Optimum Production of Oil from Heavy Oil Reservoirs – Methods & Applications

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May, 2011

Certificate

This is to certify that Ch. K. Katyayan & P. S. Kalyani, students of Intt. B.Tech (Applied Petroleum Engineering) + MBA (Upstream Asset Management) has written their thesis on "Optimum Production of Oil from Heavy Oil Reservoirs – Methods & Applications" under my supervision and have successfully completed the project within stipulated time.

They have demonstrated high performance levels and dedication during the completion of his thesis.

Signature

17 May 2011

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Optimum Production of Oil from Heavy Oil Reservoirs – Methods & Applications

A thesis submitted in partial fulfilment of the requirements for the Degree of Bachelor of Technology (Applied Petroleum Engineering, Upstream)

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Declaration

We hereby declare that the project work incorporated in this project entitled ***"Optimum Production of Oil from Heavy Oil Reservoirs – Methods & Applications"*** *is originally carried out by us under the guidance of Mr. Arvind Chittambakam (Associate Professor) and supervision of Mr. S.K.Nanda (Associate Professor) in University of Petroleum and Energy Studies, during the academic year 2011. It has not been submitted in part or in full for any Degree to any other university.*

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Abstract

Heavy oil, extra-heavy oil, and bitumen are unconventional oil resources that are characterized by high viscosities (i.e. resistance to flow) and high densities compared to conventional oil. Mostly their deposits are very shallow. They mostly result from crude oil getting degraded by being exposed to bacteria, water or air resulting in the loss of its lighter fractions while leaving behind its heavier fractions.

They are actually originated as conventional oil that is formed in deep formations, but gets migrated to the surface region where they were degraded by bacteria and by weathering, and where the lightest hydrocarbons escaped. They are deficient in hydrogen and have high carbon, sulphur, and heavy metal content. Hence, they require additional processing (upgrading) to become a suitable feedstock for a normal refinery.

The resources of heavy oil in the world are more than twice those of conventional light crude oil. As discussed above, the relatively shallow depth of heavy oil fields (often less than 3000 feet) contributes to lower production costs. Due to the above factors, the need to develop specialized techniques for exploration and production of heavy oil has been increased.

In this project, we will study the various methods that help in increasing the production of oil from heavy oil wells. We will take up a case study on Kharsang oil field (located in Arunachal Pradesh, India) where CHOPS technique gave better efficiency and is the most appropriate method for increasing the production rate. We will study about different techniques and will also analyze by using these techniques how to improve the efficiency of the pool.

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INTRODUCTION

Heavy Oil

Definition:

Heavy crude oil is any type of crude oil which does not flow easily. It is referred to as 'heavy' because its density (or specific gravity) and viscosity are higher than the conventional values of natural crude oil.

Different countries and organizations/institutions define heavy oil differently. For example:

- In 1982, the UNITAR Conference in Venezuela defined heavy crude oil as an crude petroleum having viscosity of 100 to 10,000 cP at reservoir temperature, density between 943 and 1000 kg/(cubic-meters) at 15.6° C, and API gravity from 10° to 20°.
- The US Department of Energy (DOE) defines heavy oil as crude oil having API gravities between 10.0° and 22.3°.
- The World Petroleum Congress defines heavy oil as oil whose gas-free viscosity is between 100 cp and 10,000 cp at reservoir temperature.

Heavy crude oil has generally been identified as any liquid petroleum with an API gravity less than 20°, implying that its specific gravity is greater than 0.933.

Chemical Composition:

Heavy oil is asphaltic and contains asphaltenes and resins. It is 'heavy' (dense and viscous) due to the high ratio of aromatics and naphthenes to paraffins (linear alkanes)and high amounts of NSO's (nitrogen, sulfur, oxygen and heavy metals).

Heavy oil has over 60 carbon atoms and hence a high boiling point and molecular weight. For example, the viscosity of Venezuela's Orinoco extra-heavy crude oil lies in the range 1000–5000 cP, while Canadian extra-heavy crude has a viscosity in the range 5000–10,000 cP.

A definition from the Chevron Phillips Chemical Company is as follows:

The 'heaviness' of heavy oil is primarily the result of a relatively high proportion of a mixed bag of complex, high molecular weight, non-paraffinic compounds and a low proportion of volatile, low molecular weight compounds. Heavy oils typically contain very little paraffin and may or may not contain high levels of asphaltenes. Heavy crude oils can contain 3% by weight or more of sulfur and as much as 2000ppm of vanadium. Molybdenum and nickel are also frequently encountered in heavy oils.

Types:

There are two main types of heavy crude oil:

1) Those that have more than 1% sulfur (high sulfur crude oils) with aromatics and asphaltenes. These are mostly found in Canada, United States, Mexico, Venezuela, Colombia, Ecuador, Kuwait and Saudi Arabia.

2) Those that have less than 1% sulfur (low sulfur crude oils) with aromatics, naphthenes and resins. These are mostly found in Chad, Angola and Madagascar.

Properties – Density and Viscosity:

Heavy oil can flow in some reservoirs at down-hole temperatures and/or with in situ solution gas, but at the surface, it is a thick, black fluid.

Natural crude oils exhibit a continuum of densities and viscosities. Viscosity at reservoir temperature is usually the more important measure to an oil producer because it determines how easily oil will flow. Density is more important to the oil refiner because it is a better indication of the yield from distillation. Unfortunately, no clear correlation exists between the two. A medium density, or light, crude with high paraffin content in a shallow cool reservoir can have a higher viscosity than a heavy, paraffin-free crude oil in a deep hot reservoir. Viscosity can vary greatly with temperature. Density varies little with temperature, and has become the more commonly used oilfield standard for categorizing crude oils.

Density is usually defined in terms of American Petroleum Institute (API) gravity, which is related to specific gravity - the denser the oil, the lower the API gravity. Hydrocarbon API gravities range from 4° (for tar-rich bitumen) to 70° (for condensates). Heavy oil occupies a range along this continuum between ultra-heavy oil and light oil. However, nature recognizes no such boundaries. In some reservoirs, oil with gravity as low as 7° or 8° is considered heavy rather than ultra-heavy because it can be produced by heavy-oil production methods.

Geological Origin:

When originally generated by petroleum source rock, crude oil is not heavy. Geochemists generally agree that nearly all crude oils start out with API gravity between 30° and 40°. Oil becomes heavy only after substantial degradation during migration and after entrapment.

Most heavy oil deposits are shallow. They originated as conventional oil that formed in deep formations, but migrated to the surface region where their degradation took place, and the lightest hydrocarbons escaped. Heavy oil is generally deficient in hydrogen and has high carbon, sulfur, and heavy metal content.

Degradation of heavy oil occurs through a variety of biological, chemical and physical processes:

(a) Bacteria borne by surface water metabolize paraffinic, naphthenic and aromatic hydrocarbons into heavier molecules.

(b) Formation waters also remove hydrocarbons by solution, washing away lower molecular-weight hydrocarbons, which are more soluble in water.

(c) Crude oil also degrades by volatilization when a poor-quality seal allows lighter molecules to separate and escape.

Reservoir Characteristics:

Heavy oils can be found in shallow, young reservoirs, with rocks from the Pleistocene, Pliocene, and ages (younger than 25 million years). In some cases, it can also be found in older Cretaceous, Mississippian, and Devonian reservoirs. These reservoirs tend to be poorly sealed, resulting in heavy oil and oil-sands.

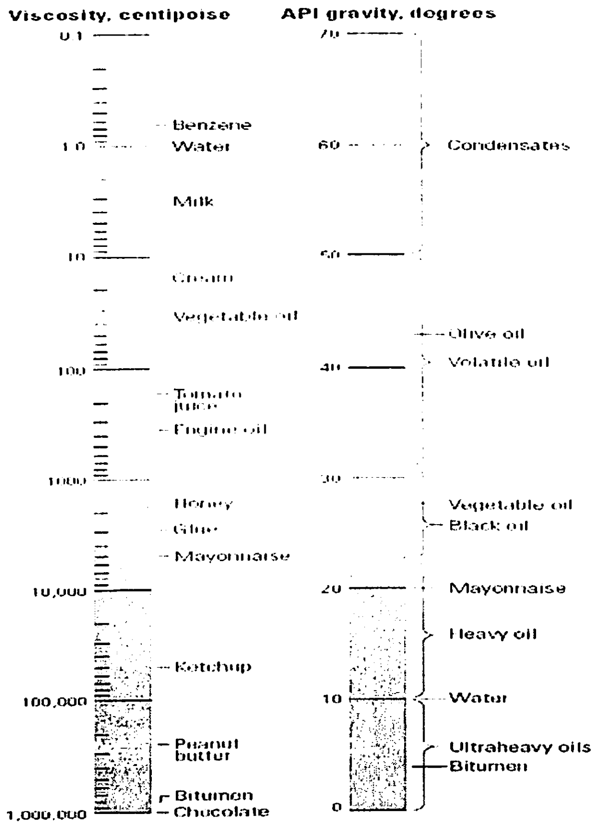
Heavy oil deposits may contain water, clay, and minerals containing sulfur, titanium and heavy metals such as nickel, vanadium and molybdenum. Frequently, unconsolidated heavy oil deposits, i.e. the reservoir fluids hold the quartzite grains together rather than cementing materials, are encountered (like in Alberta and Saskatchewan provinces in Canada).

Most heavy oil deposits occur in shallow (3000 ft or less), high permeability (1 to several Darcies), high porosity (around 30%) and poorly consolidated sand formations. Oil saturations tend to be high (50 to 80% pore volume), and formation thickness from 50 to several hundred feet.

Heavy crude oil is closely related to oil sands, the main difference being that oil sands generally do not flow at all. Canada has large reserves of oil sands, located north and northeast of Edmonton, Alberta.

Most current heavy oil production comes from quartzite sandstone formations, but heavy oil also exists in carbonate formations. Carbonate formations are much more complex than sandstone formations, and often have extensive fracturing and vugs, in addition to inter-granular porosity.

The largest reserves of heavy oil in the world are located north of the Orinoco river in Venezuela, the same amount as the conventional oil reserves of Saudi Arabia, but 30 or more countries are known to have reserves. Extra heavy oil from the Orinoco region has a viscosity of over 10,000 centipoises and 10° API gravity.



Production:

While other factors such as porosity, permeability and pressure determine how a reservoir will behave, it is the oil density and viscosity that dictate the production approach an oil company will take. Dense and viscous oils present tough production challenges. Production of heavy oil is becoming more common in many countries, with 2008 production led by Canada and Venezuela. Some of the methods for extraction include:

- Open pit mining
- Water - flooding
- Alkali – Surfactant – Polymer (ASP) flooding
- Cold heavy oil production with horizontal wells & multilaterals
- Cold heavy oil production with sand (CHOPS)
- Cyclic steam stimulation (CSS)
- Steam - flooding
- Steam Assisted Gravity Drainage (SAGD)
- Solvent with heat or steam
- Solvent without heat or steam (e.g. Vapor Assisted Petroleum Extraction)
- Fire flood with vertical and horizontal wells
- Injection of supercritical fluids (e.g. CO_2)

As discussed earlier, heavy oil typically is produced from geologically young formations Pleistocene, Pliocene and Miocene. These reservoirs tend to be shallow and have less effective seals, exposing them to conditions conducive to forming heavy oil.

Most operators try to produce as much heavy oil as possible under primary recovery, called cold production, at reservoir temperature. Typical recovery factors for cold production range from 1 to 10%. Depending on oil properties, cold production with artificial lift — including injection of light oil, or diluents, to decrease viscosity — may be successful. Many reservoirs produce most efficiently with horizontal wells. In some cases, encouraging sand production along with oil is the preferred production scheme. Choosing the optimal cold-production strategy requires an understanding of fluid and reservoir properties and production physics.

Once cold production has reached its economic limit, the next step is usually thermally enhanced recovery. Here again, several methods are available. In a technique called cyclic steam injection, producing wells can be stimulated by steam injection then returned to production. Cyclic steam injection can raise recovery factors to 20 to 40%. In steam-flooding, steam pumped into dedicated injection wells heats viscous oil that is then produced at production wells. Injection and production wells may be vertical or horizontal. Well placement and injection schedules depend on fluid and reservoir properties. Recovery factors can reach 80% in some steam-flooding operations.

Economics:

Heavy oil is often overlooked as a resource because of the difficulties and costs involved in its production. But the more than 6 trillion barrels of oil in place attributed to the heaviest hydrocarbons — triple the amount of combined world reserves of conventional oil and gas deserve a closer look.

Heavy crude oils provide an interesting situation for the economics of petroleum development. In October 2009, the USGS updated the Orinoco tar sands (Venezuela) recoverable value to 513 billion barrels (8.16×10^{10} m^3), making this area the world's first recoverable oil deposit, ahead of Saudi Arabia and Canada.

On one hand, due to increased refining costs and high sulfur content, heavy crudes are often priced at a discount to lighter ones. For oil producers involved in heavy-oil recovery, the enterprise requires a long-term investment. The high viscosity of heavy oil adds to transport difficulties and requires special, and therefore more costly, refining techniques to produce marketable products.

Technology value is assessed by its ability to reduce total cost. Since most heavy-oil fields are shallow, drilling costs have not been the dominant factor, but the growing use of complex horizontal and multilateral wells is introducing some cost at this stage of development. The primary cost typically is that of the energy needed to generate and inject the steam required to mobilize viscous oils.

The biggest problem that plagues heavy oil development at present is the cyclic price drops to uneconomical levels when production exceeds upgrading capacity. This is likely to change permanently in the coming decade or so, when the world production rate of conventional crude oil will peak at an estimated 27 billion barrels per year. Consequently, the persistent demand of crude should encourage a more permanent and economically stable development of heavy oil production.

Environmental Impact:

With current production and transportation methods, heavy crudes have a more severe environmental impact than light ones. With more difficult production comes the employment of a variety of enhanced oil recovery techniques, including steam flooding and tighter well spacing, often as close as one well per acre. Heavy crudes also carry contaminants. For example, Orinoco extra heavy oil contains 4.5% sulfur as well as vanadium and nickel.

Heavy crude oils contain more carbon in relation to hydrogen, thus releasing more carbon dioxide (a greenhouse gas) per amount of usable energy when burned. However, because crude oil is refined before use, generating specific alkanes via cracking and fractional distillation, this comparison is not valid in a practical sense. Heavy crude refining techniques may require more energy input, though, so its environmental impact is presently much more significant than that of lighter crude.

