Mechanisms of Solution Gas Drive in Heavy Oil Reservoirs

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Introduction

Solution gas drive in heavy oil reservoirs (with viscosity in the range of 10 to 1,000 poise and API gravity in the range of eight to 15), which is often referred to as cold production, has a long production history in Canada. In a recent review paper, Dussault et al. presented the information that more than 5,000 wells in Canada have produced heavy oil by cold production. In addition to Canada, cold production from heavy oil reservoirs has been practiced in Venezuela, China, and Oman. Recoveries from some of the heavy oil reservoirs by cold production are estimated to be as high as 20%. The high recovery is often associated with a low pressure decline rate in the reservoir and the slow increase ofGOR in the two phase below the bubblepoint, as well as geomechanical effects. Recoveries in the range of 10 to 20% below the bubblepoint pressure are believed unusual for very heavy oils. In this overview, we will briefly review the literature and then provide some insight into the relevant mechanisms for cold production.

Literature Review

An early paper by Smith set the stage for the understanding of cold production from solution gas drive in heavy oil reservoirs. In his work, Smith provides an analysis of solution gas drive in heavy oil reservoirs from the examination of field data. He attributes the high efficiency of solution gas drive in viscous oils to: 1) a significant reduction (around one order of magnitude) in the oil viscosity due to formation of small gas bubbles in the oil, 2) simultaneous flow of continuous oil phase and discontinuous gas phase in the form of tiny bubbles, 3) an increase in absolute permeability due to sand production, and 4) high fluid compressibility due to high gas bubble density in the oil. In order to validate some of the postulations by Smith, the bulk of research has focused on the so-called pseudo-single phase model. In the pseudo-single phase model, a new terminology has evolved to distinguish solution gas drive in heavy oil reservoirs. The so-called foamy oil terminology was introduced in 1992 by Sarma and Maini; it was defined as a viscous (heavy) oil containing dispersed gas bubbles. Claridge and Prats used the term “foamy heavy oil” and “foamy crude” mainly to imply drastic reduction in the oil viscosity due to dispersed gas bubbles. The term “foamy oil” has had a wide acceptance because the oil samples at the wellhead produced from the reservoirs seem to be in the form of oil-continuous foam, with the appearance of chocolate mousse, and may contain a large volume of dispersed gas bubbles. Hu et al. report that the density of the produced oil from a heavy oil pilot well from the Henan oil field in China is about 0.58 g/cm³, while the density after all the gas has left the oil (which may take several days) is 0.95 g/cm³.

Smith used a modified buildup analysis to infer the apparent in situ viscosity; the inferred viscosities were one order of magnitude less than the oil viscosities above the bubblepoint, as was pointed out above. He described the compressibility by the expression $c = \frac{1}{p}$, where $x$ is a constant and $p$ is the pressure. The value of $x$ was estimated to be in the range of 0.25 – 0.4 from field data. Note that the isothermal compressibility of an ideal gas is given by $c = \frac{1}{p}$. The compressibility in the two-phase with small gas bubbles in a bulk liquid phase can be calculated based on thermodynamic con-
siderations. Some other postulations from Smith’s work will be discussed later.

There are two schools of thought for the mechanistic understanding and modeling of fluid flow in solution gas drive in heavy oil reservoirs, as well as the interpretation of laboratory measurements. One school of thought relies on using a pseudo-single phase flow description for both the interpretation of laboratory data and field studies. Another school of thought uses the conventional two-phase model with the parameters of heavy oils. The former school essentially includes most of the work on cold production research. The latter school is based on our work using critical gas saturation, very low gas relative permeability, and the assumption of no supersaturation in the reservoir. In the following, these two models will be discussed.

**Pseudo-Single Phase Model**

Sheng, Maini, Hayes, and Tortorelli provide a comprehensive review of the pseudo-single phase model for cold production from heavy oil reservoirs. There are two groups of parameters that govern the efficiency of solution gas drive in a pseudo-single phase model: compressibility and viscosity, and parameters of non-equilibrium phenomena. We have already discussed the type of model which has been suggested for compressibility estimation when gas bubbles are dispersed in the oil. We would add here that in single-phase and in two-phase, whether gas is present as a continuous phase or in the form of small dispersed gas bubbles, there is sometimes an order of magnitude difference between the compressibility with few bubbles and without bubbles. Therefore, a simple expression such as $c = \rho p$ may not describe the compressibility.

