

RECOVERY MECHANISMS OF FOAMY OIL

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Abstract. *Heavy oils have strategic importance in future world oil exploration. The technology concerning production of this type of oil has gained great attention in the last 12 years, as well as has attracted the academic interest. The present work consists of a literature review in the area. The aim is to present the progress made in understanding the differences with light oil and to discuss some of the ideas that came along with the recent heavy oil exploration. It was found that solution gas drive is more efficient and more significant in heavy oils than in light oils. Even in pressures lower than the bubble point limit, the dissolved gas takes a longer time to form a free phase in heavy oils. Such time delay leads to a higher critical gas saturation and lower gas mobility in oils with high viscosity. These characteristics suggested to the first authors that these oils, in the region below bubble point pressure and carrying a high gas content in the form of small bubbles, should be referred as foamy-oils. The delay in gas flow and its presence with the oil for a longer time is the source for the energy for the oil flow, because of the gas high compressibility. Lab work has shown that the delay is associated with the viscosity of the oil. The viscosity reduction, one of the first tried attempts to model the unexpected heavy oil recovery, work against solution gas drive since with oil at lower viscosities, the gas has a higher mobility and remains attached to oil phase for a shorter time. Following these observations, in order to enhance primary production of heavy oils, the production strategy must rely on closer wells and higher depletion rates. The chosen strategy must be weighed by its contribution to the primary mechanism. Sand production contributes significantly to heavy oil recovery, yet its application in off-shore wells might be uneconomical. The presence of water as a third phase provides a preferential flow path to the gas in contact with heavy oil, increasing significantly its mobility and thus wasting the solution gas energy. Indeed, heavy oils present a behavior which is unusual to light oils and yet must be the matter of future research.*

Keywords: *foamy-oil, solution gas drive, cold production, gas mobility, critical gas saturation*

1. Introduction

Venezuela, Canada, China, Oman and other countries have been exploring heavy oils for some time. Brazil has a particular interest in the issue because of the findings of big reserves, mainly in deep water systems. Besides the fact that one of the first studies dealing with the aspects that influence the high production of heavy oils has been published in the seventies, most of the research dates from the last 11 years. Elkins and Morton (1972) studied the geo-mechanical aspects of cold production and the associated sand production in particular. Cold production refers to all heavy oil production processes that do not resort to thermal effects to ease oil production. Usually this happens by the production of formation sand, which increases the permeability of the reservoir. A significant pressure differential, sufficient to produce sand, supplies enough energy to break the connection forces of the sand particles. In reservoir regions where the porosity is high and there is few clay or cement materials and consequently the connection forces are lower, sand erosion can progress more easily, forming channels. These channels are usually called wormholes (Tremblay et al, 1999).

However, the fluid properties related to the flow and thermodynamic behavior of these oils, that later on would be the subject of a great amount of studies, have only been first scrutinized by Smith in 1988. He was the first to realize the importance of the combination of geomechanical and fluid effects in the anomalously high production of heavy oil. He suggested that the gas coming out of solution does not connect immediately and is kept in the form of micro-bubbles. The micro bubbles were of such size to pass through the pore throat and function as a set of roller balls, increasing the oil mobility.

Kraus et al (1993) proposed a pseudo bubble point model to explain the delay in the coalescence of the gas bubbles and the formation of a free gas phase. In his model, the fluids are treated as a single phase between the bubble point and the pseudo-bubble point, yet with different characteristics of the original oil with solution gas.

But Sarma and Maini (1992) only introduced the name foamy-oil in 1992. It would represent some heavy-oils in the interval between the bubble point and the critical gas saturation, where there is bubble formation but no flow of gas as a free phase yet. The bubbles remain dispersed in the oil, giving it the look of a chocolate mousse. Very distinctively of what happens to conventional oils, the bubble coalescence takes longer to complete and, by doing so, contributes to the recovery. The gas presence is always desired to sustain the pressure and warrant energy to the recovery, because of the oil's low compressibility. Maini et al (1993) attributes the differentiated recovery of oils of high viscosity to the apparent high critical gas saturation. Yet, Pooladi-Darvish and Firoozabadi (1999) observe that the critical gas saturation is as low in heavy oils as it is in light oils, but when it comes to gas mobility, it can be pointed out that it is several orders of magnitude smaller in the former than in the latter. The mobility of a fluid is a function of its relative permeability and viscosity. The authors relate the low gas oil ratio (GOR) observed in experimental tests with high viscosity oils, even in pressures lower than the bubble point, to the low gas mobility.

