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# CORE FLOW LIFT: A NEW ALTERNATIVE FOR HEAVY OIL PRODUCTION

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***Abstract.*** *Due to natural difficulties in handling, heavy oil production has been expensive specially in offshore fields with deep water sheets. In this context, a new alternative is proposed in this work: the use of core annular flow pattern (shortly "core flow"). This flow arrangement can be induced through the lateral injection of relatively small quantities of water, in order to get a lubricated oil core along the pipe. Experimental measurements of frictional pressure drop in upward vertical core flow in a 2.76 cm ID pipe, using a 17.6 Pa.s and 963 Kg/m*$^3$ *oil and water at room temperatures show a decrease of the frictional pressure losses by a factor of more than 1000 times with respect to single phase oil flow, while the total pressure drop was reduced by more than 45 times. Thus, the aim of this work is to compare the core flow technology with the other alternatives for heavy oil production, as well as to suggest ways to implement it in the field. The general conclusion is that the core flow lift of heavy oils is quite viable and advantageous, suggesting its testing in a pilot scale.*

***Keywords:*** *Liquid liquid flow, Core flow, Petroleum engineering, Heavy oil production*

## 1. INTRODUCTION

The importance of heavy oil in the world oil market (whose reserves are estimated in three trillion barrels of oil in place) is rapidly increasing, in view the progressive exhaustion of light oil reserves in the next few decades. This leads to a growing economic interest in larger heavy oil reserves and to the research of technologies capable to improve the recovery factor of heavy oil fields (Moritis,1995).

In the development of any field, the main objective is to increase the economic productivity of the wells. In the heavy oil case, this objective is more difficult to attain and a better integration of the technological solutions in each stage of the development process (Fig. 1) is necessary. This includes several actions, from improvement of the flow conditions inside the reservoir up to the analysis of the technical specifications required by the refinery. In heavy oil production, some technologies have been developed for this purpose. These are the addition of heat (thermal methods) and the addition of diluents or aqueous solutions of surfactants or dispersants (cold production).

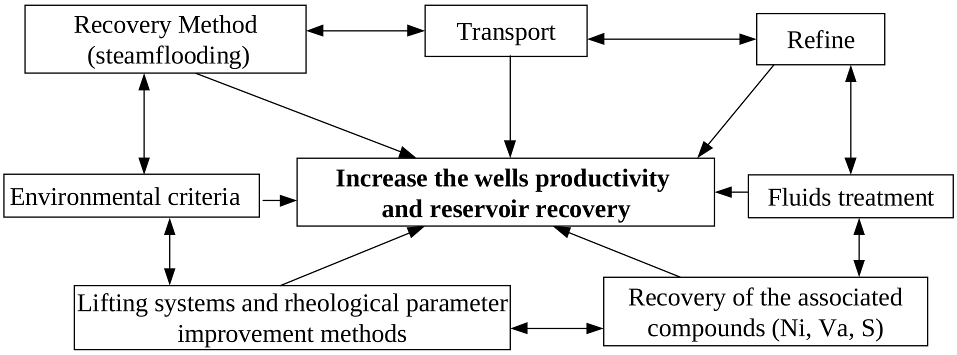



Figure 1 - Schematic view of the integration of development stages in a heavy oil field.

In this scenario, a different alternative is proposed in this work. It is based on the accumulated experience in the transportation of viscous fluids through the injection of small amounts of water, in such way to lubricate the oil and to obtain the core annular flow pattern (shortly core flow), which allows a drastic decrease in the frictional pressure drop.

Since the series of studies carried out in Canada by Russel & Charles (1959), and notably Charles, Govier & Hodgson (1961) the advantages of the core flow technology have been fully appreciated. More recently, theoretical and experimental studies have been made for horizontal flow, directed to applications in heavy oil transportation (for example Oliemans *et al.*, 1987; Arney *et al.*, 1993; Ribeiro *et al.*, 1996; Bannwart, 1998). Except for the experiments done by Bai (1995) in a 0.9525 cm ID glass tube, no experimental study has been found on vertical core flow.

However, the idea of applying the core flow technology in heavy and ultra-viscous oil production has not been tested. Thus this paper is turned to propose and discuss the "core flow lift" project in the current state of art of heavy oil production, and to make some considerations for its practical implementation in a production well.