With present technology, the extraction and refining of heavy oils and tar sands generates as much as three times the total CO_2 emissions compared to conventional oil, primarily driven by the extra energy consumption of the extraction process (which may include burning natural gas to heat and pressurize the reservoir to stimulate flow).

Heavy Oil Production Methods

Several, different production technologies have been developed for commercial exploitation of heavy oil; there are also many techniques in research or pilot development.

A general characteristic of all heavy oil reservoirs is that the oil mobility ratio, i.e. relative permeability of oil to oil viscosity ratio (k/μ), is very small. This is majorly due to the high viscosity of the heavy crude. As a consequence, the oil in-flow to well-bore is zero or negligible.

Thus, the primary aim of any heavy oil production technique is to increase the mobility ratio to such a value that encourages oil in-flux into the well-bore and ensuing lifting of oil to the surface. This can be carried by either substantially increasing the permeability or decreasing the viscosity of oil.

The remaining characteristics of heavy oil resources, however, can be markedly different. Hence, each production method must be tailored for the particular reservoir and for its fluid properties. Therefore, it is essential that the properties of the particular reservoir be completely understood before selecting a production scheme. These properties include:

1. Oil properties - composition, density, viscosity, and gas content.

2. Petro-physical and geomechanical reservoir properties-porosity, permeability (vertical and horizontal), rock strength, presence of shale layers and the variation of these properties across the reservoir.

3. Geological setting - depth, areal extent and thickness of the resource.

4. Presence of bottom water or top gas zones.

Classification:

Heavy oil production methods can be classified into surface mining and well (Subsurface) production.

- Surface (or open-pit) mining technique is useful for exploitation of very shallow heavy oil reservoirs.
- Primary subsurface production methods include: thermal production and cold (i.e. non-thermal) production.

In addition, there is ongoing research and development of new in situ production methods that are not yet commercial. These include hybrid methods with mixed steam and solvent, supercritical fluids, electric resistance, induction and radio-frequency heating, downhole steam generation, alternative fuels to natural gas, and in-situ upgrading.

Each of the 2 primary classifications of heavy oil production techniques, their sub-categories and certain examples, are described below in detail

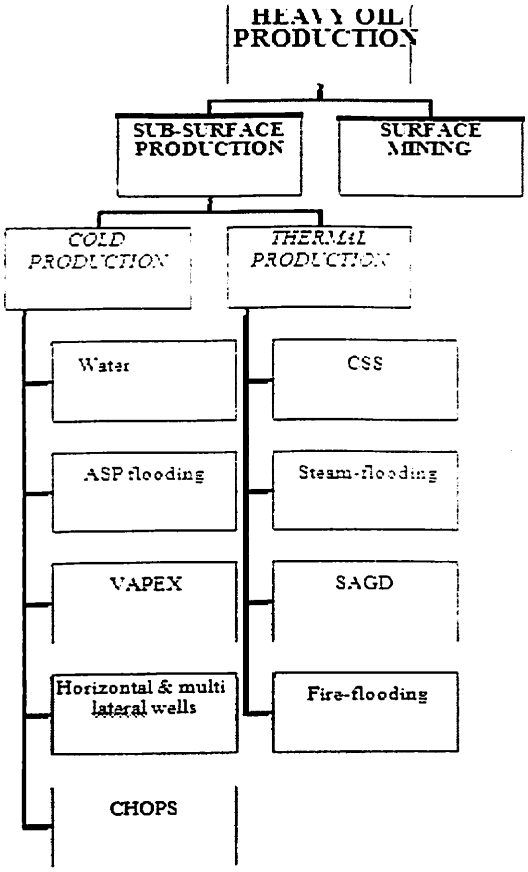


Fig: Classification of heavy oil production techniques.

Surface (Open Pit) Mining:

Application:

If the resource lies within 50 to 75 m of the surface, then open-pit mining is the only commercially applicable production method. Approximately 10% of the heavy oil and bitumen in Western Canada can be recovered by this method.

Process:

- ✓ In open-pit mining, the overburden formation is excavated, and later used for land-fills or such activities. Large shovels and trucks are used to load and transport the unconsolidated oil sands from the mine face to an ore crusher.

- ✓ After being crushed into 12 inch or smaller chunks, the ore is slurred with water in a cyclofeeder. The slurry is sent by pipeline (hydro transported) to a central processing facility for upgrading. The bitumen, sand and water mixtures create emulsions which are extremely difficult to separate, and the process of separating oil from the sand particles begins during hydro transport.

- ✓ This process is continued in the primary separation vessel (PSV) at the central facility. Bitumen froth (60% bitumen, 30% water, 10% fine solids) is removed from the PSV and then is either processed with naphtha or paraffinic solvents to remove water and fine solids. The paraffinic solvent process results in bitumen with less than 0.1% water and fines remaining.

- ✓ Clean sand from the PSV is removed and stockpiled. A combination of mixed bitumen and water, fine particles and clay (fine tailings) is transported to a holding pond. The fine tailings take a very long time to dewater.

Cold Production:

As the name clearly implies, cold production of heavy oil does not involve injection of heat into the reservoir; in other words, these methods are non-thermal.

(i) Alkali-Surfactant-Polymer Flood (ASP Flood):

ASP flooding is a new technique developed on the basis of alkali flooding, surfactant flooding and polymer flooding, and so it makes use of the benefits of the above three flooding methods, thus enhancing the oil recovery. This is done greatly by decreasing interfacial tension, increasing capillary number, enhancing microscopic displacing efficiency, improving mobility ratio and increasing macroscopic sweeping efficiency.

Application:

One of the main problems in oil recovery from oil-wet reservoirs is to overcome the surface tension forces that make the oil difficult to be extracted from rocks. In water-wet reservoirs, surface tension forces create bubbles of oil, which in turn may block the pore passages thus reducing the surface area. Thus this surface tension forces tends to reduce the permeability of oil in the reservoir, relative to water. If the interfacial tension (IFT) can be reduced between the oil and the driving fluid, then the resistance of oil flow is reduced.

Process:

In ASP flooding (Alkaline-Surfactant-Polymer), the polymer is injected to increase the sweep efficiency of the invading fluid by changing the mobility ratio between the invading fluids versus displaced fluid. The surfactant is used to change the wet ability of the formation rock and reduce the interfacial tension (IFT).

In a vertical heterogeneous reservoir, the ASP agents initially flow in the high permeability layer, and fluid changes the flow direction toward the low and the middle permeability layers because the resistance in the high permeability layer is increased under the physical and chemical action of adsorption, retention and emulsion.

ASP flooding displaces the residual oil in the high permeability layer as well as the remaining oil in the low and the middle permeability layers by increasing the volume swept and, thereby, the displacing efficiency.

Mechanism:

It is observed that the main mechanisms of ASP flooding in water-wetting reservoir are deformation, threading, emulsion (O/W) and strapping; while in oil-wetting reservoir the main mechanisms of ASP flooding are interface producing, bridging between inner-pore and outer-pore, emulsion (O/W).

Because ASP agents reduce interfacial tension, the residue oil of each layer is displaced to form oil bank (reserve). The formation time in each layer is generally the same and the movement velocity in the high permeability layer is higher and so this oil bank is earlier to reach the producing well than those in the middle and low permeability layers. So the oil recovery of the high permeability layer increases and the water cut decreases. The flow rate in the middle and low permeability layers is relatively slow; therefore the oil bank reaches the producing well later. The oil recovery of the middle and low permeability layers increases with time.

(ii) Cold Production via Horizontal and Multi-Lateral Wells:

Application:

Horizontal wells have been used to produce thin zones, fractured reservoirs, formations with water and gas coning problems, water-flooding, heavy oil reservoirs, gas reservoirs, and in EOR methods such as thermal and CO_2 flooding.

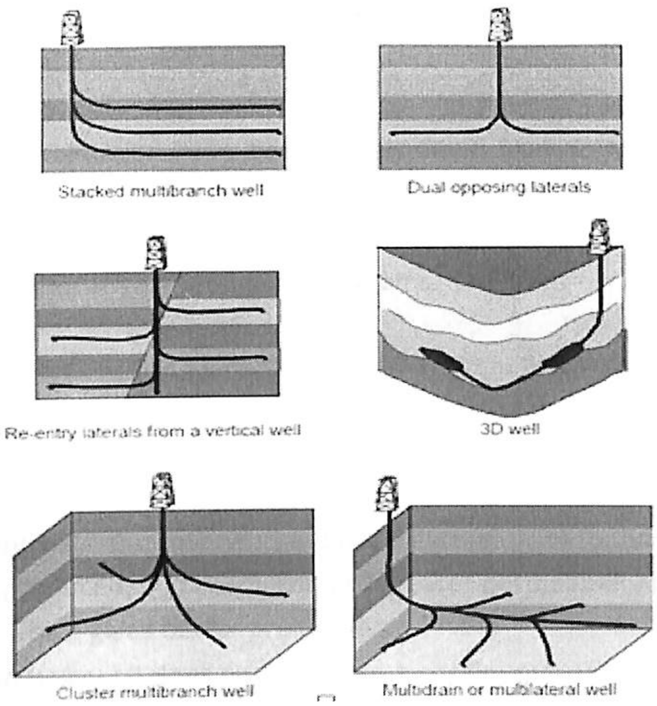
Multilateral wells have various shapes and offer the possibility of different types of completions to isolate and control production from different branches of multi-laterals. In recent times, large scale multi-lateral applications are seen in heavy oil reservoirs (where wells are completed with slotted liners) and in carbonate reservoirs using open-hole completions. The main advantage to the use of multilateral wells compared to conventional horizontal wells is cost reductions.

In combination with enhanced oil recovery methods or with assisted gravity drainage, horizontal and multilateral wells can provide means to produce more oil at an economical cost. Applications to actual field cases are provided to illustrate the potential of horizontal and multilateral wells and of their synergy with EOR methods.

Process:

The first goal of horizontal and multilateral well is to improve the primary production through increasing the reservoir exposure and accelerating recovery. In coning situations, such as production of oil reservoirs with a bottom aquifer or a gas cap, utilization of multilateral wells will reduce the detrimental coning effect, then leading to reduction in investment and operating costs.

Horizontal and multilateral wells yield higher production rates and reserves as compared to vertical wells, resulting in lower operating cost per barrel of oil produced. To produce the same amount of oil, one needs fewer horizontal wells as compared to vertical wells. This results in reduced need for surface pipelines, locations, etc.



Stacked multibranch well
Dual opposing laterals
Re-entry laterals from a vertical well
3D well
Cluster multibranch well
Multidrain or multilateral well

(iii) Cold Heavy Oil Production with Sand (CHOPS):

Application:

CHOPS (Cold Heavy Oil Production with Sand) is now widely used as a 'quasi-primary' production approach in unconsolidated sandstones, and many thousands of wells in Canada are now stably producing oil through CHOPS.

Process:

Instead of blocking sand ingress by screens or gravel packs, sand is encouraged to enter the wellbore by aggressive perforation and swabbing strategies. Wells (vertical to 45°) are operated with rotary progressive cavity pumps, rather than reciprocating pumps, giving much greater production boosts.

Typically, a well placed on CHOPS production will initially produce a high percentage of sand, greater than 10% by volume of liquids; however, this generally decays to 0.5 - 3% sand by volume (more for lower API gravity oils which are more viscous) after some weeks or months.

The huge volumes of sand are disposed of by a new technology, Slurry Fracture Injection (SFI), recently developed in Canada, and this has proven to be critical to the economics of cold production. SFI involves injecting the waste sand as aqueous slurry back into the deep formations from where it came.

Operating costs for cold production have been driven down from CAN $12-13/bbl in 1987-91 to CAN $5-7/bbl in 1999-2000, raising the profitability of small heavy oil projects. These massive cost reductions have been implemented mainly in small companies, although now large companies have instituted and carried out similar cost reduction programs.

Mechanism:

CHOPS increases productivity for four reasons:

- When sand is removed from reservoir, the basic permeability to fluids is enhanced.
- As more sand is produced, a growing zone of greater permeability is generated, similar to a large radius well which gives better production.
- Gas ex-solution in heavy oil does not generate a continuous gas phase; rather, bubbles flow with the fluid (and sand) and do not coalesce, but expand down-gradient, generating an internal gas drive, referred to as 'foamy flow'.
- Continuous sand production means that asphaltenes or fines plugging of the near-wellbore environment cannot occur (no possibility of a 'skin' effect which impairs productivity), which inhibit the free flow of liquids.

Interestingly, it has been observed that if sand control methods are installed to prevent sand ingress, oil production will drop to uneconomic levels. Productivity, in some cases, has increased to as high as 10 to 20 times over conventional primary production. Also, 12-20% of OOIP can be developed via CHOPS, rather than the 0-2% typical of primary production in such cases. Finally, because massive sand production creates a large disturbed zone, the reservoir may be positively affected for later implementation of thermal processes.

(iv) Pressure Pulse Technology (PPT):

A radically new aspect of porous media mechanics was discovered and developed into a production enhancement method in the period 1997-2002, based on theoretical developments carried out at the University of Alberta in the period 1985-1995.

Process:

Pressure pulse flow enhancement technology (PPT) is based on the discovery that large amplitude pressure pulses that are dominated by low-frequency wave energy generate enhanced flow rates in porous media. For example, in heavy oil reservoirs in Alberta, PPT has reduced the rate of depletion, increased the oil recovery ratio, and prolonged the life of wells. Also, it has been found that very large amplitude pressure pulses applied for 5-30 hours to a blocked producing well can re-establish economic production for many months, and even years.

Mechanism:

The mechanism by which PPT works is to generate local liquid movement into and out of pores, through the propagation of a porosity dilation wave. As the porosity dilation wave moves through the porous medium at a velocity of about 40-80 m/s, the small expansion and contraction of the pores with the passage of each packet of wave energy helps unblock pore throats, increase the velocity of liquid flow, overcome part of the effects of capillary blockage, and reduce some of the negative effects of certain instabilities such as viscous fingering, coning, and permeability streak channeling.

Although very new, PPT promises to be a major adjunct to a number of other heavy oil production processes.

(v) Vapor Assisted Petroleum Extraction (VAPEX):

Application:

The vapor extraction (VAPEX) process warrants attention because of its applicability to recover viscous oil in the cases when steam assisted gravity drainage fails due to the presence of bottom water aquifer, low heat conductivity, thin pay zone, and excessive heat losses to the adjacent formations.

