FLOW OF WATER-IN-OIL EMULSIONS - FIELD RESULTS VS. NUMERICAL PREDICTIONS

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Abstract. *Oil companies are familiar with the problems caused by the formation of water-in-crude oil emulsions, especially with those related to the increment of the crude oil apparent viscosity and its impact on the oil production. Many studies have been conducted to establish relation between the emulsions´ apparent viscosity and their water content. However, there is a lack of information in the literature concerning their impact on the pressure drop trough pipelines and on its consequence related to crude oil production. The thermo-hydraulic calculation of a producing oil stream is based on black-oil models for PVT properties calculation and on multiphase flow correlations and models suitable for pressure drop prediction. These models and correlations demand the knowledge of the viscosity of the liquid phase as an input data, amongst other parameters. However, the thermo-hydraulic calculation becomes more complex in the case of water-in-oil emulsions. The problem is to get a viscosity value to be used for the pressure drop calculation. This study investigates the performance of multiphase flow correlations applied for the flow of gas and water-in-oil emulsions through pipelines. Actual data from field were used to allow the evaluation of the results obtained through numerical simulations using these correlations. This information is relevant to establish how the presence of water-in-crude oil emulsions can interfere with the technical and economical viability studies.*

Keyword *:flow assurance, emulsion, multiphase flow*

1. Introduction

The process of oil production, from the reservoir to the process facility, imposes on the produced stream (composed usually by oil, gas and water) extremely high shear rates, throughout its many stages, represented in Fig. 1. This complex series of flows have an effect on the multiphase mixture of oil-water-gas. In each one of the stages in this process, the shear imposed by the flow (among other parameters) will interfere and modify the phase arrangement of this multiphase mixture.

Hence, when calculating the pressure drop of these flows, an engineer faces many difficulties, since it is almost impossible to precisely determine how the different phases are distributed along the production process. Different aspects have to be considered, such as the oil-water emulsion rheology, how much of the water is emulsioned and how much of it is free, the continuous gas liberation from the oil phase as the pressure decreases and the effects of the gas phase itself. This is even more complex if one considers the case of a heavy, viscous or waxy oil.

Because of these multiple aspects involved in the problem, most multiphase flow simulators available today to the oil industry have limited capability to handle such calculations. Usually, all these effects are dealt throughout the input of few parameters, or even a unique parameter, for example, the viscosity of the water in oil (w/o) emulsion.

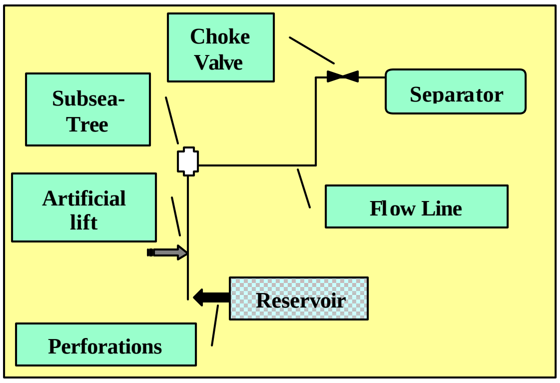

Figure 1- Schematic representation of the process of oil production

This work presents an analysis of the parameters that influence the pressure drop calculation of an oil-water-gas mixture flowing from the reservoir to the production facility. A sensibility analysis is performed aiming to identify the parameters that influence the pressure drop in these producing streams, and to evaluate their relative importance. Some results of numerical simulations of these flows are presented and compared to field data. The results of this work may serve as information to better understand the effects of emulsification in oil producing streams.

However, it is important to make clear that this work does not propose to address the complex mechanisms of rheological characterization of w/o emulsions. This subject has to be dealt not only in terms of rheological modeling, but also in terms of reproducing in laboratory the real field conditions. Even the process of obtaining a representative sample from the field to be characterized in the laboratory is still subject of debate. For a recent reference on this, one may look at Oliveira & Gonçalves (2005), that presents a detailed discussion on this subject.

2. The practice of multiphase flow simulation in oil production

To start the discussion, perhaps is of interest to comment on the practices used for the simulation of multiphase flow of oil-water-gas.

