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Gravity-Assisted Drainage Techniques for Heavy Oil Recovery in Trinidad – A Review of Macroscopic Processes and Film Drainage Considerations

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Crude oils of viscosity higher than 20 cp and a density close to that of water (>0.96 gm/cc, °API<20) are difficult to recover from the reservoir. Such oils are commonly termed 'heavy oil'. Trinidad has over 2 billion barrels of heavy oil. New process designs using horizontal wells and heat (steam) or volatile solvents such as SAGD (Steam Assisted Gravity Drainage) and Vapex (Vapour Extraction) can allow gravity to enhance the production process. These processes lower the viscosity of the oil by warming or by dilution, and the oil is produced by gravity drainage (vertical movement of fluids) to horizontal wells placed lower in the reservoir. They can be effective in producing more of the oil using less energy and at lower production costs. This paper describes these extraction techniques for heavy oil, particularly SAGD and Vapex. The gravity drainage processes at the macro- and micro- scale are examined and some experimental work is presented to demonstrate the importance of viscous film flow by gravity drainage. Finally, the new processes are discussed in the context of Trinidad's heavy oil reservoirs.

Keywords: Heavy oil, gravity drainage, thermal recovery, horizontal wells, viscosity reduction, SAGD, Vapex.

1. Introduction

Crude oils having a viscosity higher than 20 cp and a density close to that of water (>0.96 gm/cc, °API<20) are commonly termed 'heavy oil' [1]. Heavy oils are difficult to recover from reservoirs and usually the recovery is less than 10% of the volume of the oil initially in place in the pore spaces of the reservoir [1]. Trinidad has much heavy oil with most of the known reserves located in southern Trinidad. The magnitude is uncertain, perhaps 1.3 billion barrels onshore and 1.9 billion barrels offshore [2, 3]. Heavy oils have been produced from Trinidad reservoirs by:

- Primary production, which is pumping oil to the surface, and
- Thermal recovery techniques of Cyclic Steam Stimulation (CSS), and Continuous Steam Flooding (CSF), [2-5].

Thermal techniques have been tried at Forest Reserve Project III but, unfortunately, there were difficulties which resulted in the closure of projects [3-5]. For example, gravity override of the steam due to its low density led to early steam breakthrough, and corrosion caused casing and tubular failures. There was also incomplete geological information which created uncertainty in the knowledge of the clay content within the reservoir layers. The clays, particularly smectites, swell with water and reduce the permeability of the reservoir.

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New process designs are being tried where heat (steam) and solvents are used with horizontal wells placed low in the reservoir lower the viscosity of the oil allowing gravity to assist in the production process. These appear to produce more of the oil in place at a lower overall cost in terms of thermal energy and in production expenses. The techniques of SAGD (Steam Assisted Gravity Drainage) and Vapex (Vapour Extraction), are outlined in this paper. The gravity drainage processes at the macro- and micro- scale are examined and discussed in the light of some experimental work to demonstrate flow in films. Finally, SAGD and Vapex are considered in the context of Trinidad's heavy oil reservoirs.

2. The Viscosity and Density of Heavy Oil

The viscosity and density of an oil are important parameters in reservoir engineering. The viscosity controls the flowability of the oil, while the density affects the hydrostatic head of the oil (hρog) which controls the pressures needed to flow the oil to surface as well as the ease of separation of oil from water at the surface, as the smaller the density difference the harder it is, [6]. Gravity also has a very significant effect on the fluid movement characteristics of the oil/gas/water within the pore spaces of the reservoir rocks as discussed in Section 6.

The viscosity and density are affected by temperature differently, as viscosity varies strongly, perhaps more than 10% drop for 10 °C increase, whereas density changes by perhaps less than 1% drop per 10°C increase, [7]. There is no clear correlation between the viscosity and density. This is because density is proportional to molecular size of the compound, its length and number of side chains, while viscosity is affected by molecular interactions and the molecular structure.

3. Primary Heavy Oil Recovery Processes

If a reservoir is very close to the surface mining is a possibility, although disposal of the spoil can create environmental damage. Drilling a well and pumping out whatever flows into the wellbore is termed 'cold production' or CHOP (cold heavy oil production) and is a primary production process [1,8]. CHOP primary recovery requires the least initial capital outlay of all the heavy oil recovery processes, unless complex well designs are needed to provide sufficient production rate. However, well flow rates will reduce as reservoir pressure declines. Additionally, if the reservoir pressure goes below the oil bubble point, gas will come out of the oil and the viscosity of the oil will increase. Usually, less than 10% of the oil in the reservoir is recovered. CHOP is becoming more frequently used with so called foamy oil reservoirs, particularly if there is also sand production [8], CHOPS - (cold heavy oil production with sand). This occurs in high permeable unconsolidated sand reservoirs and when gas comes out of solution it becomes trapped in the viscous oil, which expands at surface to form a foam, so-called foamy oil production [2]. Finally, solvents, such as diesel oil, when injected can help dissolve and wash out heavy oil; this is practiced in Venezuela. Even so, the diesel has to be separated from the oil and recycled, otherwise the extraction can become expensive.

4. Thermal Processes – Enhanced Oil Recovery using Steam

The obvious way to improve heavy oil production rates is to lower the oil viscosity [1,9–11]. Adding thermal energy, usually in the form of steam raises the temperature of the formation and the fluids contained therein. This heat lowers the viscosity of the oil so that the oil can flow more readily within the reservoir to the wellbore. The oil viscosity, particularly heavy oil, can be reduced by factors of the order of perhaps 100 or more for 100°C rise. The viscosity of most heavy oils when heated to 250°C will become 1–10 cp, although the oil may change through cracking. Steam thermal methods either in a continuous flood, or in the form of a steam soak are the most successful of Enhanced Oil Recovery techniques and much used for heavy oil recovery, particularly in Canada, Venezuela and US, accounting for around 70% of the production by EOR [1]. However, the higher the reservoir pressure, the higher the steam generation temperature, and less latent heat is available to heat the reservoir which makes the process less energetically favourable. The critical pressure of steam (221 bar) imposes a depth limitation of about 1,500 m (5000ft). It is for this reason that steam-based EOR schemes in reservoirs deeper than -1200 m are not recommended, as the process then is hot water injection with no advantages of latent heat. The conduction of heat through rock has both an advantage and a disadvantage.

