	0.11	0.14
0.19	0.18	0.17
0.11	0.11	0.10
0.50	0.40	0.50
0.20	0.16	0.18
0.19	0.15	0.16

Above table shows turbidity of treated water in NTU at the outlet of three multimedia micron filters as A, B and C.

Turbidity of injection water should be less than 1 NTU. As observed figure shows it is well under permissible limit, so there is need to maintain it below 0.2 NTU as a precautionary measure. Sometimes it is found that it too high than 0.2. It may because seawater near platform is muddy and contains high amount of total suspended solids. So it is necessary to increase chemical dose rate to maintain turbidity less than 0.2.

(ii) Scale Formation:-

Scale deposits are a common problem in water injection, type and severity of scaling varying between fields. Seawater contains about 2650 mg/lit of sulphate and formation water contains barium and strontium, the result is the potential for significant barium and strontium sulfate scaling and possible reservoir souring. By effective removal of sulphate potential of scale formation and associated well workover can be minimize. Removing sulfate before injection reduced the potential for barium and strontium sulfate scaling and helps to prevent reservoir souring. The efficient removal of sulfate can reduce the risk of lost and deferred production.

If water scale deposits are left to accumulate, water flow may get restricted and piping may get plugged. Ultimately, ignoring scale depositions can lead to the destruction and possible failure. In addition to loss of efficiency, process contamination can occur. Water borne sedimentation i.e. Scale, rust, lime, mud and silica that builds up in the waterside of equipment may cause losses in breakdowns, unplanned shutdowns, process contamination, expensive parts replacements, production loss etc.

Mineral scales are precipitates that originate from inorganic inos that are present in the produced or injection seawater. Problems that are caused by scaling include formation plugging, down hole equipment plugging and restricted tubing. In a water injection system, scaling problems can be categorised as follows:-

Sulphate precipaitition ($BaSO4$, $SrSO4$, $CaSO4$) arising from incompatibility of injection seawwater and formation water.

Carbonate precipitation ($CaCO3$) in production tubing and topside due to the imbalnce of the carbonate-icarbonate equilibrium.

The scale precipitation/deposition is affected by various physical condition including temperature, pressure and salinity.

(iii) DO Content:-

Presence of dissolved oxygen in injection water can cause corrosion. It also allow the growth of aerobic microorganism, which can cause plugging and souring of reservoir. Therfore it is necessary to maintain the DO level within permissible limit of less than 10 ppb.

Observed DO content of injection water is as follows;

Table 3:- DO content of injection water

Date March-(6 to 15)	**DO content of injection water (ppb)**
6^{th}	60
7^{th}	60
8^{th}	60
9^{th}	40
10^{th}	30
11^{th}	40
12^{th}	40
13^{th}	40
14^{th}	80
15^{th}	60

Above table shows that DO content of injection water is more than permissible limit. It is necessary to maintain the DO content of injection water less than 10 ppb. DO content of injection water is more because only chemical means of DO removal is used i. e. oxygen scavenger, there is no arrangement of mechanical deareator is available on the platform. Therfore to maintain DO level of injection water within permissible limit required oxygen scavenger dose rate is too high.

(iv) GAnB and SRBs:-

Seawater contains more SO4, general anaerobic and sulphate reducing bacteria. It can cause souring and plugging of reservoir. Restricting the growth of general anaerobic and sulphate-reducing bacteria (SRB) is essential for the long-term performance of the water flood operation, in terms of plugging and souring. SRB are the prime cause of oilfield souring and their growth and activity within an oil reservoir is the subject of the souring.

The SRBs were generating 8-10 ppm dissolved H2S that was ultimately responsible for the iron sulfide formation. The iron sulfide resulted in poor water quality tank fouling, filter plugging, injection line scaling, and loss of injectivity due to near wellbore damage in the injection well.

Bacteria, yeast, algae are common microorganisms present in oil field water. Anaerobic bacteria are most common in the oil field. SRB (desulfovibro) can reduce sulphate to sulphide, which can create concentration cells causing pinhole corrosion. It also creates a potential plugging agent (FCS) whenever sulphide is combined with iron in solution.

Injection Water Analysis

(i) DO content

Seawater typically contains a corrosive DO level of 7 to 8 ppm. DO content of injection water should maintained <10 ppb to control corrosion. Oxygen scavenger is used to reduce DO level sufficiently within permissible level. Dissolved oxygen content of injection water is found out using Winkler method.