## 2. A REVIEW OF HEAVY OIL PRODUCTION TECHNOLOGIES

Heavy oil is usually considered as having density larger than 934 kg/m$^3$ (<20 ºAPI) and viscosity larger than 0.1 Pa.s (100 cP) at reservoir conditions (Briggs *et al.*,1988). It is characterized by the low content of light hydrocarbons and frequently, it is produced with relatively high sand proportion and foam formation. Though very viscous, heavy crudes usually behave as Newtonian fluids.

The major problems in heavy oil production are:

- The rheological properties, such as viscosity, yield point and pour-point, make the flow very difficult; this results in high pressure drop and power requirements, overloading and subsequent failure of the production equipment, increasing the production costs;
- High density, which increases the fluid hydrostatic weight;
- Sand invasion, causing equipment abrasion;
- Presence of non-hydrocarbons: vanadium, nickel, sulfur, etc. that difficult the treatment and leading to erosion problems in all productions stages.
- Problems in starting the production after the initial completion and subsequent restarting after temporary shut-ins.

- In offshore fields, these difficulties become more serious due to the adverse conditions present during production and transportation along the sea bottom.

Usually, schemes are adopted which involve the integration of methods. These are selected according to the characteristics and conditions of the fluids and reservoir. Current schemes for heavy oils are based on the improvement of the rheological parameters (viscosity reduction) inside the reservoir and the well, and are almost always associated to an artificial lift system. Figure 2 shows the main technologies used in the production of heavy oils.

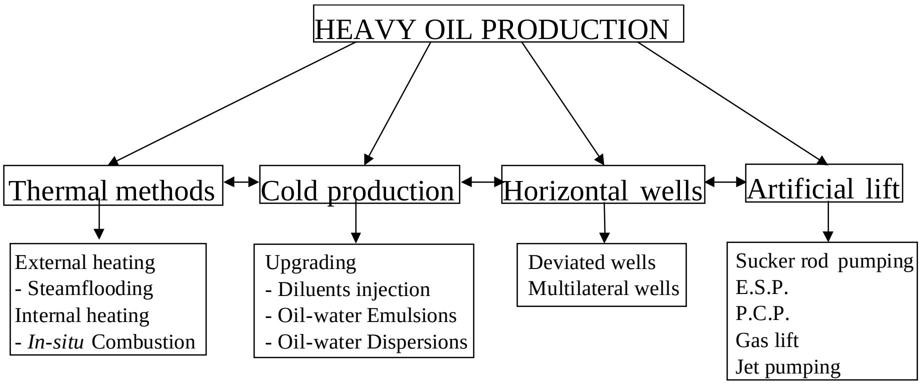


Figure 2 - Main technologies used for heavy oil lifting

### 2.1 Artificial lift

Methods currently used for heavy oil production include: sucker rod pumps, electrical submersible pumps, progressive cavity pumps, gas lift and jet pumps.

The sucker rod pumping is very common in on-shore production. However, it has been substituted due to its low efficiency and problems related to (Gonzalez & Reina, 1994): 1) frequent failures in the rod string due to the high stresses generated by the high viscosity and density and therefore increasing the number of workovers in the well; 2) pump overloading, consequently larger energy expenses. 3) restrictions when applied in deep and deviated wells; 4) gas interference in the pump. This method is impractical for offshore situations.

Electrical submersible pumps (ESP) are recommended for producing at high flow rates, and are the prevalent method in offshore wells. Some authors (Gonzalez & Reina, 1994) reported that in spite of the pump's low efficiency (aprox. 40%), relatively high oil flow rates were reached, 186 $m^3/d$ (1170 BOPD). Furthermore, the heat generated by the motor during its operation allows an important reduction in the oil viscosity at the pump intake. The main drawback of this method is the high failure rate and the need for a workover/drilling unit to replace the pump, increasing production costs. This may become dramatic in offshore fields.

Progressive cavity pumps (PCP) have good adaptability to highly viscous and abrasive fluids associated to sand invasion and may also produce in the presence of free gas. Its efficiency frequently gets to 60%. However, this system has also some disadvantages when compared with other systems (Dun *et al.*, 1995): 1) limited production flow rates (max. 500 $m^3/d$) and head lifting (max. 2000 m); 2) temperature of operation must be lower than 350 ºC; 3) high sensitivity to fluid conditions; 4) lack of experience to design, install and operate the PCP system; 5) limitations when used in reservoirs with thermal recovery (steam flooding). Though mostly applied to on-shore fields, this method has a promising future in offshore production.