- The advantage is that the heat may be conducted far ahead of the advancing heated oil displacement front in the formation leading to a lowering of viscosity even in pockets not directly contacted by the injected steam. Also, if steam moves to the top of the reservoir, it can still dissipate some of its thermal energy downwards into the reservoir.

- The disadvantage is that there will be loss of heat to the base and cap rocks, which means that steam injection is usually not economic if the pay thickness is less than about 3 m.

4.1 Steam-Oil Ratio

Thermal processes are energy-intensive. When considering the overall energy balance, it would obviously not be advantageous if more than the energy equivalent of one barrel of oil were used to generate sufficient heat to raise oil production by only one barrel, or less. The steam-oil ratio (SOR) is a convenient measure to determine the feasibility of a project. SOR is ratio of the volume of water in barrels needed to produce the steam used in the process, compared to the volume of oil recovered. However, perhaps it is more useful to make comparisons in terms of the volumes of gas needed to raise the steam. As it requires around 500 scf of natural gas to heat one barrel of water to produce the steam, and as 6000 scf of gas has about the same energy as one barrel of oil, an SOR above 12 (6000 scf) means that the process is clearly unfavourable energetically. In the field, it is found that SORs above six are uneconomic (3000 scf of gas), but where SOR < 2, the projects are energetically economic and attractive. On average, for successful thermal projects the energy needed to generate the steam uses around 25% of the energy contained within the produced oil (i.e., SOR around 3–5, 1500–2500 scf of gas).

Local fuel costs for gas and the selling prices of bitumen /heavy oil are also important in determining the financial economics. If the gas price is $US2/1000 scf (although nowadays gas is usually sold in terms of thermal capacity rather than simply volume), then the fuel costs are $US2 – 6 per barrel of produced oil.

As some three to five volumes of water, on average, are converted into steam for each volume of oil produced, there can be a limitation on the use of steam heating if fresh water is in short supply. Also, if the selling price of oil remains constant, then the profit margin for the produced oil is dependent on the oil production costs – the larger these are, the smaller the margin. A lowering of fuel costs by using a cheaper fuel e.g., coal (imported for Trinidad) or applying energy multitasking (e.g., co-generation of electricity along with the steam) is always possible. Another practical problem with steam injection is that extremely stable oil/water emulsions are sometimes formed with the produced fluids and which require special de-emulsifying equipment to process the production effluent, so reducing the profit margin. Most steam-injection plants require a reliable high-quality feed water, otherwise severe corrosion problems may develop in the equipment.

4.2 Cyclic Steam Stimulation (CSS)

CSS or steam soak or huff-and-puff is a form of well stimulation that involves transfer of heat to the reservoir by the periodic injection of steam into production wells (a few days up to a few weeks) (**Figure 1**). The well is then closed in for a week or so to allow the heat to dissipate and reduce the viscosity of the oil in the vicinity of the well bore (soak period). In this time, the steam condenses and its latent heat is transferred to the formation (and oil). The well is then placed on production for as long as the oil flow rate warrants, perhaps several months, as the reservoir temperature drops and returns to its original value, ensuring a further oil production rate loss [1,9].

With each cycle, the initial peak production rate gradually decreases as there is now less oil in the near wellbore region. After a certain number of cycles, maybe three or perhaps more, the production becomes so low that the process becomes uneconomic. At this point, it may be converted into a steam flood. Often CSS is used as a precursor to a steam flood, discussed below. Clearly, the quantity of oil recovered per cycle is a function of the amount of steam injected, the pressure (hence steam temperature, the sand thickness), the oil production rate and the number of cycles performed. CSS has been a tried-and-tested process in both vertical and horizontal wells and is the main enhanced recovery process for Venezuelan heavy and extra-heavy crudes.

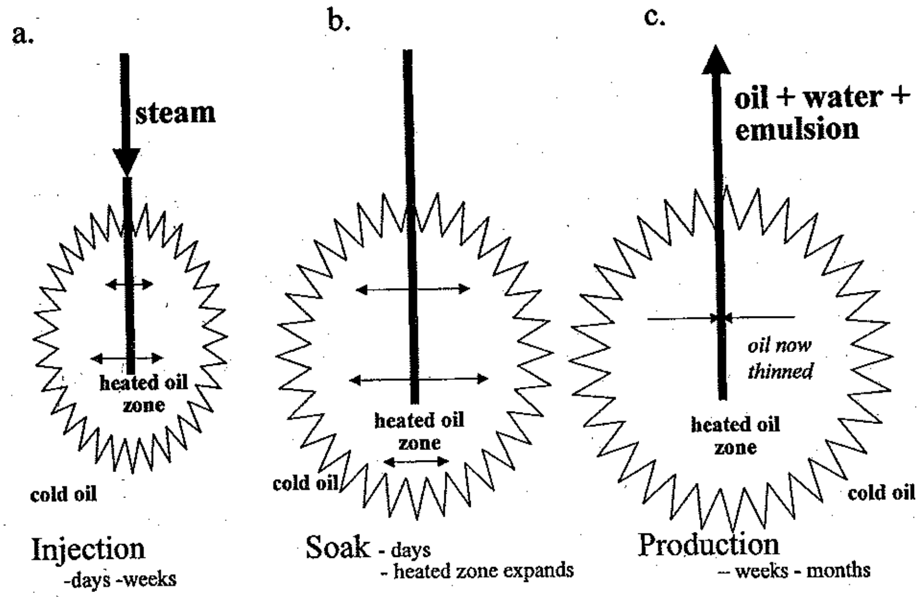

FIGURE 1: *Cyclic Steam Stimulation (Huff and Puff)*

The radial rate of heating by conduction will be very slow, so often reservoirs are fractured to allow faster and greater areal heat contact. Calculations show that for the same temperature rise, the productivity improvement is greater for high viscosity oils than for low viscosity ones, and that there is a maximum beneficial temperature rise for a given radius of heating, thus, for the same energy input, it is probably more beneficial to heat deeper into the reservoir at a lower temperature than high heating for a smaller radius [11].