Process:

In vapor extraction or VAPEX, solvents are used to reduce the viscosity of heavy oil and bitumen as an alternative to thermal process such as SAGD. VAPEX is more frequently used where the paraffin content is more in the oil, as using only steam is not as much effective. VAPEX performance can be significantly impacted by asphaltenes precipitation including reduced permeability and plugging of the formation. Low energy consumption, less environmental pollution, in situ upgrading, lower capital costs, etc., make the process superior to the currently used thermal processes.

The VAPEX process involves the injection of a vaporized solvent into a horizontal well located in the upper portions of the oil reservoir. The solvents are made of hydrocarbons that originally come from oil reservoirs so they are not harmful to the reservoir, and they cannot escape the reservoir. The solvents are recovered with the oil and recycled, so they are not released to the atmosphere. The solvent dissolves (by diffusion/dispersion) into the heavy oil reducing its viscosity and creating an expanding solvent vapor chamber. The diluted oil then drains down the edges of the chamber by gravity to a vertically aligned lower horizontal production well where it is pumped to the surface. Using vapor gas solvents, however, has certain advantages. In VAPEX, no heat or water is used.

Mechanism:

The basic mechanism of the process involves the following steps:

- Dissolution of solvent vapor at the solvent-bitumen interface.
- Diffusion of the dissolved solvent into the bulk of bitumen.
- Dissolved and diffused solvent dilutes the viscous oil and reduce the viscosity.
- If the solvent concentration is high enough the oil is de-asphalted in-situ.
- The diluted (and de-asphalted) oil drains to the production well by gravity.

In porous media, the process takes place in a contact zone. In this zone, the high viscosity oil contacts the solvent vapor in fine capillaries that offer a higher interfacial area of contact. The process involves temporary diffusion of solvent into the bitumen at the interface. As soon as the oil at the interface attains mobility due to viscosity reduction, it drains, exposing a new interface of bitumen having a very low concentration of solvent. Surface renewal, aided by capillary imbibitions, yields a higher mass transfer rate that enhances the rate of extraction.

In this process, production rate is directly related to the amount of solvent dissolved and diffused into bitumen. One important aspect of this process is de-asphalting that yields in situ upgraded oil reducing many downstream problems. The extent of de-asphalting also depends on the amount of solvent. The solubility of a vaporized solvent is at its maximum near its dew point pressure. Hence, the solvent pressure should be as close as possible to its vapor pressure at the reservoir temperature. If the dew point pressure of the solvent is lower than the reservoir pressure, the solvent liquefies and fills the extracted sand matrix with liquid solvent.

Thermal Production:

Heavy oil viscosity decreases rapidly with increasing temperatures, therefore external heat may be required for production. High-temperature steam is commonly used to deliver heat to the formation; water being readily available and having a high latent heat of vaporization. The steam oil ratio (SOR) or fuel oil ratio is an important measure of the energy required to produce heavy oil in such cases. SOR is defined as the volume of steam injected (STB water equivalent) per STB of oil recovered.

One barrel of oil can evaporate about 15 barrels of water, if burned under 100% thermal efficiency. Obviously for thermal projects to be profitable, the steam - oil ratio should be much lower.

Certain thermal techniques applied for heavy oil production are:

(i)Steam-Flood:

Steam-flooding, steam drives or steam displacement is an important heavy oil recovery method. Steam-flooding is analogous to water-flooding, in that steam is injected on a pattern basis, much like water-flooding.

Application:

Steam-flooding can be successfully implemented in reservoirs having the following characteristics:

CRITERIA	VALUES
Formation Thickness (h), ft	>30
Depth, ft	<3000
Porosity, %	>30
Permeability (k), md	4000
Oil saturation, bbl/sc-ft	1200-1700
API Gravity	13-25
Oil viscosity at reservoir conditions (μ), cp	<1000
Steam Pressure, psig	<2500
(kh/μ)	30-3000

Along with these criteria, the pattern size is an additional important consideration in a steam drive, since it would determine the heat loss, via the flood time. Reservoir pressure is another significant factor, since high pressure would require high steam pressures, and hence the attendant disadvantages of high temperature would be called into play. Ideally, reservoir pressure should be low and steam injectivity high, thus pointing to high permeability, and small formations.

Mechanism:

Consider an inverted five-spot pattern, consisting of a centre steam injection and four producing corner wells. As steam is injected into the reservoir via the center well, an expanding steam-zone is formed, the extent of which is calculated. The hot condensate, leaving the steam zone creates a hot water-flood effect ahead of the steam zone. Finally, as the condensate cools down to the formation temperature, it gives rise to the cold water-flood.

Thus, the steam drive process consists of steam zone, a hot water-flood zone and a cold water-flood zone in the remaining pattern volume. Oil recovery in this process is the result of different mechanisms operating in each zone.

The most important part of a steam drive is the steam zone, which is approximately at a constant temperature 'Ts'. The oil within this region is highly mobilized, and displaced by the gas drive effect of the steam. The oil saturation in the steam zone is reduced from initial steam saturation 'S_{oi}', to a steam-flood residual saturation, 'Sorst'. Thermal expansion of the oil further helps increase its mobility; steam distillation of lighter fraction also occurs, further lowering the oil saturation. Other complex effects such as the relative permeability of oil increases, and that to water decreases, as a result of a temperature increase.

The displaced oil is banked up ahead of the steam zone in the condensate zone. Prior to invasion by steam, a given portion of the sand has already been swept by cold water, and then, by the hot water. These flooding processes begin the oil recovery. In effect, the advancing steam sees the same oil saturation, whether the formation is previously water-flooded or not.

As a result, the steam flood residual oil saturation is usually independent of the initial oil saturation and rather strongly dependent on temperature and also on oil viscosity. Oil recovery is expected to decrease with an increase in the oil viscosity. At given initial oil saturation high or low, oil recovery would decrease with an increase in steam temperature. This is attributed to the low specific volume of steam at higher pressures, as well as the lower latent heat content.

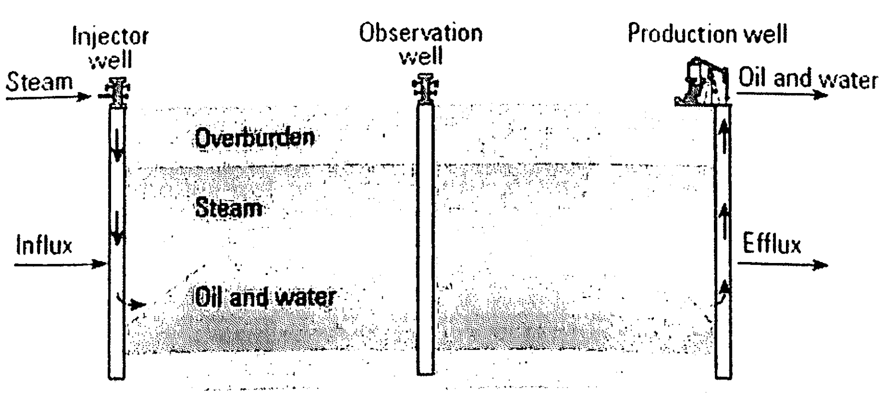


Fig: Steam-flood.

(ii)Cyclic Steam Stimulation (CSS):

Cyclic steam stimulation is the most widely used steam injection method for heavy oil recovery. The method is so popular because of the relative ease of the application of this method, low initial investment and quick return. The ultimate recovery factor is considerably less than that achieved by the steam drive method. Ideally, a combination of cyclic steaming and steam drive could offer the advantages of each process.

Application:

Although it is difficult to set any specific reservoir characteristics that would guarantee success of cyclic steaming, a rough criterion has been made on the basis of the successful projects undertaken with this method

CRITERIA	VALUES
Formation Thickness (h), ft	>30
Depth, ft	< 3000
Porosity, %	>30
Permeability (k), md	1000-2000
Oil-saturation, bbl/sc-ft	1200
API Gravity	<15
Oil Viscosity at reservoir conditions (μ), cp ≤4000	
Steam Pressure, psig	<1400
(kh/μ)	<200

These factors should be considered along with others, viz. reservoir geology (shale barriers, underlying water, and permeability stratification), drive energy, and certain reservoir characteristics (pressure, gas, saturation).

Process:

Consider a well initially producing at a very low rate or ideally not at all producing. Steam is then injected into the well at the highest possible rate to minimize heat losses, for several weeks. This period of injecting the steam is known as 'huff' period.

After injecting the desired volume of steam, which is usually expressed as equivalent water barrels, the well may be shut in for about a week. This period is known as 'soak' or 'puff' period.

The well is then placed on production by means of a suitable lifting technique. If the reservoir pressure is high enough, oil will be produced at a rate much higher than the original rate, simply as a result of increased oil mobility. As the oil in the heated zone is pumped off, replacement occurs due to oil flow from the surrounding cold formation.

The well thus produces for an extended period of time, at a rate many times the cold production rate. With the passage of the time, the steam-heated sand cools down as a result of heat losses and production rate declines.

When production rate drops to uneconomical levels, the whole cycle of injecting steam, soaking the well and again producing it, is repeated. As many cycles can be conducted as may be possible while keeping profitable outcomes in mind.

Mechanism:

The steam injected into the reservoir heats the rock and the fluid around the wellbore. It fingers into the formation due to gravity segregation, preferential injection into high permeable strata and adverse viscosity ratio. It can also be assumed that a certain volume of the sand is heated to a uniform temperature for performance calculations.

The soak period promotes partial condensation of steam, thereby heating the rocks and the fluids, as well as achieving even distribution of the injected heat. Calculating effective soak period is important for cyclic steaming because the amount of steam condensed in such a short period is quite small on one hand, and the soak period represents a loss of oil production on the other hand.

During the steam injection and soak periods, the original oil viscosity is lowered by many folds to, perhaps, a few centipoises within the steam zone. Due to the steam injection, thermal expansion of oil and water occurs; and the expansion of oil being greater, the oil production increases.

The fluid flow direction alternates during a cycle, since the injected steam flows outward while the mobilized oil flows into the well-bore. The conductive heat, whereas, flows continually outward from the steam zone into the virgin sands, since such heat flow is only governed by a temperature gradient. As a result, the oil in the cold portions of the reservoir, though unaffected by steam, is gradually heated, and the oil is mobilized on a regional basis.

As can be observed from the following figure, the total oil production declines from cycle to cycle, since the production of oil is largely derived from the same general heated volume. With increasing cycles, water production rate increases, thereby reducing oil production. On an average, 50% of the injected water may be retained by the formation.

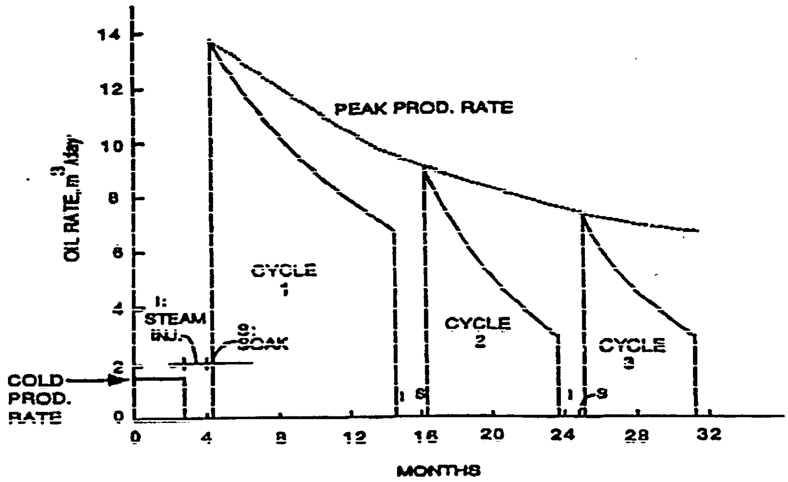


Fig: Typical oil production in cyclic steam stimulation.

(iii) Steam Assisted Gravity Drainage (SAGD):

Application:

SAGD is utilized where the heavy oil is essentially immobile due to very high viscosity, and involves drilling two horizontal wells at the bottom of a thick sandstone reservoir.

Process:

- Heat is applied via slow injection of steam into the reservoir from the upper horizontal well, leading to in-situ development of a 'steam chamber'. Injection pressures are much lower than the fracture gradient, which means that the chances of breaking into a thief zone are essentially zero.
- The heat and steam rise, whereas condensed water and mobilized oil flow downward through the porous medium due to the counter current, gravity-driven flow. These fluids are then produced through the lower horizontal well.
- This process is extremely stable because the steam chamber grows only by upward and lateral gravity segregation and there are no pressure-driven instabilities (channeling, coning and fracturing).

SAGD also seems to be insensitive to shale streaks and horizontal flow barriers that otherwise would seem to be serious impediments to the success of the technology. As the rock is heated, differential thermal expansion causes the shale's to be placed under a tensile stress, and vertical fractures are created, which serve as conduits for steam (up) and liquids (down). Furthermore, as high steam temperatures hit the shale, instead of expanding thermally, dehydration and de-hydroxylation (-OH + HO- ⇒H2O + -O- bonds) lead to volumetric shrinkage of the shale barriers, opening the induced vertical fractures even more. Thus, the combined processes of gravity segregation and shale thermal fracturing make SAGD so efficient that recovery ratios of 50-75% are probably achievable in appropriate cases (thicker horizontal sandstone reservoirs, porous-flow dominated except for the shale's).

(iv)Fire-Flood (In-situ Combustion):

Application:

This method is applied to reservoirs containing oil too viscous to be produced by conventional means. Burning some of the oil in-situ creates a combustion zone that moves through the formation toward production wells, providing a steam drive and an intense gas drive for the recovery of oil.

Process:

In-situ combustion involves the injection of enriched-air or oxygen to enable combustion of oil within the reservoir, creating chemical reactions and the release of CO_2. Heat ahead of the combustion front reduces viscosity and some in-situ distillation (upgrading) occurs. CO_2 created during combustion can also assist, by increasing pressure and mixing with the oil, further reducing viscosity and aiding flow.

After heating the surrounding rock, the heater is withdrawn, but air injection is continued to maintain the advancing combustion front. Water is sometimes injected simultaneously or alternately with air, creating steam which contributes to better heat utilization and reduced air requirements. The combustion and production zone between injection and production well is typically tens of feet wide. The combustion front is at around 800°–1000°F (430°–540°C). Sand screens and perforated pipe can handle these temperatures. The completions materials (eg: packers) are kept in the vertical section, where the produced oil is cooler, typically around 300°F (150°C).