But, Maini et al (1993) and Pooladi-Darvish and Firoozabadi (1999) agree that Smith's (1988) micro-bubble model is not valid. Maini et al conducted experiments that show that no gas is produced before critical gas saturation, putting aside the model in which there is a micro-bubble flow starting at the bubble point. Later, Andarcia et al (2001) would point that even in field tests, the micro-bubble flow is not noticed.

2. Gas Saturation, Critical Gas Saturation and Supersaturation

Before arguing about the solution gas drive influence in the recovery of heavy-oils, a brief presentation of the concepts mentioned above is necessary. First, gas saturation is the volumetric percentage that the emerged gas occupy in a given volume.. Maini et al (1993) defined the critical gas saturation (S_{gc}) as the minimal saturation in which the gas becomes continuous. However, according to Firoozabadi (2001), this definition can not be consistent for heavy oils, in which the two phase flow shows some discontinuities until high gas saturations. He observed that the gas phase could not be continuous with gas saturations (S_g) as high as 20%. Most authors define the critical gas saturation by the gas saturation measured at the moment of a sudden increase in GOR (gas oil ratio) at the production history profile. To Firoozabadi (2001), this definition introduces an error because of the time lag between bubble coalescence and its flow caused by the gas phase low mobility when traveling together with heavy oils. The super saturation represents the difference, measured in pressure terms, between the bubble point pressure and the pressure in which the first gas bubble comes out (Andarcia et al, 2001). It consists of a transient effect, that lasts as long as the solution is out of equilibrium. Kumar and Pooladi-Darvish (2000) showed that super saturation changes linearly with the depletion rate. The depletion rate effects will be treated later.

Firoozabadi's (2001) concern about the errors introduced in the critical gas saturation value when calculated by the GOR history should not be always considered. According to the author, the non-equilibrium effects, like the super saturation, are not relevant in field situations. Nevertheless, in laboratory conditions, these non-equilibrium conditions are very significant. This difference between laboratory and field condition is only because of the size of the representative volume and consequently because of the time scale. While in the former the time scale is of the order of days, in the latter the time span is measured in years. In field conditions, any non-equilibrium situation tends to stabilize sharply, with minimum consequences to the field production history. Andarcia et al (2001) brought to light that the laboratory attempts to predict field behavior have not reached success yet. More recent laboratory tests seek to reduce the super saturation effects in order to represent more accurately the field conditions (Tang and Firoozabadi, 2001).

3. Solution Gas Drive

Solution gas drive is a primary recovery mechanism (Firoozabadi, 1999). Below bubble point, the solution gas liberation and the free gas expansion are the pressure maintenance sources (Wong et al, 1999). The mechanism starts with bubble nucleation in a critical super saturation (the pressure in which the gas comes out of the supersaturated liquid) below the bubble point. The bubble nucleation can be progressive or instantaneous, according to each theory. In the progressive nucleation model, the bubble formation rate is related to the super saturation. Firoozabadi and Kaschiev (1996) created an instantaneous nucleation theory for all bubbles, when in supercritical saturation. This theory was experimentally checked in 1999 (Firoozabadi).

Two parameters affect solution gas drive efficiency: critical gas saturation and the liquid and gas phase's mobilities. A high critical saturation results in a high recovery. A 30% critical gas saturation will result in a 30% oil recovery, since the oil shrinkage is low. Firoozabadi (1999) has conducted experiments in which the oil recovery is exactly the same as the critical gas saturation. However, a low critical gas saturation does not necessarily represent a low recovery since a gas with low mobility and a liquid with high mobility will result in a high recovery.

Solution gas drive can be inefficient with light oils. In this case, critical gas saturation is low and gas mobility is high.

Firoozabadi (1999) compared the gas evolution in heavy and light oils. He realized that solution gas drive in heavy oils, compared to light oils, can be an efficient process. The bubble density in heavy oils is very high. Because of the high oil viscosity, gas mobility is low and consequently, oil mobility becomes very high. The high recoveries observed in some heavy oil fields are an exclusive consequence of primary recovery, with the absence of gravitational drainage and water influx (Firoozabadi, 1999).