4.3 Continuous Steam Flooding (CSF)

Steam flooding is a continuous process that involves the use of dedicated injection and production wells. **(Figure 2)**, [1,9]. Steam is injected into the reservoir through injection wells and oil (and water and emulsion) is produced from producer wells. As the steam moves through the reservoir from injector to producer, it creates several zones of differing temperature and fluid saturation. Around the injector is a steam-saturated zone, with a temperature close to

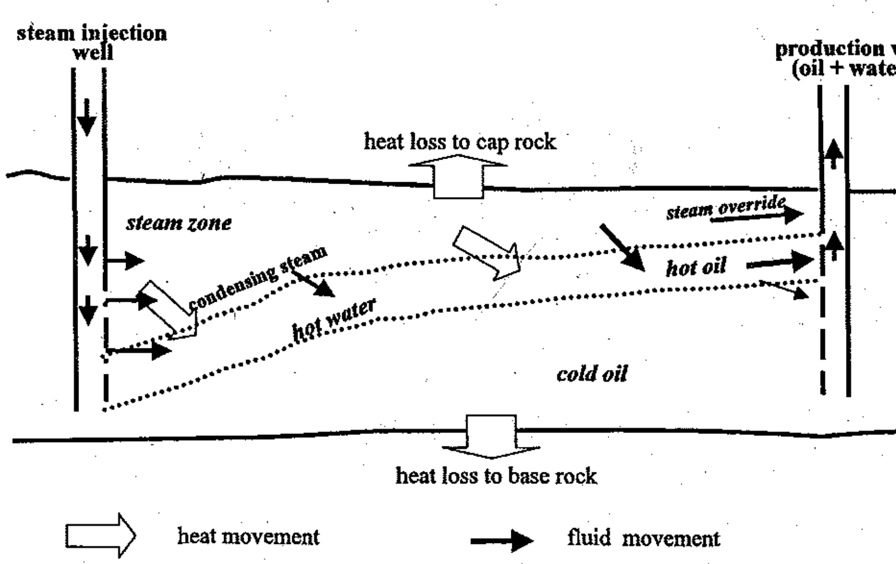

FIGURE 2: *Schematic of Steam Drive; The Role of Gravity in contacting the Cold Oil and Steam Override is critical*

that of the injected steam. This zone gradually grows as more steam is injected. Oil saturations are at their lowest. Oil moves from here to the next zone by steam distillation; just ahead of the steam front a solvent bank forms from the distilled light ends from the steam-saturated zone.

Ahead of the steam-saturated zone, the steam condenses to water as heat is lost to the reservoir; this is a hot condensate zone. Some heat is carried beyond this into the cooler regions of the reservoir until the condensed water finally equilibrates to the initial reservoir temperature. The (hot) solvent bank formed ahead of the steam zone dissolves oil from the formation and the high temperatures in this zone make the oil less viscous. In the oil bank that is mobilised and pushed ahead of the advancing steam and hot water fronts, oil saturations are often higher than they were initially. The cooler water in this zone displaces the oil bank in a process analogous to a waterflood. Total recovery from steam flooding can exceed 80% in the swept areas.

4.3.1 Gravity Effects

Gravity effects are significant in CSF. The low density of the steam means that it rises to the top of the formation and may overide some of the oil. Similarly, condensed water will sink to the lower parts of the reservoir with cooler water being below the warm water. Thus, there are complicated temperature variations throughout the reservoir from injector to producer, and at any slice in the reservoir from the top to the bottom of the formation, with hotter portions near the top and cooler portions near the bottom. There are also changes with time as the flood continues. This makes it very difficult to fully visualise and, therefore, to simulate in a reservoir simulator.

Screening criteria rank reservoir thickness and low operating pressure as the most important indicators for steam flooding. Thin reservoirs will lose heat to the surrounding rocks, wasting energy. As with CSS, reservoirs are often fractured to allow faster and greater areal heat contact. On comparison with CSF, CSS has better short-term economics, due to the immediate production response, and the fact that all of the wells produce oil, and up-front capital expenditure for CSS can be kept to a minimum by using small portable steam boilers that can be moved around from well to well.

5. New Processes

Nowadays, horizontal wells are being drilled relatively cheaply so that more of the reservoir can be drained. If the well is drilled near the base of the formation, oil can flow down to the well and be pumped to surface. When oil and gas are injected into a reservoir, gas will naturally flow upwards and oil downwards under the influence of gravity (the gradient will be proportional to the density differences between the oil, water and gas and flow rate). New gravity drainage techniques are being developed for heavy oil production using horizontal wells and heat and are more effective in producing more of the oil in place at a lower overall thermal energy usage, as well as having lower production expenses compared to CSS and CSF [1,9]. The principle new processes are Steam-Assisted Gravity Drainage (SAGD) and Vapour Extraction of Oils using a Solvent (Vapex). SAGD has already been proven successful, while Vapex is currently undergoing field trials [12–16].

5.1 Steam-Assisted Gravity Drainage (SAGD)

SAGD consists of a pair of horizontal wells; one drilled directly above the other at the base of the reservoir (**Figure 3**), which shows a vertical cross-section of reservoir [1,9–11,13,14]. The upper well is a steam injector, the lower one an oil producer. As steam is injected, a steam chamber forms above the wells at approximately the same temperature as the injected steam. The steam gradually rises and the steam chamber grows over a period of months until it reaches the top of the reservoir, when the steam chamber then expands laterally and downwards until it becomes limited by heat loss to the surroundings, or interference from adjacent well-pairs. At the edges of the steam chamber, the steam condenses and transmits heat to the surrounding oil which becomes less viscous and can flow downwards by gravity along the outer margin of the chamber to be produced by the lower well as it is denser than the steam that is replacing it (**Figure 3**). The condensed steam, oil-water condensate and any emulsified oil also drain to the base of the chamber. Within the steam chamber, the remaining oil drains as films along the pore walls or as droplets (film drainage, discussed in Section 6) so can still be produced but more slowly.