Gas lift systems have not been used frequently in heavy oil production. Their application is restricted to high gas-oil ratios (GOR), which are uncommon in heavy oil fields, to the presence of a gas cap in the reservoir, or to external gas sources.

Jet Pumps have drawn interest for heavy oil production due to the simplicity of the equipment, which does not have mobile parts, increasing its operational continuity and decreasing the number of workovers. This is reflected directly in low operational costs. The system has been tested together with a diluent, as power fluid (De Ghetto & Marco, 1994). These tests demonstrated that an appropriate combination of the jet pump system and a diluent can be an efficient and economical technique for lifting heavy oils. This fact is due to the very good mixture among the heavy oil and the diluent, which decreases the fluid viscosity and density.

### 2.2 Horizontal/deviated wells

Horizontal/deviated wells are a well established technology that significantly increases well productivity and can be applicable in almost any type of reservoir. The success of this technology has changed the face in exploration, development and production of the petroleum industry, resulting in a reevaluation in the way to look at, describe and produce petroleum reservoirs (Crouse, 1991). The main reason to apply this technology is to increase the contact area between the well and formation, increasing the productivity in all reservoir recovery stages. It can be employed in all stages of the reservoir development, from exploration to enhanced oil recovery (EOR). The use of this technology in heavy oil production is based on the important increase of the well productivity; on the better sweep efficiencies and better control when a method of thermal recovery is used (for instance, steam flooding); and on the use of the gravitational drainage mechanism in low pressure reservoirs.

### 2.3 Thermal methods

Thermal methods represent the most widespread technology used in the heavy oil production and consists in the addition of heat inside the reservoir in order to reduce the flow resistance through the oil viscosity reduction. There are basically two types of processes, Briggs *et al.* (1988): external heating - i.e. heat is injected into the reservoir from an external source - and internal heating, where heat is generated in situ.

The external heating is usually made by the injection of steam or water at high temperatures. The most common practices are the cyclic and continuous steam injection. Cyclical injection requires a great number of producing wells to drain efficiently the reservoir. Continuous injection requires a certain pattern of injection. Usually, this process is a subsequent stage of the cyclical injection, when a hydraulic communication among the wells being stimulated has been already reached. However, this method is not thermally efficient, particularly in deep reservoirs and thinner formations, where heat losses along the well and through the adjacent formations become significant. Other problems are: the high mobility of steam and therefore its low displacement capability, the requirement of a great amount of fresh water available for steam generation, and the need for maintaining heated the adjacent areas of the formation in depleted regions around the injection well.

Internal heating is made via the "in situ" combustion, which is the easiest way of generating heat inside the reservoir. In this process, the creation of a combustion front that advances slowly from an injector well to one or more producing wells is required. The oil ahead of combustion front is carbonized, producing a coke deposit among the sand grains. This deposit constitutes the principal fuel of the process. Although combustion is more energy efficient than steam flooding, the operational problems in the field are more critical (Briggs *et* *al.,* 1988). For example, the high temperature encountered when the combustion front has been reached a production well. Others problems are the sensitivity of air flow to formation heterogeneities, low air injectivity, formation damage, reduction of permeability, erosion and production problems relating to corrosion, emulsions, sand and gas locking in pumps.

### 2.4 Cold production

Cold production refers to the methods that improve the rheological characteristics of the oil without the addition of heat. This technology includes the injection of diluents and the downhole generation of oil in water emulsions or dispersions.

In the first, a diluent is injected at the wellhead to create a mixture with the oil which has better rheological characteristics than the original oil. This diluent may be a light hydrocarbon or a high °API crude oil. The mixture is made downhole, reducing the density and viscosity of the oil, and making easy its flow to surface. In most cases, this technique is associated with some artificial lift method to improve performance. The major disadvantage of this technique is great amount of diluent demanded, which increases notably the production cost. Furthermore, the produced mixture by this method alters the original features of oil, limiting its industrial application.