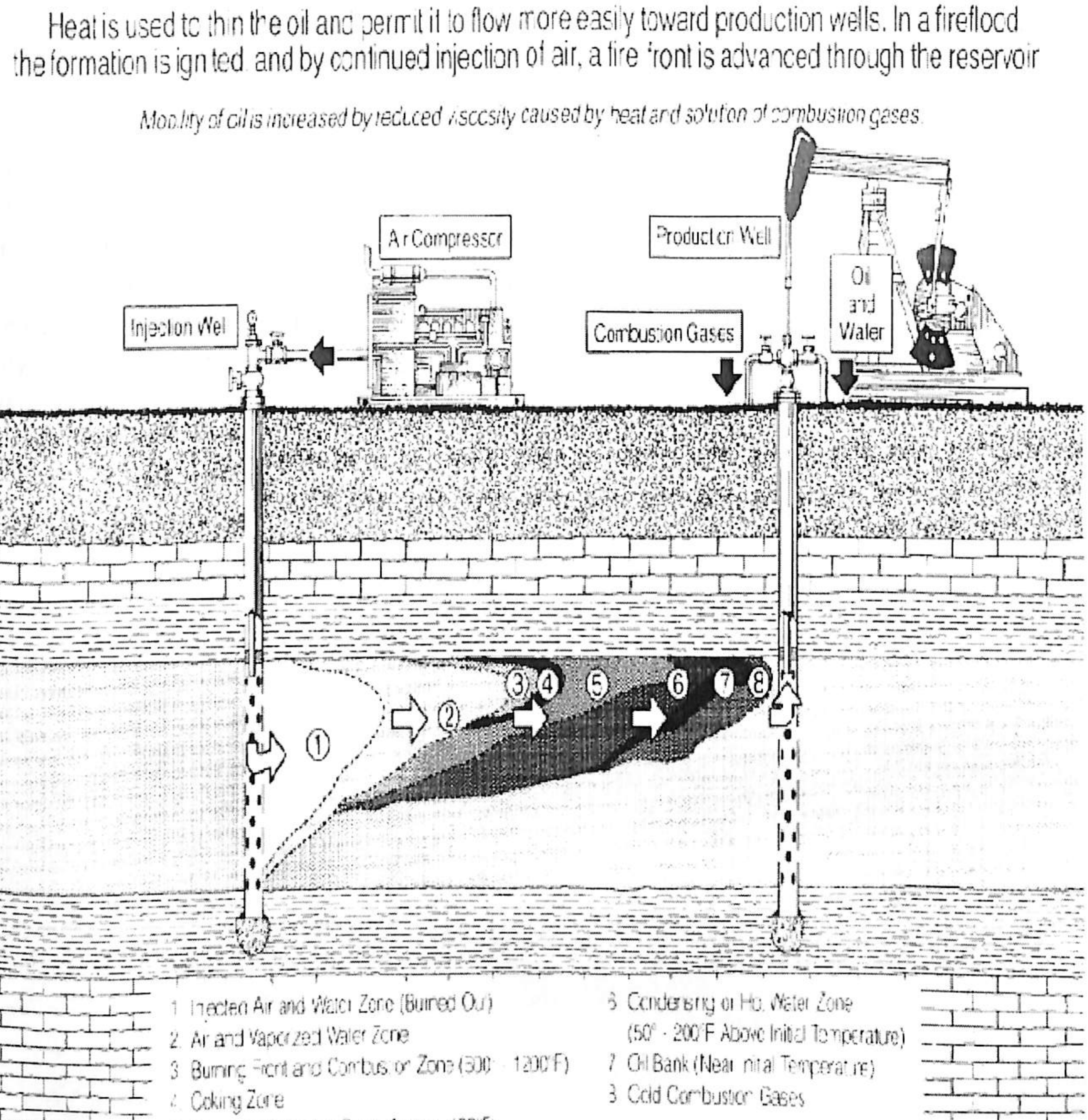
Mechanism:

Many interactions occur in this process, but the accompanying figure shows the essential elements. The numbered statements below correspond to numbers on the figure:

1. This zone is burned out as the combustion front advances.
2. Any water formed or injected will turn to steam in this zone because of residual heat. This steam flows on into the unburned area of the formation, helping to heat it.
3. This shows the combustion zone which advances through the formation.
4. High temperature just ahead of the combustion zone causes lighter fractions of the oil to vaporize, leaving a heavy deposit of residual coke or carbon as fuel for the advancing combustion front.

5. A vaporizing zone that contains combustion products, vaporized light hydrocarbons, and steam.

6. In this zone, owing to its distance from the combustion front, cooling causes light hydrocarbons to condense and steam to revert back to hot water. This action displaces oil, condensed steam thins the oil, and combustion gases aid in driving the oil to production wells.



7. In this zone, an oil bank (an accumulation of displaced oil) is formed. It contains oil, water, and combustion gases.

8. The oil bank will grow cooler as it moves toward production wells, and temperatures will drop to that near initial reservoir temperature.

When the oil bank reaches the production wells, the oil, water, and gases will be brought to the surface and separated – the oil to be sold and the water and gases sometimes re-injected. The process will be terminated by stopping air injection when pre-designated areas are burned out or the burning front reaches production wells.

Hybrid Methods:

Hybrid approaches that involve the simultaneous use of several of these technologies are evolving and will see great applications in the future.

For example, a period of primary exploitation using CHOPS can be substantially extended (producing more OOIP) using pressure pulsing. Then, after the primary phase is essentially complete, a period of gravity drainage, aided by inert gas injection and steam injection, could be used once the initial reservoir pressure is re-established. Different exploitation phases and the use of hybrid approaches may well allow the production of as much as 30-50% of the heavy oil in good quality reservoirs. Furthermore, the technologies developed for heavy oil will also be useful for conventional oil.

CASE ANALYSIS

Cold Production of Heavy Oil from Horizontal Wells in the Kharsang Oil Field

Brief History & Introduction:

The Kharsang oil-field (KSG) is located in the Changlang district of Arunachal Pradesh, India. Kharsang was discovered by Oil India Limited in 1968. In June 1995, the consortium comprising of GeoEnpro Petroleum Ltd., Enpro India Ltd. and Geopetrol International Inc. in a joint venture with Oil India Ltd., entered into a 25 years Production Sharing Contract (PSC) with the Government of India for the development of Kharsang oil-field (KSG).

KSG is a medium sized field with an area of 10 Sq.Km. and is located about 40 Km. east of the Digboi oil-field. This oil field is at an altitude of approximately 200 m above MSL with tropical, moderate and humid climate. Till date, total 56 wells have been drilled to depths ranging from 700 m to 3700 m. Out of the 56 wells, 32 are currently yielding oil, while the remaining have either been abandoned or are in the work-over phase.

Present average production rate of Kharsang oil-field is around 330 kilo-liters of oil per day (klopd), with individual wells contributing from 1 to 40 klopd (1 kl = 1 m^3). The cumulative production of oil till March 2006 was 0.860 million metric tons(MMT). The crude produced ranges from 16° - 39° API. The wax content and composition of crude varies from well to well. In general, the H_2S and CO_2 contents are negligible in the produced hydrocarbons.

A reservoir/geological study had been undertaken earlier by Institute of Reservoir Studies (ONGC) in 1986. Based on this study, 15 sand layers have been interpreted as hydrocarbon bearing in the Girujan formation, out of which 6 sands are major sands; and in the Namsang formation, there are 7 hydrocarbon bearing sand layers. In-house reserve estimations were done in 2001 and 2006.

Reservoir Geology:

As mentioned earlier, KSG is situated about 40 km. east of the Digboi oil-field in Changlang District of Arunachal Pradesh. KSG falls in the Belt of Schuppen and is geologically very complex owing to the Margherita Thrust and its associated faults.

The stratigraphic sequence consists of:

- Barail (Boragolai Formation):
    - Thickness: 400m.

- Namsang Formation:
  - Thickness: 400m.
  - The Namsang Formation is over thrust by Barail Group along Margherita Thrust. The thrust zone is composed of crushed sandstones with pebbles, gritty sandstones and dark grey shales with occasional bands of coal seams.

- Girujan Clay Formation:
  - Thickness: about 1900m.
  - Girujan overlies Tipam and is composed of medium to fine grained sandstone with bands of mottled clays.
  - Girujan is unconformable overlain by Namsang Formation which comprises medium to coarse grained sandstones with brownish and bluish clays. The unconformity above Girujan is pronounced as an erosion angular unconformity.

- Tipam Sandstone Formation:
  - Thickness: 800m.
  - The Tipam Formations consists of sandstone and shale alterations with clay bands.

Hydrocarbon accumulation is encountered mainly within Girujan Formation in KSG, at a shallow depth range of 600 – 1500 m. A few sand layers of Namsang are also hydrocarbon bearing. Evidences of hydrocarbons have also been encountered in the supra-thrust Barail formation and in highly unconsolidated crushed thrust zones at very shallow depths. However, commercial accumulations have been found in Girujan and Namsang only.

General Geology:

Margherita Thrust and Supra-Thrust Formation:

The older Barail formation (Oligocene age) were brought over the younger Namsang formation (Mio-Pliocene age) and near surface by the Margherita Thrust. This thrust is the major structural element in this field which is one of the major thrust faults associated with Naga-Patkai orogeny. Both the Barails and the Margherita Thrust generally dip towards south and the amount of dip is around 15º towards S 45º W.

Sub Thrust Formations:

Namsang Formation essentially consists of clay of variegated color and semi-consolidated sands. The average dip of Namsang Formation is about 35º towards SSE.

The Girujan formation (Miocene age) underlies the Namsang Formation. This formation comprises alterations of fine to medium sands and bluish grey clays. Mottled nature of clay is a characteristic feature of this formation. Comparatively the Girujans are more consolidated than the Namsangs. X-ray diffraction analysis of Girujan Clay samples revealed that major constituent of Girujan is montmorrilonite (50-60%) and minors are illite (10-20%), kaolinite (10-20%) and expandable mixed layer clays (15-20%). These constituents affect the bore-hole stability in the wells drilled in Kharsang Oil Field.

Formation water salinity ranges from 1000 to 2000 ppm (Nacl) in the depth range of 700-1300 m. The average dip of the Girujan Formation is about 20º towards NNE, indicating presence of a substantial angular unconformity between Girujan and Namsang formations.

UNIT	AGE	GROUP	FORMATION	THICKNESS	LITHOLOGY	RESERVOIRS
	Recent	-	Alluvium	10-50 m	Unconsolidated Sand/Clay	
Supra Thrust	Oligocene / Eocene	Barail Group	Boragolai	225-550 m	Mudstone/ Sandstone/ Coals	Non Commercial Shows
Margherita Thrust	Thrust Zone	-	-	20-88 m		Cataclastic Non Commercial Shows
Sub Thrust	Miocene / Pliocene	Dupi Tila	Namsang	225-525 m	Poorly consolidated Sandstone in Clay/Lignite	Local hydrocarbon-bearing sands of limited extent.
	Miocene	Tipam	Girujan Clay	500-2030 m	Mottled clay and Sandstone lenses	Main hydrocarbon bearing sands, oil 17-40 °API
			Tipam Sandstone	790+	Sandstones And Shales	Gas/Condensate/Oil Shows (only one well penetrated-KSG # 2)

The reservoir pressure in KSG is generally about 15% higher than the hydrostatic pressure down to a depth of about 1500 m. The pressure gradient is around 0.54 psi/ft which is calculated from measured bottom-hole pressure.

The static BHT at 1500 m is expected to be around 45- 50ºC. The geothermal gradient of Kharsang area is about 2ºC/100 m. Majority of the strata in Kharsang area have appreciable dips.

The stratigraphy in KSG is properly illustrated in the following table:

Structure:

Kharsang structure is a NW-SE trending anticline and the drilled area is a part of the North-Eastern flank of the structure. The Margherita Thrust is the most important structural element in Kharsang area and the strike & dip directions are respectively NE-SW & SE. This thrust fault is exposed in the north of the drilled wells and is encountered in the depth range of 200-500 m in the drilled wells. Thickness of this thrust ranges from 20-88 m. Due to effect of Margherita Thrust older Barails (Oligocene age) overlie the younger Namsang (Mio-Pliocene) & Girujan Formations (Miocene). Sub-thrust formations are affected by a number of associated faults and accordingly various fault blocks were formed.

Salient features of the Kharsang oil-field are highlighted below:

- Within the supra-thrust Barail Group, the dip direction is predominantly SE and the amount of dip in this section varies between 10-15º only.
- In the sub-thrust sections, formation dip of Namsang is 30-40º due SE while the structural dip is about 30-35º towards NE in the Girujan Formation. The change in the dip direction is indicative of an angular unconformity between Namsang and Girujan Formation. Structure contour map on the top of the sands shows that:
- o The Girujan beds continue to rise till they meet the Namsang - Girujan Unconformity.
- o General NW-SE dip has been indicated for the Girujan sands.

Two significant faults are present in the explored area of this structure. These faults divide the Kharsang Structure into three blocks, viz. Eastern, Central and Western Blocks. The Central Block is down faulted with respect to Eastern and Western Blocks, with the Western Block being the highest one. Hence, it may be interpreted from the above observations that the NW-SE trending Kharsang anticlinal structure is dissected by two NE-SW trending faults.

Correlation:

In KSG, oil and gas occurs in multi-layered reservoirs in, majorly, Girujan and Namsang formations. Stratigraphic correlations have been attempted taking the Namsang - Girujan unconformity as a datum and identifying natural sequences in sedimentary deposition in the form of sedimentary cycles separated by thick clays.

Girujan Formations:

Correlation of various sands in Girujan has been carried out on the basis of their log characteristics, lithology and fluid distribution. There are mainly three groups of sands:

- ✓ Upper Group (G-6 to G-22 sands): A & B layers to G-00 layer
- ✓ Middle Group (G-24 to G-60 sands): G-60 layer to J-00 layer
- ✓ Lower Group (G-70 to G-80 & Lower sands): G-90, G-100 O-00 layer to T-00 layer

Accumulations of oil and gas are within intercepted sand bodies, some of them are in the form of thin lenses. Oil accumulations in some reservoirs are associated with gas cap and edge waters. In some wells, occurrence of oil has been noticed in truncated Girujan sand bodies that have been affected by the Namsang - Girujan unconformity.