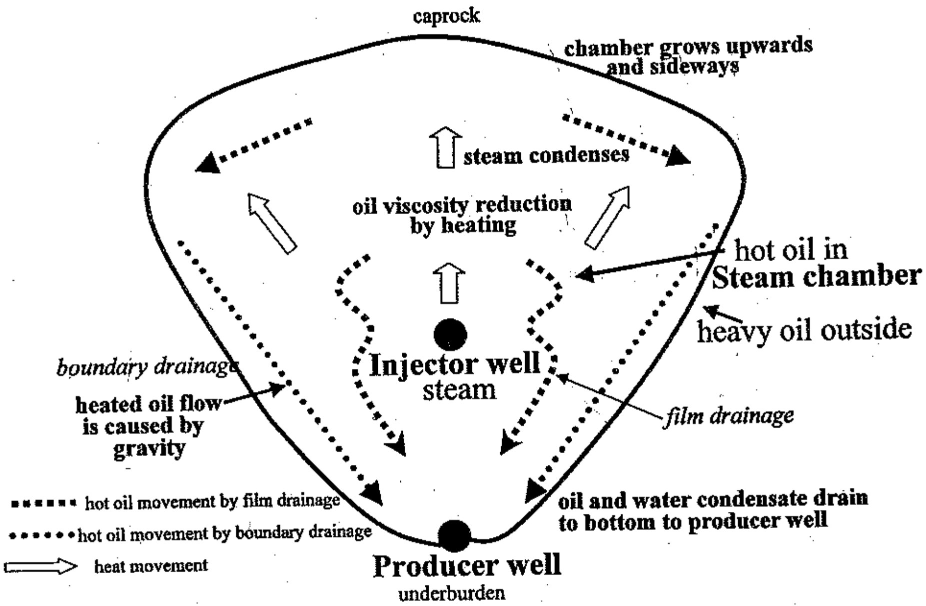

FIGURE 3: *Vertical Section through a SAGD Chamber parallel to the Horizontal Wells*

The upward growth of the steam chamber (taking perhaps a year), **Figure 3**, is a function of the steam temperature and the reservoir vertical permeability. The oil production rate rises slowly as the steam chamber spreads laterally but then decreases when the lateral spread of the chamber becomes extensive and the oil has further to travel, though this is balanced by the greater area of the interface between the steam chamber and the surrounding oil.

The suitability of a reservoir for SAGD depends on reservoir heterogeneity, shales, thief zones and whether there would be heat losses to any underlying aquifer [9,13,14]. The overall SAGD performance is affected by reservoir permeability, the heated oil viscosity and reservoir heterogeneity. The distance between the two wells depends on the thickness of the reservoir and the oil viscosity, but can be from a few metres up to several tens of metres.

5.1.1 Variations

Variants of SAGD have been proposed and include the use of vertical injectors combined with a horizontal producer, and single-well SAGD. The latter is a process that uses a single horizontal well. Steam is injected continuously via insulated tubing into the formation from the toe (end) of the well. The heated oil and steam condensate then drain back into the annulus of the horizontal wellbore to be produced. Other suggestions include multilateral injector and producer branches, and the use of offset wells that are parallel to the producer. Another possibility, discussed below, is adding inert gas along with the steam to fill the spaces previously occupied by the oil.

Clearly as CSS, CSF and SAGD use steam usually generated by gas, they are susceptible to fluctuations in natural gas prices. Also, higher greenhouse gases emissions, water use and disposal raise serious environmental concerns. Heat is lost in the produced water and in any steam that is returned to the surface. This heat must be recovered by suitable heat exchange with boiler feed water to improve thermal efficiency.

5.2 VAPEX (Vapour Extraction of Oils using a Solvent)

Vapex involves the injection of a hydrocarbon vapour into the reservoir via a horizontal injector with production from a second horizontal well beneath (**Figure 4**) [1, 15-17]. No additional heat is involved. The simplest form of the process is analogous to the SAGD process where the steam (and heat) is replaced by the gaseous hydrocarbon, which is acting as a solvent. The hydrocarbon vapour rises creating a chamber, then diffuses to the interface with the heavy oil and dissolves into it. The solvent diluted oil has a significantly reduced viscosity enabling it to drain by

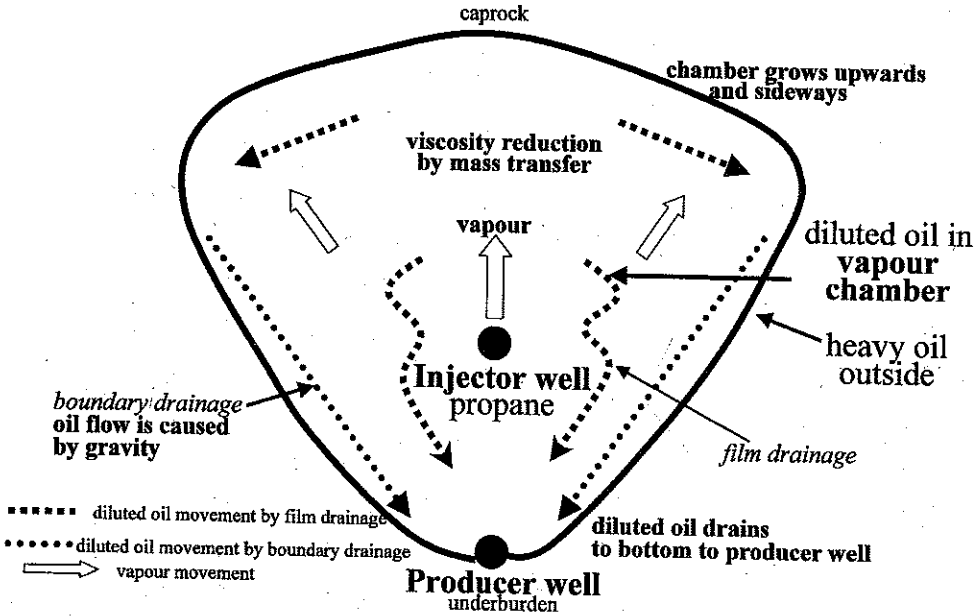

FIGURE 4: *Vertical Section through a Vapex Chamber parallel to the Horizontal Wells*

gravity into the production well. With time, the solvent chamber grows, mobilising oil from progressively larger volumes of the reservoir. The chamber expands upwards until it reaches the caprock above, then it starts spreading sideways and downwards.

The best solvent for the process is uncertain, but would probably be a low molecular weight hydrocarbon, such as ethane, propane and butane or mixtures of these hydrocarbons or maybe with some carbon dioxide. Reservoir pressure, temperature and oil composition are the major factors in choosing the solvent. However, the process may also lead to a certain degree of in situ solvent de-asphalting when the solvent mixes with the oil. Asphaltenes often precipitate from the oil in the reservoir, increasing the API gravity of the remaining oil, but can clog portions of the reservoir. This in situ upgrading process may increase the value of the produced oil.