Table 4:- Dissolved Oxygen Content @ Injection pt

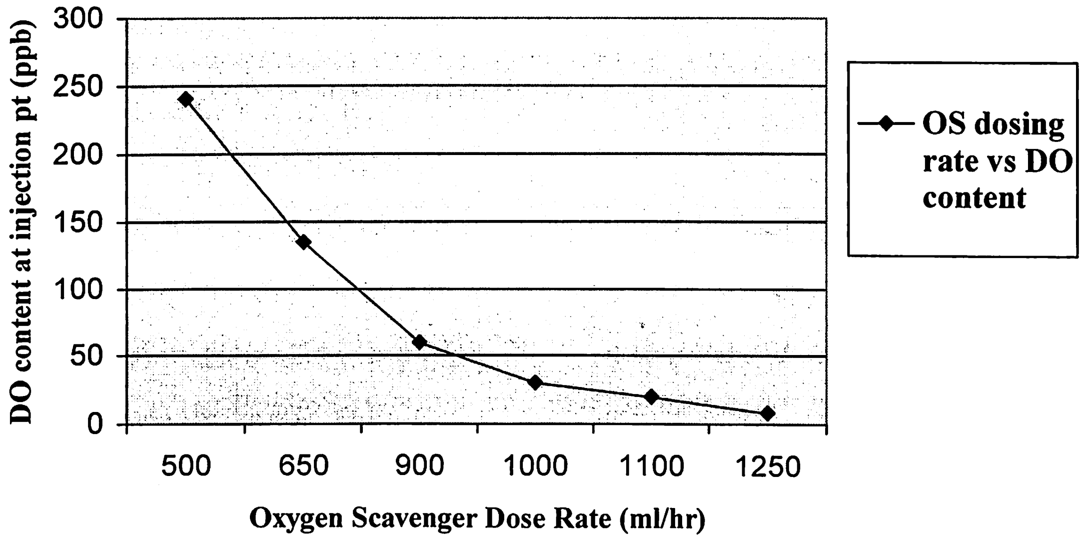
Dosing Duration, minutes	Dosing Rate of Oxygen Scavenger, ml/hr	Dosing Rate, ppm	D.O. at injection point, ppb
45	500	100	240
45	650	130	135
45	900	180	60
30	1000	200	30
30	1100	220	20
45	1250	250	<10

ppm= 1000*chemical dose rate(ml/hr)/water flow rate (ml/hr)
inlet water flowrate-5 lit/hr.

Effect of oxygen scavenger dosing rate on dissolved oxygen content:-

With increase in oxygen scavenger dosing rate-dissolved oxygen content of injection water decreases.
At a dosing rate 500ml/hr (100 ppm), DO content of injection water is high.
At a dosing rate of 1250 ml/hr (250 ppm), DO content is less than 10 ppb.

Fig 5- Effect of Oxygen Scavenger Dosing Rate on Dissolved Oxygen Content



Dissolved oxygen content is less than 10 ppb at dosing rate of 1250 ml/hr. Therefore oxygen scavenger should be injected at a rate of 1250 ml/hr.

Required oxygen scavenger dose rate is high because, mechanical means of DO removal i. e. Deareator is not available at platform.

(ii) Corrosion Coupon Test

To prevent production facilities from oxygen corrosion, corrosion inhibitor is injected before injection. To check the quality of injection water and performance of corrosion inhibitor chemical, corrosion coupon test is carried out. Corrosion rate of material is calculated using following formula,

$$\text{Corrosion Rate (CR)} = \frac{\text{Weight loss (mg)}}{\text{exposed area (cm2)} * \text{exposed time (hr)}}$$

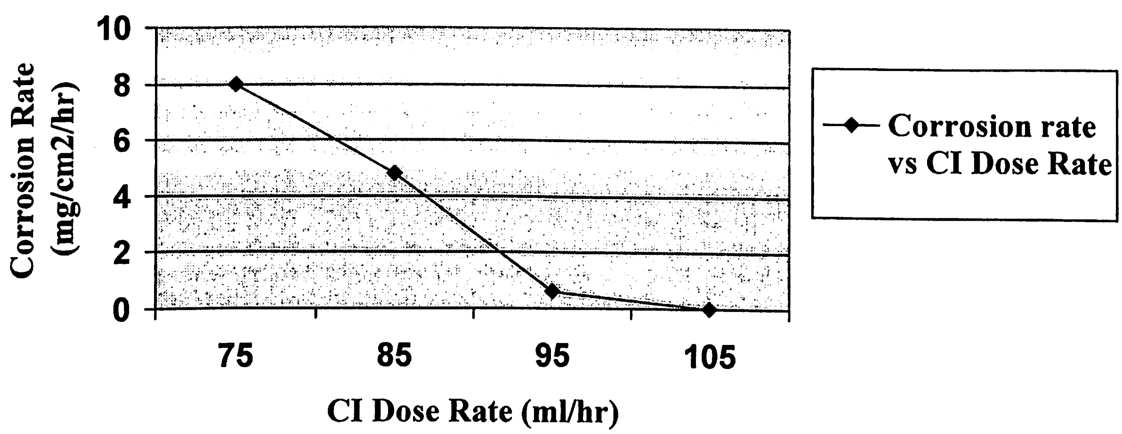
For a test, corrosion coupon of weight 50gm, 2.5cm width and height, is used. Corrosion coupon is exposed in a treated water sample for 8hr at atmospheric temperature. Coupon weight loss is found out using electronic weight balance.