Namsang Formations:

From the stratigraphic correlations of Namsang formation, it is evident that the sands are lenses of limited extent.

Heavy Oil Reservoirs in ksg:

As mentioned earlier, the API gravities of the crude produced in KSG range from 16° to 40°. It has been found that the wells that produce oil of API below 20° have been drilled in 5 sand layers of the Upper Group of the Girujan formation, viz. the A-00, B-00, C-00, C-50 and D-00 layers. Moreover, out of these 5, the A-00 & B-00 layers have been identified to have the largest heavy oil reserves. Also, these layers lie at shallower depths. Hence, heavy oil production programs in A & B layers are being given top priority.

A & B Layers: General Information:

A & B layers are present only in the northeastern flank of the Kharsang field. As of 2006, the A+B layers contributed a cumulative production of 217 kls. It is noteworthy that the analysis of crude oil from both layers suggest that the crude is of low API values (between 16° to 18°), having low solution GOR.

As of 2006, the in-place oil reserves for A-00 and B-00 layers had been estimated at 2.899 million metric cubic-meters (MMM^3) and 2.253 million metric cubic-meters (MMM^3) respectively. One estimate had also determined that the net geological reserves of the A+B layers are more than one third of the total geological reserve of the Girujan reservoir. A & B layers essentially comprise of unconsolidated sandstones, intermittent with layers of clays and coal.

Layer A

5 wells had been drilled in Layer A. The formation thickness in each well varies, along with porosity, oil saturation and original oil in place. But certain properties remain constant, some of which have been tabulated below:

Area (sq.km)	Thickness (m)	porosity (%)	Average oil Saturation(%)	Drive Mechanism	OOIP (kls)	Estimated Recovery Factor (%)
1.253	20.25	23	50	Depletion drive	2,899,800	10

This layer had been tested in a well, where it flowed mainly water, but some oil was found during swabbing; possibly suggesting that this layer contains heavy oil which is difficult to produce. There remains a large reserve volume within this layer with a relatively extensive oil column. No commercial production has yet been initiated from this layer.

Layer B

5 wells have been drilled into layer B too. However, it has been perforated in only 2 wells. One of the wells yielded no production, even on application of PCP; while the other produced oil intermittently with help of PCP.

Area (sq.km)	Net pay thickness (m)	Average porosity (%)	Average oil saturation (%)	Drive Mechanism	OOIP (kls)	Estimated Recovery Factor (%)
0.79	30	24	52	Depletion drive	2,253,531	15

So the brief description of the layers is already done. Now with the help of the data interpretation should be done. After knowing the general information about the reserves we have to know which technique should be used in order to get maximum production from the well. So there will a certain selection criteria in order to choose the appropriate method. To ascertain which of the production techniques, some of which have been described earlier, should be applied in well X, a general criteria for each technique has to be fulfilled. Different techniques require different reservoir and oil characteristics. Moreover, availability of resources and economic aspect of the techniques also need to be factored in.

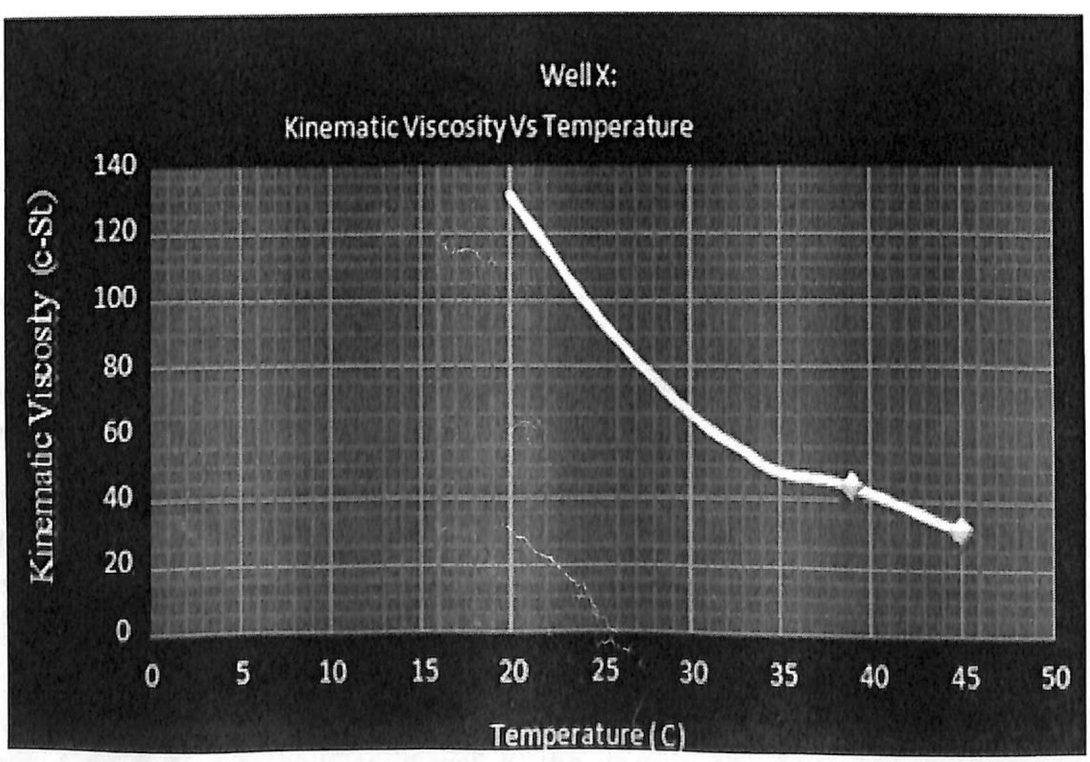
- Reservoir Parameters:
  - Reservoir Area (sq.km) : 0.053
  - Reservoir Depth (m) : 530
  - Reservoir Thickness (m) : 72
  - Net pay zone thickness (m) : 48
  - Oil Shale Contact (m) : 602
  - Porosity (%) : 22
  - Permeability (md) : 50
  - Oil Saturation (%) : 64
  - Reservoir Pressure (kg-f/cm^2) : 64.5
  - OOIP (kls) : 333,352
  - Cumulative Production till March 2006 (kls) : 208

- Crude Oil Characteristics:
  - API Gravity (°API) : 17.6
  - Specific Gravity : 0.948
  - BS & W (% vol) : 5
  - Water Content (% vol) : 4.8
  - Total Wax Content (% wt) : 0.39
  - Asphaltene Content (% wt) : 0.2
  - Resin Content (% wt) : 19.1

- Cloud Point (°C) : -36
- Pour Point (°C) : -39
- Bottom Hole Temperature (°C) : 33
- Oil Viscosity at BHT (cP) : 54.3
- Fluid Formation Volume Factor : 1.05
- Solution GOR at reservoir conditions (ft^3/bbl) : 125

- Other Well Details:
  - Drilling Floor : 210.54 m (amsl)
  - Total Depth : 1501 m (Drilling)
  - : 1498 m (Logging)
  - 7" Casing Shoe at : 1494 m
  - Cement rise below casing : 410 m from surface
  - 2" Tubing shoe at : 476 m
  - Packer at : 470 m
  - Top of Bridge Plug at : 725 m

- Viscosity – Temperature Profile:



Data Analysis:

Heavy oil viscosities are generally known to have values in excess of 500 cP. In some fields, viscosity of the oil is greater than even 3000 cP. However, in well X of KSG, the heavy oil viscosity at reservoir conditions has been found to be only 54.3 cP. Moreover, the value of the reservoir permeability (50 md) is very much comparable to that of the oil viscosity. The mobility ratio (k/μ) turns out to be 0.92, which is fairly high.

It can be clearly understood that in order to enhance the oil mobility and its in-flux into the well, the mobility ratio should be improved by increasing the reservoir permeability, rather than reducing the oil viscosity.

However, along with the influx of the oil, rampant sand ingress has also been observed. As has been seen repeatedly, the sand production in the well increases to such values that apart from significantly decreasing the production of the crude to the surface, it has destabilized the PCP, choked the perforations, weakened the cement bonding between reservoir and casing, and also led to water channeling into the well-bore.

Multiple work-over operations were carried out to check this nuisance of high sand influx, but none of them could permanently solve the problem. Hence, there is a vital need to install an efficient sand control and management technique.

Selection of Production Technique:

To ascertain which of the production techniques, some of which have been described earlier, should be applied in well X, a general criteria for each technique has to be fulfilled. Different techniques require different reservoir and oil characteristics. Moreover, availability of resources and economic aspect of the techniques also need to be factored in.

A general set of criteria for the production techniques has to be outlined in order to determine which is the most applicable. In the following table, certain well parameters and available technologies have been used as a basis to determine the production technique that is most suited for implementation in well X

The selection criteria have been segmented into two parts:

- **Well parameters:** A set of reservoir and oil properties such as formation temperature, depth, porosity, API gravity, oil viscosity, etc. The values of these parameters have been enlisted in the next column.

- **Available technologies:** The technologies necessary for the successful employment of the various production techniques in well X, the degrees to which these technologies are currently accessible to the company have been displayed in the adjoining column. The technologies comprise of:

Simulations and modeling: Being able to simulate and predict production rates, recovery factor, energy requirements, etc. Simulators require accurate data on properties of relevant fluids and the formation.

- ✓ **Geo-mechanics:** Measuring and understanding the formation and overburden, their mechanical properties under drilling and production conditions, for optimum field performance.

- ✓ **Downhole sampling:** Recovering fluids in-situ, without contamination, loss of constituents or degradation, for laboratory measurements and production planning.

- ✓ **Fluid characterization:** Determining the oil composition, gravity, viscosity, solution gas, etc.

- ✓ **Monitoring and control:** Ability to monitor and control the process, which is greatly beneficial for production methods involving heat, steam, solvent, etc.

- ✓ **Cementing:** The quality of the cement bonding between the formation and the casing. Some thermal production methods require cement capable of withstanding temperatures above 200°c.

- ✓ **Sand control:** Degree to which methods have been employed to keep the sand production in check.

- ✓ **Downhole flow control:** Devices being utilized to control the flow of fluids Downhole, such as sliding sleeves, expandable packers, controllable pumps, etc.

The table displays whether a particular technique can be employed, given the values of the various well parameters and the extents to which the required technologies are available. The ticks and crosses indicate whether the criterion of that technique has been fulfilled or not.

Eg: The value of formation temperature is not sufficiently high for water-flooding, but the cementing between the formation and the casing is good enough for the same technique. Similarly, the oil viscosity is too low for practicability of thermal processes like steam-flood, fire-flood and CSS.

Selection Criteria: Table

Criteria		Technique				
Well Parameters/ Technology Available	Value	Water-flood	Steam-flood	CSS	CHOPS	In-situ combustion
Formation temperature	33°C	x	✓	✓	✓	✓
Formation depth	530 m	✓	✓	✓	✓	✓
Formation Thickness	72 m	x	✓	✓	x	x
Porosity	22 %	x	x	x	✓	x
Permeability	50 md	x	x	x	✓	✓
API Gravity	17.6 °API	✓	✓	x	✓	✓
Oil Viscosity	54.3 cP	x	x	x	✓	x
Solution GOR	125 ft^3/bbl	✓	x	x	✓	✓
Simulations and modeling	Low	x	x	x	✓	x
Geo-mechanics	Medium	✓	x	x	x	x
Downhole sampling	High	✓	✓	✓	✓	✓
Fluid characterization	High	✓	✓	✓	✓	✓
Monitoring and control	Low	x	x	x	✓	x
Cementing	Medium	✓	x	x	✓	x
Sand control	Low	x	x	x	✓	x
Downhole flow control	Low	x	x	x	✓	✓

Here, some techniques have not been discussed due to the following reasons:

- ✓ Open-pit mining can be utilized only in shallow reservoirs (<50 m depth). Hence, it cannot be employed here.
- ✓ Techniques such as SAGD, VAPEX, cold production via horizontal or multi-lateral wells and in-situ combustion in horizontal wells are not feasible since they require drilling of new horizontal wells, a major constraint for the company, which is more interested in exploring a production technique that can be directly implemented in the existing wells. (For this reason, well X has been taken as a prototype in this project.)

Table Interpretation and Analysis:

It can be clearly interpreted from the table that the CHOPS method is the most suitable for implementation in well X. Also, the CHOPS technique will function effectively to achieve the desired results of increasing reservoir permeability and efficiently managing the sand production problem.

Moreover, CHOPS being a primary technique, it is economically much more feasible as compared to the other techniques discussed in the table. Techniques like water-flood, steam-flood and in-situ combustion involve usage of a vertical injection well. As mentioned, the company is not interested in drilling any new wells at the present moment; hence one of the currently producing wells will have to be used as the injection well, which may not be practically feasible.

CHOPS with PPT: Field Application:

It has been determined that the best production method for prototype well X in the Kharsang field is Cold Heavy Oil with Sand (CHOPS). We also recommend implementation of Pressure Pulse Technology (PPT) as a work-over operation, whenever the production rate due to CHOPS falls to uneconomic levels.

Hence, our recommendation is a hybrid of 2 techniques: CHOPS and PPT.

CHOPS:

Initiating and Sustaining Sand Influx:

To initiate sand in-flux in well X, the following steps are to be followed:

Large diameter perforations are to be made (20 mm), with spacing of 26 shots per meter. These perforations are to be placed in interval of 10m towards the bottom of the zone of net pay thickness (48 m).

A progressive cavity pump is to be placed, next, with its inlet (bottom of the 0.5m long tailpipe) 1-2m below the lowermost perforation. A reservoir-compatible fluid has to be filled into the annulus, initially keeping it completely full. The PCP is started and brought to a speed that allows sustained production of sand and oil (50 – 100 rpm, depending on sand cut). The fluid level in the annulus, thus, drops slowly while the pump runs at full capacity.

If sand in-flux does not occur, the following series of steps are to be followed to perturb the formation while the PCP is still in place:

Aggressive injection of lighter reservoir-compatible fluid into the annulus at higher rate has to be done. Heated compatible oil can also be rapidly injected. Simultaneous injection through tubing and annulus once the rotor is backed out of the stator.

If attempts to initiate sand ingress still fail, the pump is withdrawn from the hole and PPT should be carried out as a work-over method. PPT causes substantial disturbance to the formation, making it very effective in commencing or re-establishing sand ingress.