5.2.1 Differences between VAPEX and SAGD

Vapex does not involve heat injection so operates at reservoir temperature and pressure rather than at the higher temperatures of SAGD. As the process is conducted at reservoir temperature, it is a much more energy efficient than a thermal process, consuming perhaps <5% of the energy of an equivalent steam-based process, and as there are no combustion products it is cleaner than thermal processes. For a given temperature, the solubility of a vapour is maximum near its vapour pressure (i.e., the liquid has just become a vapour), but to prevent the solvent liquefying, the pressure should be slightly lower. To increase the pressure above the vapour pressure of the solvent, especially in high-pressure reservoirs, non-condensable gas can be added, but this may slow and reduce the diffusion of the solvent into the heavy oil and slow down the viscosity reduction process although the non-condensable gas maintains the operating pressure.

The well completions will also be less expensive than those needed to support a thermal process. Vapex should not suffer from the formation damage problems (e.g. swelling clays) that can affect steam floods. Vapex also has a great advantage over SAGD where the steam can condense and dissipate into any underlying aquifer, whereas the Vapex solvent will 'float' on the aquifer surface and continue to help recover oil. The solvents can be recovered from the oil at the surface by distillation and recycled.

Potential disadvantages of the Vapex process are the high cost of the solvent and the loss of the solvent remaining in the vapour chamber or in an overlying gas cap. Another potential problem is any reservoir permeability loss due to asphaltene precipitation as mentioned earlier. The start-up of the process is likely to be slow because the initial vapour diffusion into the heavy oil within the porous media is very slow, so that there will be a long induction period before there is sufficient penetration of the vapour into the oil over a large enough area. The initial fluid movement by gravity to the drain well will be low and thus production rates will also be low (in contrast to SAGD, where the thermal diffusion will enable a quicker reaction time). This may be alleviated by having the horizontal well pair fairly close together to ensure early communication, or by using a multilateral well approach to the upper borehole so covering a wide area.

5.2.2 Development

Although field trials have only recently been started, it is likely that Vapex may develop quickly into the process of choice for heavy oil recovery where there is an accessible source of solvent [15], In particular, Vapex is likely to be useful in the exploitation of heavy oil in thin formations (approximately less than 10 m) or reservoirs with bottom water and/or high water saturation, vertical fractures, low porosity and low thermal conductivity where the total thermal losses via piping and tubing may make thermal recovery uneconomic and inefficient. Higher pressure reservoirs could also be candidates because a steam flood would be reduced to a hot water flood at these conditions, and in reservoirs where SAGD is likely to fail because there will be too much heat loss to the caprock. On the other hand, the solvents required for the 'heavier' heavy oils may be too costly, so that the process may eventually be limited to 'lighter' heavy oils.

The volume of solvent used per volume of oil recovered will affect the economics of the process. Clearly, optimisation of the solvent composition, ease of solvent recovery operating pressure and well configuration will be important for field implementation.

5.2.3 Variations

As with SAGD, various well configurations have been suggested, depending on the heterogeneity of the reservoir and the viscosity of the oil. If the inert gas addition proves successful, Vapex may be able to sequester greenhouse gases as well as enable in situ upgrading of the oil by the removal of asphaltenes. In a variation of the process, a combination of SAGD and Vapex has been proposed; wet Vapex, where steam and propane would be used [11]. The steam forms a hot zone around the injector and producer. The propane moves out further than this zone and as the diluted oil falls into the hot zone region, the propane is evaporated from it and moves back up, i.e., an internal recycling of the propane. The propane convects heat and since it is miscible with oil it reduces the viscosity and interfacial tension. Adding the initial heat could create a faster start-up for the process.

Visualisation of the chamber for both the Vapex and SAGD process have been carried out in laboratory-scaled experiments, as no 4D seismic visualisation in the field has yet been reported. The chamber grows almost vertically upwards, then spreads sideways as it reaches the top of the reservoir [12–16]. For this to be possible physically, then initially, the films drain down almost vertically (90°), but as the chamber reaches the top of the reservoir, the flow becomes a combination of both vertical drainage and drainage at an angle, with the overall effective drainage angle being a function of the extent to which the chamber has formed sideways, and the reservoir heterogeneity (**Figure 4**).

On top of these macroscopic considerations, the happenings within the reservoir at the pore (microscopic) scale must also be considered. The next section introduces these processes, particularly film drainage, which occurs within the vapour chamber as the vapour diffuses into the oil and mobilises it.

6. Gravity Drainage as applied to Heavy Oil Reservoirs

Capillary, buoyancy and viscous forces control fluid displacement and flow within a porous medium. Water, oil and gas separate under the influence of gravity according to their densities and since the density of water is higher than that of oil or gas, water will move to the base of the reservoir due to gravity and gas to the top and oil downwards, if gas is present. Gravity drainage (the vertical movement of fluids) can play an important part in the recovery of oil from a reservoir [18–23] and SAGD and Vapex are examples of enhanced gravity drainage processes.

6.1 Gravity Segregation

In order to be able to design these processes, it is essential to understand the mechanisms and dynamics of 3-phase gravity segregation, but the detailed mechanisms of gravity drainage at either the bulk scale or the pore scale have not yet been properly identified. This is because the processes are controlled by the transport of fluids and/or heat within the reservoir porous media within the vapour/steam chamber, which is itself expanding in the reservoir. The chamber boundaries lie between oil mobilised by the process and outer viscous oil which has yet to be contacted by heat or solvents (**Figures 3** and **4**). As the vapour/steam chamber expands, the volume of fluids draining by bulk drainage along the chamber edges into the bottom well will increase. Within the chamber porous matrix, the oil saturation continues to decrease by film drainage. Clearly, counter current flow must occur to keep the chamber filled with fluids, but the fluids are not always flowing as interconnected phases, but can be bubbles and droplets which can move if the prevailing capillary forces acting within the porous medium allow. Fluid viscosity, interfacial tensions, wettability and pore geometry affect the rate.

6.2 Rate Problems

Unfortunately, gravity drainage is a slow process, but factors favourable to faster segregation include high vertical effective permeabilities, a large cross-sectioned area available for segregation, and the lower viscosities created in the SAGD and Vapex processes. Initially, as the steam/vapour chamber is being formed and until pathways have been established, the flow of fluids into the producing (lower) well will be very slow. Then, when pathways have been created and the viscosity of the oil lowered by heat or impregnation, the oil and condensate will flow downwards, with the oil flowing along the edges of the chamber in particular (**Figures 3** and **4**).