During the lifetime of an oil field, with the gradual increase of the water production, especially in heavy oil fields, the production engineers face problems with the numerical simulation of multiphase flow when the liquid phase forms an emulsion.

The calculation of steady-state gas-liquid flow is normally performed with simulators that adopt empirical correlations which were originally obtained from field or laboratory data. In some cases, the original data was obtained with a single liquid phase only, either oil or water. In other correlations, the data comprises more than one liquid phase. The most often used correlations are the ones from Beggs & Brill (1973), Hagedorn-Brown(1965), and Orkiszewski(1967). The viscosity of the liquid phase is one of the many parameters necessary for the calculation with these correlations. The viscosity can change not only with the temperature for Newtonian fluids, but also with the shear rate for non-Newtonian fluids. It must be remarked that these empirical correlations had been developed for Newtonian fluids only. This point may be a first source of uncertainties of the simulation processes, and these aspects will be detailed later on.

In the cases where the reservoir produces water associated with the oil, the liquid phase is actually a mixture of two fluids: the water and the oil, that can form an emulsion or not. Therefore another complication arises for the problem. Even considering that some correlations have been developed from three-phase flow data, the flow patterns may change, even when keeping constant the volumetric ratios of each phase, due to several variables, such as the chemical composition of the oil, the salinity of the water, and the different shear rates, amongst others. For the correlations based on data from two-phase gas-liquid flow, the situation is even worse. The knowledge of flow patterns of these two phases as a "single liquid", provided that only parameters for the "liquid" are given (viscosity, density, interfacial tension) is extremely limited, mainly in the heavy oil cases.

Even in the cases where it is possible to establish that exists or does exist not free water there are uncertainties such as the determination of the point of the production process where the emulsion is formed, the droplet size distribution, how this distribution changes throughout the process, and the role of the gas phase and pressure.

For lower values of water cut, it is possible to establish a procedure that allows some reliability for the simulation of these flows. The small amount of water may guarantee the inexistence of free water, hence it is possible to establish that the properties of the emulsion along the process are the same as the used for the calculation of the separation of the oil and water. The measurement of this viscosity is easily performed with some degree of reliability because it involves the sampling of the liquid phase under reasonably controlled pressure, temperature and shear rate. That allows the measurement of the emulsion droplet size distribution, making possible the use of synthetic emulsions to obtain realistic viscosity data. This is the basic idea considered by Oliveira et al (2001) and that grants good results on the simulation of the emulsion flow with low water content. In fact, in these cases, the emulsion is a single liquid phase homogeneous along the process, usually with Newtonian behavior and with established properties that allows a good agreement between the simulated values and the field data.

However, as the values of water cut increase, significant changes are observed in the arrangement of phases and the physical parameters of the emulsion along the process. These phenomena, beyond the obvious impacts in the emulsion rheology certainly add issues that had not been addressed in the development of the published correlations for multiphase flow.

Other sources of uncertainties must also be added in a simulation for production adjustment, comprising the input data, such as those resultant of bad functioning of in-line meters (pressure, temperature, and flow rate meters), typical uncertainties of reservoir and evaluation of the Productivity Index (PI), - parameter used to calculate a well flowrate as a function of the reservoir pressure and the bottom of the well pressure. There is also a possible effect of wax deposition – decreasing the flow area - or viscosity increase due to hydrate slurries formation.

Among these as many sources of uncertainties the engineer has few alternatives. Perhaps the most attractive of them is to use "correction factors" or an "adjustment" in the liquid viscosity in order to fit field data. Another option is to use different correlations for pressure drop, accepting the result of the one that fits better production data in a given situation, sometimes without considering the applicability of this specific correlation to this specific situation. In short term these are in fact alternatives easier to perform, however the persistence of inconsistencies in the values predicted by the simulator and observed in the field as time goes by (and the water cut increases) eventually generate situations where more and more correction factors accumulate progressively increasing the distance to the physical reality simulated.