Corrosion Coupon Test Result: -

Initial Weight of Coupon- 50 gm

Corrosion Inhibitor Dose Rate (ml/hr)	**Final Weight (gm)**	**Weight Loss (mg)**	**Exposure Time (hr)**	**Corrosion Rate (mg/cm2/hr)**
75	49.6	400	8	8
85	49.76	240	8	4.8
95	49.92	80	8	0.6
105	50	Free of corrosion	8	0

Fig 6. Effect of Corrosion Inhibitor Dose Rate on Corrosion Rate



Result: - At a corrosion inhibitor dose rate of 105 ml/hr, coupon is free of corrosion.

(iii) Turbidity

Turbidity is the measure of the clarity of water. Turbid water is caused by suspended and colloidal matter including clay, silt, organic and inorganic matter and microscopic organisms. Turbidity of injection water should be less than 1 NTU.

Turbidity of water checked at multimedia outlet using turbidity meter. As water near platform is muddy turbidity observed is near about 0.1 to o.6 NTU.

Table: - Turbidity observed in online turbidity meter.

TURBIDITY AT MMF O/L (NTU) :A	TURBIDITY AT MMF O/L (NTU) :B	TURBIDITY AT MMF O/L (NTU) :C
0.2 Max	0.2 Max	0.2 Max
0.1	0.09	0.11
0.07	0.06	0.09
0.08	0.09	0.10
0.09	0.10	0.12
0.09	0.09	0.11
0.15	0.11	0.14
0.19	0.18	0.17
0.11	0.11	0.10
0.50	0.40	0.50
0.20	0.16	0.18
0.19	0.15	0.16

Table 5:- Alum and magnaclear dose rate.

CHEMICAL DOSING IN CLARIFRIER INLET			
INTAKE FLOW	**MAGNACLEAR**		**ALUM**
M3/DAY	**L/DAY**	**PPM**	**L/H**
171	1.00	5.85	7
169	1.00	5.92	7
139	0.80	5.76	7
139	1.00	7.19	7
143	0.85	5.94	7
151	0.88	5.83	10
165	1.00	6.06	10
149	2.20	14.77	10
135	1.60	11.85	15
168	2.00	11.90	15

Fig 7. Effect of Alum Dose Rate on Turbidity

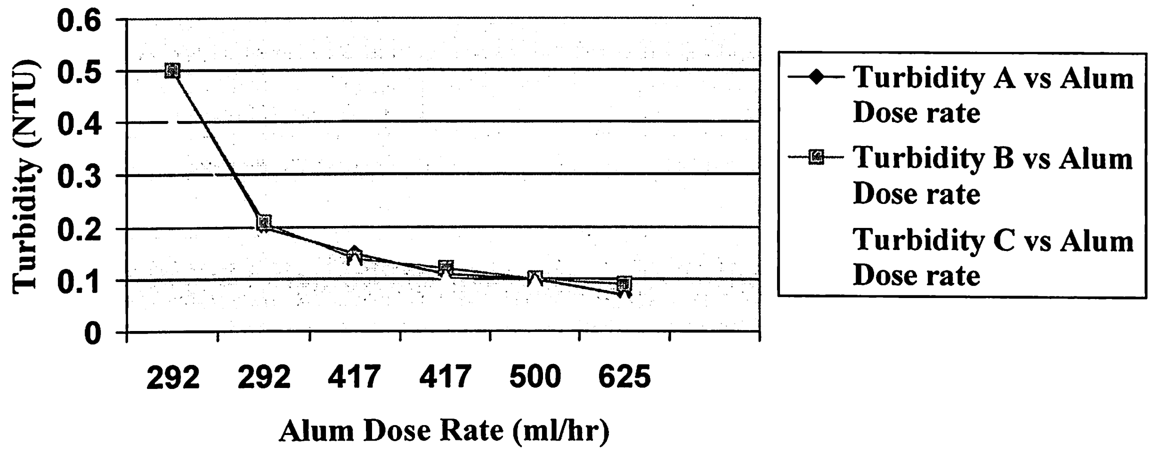
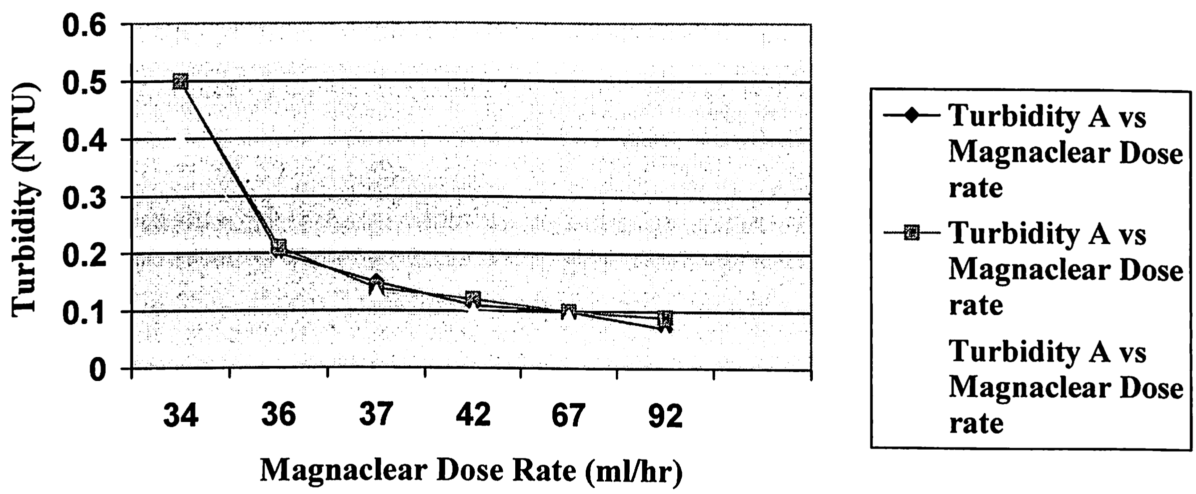