Generating oil-water emulsions is another technique used to reduce viscosity. This is accomplished through the injection of a solution of water and surfactant at the wellhead (Browne *et al.,* 1996). The surfactants are chemical products that reduce the oil/water interfacial tension, facilitating the formation of an oil-in-water emulsion. This technique is suggested to be quite efficient. However, it requires an additional separation and treating system to leave the oil under sale conditions and reuse the aqueous solution containing the surfactant. Other problems to be solved are: 1) the formation of a stable emulsion inside the well requires the use of special devices to facilitate the mixture of the aqueous solution with the reservoir fluids; 2) the possible occurrence of inversion of the oil - water emulsion in a water - oil emulsion, deteriorating the rheological properties of the produced fluid; 3) the foam production during the stage of gas separation, making necessary the use of antifoaming agents. To overcome these difficulties, Bertero *et al.* (1994) proposed the use of dispersants, which favor the formation of the oil-water emulsion without reducing the interfacial tension.

## 3. CORE FLOW LIFT

The new alternative for heavy oil production proposed in this work can be called "core flow lift". This technique increases the well productivity significantly, since it decreases, in a drastic way, the friction pressure losses without heat addition (i.e. totally in cold conditions) and without using chemical agents or diluents.

The proposed technology is based on the use of the oil-water core annular flow pattern, which can be induced by the lateral injection of relatively small quantities of (cold) water into the pipe, in order to get a lubricated oil core along the production string. The technology is well known in the pipeline transportation of viscous oils, and two examples of commercial applications can be mentioned, one in California (39 Km and 6 inch pipe from North Midway Sunset Reservoir to the central facilities at Ten Section) which operated for 12 years since 1970, and another in Venezuela (55 Km and 6 inch pipe from San Diego, Anzoategui to the Budaré treatment station) which is operating at the moment. Both with excellent results.

The new feature introduced in this work is to adapt the technology for production operations of heavy oils in vertical wells. Since the resultant friction pressure loss in core flow is comparable to the flow of water alone at total flow rate (see, for example, Bannwart, 1998) it can be a very attractive option for offshore fields with deep water sheets, in view of the adverse sea bottom conditions.

Figure 3 shows schematically the basic requirements of a "core flow lift" system: a water injection system, an injector nozzle, a downhole oil pump and a surface separation system that allows to reuse the injected water.

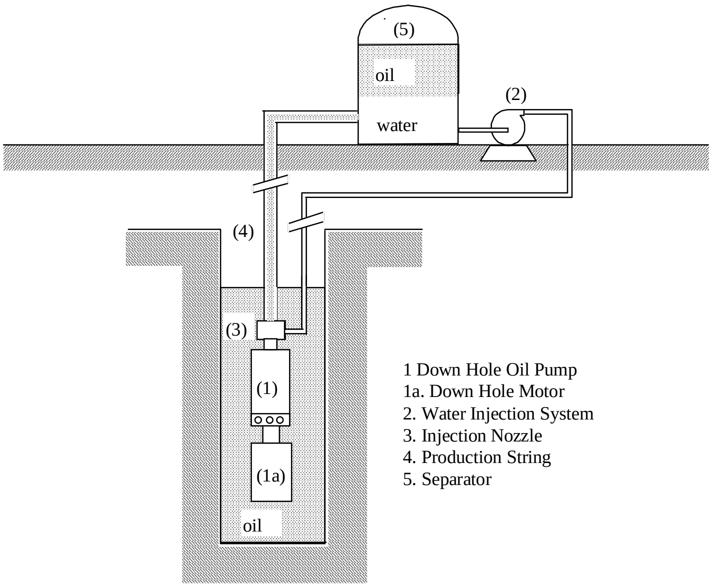



Figure 3- Schematic representation of a producing well using *core flow*

The heavy oil is driven by a down hole pump which is associated to a bottom hole electric motor. A water injection nozzle is placed at the pump discharge that allows to induce the core annular flow pattern. The oil-water mixture flows in production string to the surface facilities, where is separated and the water is pumped back to the nozzle. The bottom pump, of ESP or PCP type, would desirably have a down hole motor, not a transmission system by rod string (which could destroy the flow structure). The best combination would be a "core flow lift" associated to a PCP system, since the later has a better performance with highly viscous and abrasive fluids.

Figure 4a shows a conic injector nozzle, which was used in the experiments done by Vanegas (1999). This device allows to reduce the oil pump outlet diameter to the desired well size, while injecting water laterally. Figure 4b shows another possible injector nozzle for applications which does not require reduction in pipe diameter. In both devices, the oil is placed in the pipe center and the water leaves the injector nozzle forming an annulus around the oil flow.