At this point is reasonable to raise some questions regarding the picture presented for simulation of the multiphase flow of oil-water and gas:

1. Concentrate oil-water emulsions are non-Newtonian fluids, although this is not considered by the computational models. This aspect adds differences to flow behavior for the range of typical shear rates? Which are the typical shear rates? Where the typical shear rate shall be considered?

2. There is a need to obtain experimentally the values of emulsion viscositiy. How to do that? How to prepare synthetic emulsions that are similar to the actual ones? How to determine the maximum volumetric concentration of droplets at dispersed phase? How to determine the droplet size distribution in the pipe? This distribution changes along the flow?

3. How to predict the amounts of emulsioned and free water?

4. For concentrated emulsions, it is possible that wall slippage may occur. How to determine if this is or not occurring in determined point of the pipeline?

5. For long shut down periods droplets sedimentation will occur. Will the increase of the concentration of the dispersed phase (due to sedimentation) together with the low temperatures enlarge the viscosity to a level that can harm the well startup?

6. How the gas phase at high pressure effects the emulsion viscosity? How easily the gas leaves solution from the oil phase when depressurized? Which are the effects of the micro gas bubbles moving up while the flow proceeds?

7. Where the emulsion is actually formed? Is There already emulsion in the reservoir or it forms during flow from well bore to facilities?

3. Multiphase flow correlations

In principle empirical correlations should be adjusted to situations similar to the ones they had been developed. In reality, the simulation of fluid flow in production lines has been problematic because there are several different combinations of input data and correlations that provide the same results.

One reason for these difficulties can be the fact of that these correlations are not adjusted to the emulsion flow that can, for example, have a higher viscosity than the oils used in their development.

Each of the correlations mentioned in the previous section was developed from field or laboratory data set. The correlation of Beggs & Brill (1973), for example, was developed from laboratory data with 1" and 1 ½" diameter pipes and with air and water. The correlation of Hagedorn & Brown (1965) used field data with oil, water and gas in lines with diameter varying between 1"and 4". Next a short summary on how each one of the most used correlations considers the oil-water emulsion.

- Hagedorn-Brown (1965):

The authors present a deepened discussion on how the gas-liquid mixture could effect the viscosity calculation. However, they did not analyze the mixture between water and oil.

- Duns & Ros (1963):

These authors state that their correlation was developed only for gas-oil mixtures. They affirm that for oil-water mixtures the pressure gradient may be unpredictable if they form stable emulsions.

- Orkiszewski (1967)

This correlation has a correction factor (liquid distribution coefficient) to take into account for the emulsion presence. However the experimental data used in the development of this correlation goes up to 30% water cut only.

- Beggs & Brill (1973);

This correlation was developed for air-water flow only.

It is added to the fact that with high water content the emulsion starts to have a non-Newtonian behavior, an aspect not considered in any of the correlations. Other factors, however, also can contribute for this uncertainty in these correlations, such as: the superficial tension of the emulsified fluid, that modifies the arrangement of phases and consequence by the hold-Up in the vertical flow, the specific mass of the gas at high pressure - almost all the correlations had been developed for low pressure -, the thermal calculation and finally the calculation of fluid properties.

An alternative to these correlations is the use of mechanist models such as the one of Bendiksen et al (1991), used in the transient simulator OLGA®. These models had been developed for each one of regimes of flow - bubbles, intermittent and annular - in the case of vertical flow - and also stratified - for horizontal flow. Several published models make possible the determination of the flow patterns for one given installation with different flow rates, but the more often used was developed by Taitel & Dukler (1976).

These models are based on the application of laws of conservation and therefore they should have generalized application, regardless the conditions where they had been originally tested. However this is not true because they need closure relation to allow their solution. Such equations derive from the combination of laboratory data, normally gotten with Newtonian fluids and with low viscosity fluids and usually at low pressure. As consequence these models can not describe well the flow regimes of viscous liquids (and non-Newtonian in some cases).