Fig . Effect of Magnaclear Dose Rate on Turbidity



Seawater near platform is a muddy, high total suspended solid content; therefore there is fluctuation in turbidity for the same chemical dose rate.

With increase in dose rate of alum and magnaclear turbidity reduced to certain value less than 0.1 NTU.

To maintain turbidity of water below 0.2, dosing rate of chemicals should be according to inlet water quality, therefore there is need to check total suspended solid and biomass content of water every week.

(iv) Free Residual Chlorine

It is important parameter to check before injection of water. It indicates the total chorine required for disinfections of biomass. Chlorine is used as primary disinfectant for treatment of seawater. Hydrochloric and hypochlorous acids are formed when chlorine is added to water. The disinfectant and the form causing bleaching action is hypochlorous acid.

$Cl2 + H20 \longrightarrow H+ + Cl- + HOCl$

Depending upon variables such as pH, temperature and the amount of organic or ammonia nitrogen, other forms of chlorine in water may include hypochlorite ions (OCl_-) and chloramines. Chlorine existing in water as hypochlorous acid or the hypochlorite ion is termed free available chlorine.

The method used to find out is, colorimetric DPD. DPD (N, N-diethyl-p-phenylenediamine) is oxidized by chlorine, causing a magenta (red) color. The intensity of color is directly proportional to the chlorine concentration. DPD reacts in much the same way with other oxidants, including bromine, iodine, ozone and permanganate.

Table 6: - FRC observed at Filter outlet and injection pt.

FRC AT FILTER O/L (PPM)	FRC AT WATER INJECTION (PPM)	Chlorine
0.6 Max	0.1 max	Dose rate (L/H)
0.2	0.0	2.2
0.2	0.0	2.2
0.1	0.0	2.5
0.1	0.0	2.5
0.1	0.0	2.5
0.1	0.0	2.5
0.1	0.0	2.5

At a dose rate of 2.5 l/hr of chlorine free residual chlorine at filter outlet is less than 0.3 and it is zero at injection point.

It shows that chlorine required for disinfections of biomass is injected with sufficient dose rate.

Analysis Result

(i) Sea water near platform contains very high TSS, high DO.

(ii) Chemical responses to the water i. e. reaction rates are pretty tedious.

(iii) Biomass contain of seawater is more.

(iv) With increase in oxygen scavenger dose rate DO content of injection water reduced sufficiently

(v) At 250 ppm of oxygen scavenger dosing rate DO content found <10ppb.

(vi) Corrosion coupon is free of corrosion at CI dosing rate of 21 ppm.

(vii) Turbidity of injection water is well under control with increase in alum and magnaclear dose rate.

Beneficial Modification: -

(1) Alum is used as coagulant to destabilize colloidal particles from the raw water and sodium hypochlorite is used as a primary biocide to control bacteria. The main objective of using sodium hypochlorite is to kill biological organisms that could grow and form deposits that foul equipment.

It is observed that alum and hypo injected inline followed by static mixer.

(i) As hypo is primary biocide it should have to inject outlet of the seawater lift pump so that it will get mixed thoroughly with raw seawater and destroy bacterial ingress.