On the other hand, the advances in horizontal well technologies removed a great deal of the uncertainties around cold production. According to Maini (1999), long horizontal wells take the production rate to an economically attractive level, even in the absence of wormholes and other cold production effects.

Maini stated that at least part of the effects causing high recoveries in heavy oil wells are related to foamy-oil flow. He has conducted several experiments showing that foamy-oil formation is directly associated with oil viscosity and the depletion rate applied. The higher the depletion rate, the higher is the super saturation and the better the foamy oil flow. However, when dealing with lighter oils, the minimum depletion rate necessary to generate foamy-oil is significantly higher. The natural conclusion being that foamy-oil is a phenomenon present mainly in heavy-oils. The author observed that higher recovery factors were obtained in tests with higher depletion rates. He connects these observations to the dependence that the critical gas saturation has on the depletion rates. Higher depletion rates leading to higher gas critical saturation.

However, Maini's tests do not set the final word on the issue since the depletion rates used in the laboratory to render the foamy-oil behavior can never be achieved in field situations. Even though, some wellhead samples reveal foamy-oil when it would be theoretically impossible to have oil of this nature with the regularly used depletion rate values. As a second point, some fields with low critical gas saturation have high recovery factors. Other authors (Denbina et al, 1998; Tremblay et al, 1999) attribute the formation of foamy oil to the sand flux at the wellhead. The turbulence generated by the sand flux would be directly connected to the foam generation. Maini emphasizes the importance of differentiating "foamy oil solution gas drive" to usual "solution gas drive mechanisms". To him, laboratory tests suggest that primary energy can be wasted in wells that don't stimulate foamy. To avoid wasting of reservoir energy, the author calls attention to the development strategy of foamy oil reservoirs. The development here must be made with smaller-than-usual well spacing and at the maximum depletion rate possible.

Tang et al (1999) suggest the abandonment of the term foamy-oil. The authors have conducted depletion experiments with two very viscous oils. One was the E-oil with a 12.1 API and the other was a 14.4 API silicon oil. The silicon oil used does not sustain any foam generation. Both depletion experiments resulted in good recovery factors—10,3%OOIP (original oil in place) for the silicon oil and 13,6%OOIP for the E-oil. The authors analyzed the relative permeability of the gas in these oils and came to the conclusion that such property was very low for both oils. The critical gas saturations were also low (5.5% for the E-oil and 1.1% for the silicon oil), which lead them to conclude that the low gas mobility was the key aspect responsible for the high heavy oil recovery when submitted to solution gas drive. Nevertheless, Tang et al (1999) results partly agree with Maini's (1999) observations over the foamy-oil behavior contributing to higher critical gas saturation, a parameter that according to Firoozabadi (1999) affects directly the solution gas drive efficiency.

Pooladi-Darvish and Firoozabadi (1999) point to the low gas mobility as the most reasonable explanation to the good performance of solution gas drive in heavy oils. The authors compare the gas relative permeability when flowing along with a light and a heavy oil to support their arguments.

4. Usual Enhanced Recovery Techniques for Heavy-Oils

The difficulties for the production of heavy oils when compared to light oils may induce one to consider high viscosity as a detrimental factor and to nurture thinkings of viscosity reduction techniques as an evident solution to these problems. Such thinking has been widely common, as the illustration in Figure 1 shows.