This technology can be applied to either onshore or offshore, horizontal or vertical wells, with a few modifications in the well configuration. Of course, heavy oil transportation from wellhead to separators can be also accomplished via core flow.

Core flow (oil-water) can be used for heavy oil lifting in production systems where a direct communication between the well and the production facilities exists, as for example in offshore deep water wells shown in Fig. 5. In these cases, the core annular flow pattern may be induced either in the whole well, or just when the oil flow gets the water sheet (well head), where the temperatures are lower. Application of this technology to production systems based on submarine production manifolds, where the production of several wells (operating in core flow) is grouped, requires a submarine separation system associated to an injection system to induce core flow in the grouped production tubing up to the surface.

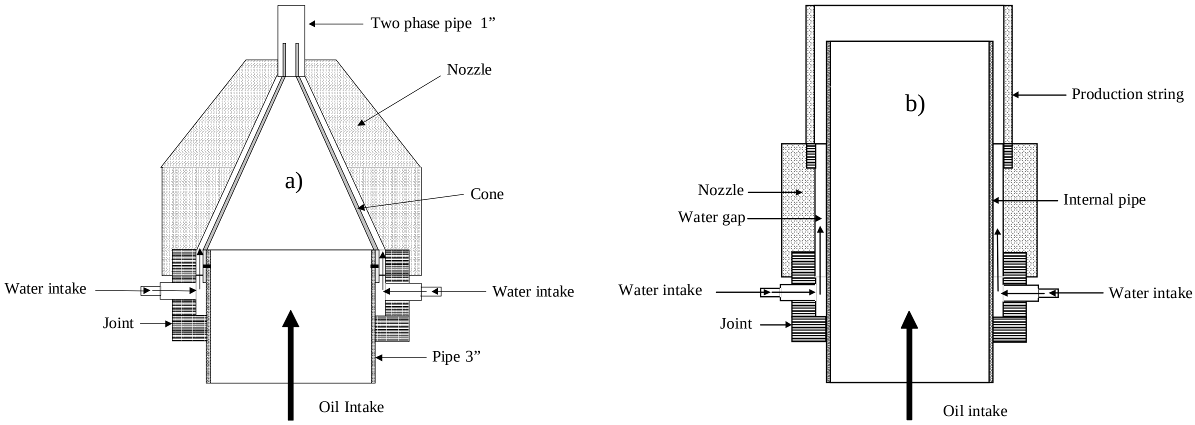



Figure 4 – Injector nozzle configurations

An important limitation of this technology as proposed in this paper is the need for a surface separation system, which usually takes a significant space in platforms or production ships. However, in the case of heavy oil this may be compensated by the gain in production rate.