The recent experiments carried by Rosa (2002) gives significant importance for this argument, showing the possibility of differences in the format of the gas bubbles in horizontal intermittent flow as show Fig. 2 and Fig. 3. Both photographs show the nose of the gas bubble (air) with low flow rate-, the first one with water (viscosity of 1cP) as liquid phase and the second with a mixture of water and glycerin, with viscosity of 27 cP. One can notice that there is a difference between the two cases with the front of the bubble being deformed towards the center of the pipe when the liquid is more viscous. It is important to consider that the different interfacial tensions with the air and angles of contact with the walls of the tubing also can be acting for the change of the format of the bubble, but is clear that the form of the interfaces can move in function of the alteration of the properties of the liquid phase. Without doubt, it is then reasonable to question the validity of the use of models developed for the water or low viscosity fluid for the simulation of the heavy oil flow. With the different form of the interfaces, the local speeds change and consequently the gradients of pressure due to the friction and acceleration may also change. In the case of vertical flow the term of higher relevance, the hold-Up, can be modified if the distribution of the phases changes as well.

Figure 2 - Gas bubble nose in intermittent horizontal flow of water-air

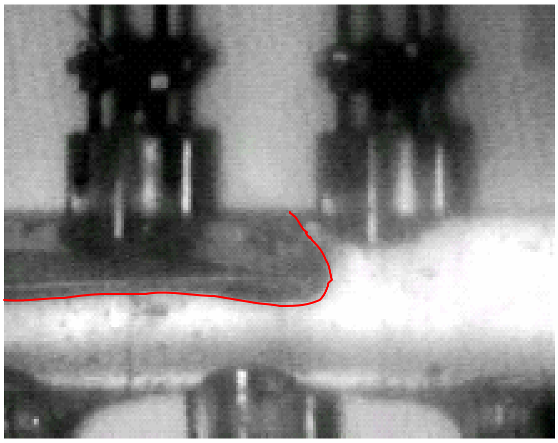

Figure 3 - Gas bubble nose in horizontal intermittent flow (water+glycerin)-air

This subject was not studied enough; however the preliminary analyses seem to suggest the need of a survey of heavy oil field data to allow the development of correlations better adjusted to this type of flow.

4. Sensibility analisys

To evaluate the influence of the uncertainties of the input parameters on the calculation of pressure drop in multiphase lines, a study was carried using PETROBRAS in house multiphase flow simulator MARLIM® (Almeida, 1998). This code features most of published multiphase flow pressure drop correlations coupled with thermal calculation and considers the Black Oil model for phase behavior prediction.

This analysis takes into account only for the influence of input parameters uncertainties for the simulation result. A discrete model for tubing and flowlines representing an actual oil well was considered with all boundary conditions applied. The Hagedorn-Brown (1965) and Beggs & Brill (1973) correlations were used in this case for vertical and inclined flow computation, respectively. The Bottom Hole Flowing Pressure (BHFP) was chosen as a parameter for comparison with field data.

The total uncertainty U due to input data was estimated through the equation:

$$U = k\sqrt{\sum_i \left(c_i \frac{U_i}{k_i} \right)^2} \qquad (1)$$

where the term inside the parenthesis expresses the contribution of each input parameter to the uncertainty.

Thus the calculated value for BHFP for a given particular case of a Campos Basin well was equal to 230.2 bar. Using estimated input data uncertainties and Equation (1) the overall uncertainty obtained was equal to $\pm$ 5.6 bar or 2.4%.

The rate between each parcel and the total square sum gives a good representation of the contribution of each parameter to the overall uncertainty. This information allows the determination of the parameters that imposes higher uncertainty on the calculation of the BHFP.

The input data which uncertainties are more relevant for the calculated BHFP value are the gas-oil ratio from the formation (responsible for 24% of the total BHFP uncertainty), the Water cut (54%), the liquid phase viscosity (5%) and the pipeline roughness (7%).

This means that, for the purpose of calculating multiphase flow through computer simulators, the question resumes into how much water is actually being produced an how this amount of water is partitioned as free or emulsioned water. The fact that the dominant parameters are the gas-oil ratio and the water cut related to the fact that those are determinant to the bulk fluid density and this parameter strongly effects the pressure drop in vertical flow, which is mostly due to the gravitational (lift) parcel.

5. The influence of different models for emulsion viscosity calculation

The liquid phase (emulsion) viscosity is among the relevant parameters for the computational flow simulation. Therefore, the selection of the proper model of emulsion viscosity is important and must be investigated.