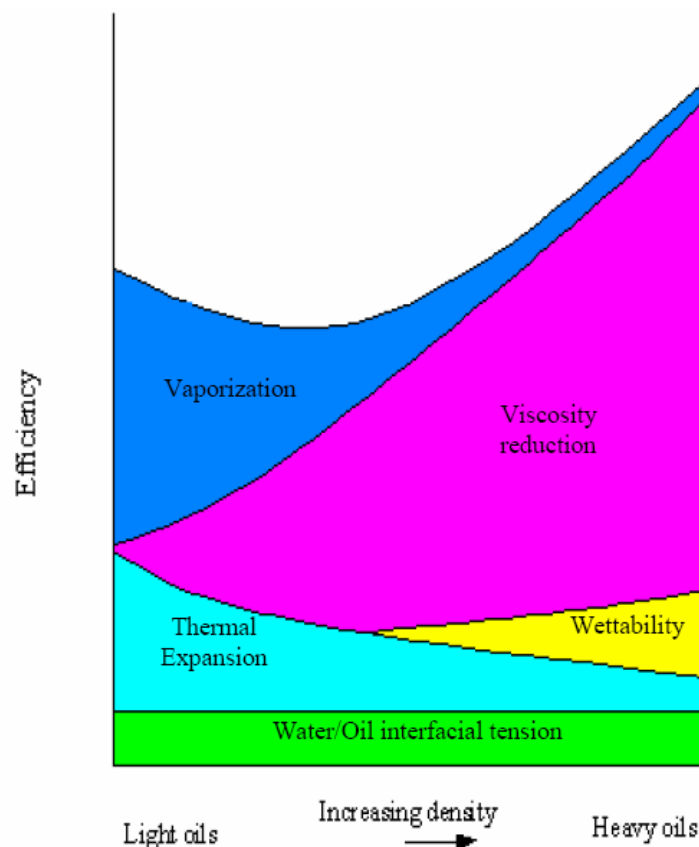


Figure 1 – EOR usual mechanisms in 1985, from light to heavy oils. Kovscek et al (1985)

Viscosity reduction can be obtained with the injection of solvents or with the increase of reservoir temperature. In some wells of the Orinoco belt in Venezuela, dead light oils of API 26 were injected so that live 8.5 API would be enhanced to an intermediary API. The raise of reservoir temperature to reduce the oil viscosity is the subject of several papers and books. It can be obtained by steam injection (Kovscek et al, 2001; Kovscek and Brigham, 2001; Law, 2004) or by in-situ combustion. In Brazil, the most EOR (enhanced oil recovery) method for viscous oil is steam injection. Water injection is the common method after primary production in both light and heavy oil fields.

Tang and Firoozabadi (2001) carried out an interesting study that may serve as the base for the following reasoning. The authors evaluate the effects of GOR, temperature and initial water saturation in the solution gas drive in heavy oil reservoirs. The authors concur with the previously published conclusions that, the higher the GOR, the better the performance of solution gas drive mechanism and the greater the recovery factor that can be obtained. In terms of pressure history, an increase in the content of gas dissolved in the oil improves the reservoir pressure maintenance.

But, the most important contribution to the understanding of the heavy oil recovery mechanisms comes from the temperature and initial water saturation tests. From the fluid properties obtained in bulk tests, as the temperature increases, the oil viscosity is drastically reduced. But against the sense that high viscosity is the unfavorable parameter responsible for all difficulties related to heavy oil extraction, the authors have shown that high temperatures are also associated with high gas mobility (Figure 2) which compromises the solution gas drive efficiency. The increased gas mobility leads to lower recoveries of the live oil (the term live oil refers to every oil that contains solution gas), as the oil is bypassed by the faster free gas..