The rate of movement due to gravity segregation is controlled by the density difference, $\Delta\rho$, between the fluids. Clearly, gas will separate the fastest. For typical reservoir flow rates away from the wellbore (where oil moves at less than one foot per day, mm per sec), the gravity pressure gradient of $\Delta\rho / h = \Delta\rho g$ is greater than the viscous pressure gradients created by flow (calculated by Darcy's law, $q\eta / kh$ where q is the flowrate, η the fluid viscosity, k the permeability and h the sand thickness), although as discussed below, because much of the gravity flow is through thin films, the actual flow rates are low.

6.3 Wettability and Spreading

In the absence of density differences, the oil/gas/water are distributed in a hierarchy within the porous media according to the wetting and spreading preferences of the fluids. Thus, the fluid/fluid interactions (such as interfacial tension) combined with the fluid/solid interactions determine the wettability and spreading properties of the system, which in turn control the configuration (topology and morphology) of the phases within the porous media. The wettability determines the preference of one fluid to adhere to a solid (wetting fluid) in the presence of other immiscible fluids (non-wetting fluids). The wetting fluid forms a stable wetting film, which is in hydraulic continuity even at low saturation. The spreading characteristics determine the ability of a liquid to form a fluid layer (spreading film) onto this interface.

The spreading coefficient of a fluid, S, is the imbalance between the interfacial tensions (forces) acting along a contact line between fluid phases. For the gas-oil-water system, the oil spreading coefficient on a water-gas interface is defined as [3, 23]:

$$S_o = \gamma_{wg} - \gamma_{ow} - \gamma_{og}$$

where γ_{wg} is the water-gas surface tension, mNm^{-1} (dynes/cm), γ_{ow} is the oil-water interfacial tension and γ_{og} is the oil-gas surface tension. A spreading coefficient can be either positive or negative. If negative, the oil does not spread and tends to form a lens. If S_o is positive, it indicates that oil tends to form a spreading film on the water-gas interface because γ_{wg} is larger than the sum of other two interfacial tensions $(\gamma_{ow} + \gamma_{og})$.

The capillary pressure is the combined effect of interfacial tensions and the rock characteristics (pore geometry and wettability) and controls the equilibrium configuration of fluids. Any change in these interactions can modify the trapping and movement of gas/oil/water. For example, when oil is spreading between gas and water and the medium is water-wet, gravity forces will favour the downward flow of oil by spreading film drainage and create a bottom zone of high oil saturation.

6.4 Drainage

6.4.1 Gravity Drainage

Density differences can modify the fluid movements. There are two gravity drainage flow types occurring during SAGD and Vapex, boundary (bulk) and drainage within thin films.

6.4.2 Boundary (Bulk) Drainage

Boundary (bulk) drainage is where the oil saturation is high so that the effective permeability to the oil (heated or solvent impregnated) is close to that of the absolute permeability of the porous media (**Figure 5**). This occurs at the edges of the steam/vapour chamber as shown in **Figures 3** and **4**. The oil flows at a rate inversely proportional to viscosity according to Darcy's law; the lower, the faster.

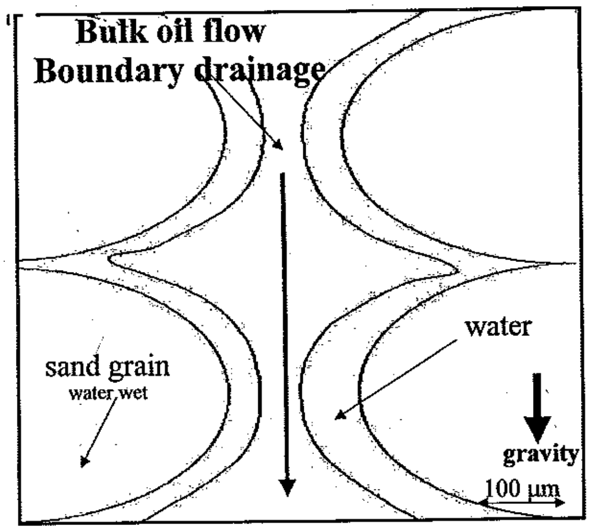

FIGURE 5: *Bulk Gravity Drainage; Oil flows through the Centre of the Pore Space and Connate Water adheres to the Sand Grains (which are Water Wet)*

6.4.3 Oil Film Flow Drainage

Oil film flow drainage occurs within the porous matrix of the steam/vapour chamber and is the flow of oil at much lower saturations, probably close to the residual oil saturation. Here, the oil moves within thin oil films along the connate water attached to the pore walls (assuming water-wet conditions) or as droplets mixed with the condensed steam or vapour within the porous matrix. This flow will be slower than boundary drainage. Fuller details are discussed in Section 6.1.2. There will also be flow of emulsified oil and water for SAGD and vapour for Vapex.

6.5 Gravity Drainage Experimental Examples

6.5.1 Raschig Rig Example

A clear demonstration of the gravity drainage processes of bulk and film flow can be seen during the draining of a fluid from a column filled with Raschig rings. In our experiments, the rings were plastic cylinders, 1 cm outside diameter 0.8 cm inner diameter and 1 cm length randomly packed in a cylindrical tube of length 48 cm and diameter 3.5cm. The tube was first filled with water (viscosity 1 cp) and the time taken for it to drain recorded.

Initially, the column drained fast until only the water trapped by capillary forces between the rings was left with the bulk of the space filled with air. Then, film drainage took over (albeit a slow process) as the water drained further from the Raschig rings to a low water saturation, but this was slow (**Figure 6**). If the fluid viscosity was changed to diluted molasses (viscosity 110 cp), the rate of drainage would have been much slower. From **Figure 6**, it can be seen that with water after the bulk drainage, there was little film drainage, but with molasses because of viscous hold-up, some 20% of the molasses drained after the bulk drainage had been completed. Other examples have been presented elsewhere [22,23].