(ii) Injection of sodium hypochlorite at outlet of seawater lift pump will be effective treatment, as it will allow more time for reaction and assist in further efficient clarification. It will also reduce the amount of hypo required currently which is otherwise more.

Table shows the advantages of changing injection pt of Hypochlorite.

	Current		After	
	Alum	Sodium Hypochlorite	Alum (15 % less of current)	Sodium Hypochlorite
Dose Rate	300 lit/day	60 lit/day	255 lit/day	51 lit/day
Time of reaction	Extra 42 sec for reaction compare to previous injection pt.			
		Time = Pipe Volume/ Flowrate		

(2) To maintain DO content within permissible limit required oxygen scavenger dosing rate is about 250 ppm is very much high, which is a costly affair. Installation of deareator on site will be beneficial to reduce the amount of oxygen scavenger required and ultimately it will reduce the cost of chemical. It will also helpful in efficient removal of DO of water.

Table shows the changes in parameter with installation of deareator,

	Current Oxygen Scavenger requiremnet		After Oxygen	
Dose Rate	250 ppm		50 (20 % of current)	
DO content removal	80 % with deareator, 20 % with oxygen scavenger			

(3) From injection water analysis result it is found that injection seawater contains bacterial population of both GAnB ttype and SRB type.

Therefore it is necessary to inject following additives;

For prevention of GanB and SRB growth, bacteriacide I (amine base) and bacteriacide II (aldehyde base) should be injected to treated water. Biocides should be applied at 1000 ppm for a period of 8 hrs an alternative weeks. The use of two alternate biocide prevents the growth of a biocide species, which could if left unreacted contaminate the water injection system.

Quantity of Chemicals Required per Year

750 barrels of treated water injected daily for maintaining wellhead pressure of 520 psi, chemicals required for treatment is as follows,

Table 7:- Estimated requirement of chemicals per year

	Chemical Injection Dose Rate (ppm)	Chemical Injection Dose rate lit/day	Density Kg/m3	Water Flowrate Lit/day	Estimated Requirement Per Year (lits)
Corrosion Inhibitor	22	2.57	1.07	120	938.05
Scale Inhibitor	20	2.3	1.28	120	839.50
Oxygen Scavenger	250	30	1.35	120	10950
Filter Aid (Magnaclear)	-	1.1	1.15	161 m3/day	401.50
Alum	-	300	1.85	161 m3/day	109500
Chlorine	150	60	3.36	161 m3/day	21900

Alum, sodium hypochlorite and magnaclear chemicals used with 1% dilution.

Alum Required per Year:-

Alum 14% 35.7 kg with 500 lits of water to get 1% diluted solution.

$$\text{Alum required (kg)} = \frac{109500\ \text{(lits/year)} * 5\ \text{(kg)}}{500\ \text{(lit)}}$$

$$= \mathbf{1095\ kg/year.}$$

Chlorine Required per Year: -

Chlorine 10% 30 liters with 300 litres of water to get 1% diluted solution.

$$\text{Chlorine required (kg)} = \frac{21900 \text{ (lits/year)} * 3 \text{ (lit)}}{303 \text{ (lit)}}$$

= **216.85 lit/year.**

Magnaclear required per year: -

Magnaclear 5 liters with 500 litres of water to get 1% diluted solution.

$$\text{Chlorine required (kg)} = \frac{401.5 \text{ (lits/year)} * 5 \text{ (lit)}}{505 \text{ (lit)}}$$

= **4 lit/year.**

Corrosion Inhibitor required per year: - 938.05 lit/year.

Scale Inhibitor required per year: - 840 lit/year.

Oxygen Scavenger required per year: - 10950 lit/year.

Chapter-6

Case Study: 2
(Source: Niko Gas Processing Plant)

Problem: -

Sometimes Liquid propane condenses and settled down at bottom of oil separator when compressor is in stand by mode and when compressor lube oil pump starts the propane liquid goes first, results in loss of propane and may result in bearing failure if propane phase is carried into the compressor.

Process Description:-

After being discharged from the screw compressors, the propane refrigerant and lube oils are separated in the lube oil separators. The lube oil separator contains five coalescing filter elements that remove lube oil particles 0.3 micron in size and larger.