Table 1 presents the values of viscosity of the emulsion calculated by the different models available at MARLIM® (Almeida, 1998) (Black Oil- not considering emulsion formation, Woelflin ((1942), Farah et al (2002) and Ronningsen (1995)) and the corresponding values of BHFP. The purpose here is to evaluate only the influence of the viscosity model to be adopted, therefore the same multiphase flow pressure drop correlations were used for all cases (Hagedorn & Brown (1965) for vertical and Beggs & Brill (1973) for horizontal pipes). Also presented in Tab. 1 are the results of simulations with OLGA® conjugated to the PVTSim® for calculation of the fluids properties.

These BHFP data for different models were calculated for two Campos Basin wells, that have a Pressure Downhole Gauge installed. The calculated values can be compared to the measured ones that are 243 bar for Well A and 230 bar for Well B. It is important to mention that these values are subject to measurement uncertainties themselves.

The analysis of this data indicates that even though there is a significant discrepancy for the values of the emulsion viscosity depending of the selected viscosity correlation, the results of BHFP only changes slightly. The values calculated by all models over predict the value of the BHFP, except those that does not consider the emulsion formation. This results from the fact that the used multiphase flow correlations tend to over predict the pressure drop, and apparently the assumption of no emulsion formation somewhat compensates for this fact.

The mechanistic model used by OLGA® also gave a good forecast of the BHFP.

Although the differences found among the numerically calculated values and between them and the measured values are small, it is important to note that offshore wells usually have very high Productivity Indices (PI), and a small difference in the pressure drop could result into a large absolute change in the production flow rates.

Well A

	Viscosity (cP)								
Temp. °C	*No Emulsion cP*	*Live Oil cP*	*Woelflin (Loose) cP*	*Woelflin (Medium) cP*	*Woelflin (Tight) cP*	*Farah cP*	*Ronningsen cP*	*OLGA / PVTSim No Emulsion*	*OLGA / PVTSim Emulsion*
50	17,14	21,53	44,36	42,06	46,21	28,46	37,71	32,72	68,77
70	3,09	3,71	6,77	6,39	6,95	4,73	5,76	9.84	16,93
BHFP (bar)	240,28	**243,31**	253,12	252,29	253,66	246,18	249,18	234,41	240,20

Well B

	Viscosity (cP)								
Temp. °C	*No Emulsion cP*	*Live Oil cP*	*Woelflin (Loose) cP*	*Woelflin (Medium) cP*	*Woelflin (Tight) cP*	*Farah cP*	*Ronningsen cP*	*OLGA / PVTSim No Emulsion*	*OLGA / PVTSim Emulsion*
50	9,08	16,46	104,30	124,55	207,51	87,93	87,82	20,48	194,62
70	2,84	5,26	33,26	39,54	50,86	16,00	27,34	6,05	55,45
BHFP (bar)	**230,17**	235,83	254,19	255,80	257,52	252,29	252,48	189,72	237,96

Table 1 Values of emulsion viscosity calculated by the different models and the corresponding BHFP.

6. Pressure drop behavior related to emulsion water cut

As the amount of produced water rises, one can expect a corresponding increase of the emulsion viscosity, and as a consequence the pressure drop through the producing system should increase as well. The graphs presented in Fig. 4, obtained in three wells of the Campos Basin, however, show a different behavior from the expected one.

In the case of Well X, for example, there is a decrease in the pressure drop in the interval between 0 and 30% of water cut and above this value the pressure drop starts to increase as expected. For the Well Y, one evidences that there is a significant variation of the pressure drop although the water cut remain basically constant, indicating the influence of other parameters not presented in the graph. Finally, in the case of the Well Z, a significant variation of the pressure drop is not observed, although the water cut to vary between 5% and 40%.

It must be stressed that this data may be subjected to measurement errors. However, they strongly suggest that parameters other than emulsion viscosity may be having a decisive role in the flow.