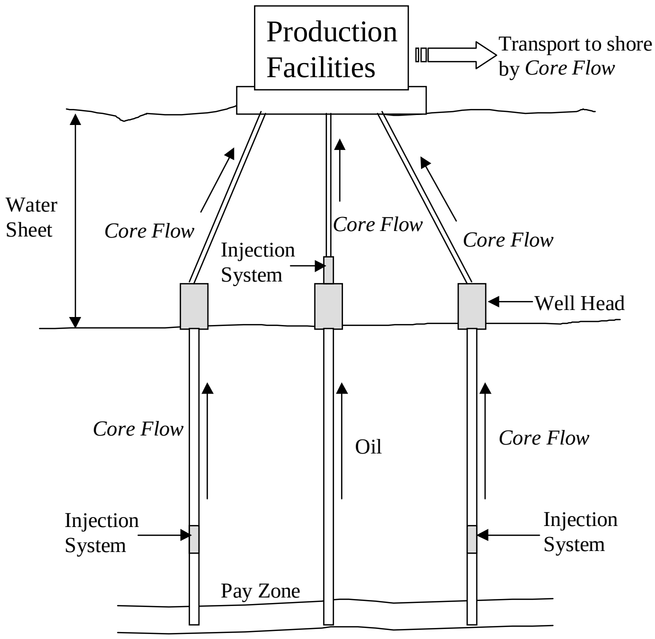


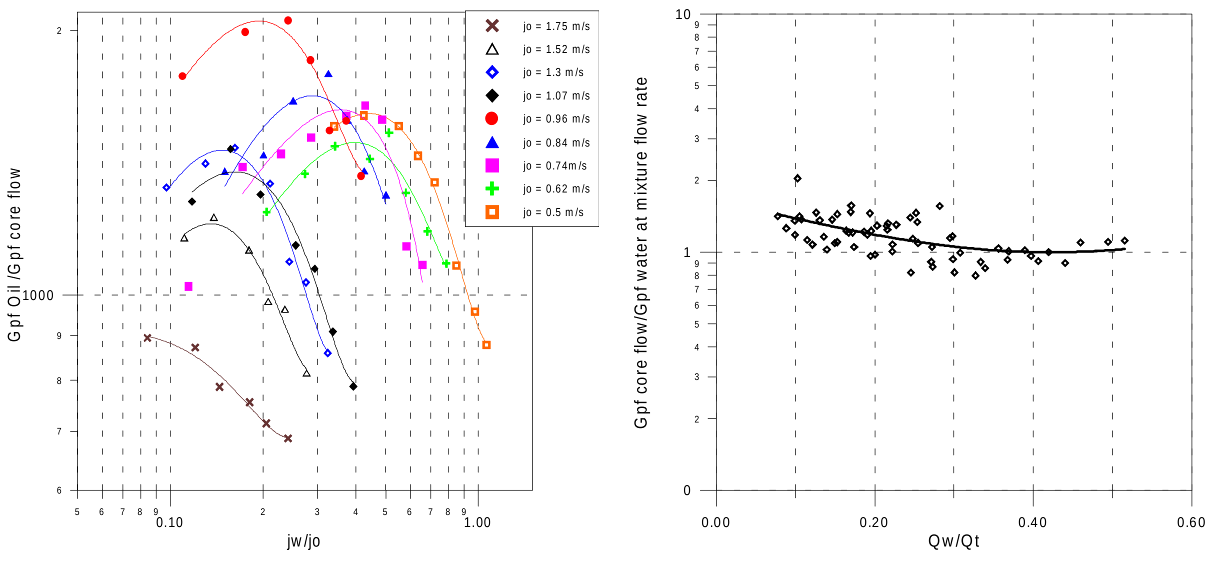

Figure 5 - Schematic representation of core flow application to heavy oil offshore production, where a direct communication between each well and surface facility exists

As observed in experiments (Bai, 1995; Vanegas, 1999), the core annular flow is a hydrodinamically stable and robust flow pattern, which can be preserved through different types of pipe fittings. This is a significant fact, since in a typical length of a production string several fittings are usually present. However, use of smooth bends and joints is advisable in order to favor the core flow stability.

Another important aspect is the tendency of the oil to stick on the pipe wall. This fouling may progressively build up, causing the blockage of pipe flow section. This situation can be also found in a sudden shut-down of the line, when oil-water separation occurs. To minimize this problem, Ribeiro (1994) proposes the use of *meta-silicate of sodium* together with cement-lined pipes for water lubricated transport of heavy oil, with excellent results in laboratory tests. For field applications, however, we suggest a simple treatment with *m-silicate of sodium* whenever necessary, since the resistance of the internal coating of mortars of portland cement may be seriously limited by the efforts generated by the own weight of the production string. The fouling problem in heavy oil-water flow is therefore open to future research.

In view of the above, we suggest that the water used to induce core flow be the same production water, which often contains small amounts of salts (such as *m-silicate of sodium*), that help keep the pipe wall from fouling by the oil.

The most important advantage of the core flow lift is the reduction of pumping energy. This fact was confirmed by the experimental study made by Vanegas (1999), where an apparatus was built and tested at laboratory scale. The test section consisted of a 2.75 cm ID galvanized steel vertical pipe. The fluids used were a 17.6 Pa.s, 963 kg/m$^3$ oil and water at room temperatures (25 ºC approx.). The frictional pressure gradient in core flow (*Gpf*) was measured with a Valydine pressure transducer for different water-oil input ratios, and the reduction factor was determined by comparison of *Gpf* with the pressure gradient in single phase oil flow. Figure 6a shows the behavior of this factor as a function of the water-oil input ratio ($j_w/j_o$), for each oil superficial velocity ($j_o$); $j_w$ is the superficial water velocity. As can be seen in this figure, the reduction factor was in the range 700 – 2000, and a maximum reduction factor exists for each oil flow rate. This means that the injected water can be adjusted in order to reach the minimum frictional pressure gradient. This optimal input ratio was in the range 0.07 - 0.5 for the whole set of runs. Another way to see the benefits of core flow is to compare the frictional pressure gradient in core flow with the single phase water flow at mixture flow rate. This is shown in Fig. 6b, as a function of the ratio between water and total (mixture) flow rates. It can be observed that both pressure drops have the same magnitude, because in core flow, water is in contact with the wall.