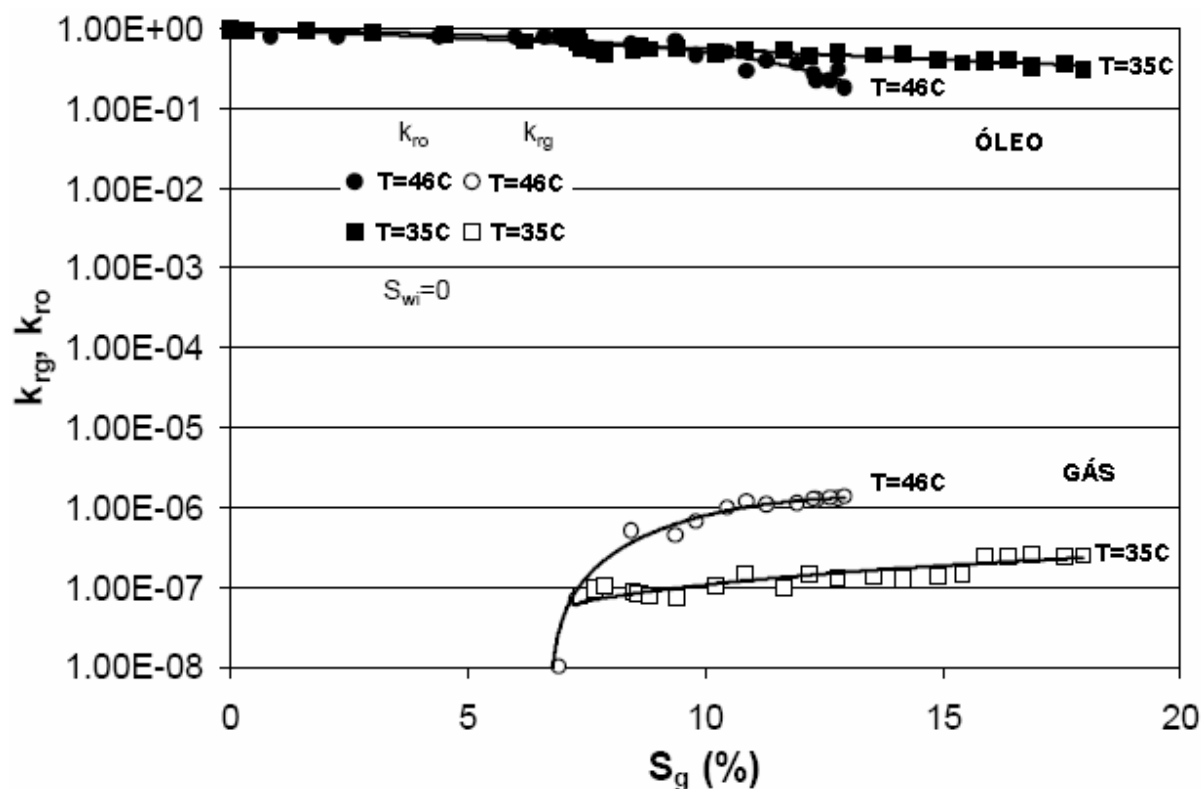


Figure 2 – Oil and gas relative permeability for different temperatures (35°C and 46°C). Tang and Firoozabadi (2001)

The initial water saturation tests end up revealing an important characteristic of the aqueous phase: its presence increases the gas mobility and reduces the efficiency of the solution gas drive. Tests in which only S_{wi} (initial water saturation) was varied indicated that by increasing the water content the bubble density was reduced in the system. Since the reasoning is that the newly generated gas displaces oil in the competition for space, the higher the bubble density, the greater the oil volume expelled. The bubble density contributes directly to oil recovery. Accordingly, tests with high S_{wi} yielded low recovery factors.

The aforementioned recovery loss is a direct consequence of the solution gas drive efficiency loss, caused by the increase in the gas mobility, as shown in Figure 3. This association is extremely important and deserves special attention. The low gas mobility has been attributed by Pooladi-Darvish and Firoozabadi (1999) and Tang and Firoozabadi (1999) as the main factor responsible for the high recovery factor in heavy oils. Its low value is responsible for the delay in the flow of the gas as a free phase between the bubble point and the critical gas saturation. The low gas mobility is associated with the oil high viscosity. Nevertheless, the water has a viscosity several magnitude orders lower than the oil and its presence as a third phase, in contact with the oil and the gas, can add flow channels to the gas, which, in turn, increases its mobility.