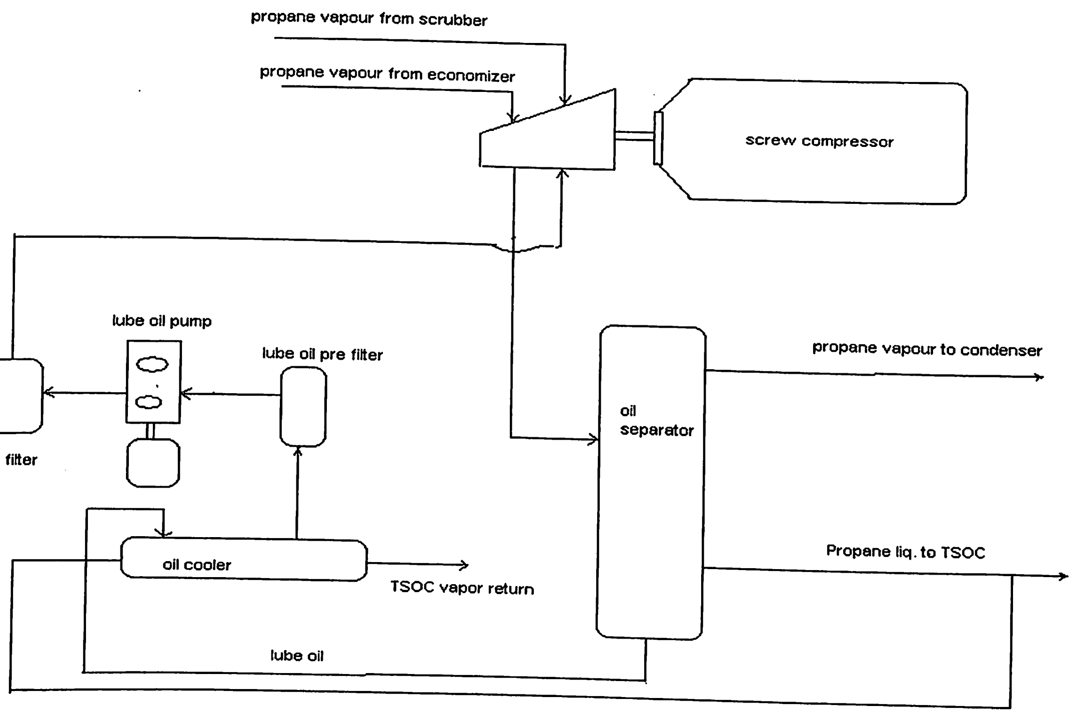


Figure 8:- Process flow diagram Refrigerant Compressor

One oil heater controls oil temperature exits in shutdown conditions. From the lube oil separator, the lube oil is passed through the oil cooler, where it is cooled by vaporization of propane refrigerant. After being cooled to approximately 60°C, the lube oil travels through a washable stainless steel 300 mesh pre-filter. From lube oil pre-filter lube oil flow is injected into the rotor for cooling of the compressed gas.

Compressor lube oil specification:-

Trade Name: - CP-1516-100 is a custom blend of polyalkylene glycols with additives for oxidation stability, corrosion protection and lubricity. The ability of the lubricant to withstand dilution by hydrocarbons and other compressed gases is particularly advantageous in flooded screw compressors. Other advantages include stability, low ash content, high viscosity index and excellent lubricity.

Viscosity: - Temperature	cSt
At 40 °C	92.3
At 100 °C	18.6

Density: - 8.27 lbs/gal

Pour point: -40 °C

Flash Point: - 260 °C

Fire Point: - 270 °C

Propane Properties:-

Chemical formula: - C_3H_8

Molecular Weight: - 44 g/mol

Boiling Point: - -42 °C

Melting Point: - -186 °C

Vapor Density (1.013 bar at boiling point):- 2.423Kg/m^3

Vapor Density (1.013 bar and 15 C):- 1.91Kg/m^3

Liquid Density (1.013 bar at boiling point):- 582Kg/m^3

Vapor pressure at 40 C: - 15.81 Kg/cm^2

Dew Point (at 1.013 bar):- -26.5 °C

Table: - Operating Parameters

Propane Compressor	Suction Pressure	Barg	2.59
	Discharge Pressure	"	14.15
	Compressor oil Pressure	"	2.81
	Discharge Temperature	°C	65.9
	Comp oil Temperature	°C	52.8

Oil Separator	Separator Temp	°C	55
	Oil Temp	°C	65.7

Probable Cause of Problem:-

After the oil exits the discharge oil separator and retains in the oil reservoir, the diluted pressurized lubricant is cooled, filtered and supplied to the compressor radial bearings, axial thrust bearings, balance pistons and mechanical shaft seal, and injected into the compression chambers. The oil viscosity will dilute by absorbing a percentage of the gas. The amount of gas dilution entrained in the oil is dependent on three factors.

(i) Molecular weight of the refrigerant: -

The molecular weight of the gas compressed is the primary factor of oil dilution characteristics (figure 1). Lighter molecular weight refrigerants like ammonia have low dilution characteristics of 3 to 5% where heavier molecular weight refrigerants like propane, R-22 and R-134a result in higher dilution characteristics of 15 to 20%. Low molecular weight refrigerants also have a higher dependency on injection oil to seal leakage paths to maintain peak volumetric efficiency.