a) b)

Figure 6 – Experimental results for the frictional pressure gradient: a) compared with single phase oil flow; b) compared with single phase water flow at mixture flow rate

In terms of the total pressure gradient (friction + gravitational effect), the reduction factor was between 45 and 150, as illustrated in Fig. 7, and the optimal water-oil input ratio ($j_w/j_o$) was also in the range 0.07 and 0.5, depending on the superficial velocity of the oil. However, this optimal input ratio is much less pronounced than when only friction is analyzed, favoring the use of smaller water-oil injection ratio. Note that in some experiments the superficial velocity of the oil reached 1.75 m/s, which is an auspicious result for a so viscous oil. In field applications, the well head pressure can be monitored as a function of the injected water flow rate, in order to determine the optimum operational point for which the well productivity is maximized.

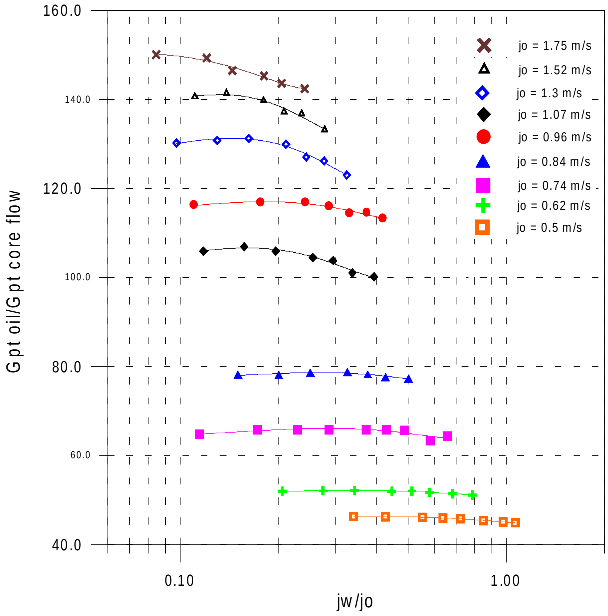



Figure 7 - Total pressure gradient reduction factor as a function of the input ratio, with $j_o$ as parameter

The experiments also showed the great stability of vertical upward core flow in a wide range of operating conditions. In fact, vertical upward core flow is even more stable than horizontal flow, because the net buoyancy force helps upward flow but is unfavorable in horizontal flow. This is an important reason to propose the development of this technology for heavy oil lift.

In spite of its advantages in comparison with other technologies, field applications of core flow lift of heavy oils lift require consideration of the following:

- Integration of core flow lift with other production schemes and pump selection;
- The facilities required to generate the flow pattern must be adjusted to the limited space of a platform (offshore situations);
- Need for appropriate devices that help induce this flow pattern in the well;
- Materials or/and chemical agents may be required for fouling control.

## 4. CONCLUSION

Core flow lift is a new alternative for heavy oil production that significantly increases the well productivity by decreasing of the frictional pressure losses, without the addition of heat and without the use of chemical agents neither diluents. The technology can be applied in either onshore or offshore fields, horizontal or vertical wells, and its installation in the field is relatively simple. The basic components of the core flow lift technique are: a water injection system, an injector nozzle, a downhole oil pump and a surface separation system that allows to re-use the injected water, which could be the same production water. In the experiments done by the authors the frictional pressure drop was reduced by a factor ranging from 700 to 2000 times, while the total pressure gradient was reduced 45-150 times. The optimum water-oil input ratio was in the range 0.07-0.5, depending on the superficial velocity of the oil. The vertical upward core flow was observed to be a hydrodynamic stable flow pattern that can be obtained in a wide range of operating conditions and can be preserved through different types of accidents present in the pipe. This fact favors its application in practical situations. Finally, the positive results of this work, based on a laboratory model, allow to think of the validation of core flow lift technology through the design and test of a future field prototype.

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