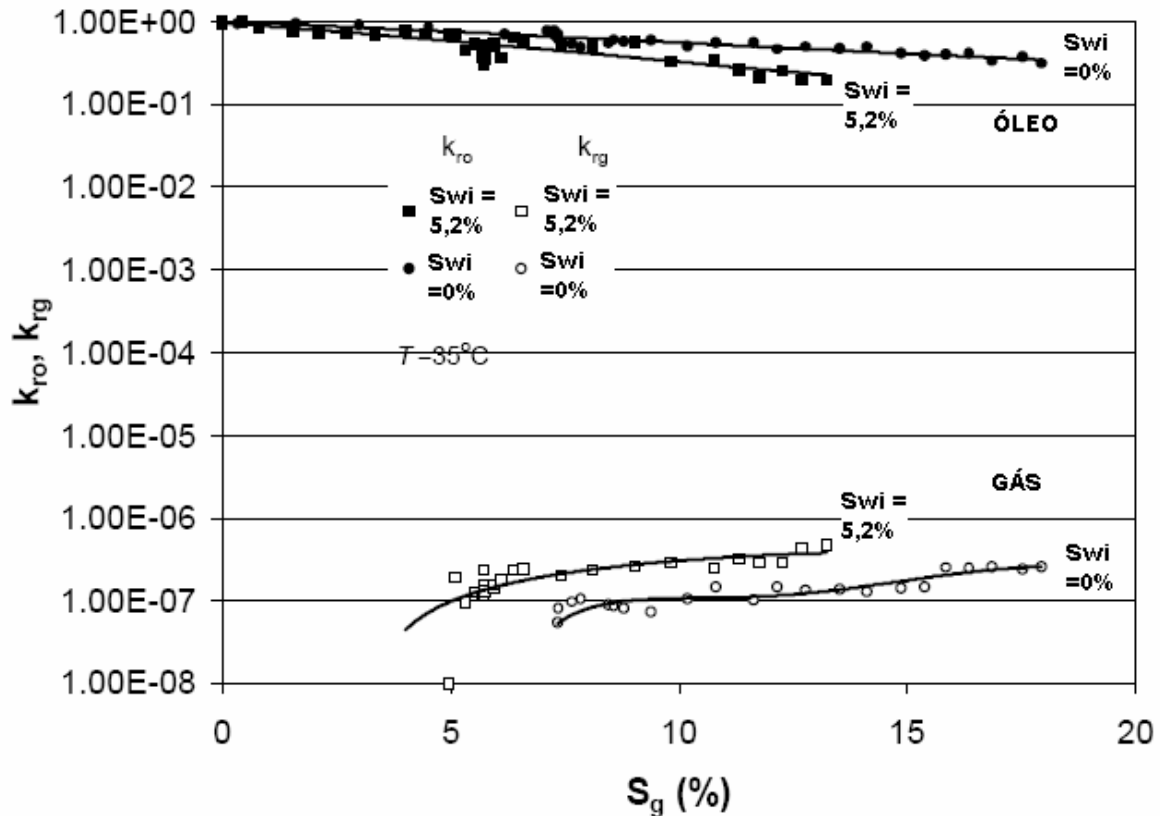


Figure 3 – Oil and gas relative permeability for different initial water saturation (0% and 5,25%). Tang and Firoozabadi (2001)

Based on the previous rationale, water injection represents a risk to the success of the solution gas drive mechanism. Comparative studies between the contributions to the recovery factor of the primary solution gas drive and the secondary method of the water injection in heavy oils are necessary. However, it is clear that the secondary drive mechanisms that traditionally work for light oil recovery may not have its performance extended straightforward to projects involving heavy oils.

5. Depletion Rate

Many authors (Maini et al, 1993; Maini, 1996; Firoozabadi and Kaschiev, 1996; Tremblay et al, 1999; Kumar and Pooladi-Darvish, 2000) pointed the depletion rate as a significant factor in the heavy oil production. Higher depletion rates increase the differential pressure and the super-saturation effect (Kumar and Pooladi-Darvish, 2000). It also decreases the gas production and increases oil recovery. The super-saturation increase is directly related to better results for the oil recovery (Tang et al, 1999). The increase in the differential pressure also sets in better wormhole genesis conditions, which is pointed by other authors as an important oil production mechanism.

6. Sand Production

Cold production is the primary non-thermal process in which sand and oil are produced together in order to increase oil production (Tremblay et al, 1999). The importance of sand production in the cold production process was pointed out by the authors after the comparison of production data of a vertical well located in the Lloydminster field in Canada to the expected rate in the case that no permeability formation changes are obtained (this situation of no sand production was created by simulation). The maximum oil production if no formation sand is produced and the permeability of the reservoir remains the same: 0.33 m³/day. Lloydminster field history of sand production is typical of a well submitted to cold production. Sand cut, i.e., the percentage of the total volume produced that is sand, is usually high in the first months (10-50% Elkins et al, 1972; 30-40% Mccaffrey and Bowman, 1991, 20-30% Yeung, 1995). Usually, sand cut tends to stabilize in lower values after 6 months to 1 year (0,1-2% Elkins et al, 1972; 0,5-1% Mccaffrey and Bowman, 1991; and less than 5% Yeung, 1995). Sand production promotes better results to oil production by increasing the reservoir absolute permeability. Such gain in permeability is usually a consequence of a wormhole channel system construction, caused by the differential pressure in regions with lower connection forces in the sand body. When the