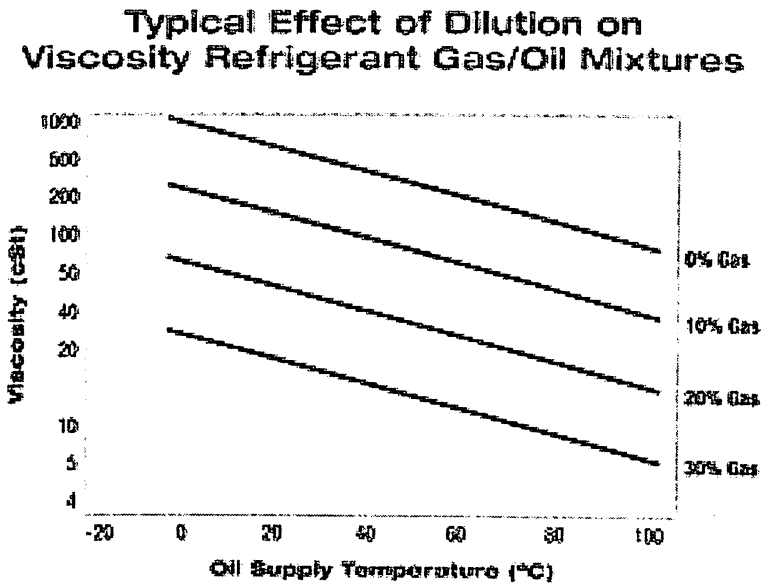


Figure 9 The molecular weight of the gas-compressed gas is the primary factor of oil dilution characteristics. Once the gas is trapped in the oil and externally cooled, the bearing oil supply viscosity is determined at the compressor supply temperature.

(ii) Operating Discharge Pressure.

The higher the operating discharge pressures, higher the oil dilution rates. When operating screw compressor systems, sudden reductions of discharge pressure will release the dilution effect too quickly, causing the oil to foam and disrupting the oil management system. High or abnormal dilution rates will tend to swell the oil operating level in the reservoir.

(iii) Operating Discharge Superheat.

The operating discharge temperature plays a key role when striving for a steady-state normal oil dilution rate. Adequate discharge superheat measurements are an excellent indicator of stabilized oil dilution. Discharge oil separators should operate above 30°F (-1°C) discharge superheat. If the discharge temperature has an insufficient margin from the condensing temperature, refrigerant dilution can become extreme and detrimental to the bearing oil supply viscosity. Extreme low ambient temperature exposure to the oil separator/reservoir can have a detrimental impact to the oil dilution rate. Abnormally sustained liquid slugging into the suction of a screw compressor due to unbalanced evaporator heat loads will disturb the discharge superheat and may jeopardize the resultant bearing oil supply viscosity.

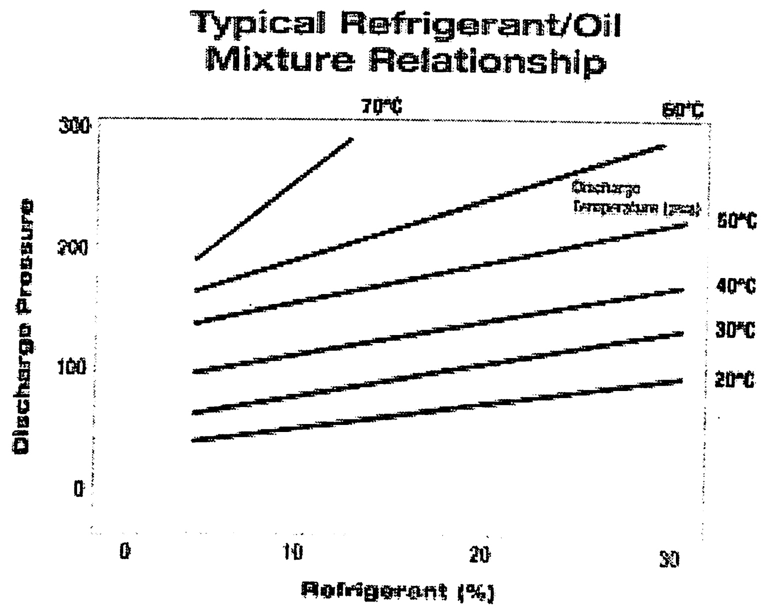


Figure 10. At higher compression ratios, more heat of compression is distributed as oil cooler heat rejection. Discharge superheat in the oil separator determines the amount of gas absorbed in the oil.

Observation:-

(i) Propane used as a refrigerant, having more dilution characteristics compare to ammonia. So it is necessary to use high grade lubrication oil. CP-1516-100 good quality lubrication oil is changed with previous poor quality lubrication oil.