Viscosity is an important parameter in well rate calculations. As was stated above, Smith suggested that the apparent viscosity of a heavy oil with dispersed gas bubbles decreases drastically. He showed that the apparent viscosities calculated from the build-up analysis were of the order of 1 - 5 poise, whereas for the same oils in single phase, the viscosities were in the 17 - 35 poise range. Among other parameters, Smith used the compressibility from $c = \rho p$ to calculate the apparent viscosity. The experimental work of Islam and Chakma on pressure drop measurements in a capillary tube is in apparent support of Smith’s work. These authors used several oils of 0.1 to 50 poise viscosity with microbubbles in different gas-liquid volume ratios. However, in 1996, the experimental work by Huerta et al. showed that there is no change in oil viscosity before and after gas bubble formation in porous media with heavy oils. In 1999, Pooaladi-Darvish and Firoozabadi showed that the pressure drop across a core increases when gas bubbles form in the oil. A visual coreholder was used in the tests with a low flow rate.

In addition to compressibility and viscosity, the supersaturation phenomena also affect the pseudo-single phase model. The effect of supersaturation will be briefly discussed in the next section.

**Conventional Two-Phase Flow Model**

In a departure from the pseudo-single phase model, we have suggested the use of the conventional two-phase flow model for the cold production process. Solution gas drive, whether in light oils or in heavy oils, is describable by two parameters: 1) critical gas saturation and 2) oil and gas relative permeabilities. We assign gas viscosity to the viscosity of the disconnected gas phase and the oil viscosity to the viscosity of the continuous oil phase. There is no need for an apparent viscosity. We recognize that in a heavy oil, viscosity is a function of rate or velocity due to the viscous elastic behaviour. Therefore, one should measure the viscosity at low rates for the purpose of recovery performance studies away from the wellbore.

Next we will discuss the critical gas saturation and gas and oil relative permeabilities.

**Critical Gas Saturation**

$S_c$ - Critical gas saturation is one of the two most important parameters of solution gas drive in heavy oil reservoirs. In general, the higher the critical gas saturation, the higher is the recovery efficiency.

There are various definitions for critical gas saturation. One may define critical gas saturation as the minimum gas saturation at
which gas flow occurs in the two-phase gas-oil flow regime\(^{(14)}\). Maini et al.\(^{(13)}\) define the critical gas saturation as the minimum gas saturation at which the gas becomes continuous. This definition is in line with the concept of relative permeability, but may not be practical for some applications due to the discontinuity of phases in many two-phase flow processes.

The value of critical gas saturation and the efficiency of solution drive gas is a strong function of the rate of pressure decline (that is, \(\frac{\Delta P}{\Delta t}\)) due to the considerations in new phase formation. At high rates of pressure decline, a larger number of nucleation sites may be activated and, therefore, critical gas saturation can be two to five times higher than the values at low \(\frac{\Delta P}{\Delta t}\). At field conditions, even near the wellbore, \(\frac{\Delta P}{\Delta t}\) is low. Therefore, one may not apply the results from the laboratory at high rates of pressure decline to field conditions. Due to low gas mobility in heavy oils, perhaps one should use visual observations to detect the initial gas flow from a core\(^{(16)}\) to establish the critical gas saturation. Most authors infer \(S_{gc}\) from GOR data, which may have some error, especially if the gas mobility is very low.

Critical gas saturation in light oils is generally very low at low rates of pressure decline away from the critical point. Typical values are often in the range of 1 – 3%\(^{(14,16)}\). Figure 1 shows the correlation of critical gas saturation as a function of pressure decline rate and gas-oil interfacial tension\(^{(17)}\). This figure shows that as the rate of pressure decline decreases, \(S_{gc}\) can be less than 2% at field conditions for \(\sigma = 5\) dyn/cm. In the Appendix we provide a brief discussion on the effect of \(\sigma\) on nucleation rate and \(S_{gc}\).

Several authors have measured critical gas saturation in heavy oils. Maini, Sarma, and George\(^{(13)}\) are perhaps the first who report critical gas saturation for a heavy oil of about 30 poise. They used a sand pack of 2 m long and produced the fluid system by sudden decrease of pressure to atmospheric pressure from one end while the other end was closed. The initial pressure was about 3,000 psi. Maini et al. estimated critical gas saturation of about 40%. This high value is due to very high pressure decline rate. Huerta et al.\(^{(11)}\) performed depletion tests with Hamaca oil using clean Hamaca sand from the reservoir. The critical gas saturation was estimated to be 10%. The rate of pressure decline was not provided by these authors. Firoozabadi and Aronson\(^{(10)}\) reported critical gas saturation of around 3% for a heavy oil of 11 API gravity in Berre. Poojadi-Darvish and Firoozabadi\(^{(13)}\) measured critical gas saturation for an 11 API gravity crude with GOR = 5 5 v/v. The pressure decline rate was about 130 psid/day in the single phase region. A sand pack was used by the authors.