According to the theory of single-phase flow, for high values of Reynolds numbers - turbulent pattern - the increase of viscosity does not impact significantly friction factor. Table 2 below presents this parameter for three wells from Fig. 4, considering their different sections of the sub sea production system and properties along the flow path. Reynolds was calculated considering the values for emulsion viscosity and the mixture velocity The predominance of the turbulent flow was observed, and the only exception corresponds to the transition between laminar and turbulent patterns. Probably this fact explains the low impact of the emulsion viscosity on the pressure drop of most production systems.

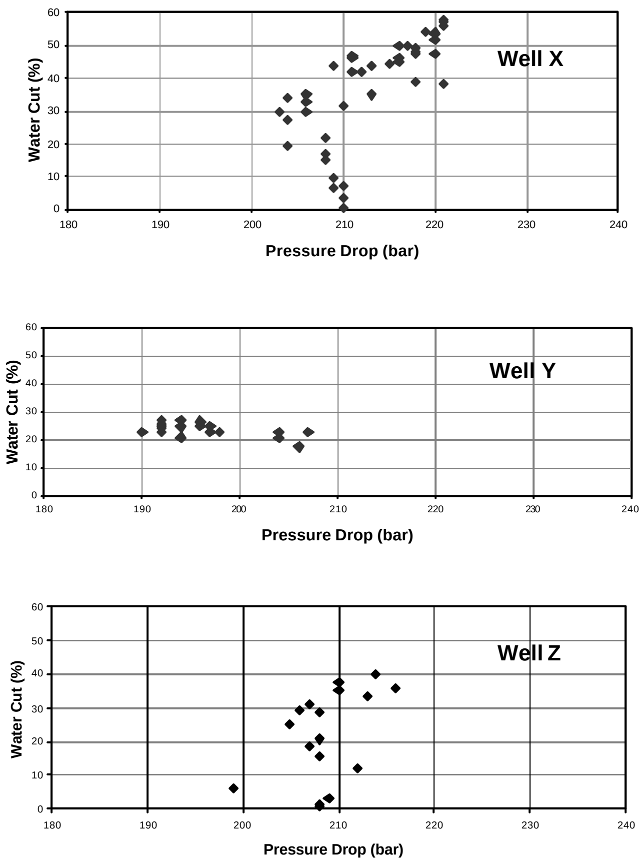

Figure 4: Pressure drop of three sub sea wells related with water cut evolution.

Well	Postion	Reynolds	Pattern
X	Bottom hole	4.761	Transition
	Well head	3.756	Transition
	Pipe end	4.680	Transição
	Pipe start	2.241	Laminar
	Riser base	2.142	Laminar
	Riser top	1.880	Laminar
Y	Bottom hole	65.677	Turbulent
	Well head	46.047	Turbulent
	Pipe end	47.030	Turbulent
	Pipe start	15.932	Turbulent
	Riser base	17.834	Turbulent
	Riser top	15.188	Turbulent
Z	Bottom hole	38.522	Turbulent
	Well head	30.776	Turbulent
	Pipe end	18.053	Turbulent
	Pipe start	10.187	Turbulent
	Riser base	11.415	Turbulent
	Riser top	9.615	Turbulent

Table 4: Reynolds and pattern of the subsea wells

7. Conclusions

This work addresses the simulation of gas-emulsion flow through pipelines, summarizing the procedures adopted and raising questions aiming to identify the aspects that require further understanding regarding this issue. Applying the current knowledge it presents a study on the influence of the emulsion viscosity on the multiphase flow of the produced stream, concluding that:

- the knowledge of the emulsion rheology uniquely is not enough for pressure drop prediction. A suitable multiphase flow model or correlation is required;
- there are no published multiphase flow pressure drop model or correlation specific for gas-emulsion flow;
- the multiphase flow pressure drop tend to be over predicted by most of published correlations;
- due to the turbulent nature of the wells under analyze (which reproduce typical offshore scenarios) and the predominance of the vertical parcel on the pressure drop, the exact knowledge of emulsion viscosity may have limited importance for the prediction of the multiphase flow pressure drop;
- field data correlating pressure drop with water cut seem to suggest that other parameters beside the viscosity may be strongly effecting the multiphase flow behavior.

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