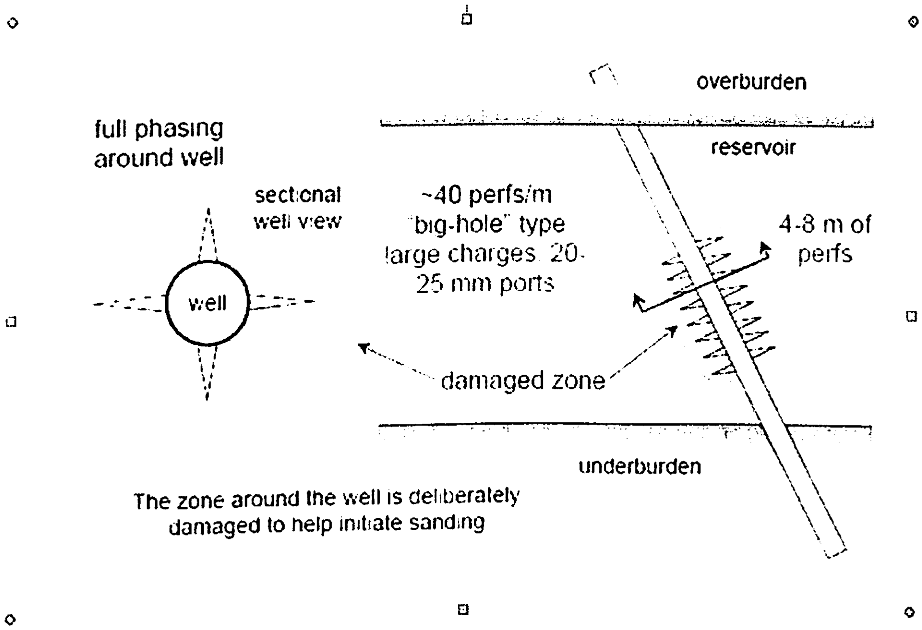


Fig: Perforations in CHOPS well.

Lifting Approaches: Description:

The main principle behind the working of CHOPS is encouraging the production of sand for increasing the production of heavy oil. So to lift the sand from the wellbore to the surface or actually from the reservoir to the wellbore and then to the surface, requirement of a proper pump is necessary.

The pump should be able to handle and lift the sand even at very high influx (may be >40%). Normal reciprocating pumps or sucker rod pumps are not able to lift this much amount of sand and tend to get stuck up due to high ingress of sand, thus requiring work-over operations frequently.

As the production history of well X suggests, the in-flux of sand into the well-bore is very high, easily above 40-45%. Consequently, the problem of the installed PCP getting stuck up due to its inability to handle such high levels of sand cut was encountered. There is clearly a need to employ a pump that can function efficiently even at such high sand rates.

The following are descriptions about pumps that are used commercially to tolerate and maintain high sand in-flux in CHOPS:

Progressive Cavity Pump:

The PC pump was developed in 1920, by a French Professor Moineau. In this pump the fluid moves in fully isolated cavities in any direction, even downward. The concept is used for mud motors that rotate the drill bit at the bottom of the hole during drilling, particularly in highly deviated and horizontal wells. Since the sealed cavities progress along the pump body between the stator and rotor, the term Progressing Cavity pump, or PC pump, is used.

The early designs of this pumps had short life spans (~3-6 months), and there was little confidence in their ability to operate under the demanding conditions of sand influx, particularly with the large sand cuts at the beginning of production. Nevertheless, based on some experiences where pumps lasted reasonably well and also because they overcame the rate limitation associated with slow rod fall in reciprocating pumps, PC pumps continued to be tried by various small operating companies. The most important factor was that these pumps often could double and triple well production rates, and even though margins for heavy oil were slim, this greatly affected profitability.

PC pumps with capacities as large as 1000 m^3/d with 2500 m lift capacities are available for conventional light oil. For lifting of gassy heavy oil and sand slurries, pump life has been extended from 6-8 months to 15-20 months, and a wide variety of capacities and sizes are available.

For CHOPS applications, the maximum volumetric rates are 70 m^3/d/100 rpm, and the p lift capacity tends to be approximately 800-1200 m, with lower capacities for shallower wells (some slow wells may use pumps as low as 7 m^3/d/100 rpm).

Current PC Pump Practices for Heavy Oil Extraction:

A relatively standard configuration for new CHOPS well is a PC pump 6 –10 m long with a differential pressure (p) capacity of 1000 m of differential lift, designed at a stator-rotor pitch to give a production rate of between 10 and 50 m^3/100 rpm. The details as to the pitch, eccentricity, and other design parameters depend on the expectations of the producing company and various well factors such as viscosity, expected annular fluid level drawdown, gas content, and so on. Currently, new CHOPS wells coming onto production in the heavy oil region not only use PC pumps almost exclusively, but use hybrid pump design, as these are designed to provide the necessary resistance to sand in the fluid. If a work-over is done on old CHOPS well to increase productivity, usually the reciprocating pump is removed and a PC pump installed.

The advantages of PC pumps for heavy oil lifting in CHOPS well configurations are the following:

A PC pump can lift the high viscosity fluids with large solids concentration that are produced during CHOPS initiation. Sand cuts up to 45-50% of the dead fluids can be lifted (remember that foamy gas behavior reduces the volumetric sand concentration entering the well, allowing the slurry to behave as a compressible fluid).

The PC configuration can operate under conditions of substantial gas volumes, as long as the gas is in the form of foam, and not as large gas slugs (heat build-up is an issue if the pumps operate for any substantial time with free gas).

A PC pump has low internal fluid shear rate because the pump physically lifts the fluid in each cavity (the fluid moves up the pump body with little rotation, in contrast to a centrifugal pump). This low shear rate limits fluid emulsification problems. The low fluid velocities in the PC pump mean that steel erosion is not an issue, although some abrasion of the rotor invariably takes place.

There are no valves to clog or gas lock, as in some other types of pumps. In general, a PC pump has relatively low capital costs and power costs. The low wellhead profile associated with the rotary drive units, particularly the new hydraulic drive units, gives less visual "disturbance" or clutter at multiple well pads, and allows more effective placement of wells a smaller surface footprint for multiple well pads, and greater ease in maintenance and change outs (compared to a large pump jack for example).

There are some disadvantages that must be kept in mind when operating PC pumps in CHOPS wells:

- ✓ A rapid failure rate occurs if the pump is allowed to run dry. This may arise because of excessive annular fluid drawdown or because a large gas cap generates a prolonged gas slug.
- ✓ There is a tendency for elastomer ripping if a pebble or a piece of metal enters the pump.

Even though PC pumps have so many advantages to qualify to be used in CHOPS for extracting and lifting heavy oil, sometimes during very heavy influx of sand they do not tend to work properly i.e. they get stuck and work over is required. To avoid such problems from occurring frequently many modifications are made in PC pumps that are to be used in during the CHOPS operations, out of which 2 have been discussed below:

Sloppy-Fit PCP:

PC pump efficiency is determined with water pump tests in the factory, using manufacturers' criteria. Earlier it was recognized that PC pumps retained a high efficiency (>80%) for pumping viscous heavy oil despite substantial rotor wear from sand abrasion that destroyed the interference fit. When worn pumps were tested with pure water, efficiencies of only 10-30% were found because of fluid slip between the rotor and stator (slip depends on viscosity, efficiency of the rotor-stator interference fit, and the number of cavities per meter).

Now, PC pump manufacturers offer sloppy-fit pumps for CHOPS applications, recognizing that using a tight-fit pump will result in abrasion of the leading edges of the rotors after a few months of use, leading to a 'sloppy fit' in any case. An initial sloppy fit prolongs rotor life, and permits rotors to be resurfaced and reused several times.

Charge Pumps:

Conventional PC pumps discharge all their fluids directly into the production tubing. PC charge pumps have two sections; the lower one operates at a higher flow rate than the upper one at the same rpm because the rotor/stator pitch is longer. Bypass ports in the stator at the junction of the two sections allow the excess fluid to be expelled into the annulus, and provide 'charge fluid' to the upper pump at a somewhat elevated pressure. Thus, differential pressure (p) requirements across the upper pump are reduced and the gas bubbles in the produced fluid are partially compressed. This increases the efficiency of the upper PC pump stage.

Also, the fluid that is by passed apparently has some beneficial effects on wellbore performance. The recirculation of part of the fluid back down the annulus across the perforations tends to homogenize the pump intake fluid, reducing chances of pump blockage by sudden sand slug influx, and perhaps somewhat reducing the negative effects of a large gas slug.

Furthermore, blockage tendencies because of sand arching in the annulus between the pump stator and the casing are apparently reduced (a typical 4.2 PC pump diameter gives a total annulus of 70 mm for 7" casing, 33 mm for 5½" casing, but small diameter casings are no longer used because of well work-over difficulties).

Continuous Sand Extraction Pumps (CSE pump):

A device developed in Lloydminster for pumping packed sand of 35-50% porosity from wells in the 1990s, the Continuous Sand Extraction pump is a 3m stroke piston pump lowered on the bottom of tubing. It is used as an alternative to a mechanical bailer and other devices to clean sand from the hole, or to cope with periods of extremely high sand influx (>40% sand) with no free gas in the incoming fluid, where even a PC pump will have difficulties.

Reciprocating the tubing actuates the CSE pump cylinder and piston at bore-hole bottom so that a thick slurry or even solid sand can be drawn up into the body of the pump while the dense sand in the tubing above the pump is displaced upward.

Continued stroking of the CSE pump results in a large column of sand, and in cases where there is a high annular fluid level so that differential pressure (p) is not excessive, the sand can be directly pumped to surface.

If the sand cannot be pumped to surface easily, it is also possible to feed viscous oil into the annulus to promote the dilution of the sand in the wellbore and allow easier inflow to the CSE pump.

If no fluid is trickled into the annulus, the CSE pump will draw down the annular level until the differential pressure (p) between the wellbore and the formation is large, and this promotes sand influx.

Typically, a CSE unit will be used for the period of CHOPS well when the sand content is high, which is usually during the initial stages. The PC pump will, thus, not have to contend with sand concentrations combined with the possibility of steel fragments or perforation charge fragments that could damage the elastomer.

Once the sand content drops below 10%, the low capacity CSE pump can be replaced with a higher capacity PC pump.

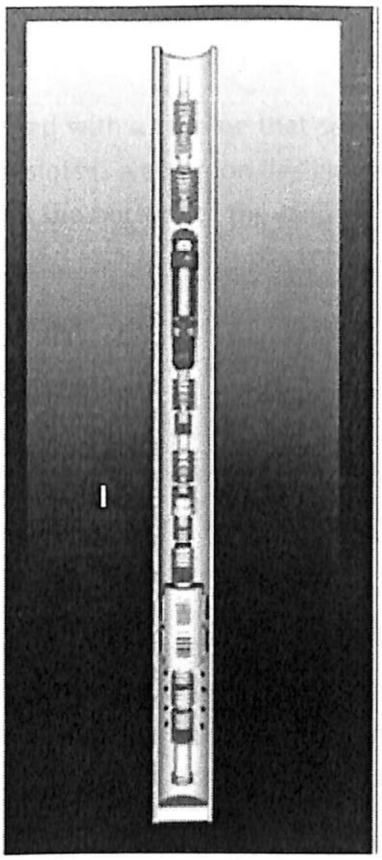


Fig: CSE Pump.

Lifting Approaches: Selection

The CSE pump seems best-equipped to handle high rates of sand in-flux, which is a major problem being encountered in well X. Hence, the CSE pump is recommended to be installed during the early stages of the CHOPS operation.

Although the CSE pump can be used at high sand rates, its production capacity is not as high as other pumps, such as PCP or charge pump. Therefore, once the sand cut drops to below 10%, the CSE pump can be replaced by a PCP of suitable make and size. If, however, the sand production rate does not drop to such a low range, a charge pump can be installed.

Pump Bottom-Hole Installation

The major features of the pump installation in well X are listed here:
The PCP is to be seated about 2 to 4 casing joints above the bottom of the casing. A typical PC pump of about 4.25" OD is to be installed on 3½" or 4½" tubing, depending on the magnitude of torque expected.

The stator of the PCP can be driven with a standard sucker rod string or a continuous rod (Corod) string operating within the tubing. Some field operators have tried elliptical rods to achieve higher torque without impeding the flow in the tubing. Special nylon sleeves and other devices are used to reduce sucker rod coupling wear or tubing wear in doglegs or where the couplings contact the tubing.

The bottom of the stator is to be fitted with a tailpipe that serves as an inlet. A 0.5 m long tailpipe with several 10-12 mm wide vertical slots is a common design, and a horizontal cylinder (~6 mm) of metal, the "tag bar", is welded across the bottom of the tailpipe to serve as a firm location that can be tagged when lowering the rotor, and also to catch the rotor if rod twist-off should occur, hence saving a fishing trip.

The inlet of the pump, or the highest inlet port on the tailpipe, is to be set at least 1 m below the lowest perforation opening to allow some flow path in the annulus to help homogenize the pump feed. If the pump is placed higher in the hole, the lower perforations will become blocked with sand settling in the casing, rendering them ineffective in providing slurry to the wellbore and reducing reservoir access.

A "no-turn" tool or torque anchor is to be installed to prevent the tubing from backing off during rod rotation. The torque anchor has to be placed at the bottom of the stator (just above the tailpipe) in order to increase the amount of gas escaping unimpeded up the annulus, with seemingly acceptable results (i.e. no substantial increase in well plugging).

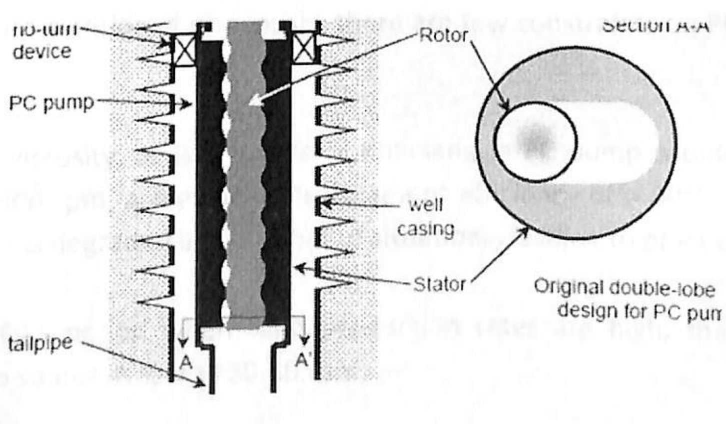


Fig: PCP at bottom of a well.