(i) At particular operating discharge pressures their is certain oil dilution rate. For higher operating discharge pressures higher the oil dilution rates. In operating screw compressor systems, sudden reductions of discharge pressure will release the dilution effect too quickly, causing the oil to foam and disrupting the oil management system. High or abnormal dilution rates tend to swell the oil level in the reservoir.

At the same time at high operating pressures the hydrocarbons will continue to condense and build a separate hydrocarbon-rich liquid phase in the lubricant separator tank. This hydrocarbon phases has a very low viscosity and poor lubricity. If this hydrocarbon liquid is carried into the compressor, a bearing failure can occur.

Recommendations: -

(i) It is require to note down the standby system readings whenever such problem occurs, which will be helpful to know the critical points of cause and preventive actions can be taken in future.

(ii) The two liquid phases (lubricant and hydrocarbon condensable) do not readily separate by gravity so it is necessary to evaporate or flash off the hydrocarbon phase, so oil separator heater should start, 24 hrs before start of the compressor system so that condensed refrigerant will get flashed and oil will be stabilized.

CONCLUSION

Seawater injection is one of the economical method of enhance oil recovery, it improves oil recovery significantly. Seawater injection improves the recoverable reserves from a reservoir by establishing an external water drive and by maintaining reservoir pressure. Injecting water into the oil bearing layers or into pressure supporting aquifers for the reservoir sweeps oil out of the pore space and into the production wells. Injection of poor quality water can lead to reservoir plugging, leading to injection losses, a decline in the injection rate, and a sub-sequent decline in production. Often an increase in the injection pressure is required to sustain injection rates, instead of well workover, reperforating the wells, or the drilling of new wells. By proper seawater treatment process and chemical dosing rate, quality of injection water can be maintained effectively. Proper injection water quality can minimize the various problem of offshore production like reduction in well injectivity, reservoir pressure loss, fouling of production facilities, improves oil recovery rate and increases well life. Problem of reservoir plugging, reduction in well injectivity, reservoir pressure loss causes because of poor injection water quality. If injection water contains the suspended and colloidal particles, results in plugging of reservoir voids. Therefore removal of suspended and colloidal particles effectively is must and it can achieve using proper chemical treatment. Sodium hypochlorite is used to kill biological organisms that could grow and form deposits that foul equipment should have to inject at outlet of the seawater lift pump so that it will get mixed thoroughly with raw seawater and destroy bacterial ingress. From water analysis it is cleared that seawater contains both GAnB and SRB type of bacteria, which causes severe pipeline corrosion and formation plugging. To maintain good water quality for a seawater flood system to control bacteria at an acceptable level. To counter contamination of bacteria into a waterflood distribution system, organic biocide should have to use, it will control both GAnB and anaerobic sulphate reducing bacteria (SRB).

Problem of fluctuation in production, sudden reservoir pressure loss can be resolve by maintaining injection water parameters under control like turbidity, DO content, corrosion rate and free residual chlorine.

Turbidity observed at multimedia filter outlet crosses value of 0.5 NTU. With increase in dose rate of alum and coagulant turbidity decreases. At an alum dose rate of 625-ml/hr and magnaclear dose rate of 92-ml/hr turbidity observed is less than 0.1 NTU. Therefore alum and magnaclear should be injected at a dose rate of 625-ml/hr and 92-ml/hr respectively.

DO content found out of injection water is much more high. With increase in oxygen scavenger dosing rate DO content observed is decreases. At an oxygen scavenger dose rate of 1250 ml/hr DO content at an injection point is observed less than 10 ppb. Therefore oxygen scavenger should inject at a dose rate 1250 ml/hr to maintain DO content of injection water within permissible limit.

Corrosion rate of injection water is decreases with increase in corrosion inhibitor dose rate. At a corrosion inhibitor dose rate 105-ml/hr-corrosion coupon found out is free of corrosion. Therefore corrosion inhibitor should be injected at a dose rate 105 ml/hr.

At a dose rate of 2.5 ml/hr of chlorine, free residual chlorine observed at filter outlet is less than 0.3 ppm and it is zero at injection point.

General anaerobic and sulphate reducing bacteria observed in injection water analysis, which can cause reservoir souring and plugging, therefore to control growth of these bacteria it is necessary to inject aldehyde based and amine based biocide to treated water before injection.

Condensed propane liquid settled at the bottom of the oil separator and flows through the lube oil pump to screw compressor results in propane loss, causes bearing failure of the compressor and sometimes tripping of the compressor. Problem generally arises when low-grade oil is used for lubrication purpose. Problem occurrence also depends on operating parameters like operating discharge pressure and operating discharge temperature. To avoid occurrence of problem it is necessary to find out operating parameters at which problem is arising and whenever such problem arises it is necessary to evaporate or flash off the hydrocarbon phase, so oil separator heater should start, 24 hrs before start of the compressor system so that condensed refrigerant will get flashed and oil will be stabilized.

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