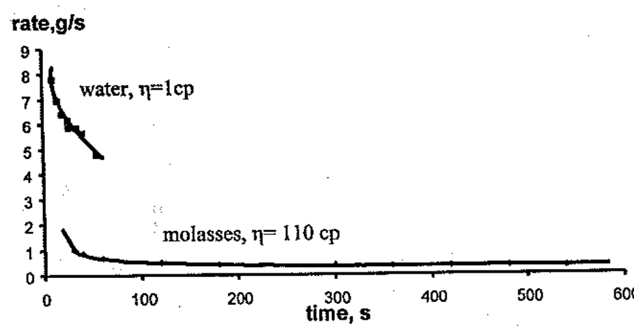

FIGURE 6: *Drainage Rates for Raschig Ring Experiments for Water and Molasses*

6.5.2 Film Flow Demonstration by Micromodel

A study of the flow within thin films within porous media saturated with three phases has been carried out to compliment those performed elsewhere [24-26]. In this work, micromodels were used. Micromodels

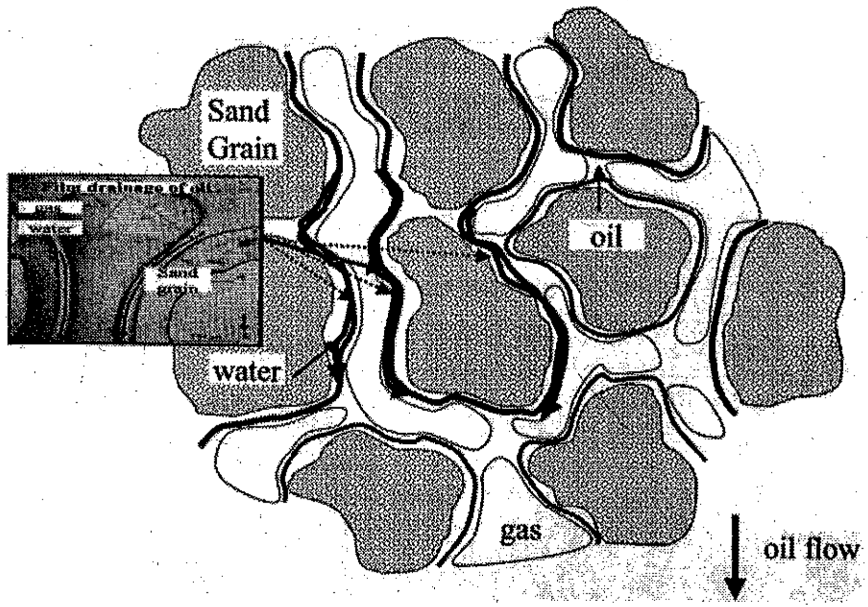

FIGURE 7: *Film Flow*

are 2-D transparent etched networks usually manufactured in glass, and in this case sealed, which can give a visual demonstration of many important phenomena occurring within porous media [e.g., 18,20,21,26].

In this work, the pore matrix was water-wetting and the gas non-wetting. For our system, the oil was spreading over water as γ_{wg} was 72 mNm^{-2} γ_{ow} was 38 mNm^{-2} and γ_{og} was 24 mNm^{-2} The glass micromodels were cleaned using 0.1% N sodium hydroxide. Water, dyed pink, was injected into the model by syringe followed by oil, dyed blue to displace the water until no more water could be displaced, (connate water conditions). The model was placed vertically and the system allowed to drain (gravity drainage), with air being injected into the bottom of the model and the top of the model closed, with the bottom of the model remaining open. This displaced around 50% of the oil. At regular intervals (days), the position of the fluids were monitored and recorded using a video camera. This video recording was performed with the model horizontal, but no disturbances to the fluid positions were noted during this procedure.

Figures 7 and **8** illustrate the oil flow mechanisms where the oil in continuous state drains slowly downwards along the water surface. Other mechanisms of oil droplet 'hopping' and droplet movement have been reported previously [20,21]. The thickness of the oil films were observed to decrease with time and were not always continuously connected throughout the model, and may only be interconnected across a few pore throats at any one time, but the connections were continually forming and breaking. The oil collected in the pore throats and the bubbles moved up slightly. The oil film thinned at the top and became thicker at the bottom. Gas bubbles exist as individual bubbles held by capillary pressure at smaller pore throats or may continue across a number of pores. However, as the drainage progresses, the bubbles also continually break and then re-establish their continuity across a number of pore throats. This allows the gas to percolate upwards.

On a larger scale, the flow was clearly counter-current as the oil was easily replaced by the injected gas. If the oil viscosity is higher, the oil cannot drain as fast as the gas is being injected into the model then some of the gas has to flow co-current with the oil as the oil leaves the model. Thus, counter-current flow always occurs, but in some cases both counter-current and co-current flow occur simultaneously.

The rate of oil drainage within the SAGD or Vapex chamber through films will be a function of viscosity. Rates of oil drainage through thin films has been demonstrated and calculated by **Blunt *et al.*** [22, 23], where they derived a general equation for a vertical liquid film to drain by Poiseuille flow show that the