Tang and Firoozabadi\(^{(13)}\) used a heavy crude from Venezuela with GOR = 6.5 v/v and viscosity = 92 poise at 35°C. The critical gas saturation was about 5.5% for a pressure decline rate of some 50 psid/day in the single phase. A silicone oil of 320 cp (at T = 25°C) was also used with GOR = 6.5 v/v. The measured critical gas saturation was 1.5%. However, the recovery efficiency of the silicone oil was as high as the heavy oil recovery due to low gas mobility. Urgelli et al.\(^{(18)}\) measured critical gas saturation of around 5% for the Zuata heavy oil (API = 9°, GOR = 13 v/v, bubblepoint pressure = 710.5 psig). The 5% critical gas saturation was measured at a low pressure decline rate. At high rates of pressure decline, critical gas saturation of 25% was measured.

Current work in progress, which we will publish later, shows that the critical gas saturation increases as the GOR increases. Values as high as 10% may be measured at very low rates with high GOR.

**Gas and Oil Phase Mobilities (Relative Permeabilities)**

Based on visual observation of gas flow and oil recovery data for a heavy oil of 170 poise viscosity, Firoozabadi and Aronson\(^{(10)}\) concluded that the high recovery efficiency in solution gas drive for heavy oils is due to very low gas mobility. The low gas mobility was later quantified by Poojadi-Darvish and Firoozabadi\(^{(12)}\). The authors showed that over a gas saturation range of 4.2 to 6.8%, the gas relative permeability was about 10\(^{-6}\).
The concept of gas and oil relative permeability for cold production in heavy oils was introduced by Tang and Finozabadí (13). A heavy crude of 100 poise viscosity at 35°C with GOR = 6.5 v/v was used. Figure 2 shows both oil and gas phase relative permeabilities (13). This is the first set of data for relative permeabilities in a heavy oil for solution gas drive. Two features of relative permeability for a heavy oil can be observed from Figure 2: the oil relative permeability looks very similar to light oils. The gas relative permeability is, however, very low, around 10^{-5} over a gas saturation range of 5.5 to 14%. The low gas mobility is the prime factor in high recovery efficiency in cold production. Figure 3 shows oil and gas relative permeabilities for a silicone oil of 300 poise with GOR = 6.5 v/v. Although the critical gas saturation is around 1.5% (due to low bubble density), the recovery is around 10% for the test duration. Note that the gas relative permeability is around 10^{-6}. The results from the solution gas drive test with silicone oil imply that the mechanism of solution gas drive in heavy oil reservoirs may not be due to the foamy nature of oil. This point will be addressed further in the next section.

**Process Mechanism**

Figures 4 and 5 show the evolution of gas bubbles on the surface of the core for the heavy oil and the viscous silicone oil. For the heavy oil, Figure 4a shows the bubble distribution prior to the critical gas saturation. The bubble distribution at the onset of gas flow is shown in Figure 4b. Figures 4c and 4d show the gas phase distribution after 7.1 and 11.5% of PV fluid production from expansion; the gas phase is discontinuous even at 11.5% PV expansion. The same is also true for the silicone oil. Figure 5 shows that the bubble density is very low for the silicone oil. As a result, the critical gas saturation is only 1.5% of PV. However, even at 3.2% PV, the gas phase is not continuous. In this respect,
the silicone oil, which cannot generate foam, behaves the same as a heavy crude. To further demonstrate that the flow of gas is intermittent in both a heavy crude and a viscous silicone, the measured pressure drop across the core is shown in Figures 6 and 7 for the heavy crude and the silicone oil, respectively. In Figure 6, the pressure drop across the core is shown at 35 and 24°C for the heavy crude. Figure 7 shows the pressure drop for the silicone oil. The fluctuation in pressure is due to the intermittent nature of gas flow; it is not due to the foamy nature of the oil. We have recently confirmed that up to a gas saturation of 20%, the gas phase may not be continuous in solution gas drive in a heavy crude. Avraam and Payatakes(20) did a systematic study of immiscible two-phase flow in a visual micromodel and observed that disconnected oil contributes substantially to flow. Based on their experiments, Avraam and Payatakes rejected the presumption that in immiscible two-phase flow, the effective permeability to a liquid phase becomes zero when that phase is disconnected. On the other hand, the microbubbles do not flow in the form of dispersed phase as suggested by Smith. In 1997, Bora, Maini, and Chakma(21) studied solution gas drive in heavy oils using micromodels. Their observations revealed that the production of heavy oil is not accomplished by flow of microbubbles. Firoozabadi and Aronson(13) have also shown that prior to critical gas saturation, there is no gas production, even in the form of bubbles. When the gas saturation in the core exceeds the critical gas saturation, slugs of gas are produced with the oil. The production of slugs is accompanied by pressure fluctuation.

Discussion and Conclusions

There are over 150 papers on various aspects of cold production. Various authors from Canada, Venezuela, the U.S., and other parts of the world have contributed to our understanding. In this overview, space did not allow us to include much of the contribution from the literature, which has been made in a short period of 10 – 12 years. We have mainly focused on certain aspects of solution gas drive in cold production. The geomechanical aspects, including sand production, which affect the well productivity in Canadian reservoirs are not addressed.