PC PUMP Operation in a New CHOPS Well:

The details of PC pump operation during start-up vary from company to company, but there is a generally accepted set of practices followed in the heavy oil industry to cope with the large sand cuts typical of early production in new CHOPS wells. A few of these guidelines are listed below:

During start-up of a new CHOPS well, annular fluid is usually added to allow the full system to achieve momentum, then the annular fluid level is allowed to drop gradually, and formation fluids are produced in an increasing proportion as the input annulus fluid volumes are diminished.

Generally, the more viscous the oil, the slower the rotational speed; 10,000 cP oil is usually produced at 50-80 rpm, 500 cP oil at 200-250 rpm (light oils at 300 rpm). If higher production rates are desired because the well is exceeding expectations, a larger pump is installed. During the initial start up with high sand cuts, rotational speeds are even lower because of high torque requirements.

As time goes on, the tubing may be lifted and turned between 40° and 90° on a regular schedule (several months) to minimize concentrated wear on the tubing. The seating depth of the rotor vis-à-vis the stator is changed regularly for the same reason.

In general, the annular fluid level in the well is not dropped to extremely low levels. Many field operators use values between 5 and 10 casing joints (50-100 m), but with the arrival of Downhole pressure gauges, field operators are tending to use lower annular fluid levels, normally two to three joints. The lower the annular fluid level, the greater the drawdown on the well, and the greater is the well production capacity. However, the risk of too low a level is substantial in a well that does not have a BHP gauge, as a period of gas throughput will almost invariably ruin the stator elastomer.

PCP Rates, Sand Tolerance and Rotor Wear:

With the developments mentioned previously, there are few constraints on PC pump rates in most practical situations.

If the fluid is of low viscosity, as is the case in Kharsang, a PC pump should be able to operate continuously at 250-300 rpm, achieving a displacement efficiency of > 90% indefinitely. However, PC pump performance is degraded in a number of situations, leading to practical rate limitations:

During the early CHOPS period when sand production rates are high, the viscosity limitations restrict rotor speed to values as low as 30-50 rpm.

As PC pumps are used in deeper wells with large reservoir drawdown values, limits of efficiency are challenged, and keeping fluid slip (fluids bypassing the stator- rotor seal) low is difficult in cases of sand production and high differential pressure (p) values across the pump. In such cases, longer pumps with a larger number of rotor turns are used to achieve about the same differential pressure (p) across each rotor cycle as for shallower pumps, thereby maintaining reasonable fluid slip levels.

Sand settling out of the fluid in the production tubing on top of the PC pump can occur in some situations (e.g. power shut-down, water influx). The sand settling velocity in the viscous fluid can be estimated only poorly with a Stokian settlement assumption.

Sand blockage becomes more likely as the CHOPS well produce more and more water in the fluid. There is a widely held view in the conventional oil industry that sudden sand influx accompanies rapid water breakthrough because of the reduction of capillarity with multiphase state changes. In CHOPS wells, this is not the case, but a sudden increase in water cut (and of course gas content at the same time) can rapidly increase settlement velocity so that a shutdown leads more rapidly to pump blockage and need for a work-over.

The leading edges of the PC pump rotors are subject to the greatest wear rate from sand abrasion. To reduce the wear rate and maintain pump efficiency, the technique of boronizing the rotors was developed (rotors can also be chromed, and even re-chromed). In general, this can be expected to increase pump rotor life by 10-30%, perhaps more in the case of abrasive sand.

Finally, the major reason for premature PC pump breakdown historically apparently has been allowing the pump to operate without liquid intake (i.e. gas or air only). This problem is being eliminated with continuous BHP monitoring that will eventually become standard.

Well Instrumentation:

The presence of sand in heavy oil apparently doesn't cause difficulties with any properly designed conventional instruments because there is no abrasion or blocking that takes place. However complex nature of the produced heavy oil slurry makes interpretation of many types of measurements more difficult. In CHOPS industry, instrumentation has deliberately been kept simple, direct, and inexpensive because of the traditionally narrow profit margins in the heavy oil exploitation.

BHP Gauges:

Downhole pressure gauge is frequently mounted outside the tubing in the annular space, where they do not come into direct contact with sand. These gauges measure the level of fluid in the annulus as well as the pressure just above the PC pump in the production tubing. These BHP measurements, brought to surface through a shielded carrier, can be used to reduce risk and optimize production. The fluid level in the annulus is directly measured using the annulus pressure.

This electronic input can be used to control the pump speed to maintain the desired fluid back-pressure on the well and eliminate the chances of surface gas breakthrough to the pump. The tubing pressure can be used as well to detect blockages that on rare occasions may suddenly develop within the tubing.

For BHP devices that require direct fluid contact, the orifice that is necessary to connect the gauge to the slurry inside the tubing appears not to plug, even though the amount of sand can be substantial. It is also possible to use devices that are immune to plugging. Thus, no significant difficulty arises in bottom-hole pressure (BHP) or temperature measurements in CHOPS wells, even if the sand contents are high and the behavior strongly nonlinear.

Surface Monitoring Equipment:

Direct measurements of surface pressures, torque, and temperature and so on are straightforward, and are being increasingly used to manage PC pumping systems. Many companies collect other information at the surface, such as densimeter readings, which are used in a semi-quantitative manner to evaluate production behavior.

Fluid Production Metering:

The fluid being drawn into the PC pumps is a complex compressible mixture, and the efficiency of a particular pump is never known precisely; therefore accurate volume tracking, even of total fluid produced, is not possible using the PC pump rotation speed alone.

Gas Sampling:

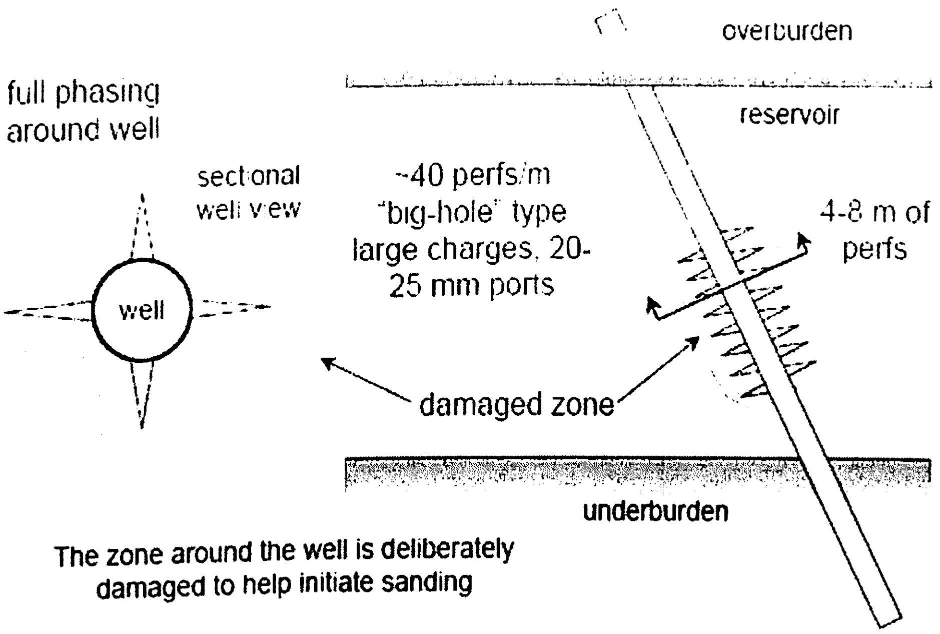
Systematic determination of the gas/oil ratio (GOR) in the produced fluids from CHOPS wells provides important data that can be related to the behavior of the fluids in the formation. For example, if the GOR is rising, it is clear that gas is separating from the fluids and flowing to the wellbore more rapidly through a large and continuous gas phase.

This is evidence of the generation of an interconnected gas phase in the far-field beyond the wellbore; a behavior commonly seen in conventional oil production as depletion occurs.

In CHOPS wells, because of the foamy flow process and the extremely slow equilibration time, GOR values have been known to remain stable for years, indicating that a continuous gas phase is not being generated in the wellbore region or in the far field. As long as no continuous gas phase exists, gas expansion drive continues to be highly efficient. Changes in GOR can be used to help track the long-term behavior of wells and help decide optimum work-over strategies.

BS&W Measurements:

Accurate measurements of basic sand and water (BS&W) produced in individual wells are valuable for well management and work-over decisions. These are obtained by analyzing samples collected at the flow line.



Waste Generated During CHOPS:

CHOPS technology is highly effective in many of the unconsolidated sandstone heavy oil reservoirs. However CHOPS generates large amount of waste that have no commercial value and that represent a substantial additional environmental liability if improperly dispatched. The wastes are mainly of following types:

- ✓ Large volume of sand containing from 1% to 5% of heavy oil by weight. Approximately 30-40 kg of sand is generated for every cubic meter of heavy oil produced.
- ✓ Stable emulsion, consisting of mixture or oil, water and finely grained minerals such as clays. Approximately 3-5 kilograms of emulsions are generated for every cubic meter of heavy oil produced.
- ✓ Tank sludge, consisting of mixture of emulsions, additional asphaltenes and fine-grained sand.

Currently the technology to dispose of these waste are limited to landfill placement, salt cavern disposal, and slurry fracture injection for the oily sand. Other technologies are either environmental damaging or are extremely expensive (e.g. sand washing). For the emulsions and tank bottom landfill placement is not an option because of fluid nature of these material. They have to be treated in expensive separation processes such as centrifuge treatment or heat separation.

Environmental Aspects:

Oilfield wastes are divided into Non-hazardous Oil Waste (NOW) and Dangerous Oilfield Wastes (DOW). Specific levels of toxic materials (such as cadmium, mercaptans, etc) used to classify waste materials. The major approach used in most jurisdictions is to carefully define what DOW is, and then by default, other materials are classified as NOW.

The solid wastes generated in CHOPS can be disposed of with any of the technologies, including direct placement in a landfill, washing, road spreading, and land spreading, but obviously within the limitations of chloride contents etc, slurry injection and salt cavern disposal. Liquid wastes can be disposed of by slurry injection and salt cavern disposal, or the phases (oil and water) can be separated, treated, and the clean water disposed of in a licensed water disposal well.

Hydrocarbon Fluid Waste from CHOPS:

Stable Emulsion:

Stable emulsion is empirically defined as homogenous colloidal mixture of water, HC and fine-grained minerals that does not segregate gravitationally over long residence time in the tank. It is formed during CHOPS production, and partially due to stock tank cleaning.

The composition of the emulsion varies greatly depending upon factors such as oil viscosity (linked to asphaltenes content in crude oil), the fraction of clay minerals and fine–grained silicate minerals in the produced solids and the temperature at which the emulsion was formed. CHOPS activities in coarse-grained sand with a few clay minerals will generate lesser emulsions than CHOPS from unconsolidated sandstones with high clay content.

Emulsion contains about 50-85% of water, 10-50% of HC and 1-10% of minerals matter. Density can vary from less than 0.98 if the emulsion has high oil content to as high as 1.08 if it has high solid content. Heavy oil contains 8-15% of asphaltenes, but the HC phase in the emulsion is asphaltenes-enriched.

The emulsion is classified as NOW and as with all other liquid NOW wastes, the option are salt cavern placement, slurry injection or phase separation with separate or co-disposal of solid and water phases.

Slops, Site Clean-Up Wastes and Treater Residues:

These wastes are classified as NOW. Slops are generally considered to be non-emulsified mixture of aqueous and HC liquids; the term 'slops' often includes many of the wastes that might even be classified as emulsions or aqueous tank bottoms.

Spills of oil or water into the ground must be cleaned up quickly to avoid groundwater contamination. Since the clean-up is carried out using water, more slop is generated. The clean-up wastes may be 'dry' or 'wet'; the latter contain excess water that will drain if the solids are stacked and left to sit. Because of the generally low oil content of slops, there is little incentive to try to recover oil directly. For example, the placement in large tank concentrates the solid at the bottom and the oil floating on the top of the water; both are withdrawn and handled by other means. Similarly, slops placement in salt caverns allow slow gravitational separation, and high oil content 'cavern returns' are sent to treaters.

Treater residues are generally viscous mixtures of solids and tarry oils that accumulate slowly during battery treatment of heavy oil. Unless particular chemicals have been added to aid treatment or to break emulsions, treaters residues are classified by EUB as NOW. Treater residue can be separated physically by high-speed centrifuge. Other options include number of technologies available for chemically, electro statically and physically enhanced phase separation, resulting in the materials that can be disposed of in landfills or disposal wells, or can be sent to batteries for inclusion in the oil treatment stream, but ideally most methods are singularly ineffective in these emulsions.

Pressure Pulse Technology (PPT):

Pressure pulse technology (PPT) is a new technology which can be used to enhance the recovery rate of non-aqueous phase liquid (NAPL) and to reduce solids clogging in wells, permeable reactive barriers (PRBs), and fractured media.

The technology uses steady, non-seismic pulse vibrations (e.g. 15 pulses per minute) that generate a low velocity wave effect to encourage flow of oils and small solid particles. Applied to geologic formations exhibiting elastic properties, this energy dislodges blocking matter, opens perforations, increases pressure, re-establishes connectivity to reservoir pressures and, generally, enhances or restores the capacity of the well to produce fluids.

This high-energy input has the beneficial effect of increasing:

- ✓ The fluid levels and free-phase liquid levels in wells.
- ✓ The recovery rates of free-phase liquids in recovery wells.

- ✓ The well efficiencies and specific capacities in production wells.
- ✓ The permeability of various types of materials, such as reactive barriers.

High-amplitude wave pulses are generated by blasts of air delivered by a proprietary pneumatic system, shown schematically in the following figure. Pulse rate and amplitude are calculated based on site parameters. A porosity-pressure pulse propagates at velocities between 5 m/s and 300 m/s, depending on the fluid viscosity, permeability and the scale of the pulse. Mechanical energy capture causes a buildup of pressure in the reservoir, deforming the material elastically outward.