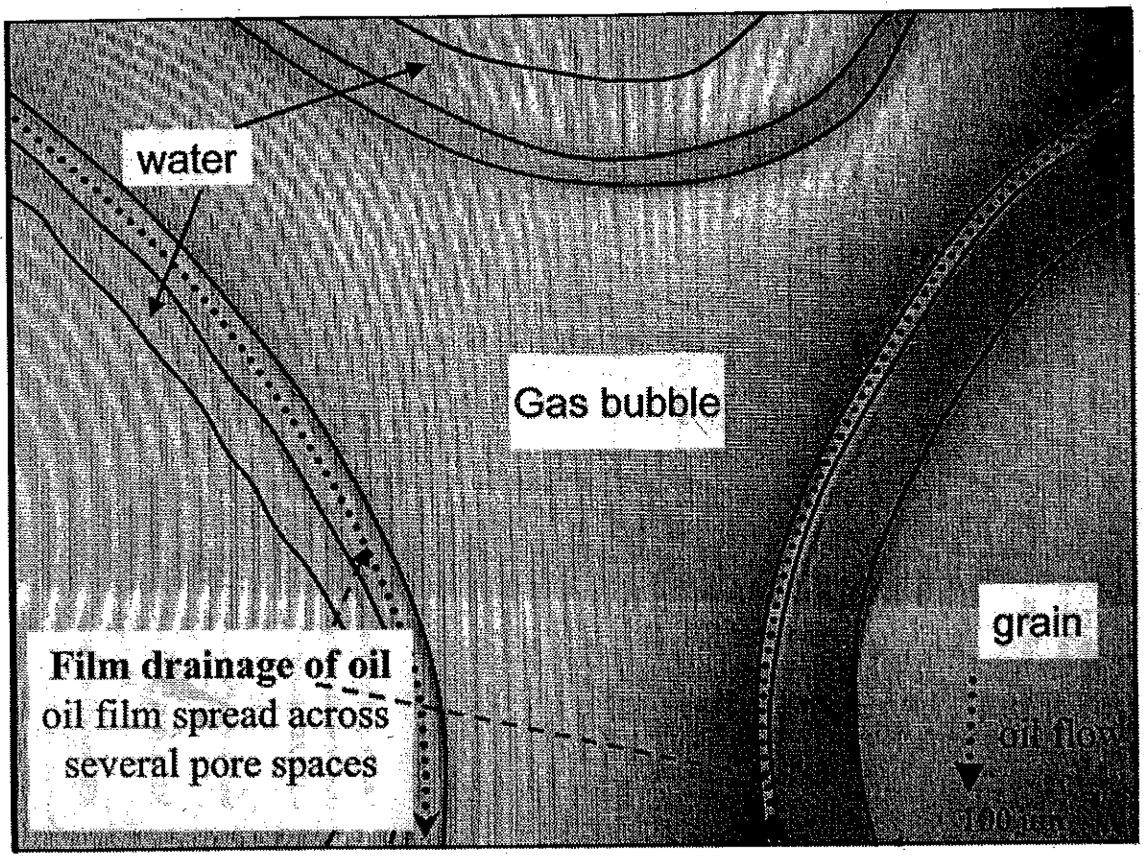

FIGURE 8: *Film Flow – Detail*

drainage flow rate depends inversely proportionally on the fluid viscosity. In our experiments, we observed the movement of marker particles and our calculations showed that the average drainage velocity for a 187 cp oil was approximately 40 nm/sec (0.003m/day), which is some 1000 times slower than the average movement in a oil reservoir due to viscous displacement of one foot per day (~0.3 m/day, 3 μm/sec). Thus, gravity drainage is a very slow process but given time or a suitable area over which the flow is active, then economic volumes can be transported to the (horizontal) production wells at the bottom of the SAGD or Vapex chamber. However, crevices and corner effects also significantly affect the rate of flow of films, in particular wetting films. Experiments have showed that an oil film drainage took almost 1000 times longer to drain in a circular capillary tube than a square one [22], indicating the morphology of the porous matrix, film thickness and wettability are very significant.

The implication of all these studies is that the make-up of the porous matrix along with the composition and physical properties of the heavy oil are important when designing a gravity drainage process.

7. Implications of Gravity Drainage Methods for Trinidad

Trinidad has over 1 billion barrels (109) of heavy oil both onshore and offshore, [2], which although small compared to the total world resource is still a considerable quantity, because if 20% could be recovered over 20 years, there would be a flowrate of 50,000 barrels/day of oil. SAGD and Vapex could be successfully applied to Trinidad's heavy oil reservoirs if the proper geological assessments suggest it is possible. Additionally, supercritical fluid extraction has been explored, at least at a laboratory level, for tar sands in Trinidad and extraction been shown to be feasible [27]. By picking up light hydrocarbons from the reservoir oil, it has been shown that miscibility can be achieved, also CO_2 around 2000 psia (136 atm) and 40–70°C is able to dissolve in the oil and swell it so that more of the oil is displaced. CO_2 also dissolves in the water and this too expands, displacing more fluid. Unfortunately, as the CO_2 strips off the lighter hydrocarbons, depending on the composition of the oil/tar, it can leave behind an asphaltic residue which could clog some of the porous matrix which would be detrimental to the process if the precipitation was near to the production well.

Nevertheless Vapex using CO_2 (the critical point of CO_2 is 1073 psia (73 atm) and 31.1°C (88°F)), with perhaps some additional hydrocarbon gas, such as propane, and with multilateral wells, could be beneficial to certain Trinidadian heavy oil reservoirs, where the reservoir temperature is perhaps 40–50°C i.e., ~2000ft or deeper.

8. Conclusions

- Economic recovery of oils of viscosity >100cp is possible by gravity drainage by the reduction of the heavy oil viscosity by heat or solvents.
- The advantages of SAGD and Vapex over conventional steam flooding include the following:
  - Gravity is exploited since steam/hydrocarbon vapour are injected through the top horizontal well, rise and reduce the oil viscosity and enlarge the density difference which creates an upward movement of the less dense steam/hydrocarbon vapour and enables the heated/diluted less viscous oil to move downwards to the producer well.
  - Unlike the cold production or steam drive, the oil does not have far to move to the production well.
- Recovery is due to boundary drainage and film drainage within the steam/solvent chamber.
- Horizontal wells are essential. They allow more reservoir volume to be exploited with fewer wells, and the distance between injector and producer allow reasonably rapid communication. The horizontal well length can be optimised based on a better understanding of the in situ pressure drop that occurs from the heel to toe of the well. It is necessary to monitor the pressures so that the fracture pressures of the area are not exceeded due to the unconsolidated nature of some reservoirs that could lead to the loss of steam or vapour to thief zones.
- Highly heterogeneous reservoirs (fractures and shaly sands) might be detrimental to the formation of the steam/vapour chamber for SAGD and Vapex. The incorporation of CHOPS (Cold Horizontal Oil Production with Sanding, [8]) before any of the advanced thermal or vapour injection processes can help to characterise the reservoir, including the identification of thief zones that would lead to early steam breakthrough in CSS, Cyclic Steam Stimulation, and SAGD or vapour loss in processes that involves mass transfer (Vapex).
- The exact mechanisms of fluid flow within the porous matrix of the reservoir are not fully understood; in particular the rate of film drainage that occurs in the three phase flow processes of gas, water and oil. Clearly, they depend on the effects of temperature on viscosity, mass transfer, interfacial tension and wettability, particularly if asphaltine dropout changes the rock wettability as well as clogging the pores. Microscale experiments using etched glass micromodels can show aspects

of these mechanisms. More research is needed here.

- Vapex and SAGD, and including perhaps supercritical fluid extraction could allow re-entry into some of Trinidad's older fields and recover some of the remaining oil, perhaps with a combination of processes.

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