As a whole, we believe it is the high oil viscosity that contributes to the recovery efficiency away from the wellbore. The issue of supersaturation, which is a laboratory phenomenon may not be of relevance at reservoir conditions. We have been conducting some experiments at a pressure decline rate of 20 psi/day in the laboratory for a heavy crude in single phase. Our measurements reveal that the supersaturation is very small. In the past we have shown that even with a high initial pressure decline rate, the supersaturation becomes negligible after two to three weeks. All of our measurements indicate that at field conditions, nonequilibrium phenomena can be safely neglected, except possibly around the wellbore. Even around the wellbore, supersaturation, if it exists, is expected to be small.

The concept of relative permeability is based on the premise of continuousness of a phase. Therefore, the relative permeabilities shown in Figures 2 and 3 for the gas phase should be looked at as pseudo relative permeability.

There is ample evidence that the term foamy oil does not apply to solution gas drive in heavy oil reservoirs. It is mainly the high oil viscosity that contributes to a substantial decrease in gas mobility: as a result, the solution gas drive process becomes efficient. Perhaps it is time to drop this term as did the early investigators on the subject.

NOMENCLATURE

<table>
<thead>
<tr>
<th>Symbol</th>
<th>Description</th>
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<tbody>
<tr>
<td>k</td>
<td>Boltzmann constant</td>
</tr>
<tr>
<td>J</td>
<td>nucleation rate per unit volume per unit time</td>
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<tr>
<td>p</td>
<td>pressure</td>
</tr>
<tr>
<td>p_e</td>
<td>equilibrium pressure in two-phase gas-liquid state</td>
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<tr>
<td>S_{cr}</td>
<td>critical gas saturation</td>
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<tr>
<td>T</td>
<td>temperature</td>
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<tr>
<td>W</td>
<td>work of forming a critical bubble nucleus</td>
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<tr>
<td>σ</td>
<td>effective interfacial tension, effective surface free energy</td>
</tr>
<tr>
<td>Δp</td>
<td>supersaturation in pressure</td>
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Appendix—Effect of Interfacial Tension on Bubble Formation

The work of forming a spherical critical nucleus (that is, a bubble which is in unstable equilibrium with the bulk liquid phase) is given by \( W \)

\[
W = \frac{16 \pi \sigma^3}{3 (\Delta \rho)^2}
\]

(A-1)

In Equation (A-1), \( \sigma \) is an effective interfacial tension (or an effective surface free energy), \( \Delta \rho = \rho_s - \rho \) where \( \rho_s \) is the equilibrium two-phase pressure (\( \rho_s \) is an approximation for the pressure inside the bubble), and \( \rho \) is the pressure of the bulk liquid phase. The work of forming a critical nucleus is the main component of the thermodynamic parameter in the nucleation rate expression \( J = A e^{(-C/JKT)} \) where \( J \) is the rate of bubble formation per unit volume per unit time, \( A \) is a kinetic parameter of nucleation rate expression, \( k \) is the Boltzmann constant, and \( T \) is the absolute temperature. The expression for \( J \) indicates that the lower the value of \( W \), the higher is the nucleation rate.

Let us consider two hydrocarbon mixtures with the same bubblepoint pressure of 5,000 psi at 700°F. For one mixture, the interfacial tension at the bubblepoint is 5 dynes/cm (mixture I). For the other, the interfacial tension at the bubblepoint is very low and is equal to 0.2 dynes/cm (mixture II). We are interested to calculate the work of critical nucleus bubble formation corresponding to \( \Delta \rho = 400 \) for mixture I and \( \Delta \rho = 50 \) psi for mixture II. We are also interested to find out at what \( \Delta \rho \) for mixture II the work of forming the critical bubble nucleus is the same as the work of critical bubble nucleus for mixture I at \( \Delta \rho = 400 \) psi. Equation (A-1) provides the results for mixture I, \( W/KT = 55 \) at \( \Delta \rho = 400 \) psi and for mixture II, \( W/KT = 0.22 \) at \( \Delta \rho = 50 \) psi. Therefore, despite higher supersaturation for mixture I, the rate of homogenous nucleation for mixture II is considerably higher. The work of forming the critical bubble nucleus for mixture II is about 250 times less than the work of forming the critical bubble nucleus for mixture I. For a small supersaturation (that is, \( \Delta \rho = 3.2 \) psi), the work of forming of the critical bubble nucleus for mixture II would be equal to that of mixture I with \( \Delta \rho = 400 \) psi.

The above simple illustration shows that for a near critical oil, one may activate a large number of nucleation sites with a small supersaturation, giving a high \( S_p \). However, as the critical point is approached, the maximum supersaturation in pressure also decreases [see Figure 4.28 of Reference (23)].