differential pressure overcomes the adhesion forces in the sand, channels begin to develop. Some authors observed wormhole genesis velocities as high as 0,11m/s (Denbina et al, 1998). Through these channels, the effective permeability of the reservoir is substantially increased. Several authors modeled the genesis and growth of wormholes (Denbina et al, 1998; Tremblay et al, 1999; Wang et al, 2002). Even though the advantages of producing sands are many, its application in Brazil is questionable, basically because of the field locations. While in Canada and China, countries where most of the studies in sand production were carried out, heavy oil is located mainly inshore fields; in Brazil the heavy oil fields are mainly located offshore. A quick calculation may show the impossibilities of producing sand in most of Brazil's heavy oil fields. The P-36 platform, one of the biggest platforms in the world, had a production capacity of 180 thousand barrels per day. If it were used to produce heavy-oil in a field in which the chosen production strategy was sand production, by the usual performance figures(Elkins et al, 1972) it would produce 10% of this volume of sand in the first 6 months. That would represent an output volume of approximately 2960 cubic meters of sand per day. Such volume of sand weights nearly 5000 tons, about 16% of the platform weight. And that corresponds only to the production of one day. Clearly the costs of sand disposal would be extremely high in the offshore scenario for the sand production mechanism. Not mentioning the environmental aspects of such endeavor.

7. Secondary Mechanisms

While the main energy for the oil and gas flow in the primary mechanism comes from the reservoir, in the secondary methods it is supplied by an external source. From the thermal secondary mechanisms there is vapor injection and in-situ combustion. In the former, the viscosity reduction is one of the expected results to improve the recovery factor. As shown by Tang et al (2001), viscosity decrease is undesirable in heavy oils in which solution gas drive is the most important recovery mechanism (which depends on how "alive" the oil is, that is, how much solution gas there is dissolved in the oil). In-situ combustion, besides reducing the oil viscosity, also pushes the oil volume directly to the production well through the movement of the combustion front. Likewise, it is common that the non-thermal secondary mechanisms push the oil through the movement of an injected fluid. Several authors (Butler, 1992; Metwally, 1996; Srivastava and Huang, 1997; Mungan, 2000; Law et al, 2004) point to the benefits of injecting gas to maintain the reservoir pressure. While water, which has significantly lower viscosity and is immiscible to oil, breaks through the oil patch and moves directly towards the well, the injected gas may remain there for a certain time, for having a low mobility when associated with heavy oil. Nevertheless, gas injection may add energy to the solution gas instead of wasting it through water injection. Tang and Firoozabadi (2001) show that the solution gas mobility increases greatly with the presence of water.

8. Conclusions

Concerning solution gas drive in heavy oil reservoirs, both critical gas saturation and the low gas mobility are related to high recovery factors. The former is directly associated with the recovery because it is involved in the volumetric calculation, representing the maximum reservoir volumetric percentage that will be occupied by gas. This gas volume will push an oil volume of the same magnitude (because of the oil low compressibility) to production. However, the critical gas saturation does not have an exclusive role in recovery. The low mobility of the gas, a result of the oil high viscosity, is relevant in the solution gas drive of heavy oils.

Greater depletion rates promote greater recoveries by increasing the super-saturation effects and the critical gas saturation. Both mentioned parameters retard the flow of gas as a free phase and contribute to the reservoir pressure maintenance by the solution gas drive. Formation-sand production sets a higher standard to the reservoir permeability by the genesis of wormholes, generating flow rates even as high as 50 times that which would be expected without any changes in reservoir permeability (Tremblay et al,1999). However, it might not be economically applicable in Brazil's offshore heavy oil scenario.

9. Suggestions

1. Solution gas drive must be properly valued in primary depletion of heavy oil fields.
2. If the chosen production strategy, especially when considering secondary oil recovery methods, improves the gas mobility it will consequently waste primary energy that is vital for the solution gas drive.
3. When it comes to heavy oils, water injection efficiency must be weighted against the loss of efficiency that it promotes in the solution gas primary drive, by increasing the gas mobility.
4. Miscible gas injection seems to be an alternative that does not compromise solution gas drive in heavy oil fields, yet more studies on this matter are required.
5. Sand production, albeit promoting significant increases in the recovery factor, may be economically unpractical in Brazil's offshore heavy oil fields, .

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