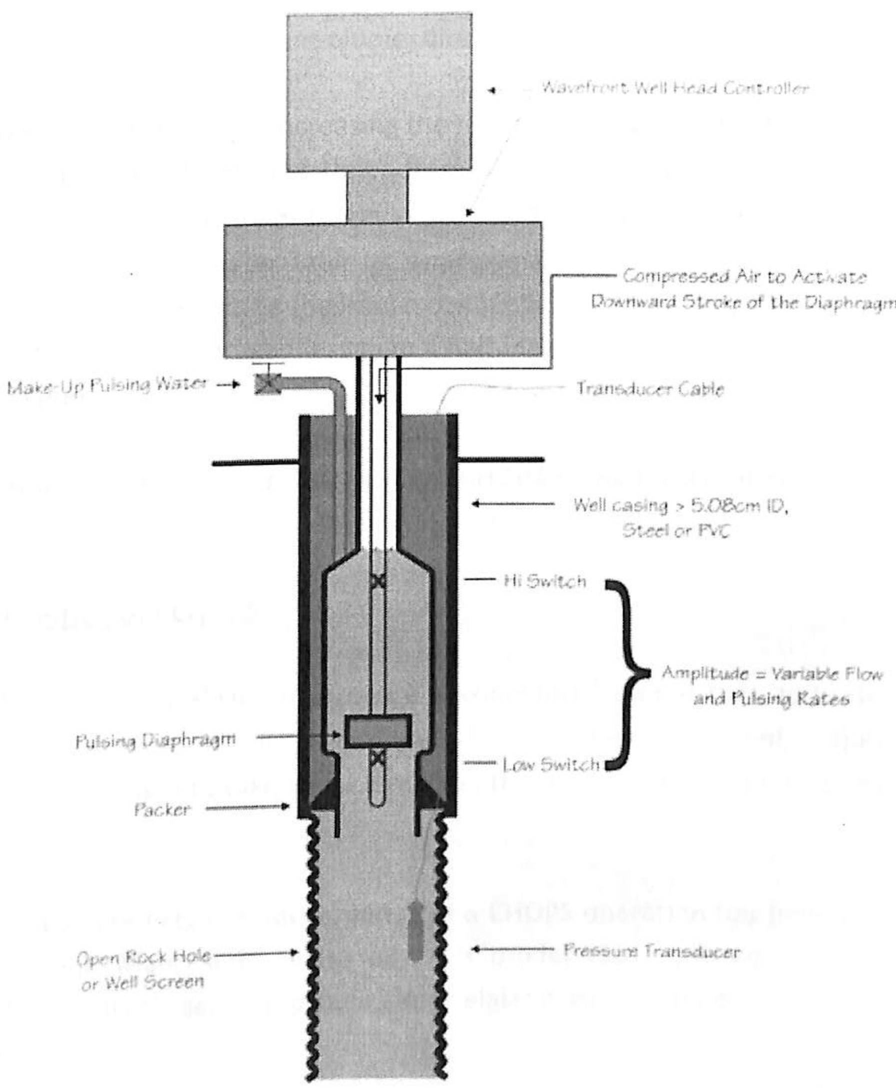


Fig: Schematic of pneumatic pressure pulsing tool

It is most effective in geologic formations exhibiting elastic properties, such as unconsolidated sediments and sedimentary rocks. It must be applied in a down-hole manner in order to be effective. It has been used to improve oil recovery from otherwise exhausted reserves for many years.

The actual work (energy input) performed on the reservoir by the PPT method is far greater than that in fluid flushing or other common techniques. Field studies indicate that PPT can be used in all liquid-saturated systems, inducing recovery of both light and heavy oil.

Pressure Pulse Technology can be implemented at an individual well site or used for field-wide excitations. It can be applied to horizontal, vertical, slanted or directional wells. Depending on the site characteristics and requirements, pulsing can be applied at a single well or at existing delineation wells beyond a contaminant plume, directing the flow to a central recovery well.

It has been shown to be effective in increasing the rate of removal of light NAPL (LNAPL) by as much as 750% (in effect reducing treatment times from 37 years to 5 years). Pulsing was applied at a single well to enhance the recovery of LNAPL (viscosity: 150 centipoise; density: 0.9861 gram/cm^3). LNAPL was present atop the water table at approximately 8 feet below ground surface in the uppermost weathered bedrock zone (hydraulic conductivity 2.5x10-5cm/sec, porosity 5-10%). The thickness of the LNAPL layer averaged less than a half-inch. Estimated free product volumes ranged from 500 to 1000 liters.

PPT is recommended as a work-over method for CHOPS in well X, i.e. it should be implemented whenever the oil production reduces to uneconomic levels in well X.

Performance Prediction: CHOPS

It has proven to be quite difficult to prepare a conceptual model that accurately predicts the behavior of a well operating on CHOPS. Many models have been proposed, majority of them not applied since they are unable to take into account all the mechanisms and processes taking place in CHOPS.

A suitable model that predicts the performance of a CHOPS operation has been proposed by Gang Han, Mike Bruno and Maurice B. Dusseault. This model takes into consideration the 3 main mechanisms behind CHOPS: sanding propagation, elastoplastic stress on formation and foamy oil behavior.

Prediction Model: Brief Summary

It has well been understood that the recovery of heavy oil from unconsolidated sands is directly dependent upon the recovery of the sand itself. This is the principle behind the CHOPS operation.

The mechanisms responsible for the enhanced production rate in CHOPS are:

- ✓ Enhancement in porosity and permeability as sand is removed from the formation, along with mechanical skin around the well-bore.
- ✓ Foamy oil behavior, i.e. solution gas remains as bubbles (not as a continuous gas phase) in the oil phase, further gives an impetus to oil production since the gas bubbles expand as they flow down the pressure gradient to the well, and help block pore throats which leads to sand destabilization and consequent shearing of sand.
- ✓ Increased compressibility and porosity dilation, leading to easier formation compression and compaction drive. Sand removal leads to vertical stress concentrations and lateral stress reductions, causing shear dilation, continued sand destabilization, and plastic extrusion of sand to the wellbore.
- ✓ The oil flow velocity relative to fixed coordinates is increased if the matrix is partially mobilized; therefore production rate increases, as predicted from Darcy's law.

The proposed model is based on an assumed difference in mechanical behavior of the reservoir rock, between an elastic region and a region where plastic behavior, including pore dilation, occurs. Accordingly, the formation around the wellbore can be divided into elastic and plastic zones, and this system is treated axis symmetrically.

The boundary between the elastic and plastic regions is called the critical radius (R_C). It is the radius at which the sand has just experienced shear failure, defined by a Mohr-Coulomb yield criterion based on the effective radial and tangential stresses. The critical radius propagates outward from the well with continuous sand flow, while the sand within the plastic zone continues to be flow into the well. Hence, both the porosity and the critical radius are variables dependent upon time and location. To simplify the model, the porosity of the elasto-plastic zone is treated as an average value, and like the critical radius, assumed to vary only with time. Outside the critical radius ($r > R_C$), i.e. in the elastic zone, the porosity is assumed to be constant.

Now, the permeability depends upon the porosity, and here the Carman-Kozeny relationship between the two has been used to calculate the enhanced value of permeability in the plastic region.

With help of the parameters listed in the next section, the critical radius is first determined at each time step. Accordingly, the porosity and permeability are updated, and finally, the enhanced oil rate is determined, which then serves as an input to calculate the new critical radius for the next time step.

However, the porosity can increase only up to a value after which the formation starts to collapse. This value is called a 'porosity cap' and once the porosity reaches this limit, the produced sands originate only from the continuous growth of the plastic zone. The value of the porosity cap may depend on various factors such as cohesion strength of the reservoir rock and overlying formation, frictional strength in the yielded state, etc.

Here, value of 50% is assumed to be the porosity cap. It automatically implies that the permeability value will also not increase once the porosity cap is reached. This conceptual model is consistent with laboratory observations of and production around cavities.

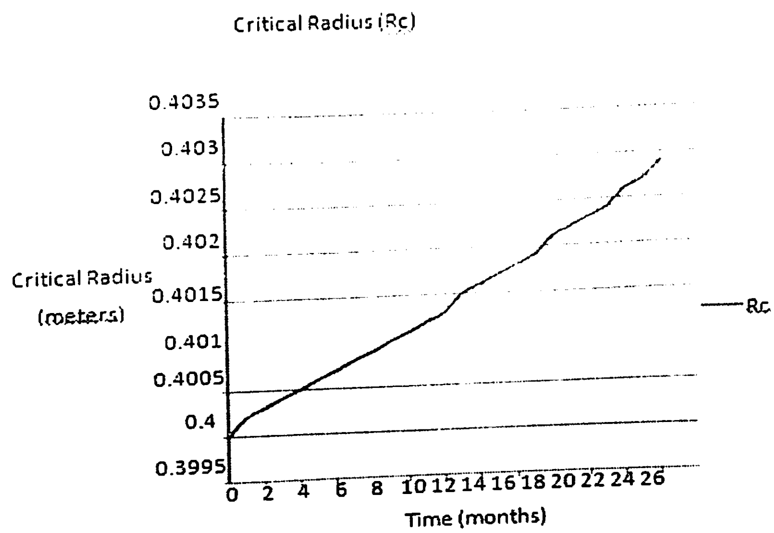
Certain assumptions were made in the development of this model, viz.:

- ✓ All produced sand is assumed to come from the increase of critical radius and porosity in the plastic zone.
- ✓ The deformation in the plastic zone is so small that the compression effect can be neglected.
- ✓ Porosity and permeability in the plastic zone are only functions of time.
- ✓ The bottom-hole pressure is taken a constant throughout.

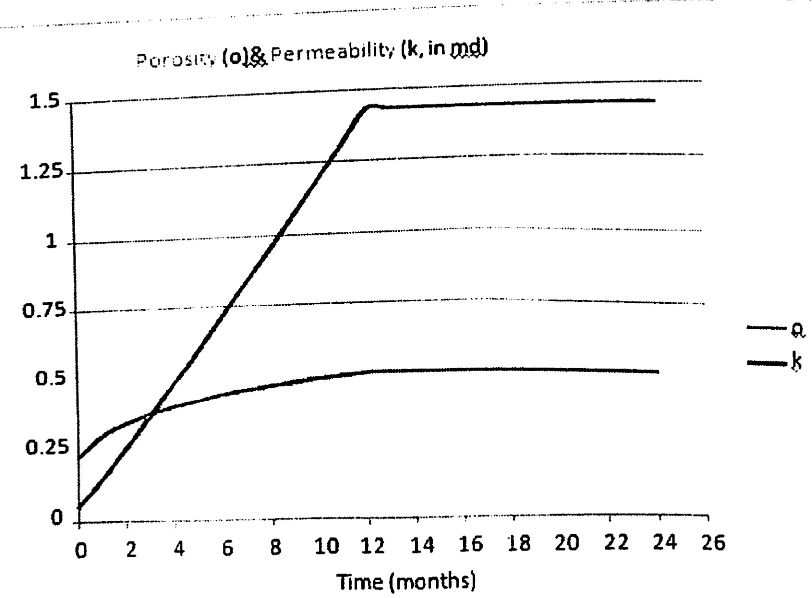
CONCLUSION

We used the above provided data to predict the results of a CHOPS operation in well X for duration of 24 months, using MATLAB engineering software.

Development of Critical Radius over Time:

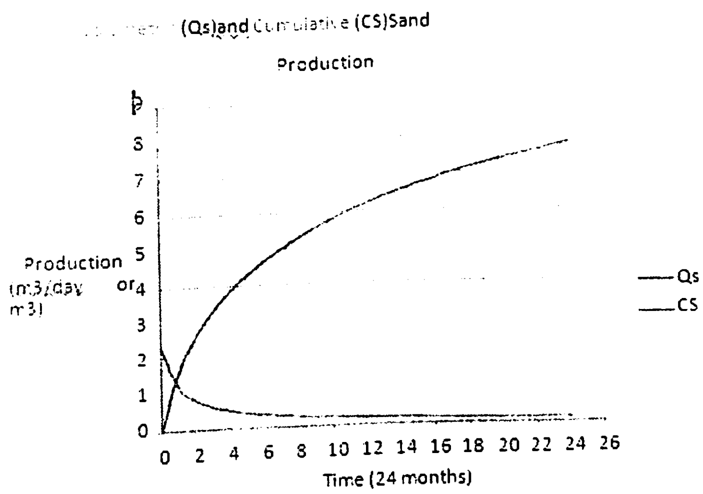


The above graph displays the manner in which the critical radius propagates on application of CHOPS. The initial value is 0.4 meters.



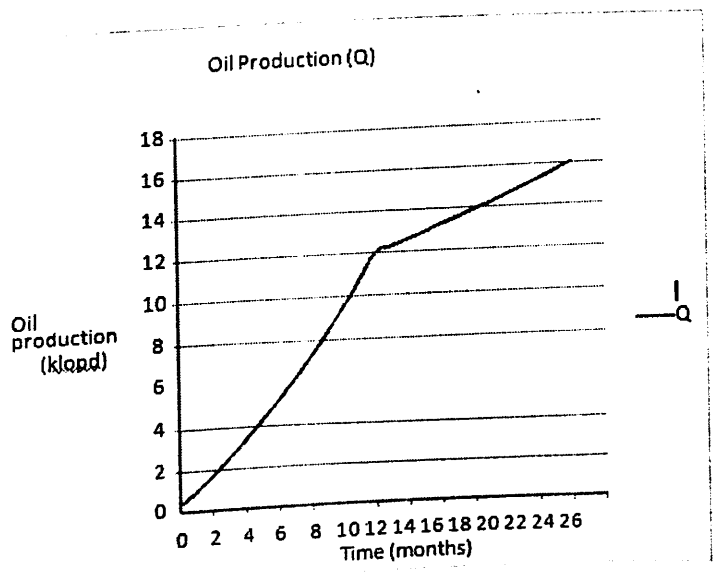
The initial porosity is 22%, and it reaches 50% (porosity cap) after duration of 12 months. The permeability increases from 50 md to nearly 1431 md in the same duration.

Sand Production:



The graph clearly shows that the sand production rate decreases rapidly, from the initial value of $2.3m^3$/day. In fact, the decline in volumetric sand production is exponential in this case. There is a corresponding exponential increase in the volume of sand accumulated in 24 months.

Oil Production:



The oil production from well X increases from 0.3 klpd to almost 16klpd in 24 months time, at an average of 9.55 klpd. The total volume of heavy oil produced in this duration is determined to be 6968.33 kls. This determination was accomplished using Simpson's 3/8 Rule of Integration. It should be noted that there is decrease in rate of increase of oil production once porosity cap is reached after 12 months.

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