STUDY OF THREE-PHASE FLUID DYNAMICS IN A SURGING PRODUCTION SYSTEM

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Abstract. *Among others factors, petroleum extraction is subordinate to the reservoir pressure and the required pressure to rise it to the surface production facilities. Reservoir deliverability equations tied production rate with reservoir driving force (Economides, 1994). The Inflow Performance Relationship (IPR) is obtained by measuring the production rates under various drawdown pressures, and is used to assess well performance by plotting the well production rate against the flowing bottonhole pressure. Others limiting rate of production factors are imposed by wellhead required pressure and the production tubing performance. The tubing performance is sensitive to several parameters among which we can highlight the production tubing geometry and the properties of the produced fluids (Guo, 2007). Therewith we can define the Tubing Performance Relationship (TPR) similarly to the IPR. Thus the present work aims the hydraulic performance analysis of a production system with a flowing well without artificial elevation methods. Furthermore the triphasic (water-oil-gas) flow studies, both in the production string and the production line, allowed the inspection of the main variables of the system, fluid properties, operation conditions and geometric parameters, on the head loss. In order obtain all these, several methods were developed, each one with specifics limitations to include all flow patterns. The most common biphasic horizontal flow patterns according to Brill & Beggs (1975) are: mist flow, bubble flow, plug flow, slug flow, stratified flow, wavy flow and annular flow. Yet according to Brill & Beggs (1975) the most common biphasic vertical flow patterns are: bubbly flow, slug flow, churn flow, and annular flow. Accordingly to these, another outbreak discussed is the pattern flow sensibility on the head loss. The methodology used in the present work is based on the discretization of the system in several discrete counterparts cells, in which was where it was applied the most consistent empirical correlation. For both vertical and horizontal sections was applied the Beggs & Brill (Beggs & Brill, 1973) methodology. This choice was reasoned on the history of several studies for the petroleum industry (Tackacs, 2001). The black oil approach was adopted, and the computational code was developed in MatLab in order to predict all physical properties needed employing the consistent model and correlation present in literature.*

Keywords*: multiphase flow, fluid dynamics study, black oil*

1. INTRODUCTION

Multiphase flows are commonly found in the production and transportation of oil, water and gas. In this sort of flow, present phases can be arranged differently inside the duct, these configurations are called flow patterns. The correctly identification of these flow patterns is essential to technical and economical feasibility issues, e.g. volumetric measured rates, head loss along flow lines, production management and supervision. Those are critical factors in an offshore production system where high distances and costs are involved. Several methods that take into account the present flow regime are used to evaluate pressure gradients along production and transportation lines. Those methods are based in mechanistic models and empirical correlations. Mechanistic models are reasoned on specific fluid mechanics flow models. On the other hand, empirical methods are reasoned on correlations obtained through experimental data and embrace a wide range of operational conditions (Pacheco et.al, 2007).

During oil production and transportation, three phase flow is frequently observed in the interior of production lines, occurring in vertical, inclined or horizontal sections. Due to the complexity of the multiphase flow, several methods were developed in order to identify the flow pattern and to estimate the pressure gradient. This knowledge is essential to the correct design of production lines and equipments. The most common biphasic horizontal flow patterns according to Brill & Beggs (1975) are: mist flow, bubble flow, plug flow, slug flow, stratified flow, wavy flow and annular flow. The total head loss in two phase flows (liquid and gas) is manly influenced by the hydrostatic pressure drop, except for the particular case of gas flowing at extremely high velocities and, due to that fact, the friction pressure drop becomes substantial. Yet according to Brill & Beggs (1975) the most common biphasic vertical flow patterns are: bubbly flow, slug flow, churn flow, and annular flow. Accordingly to these, this study aims the evaluation of the flow pattern influence on the friction factor for multiphase flows, settling system operation conditions contribution and fluid properties.

In an increasingly aggressive scenario, petroleum industry develops itself rapidly, creating a technical development need that allows the specification and design of production system capable of handling multiphase flows. Thus this work aims to contribute with oil production in order to comprehend and quantify head loss in both production columns as in production lines in an effort to assist solutions obtained to problems increasingly challenging.

2. METHODOLOGY

The present work aims to estimate the major flow pattern in a production line, since the perforation to the separator vessels, and how these influence in the system head loss prediction. Thus it was considered an offshore production scenario in which production and injection wells were assigned reasoned on average saturation and permeability maps and topography map. Reservoir data is assigned on Tab. 1. The simulation was performed on a reservoir model implemented on BOAST98 software (developed by the United States of America Department of Energy) and a particular well production data was selected for the flow pattern temporal analysis. The simulation main results were used as input parameters for the analysis of the fluid natural lift from the perforation to the separator vessel, described on Tab. 2.

Table 1. Reservoir and fluid data used in the simulation model

Reservoir data	
Initial Reservoir Pressure	8575 *psi*
Saturation Pressure	3525 *psi*
Reservoir Temperature	200 °*C*
Average Porosity	20 %
Absolute Permeability (avg)	329 *md*
Vertical Permeability (avg)	31,4 *md*
Connate Water Saturation	18 %
Oil Specific Mass	31,9 °API
Gas Specific Mass (air = 1)	0,75

Table 2. BOAST98 reservoir simulation results used as the production simulation input parameters

	1 day	***1826 days***	***3651 days***	***5476 days***
Oil Productin Rate (stb/d)	17000,00	9317,80	5925,20	4977,90
Gas Production Rate (Mscf)	10688,00	8031,00	16070,00	11156,00
Water Production Rate (stb/d)	0,00	4928,40	8492,10	11471,80
BSW (%)	0,00	34,59	58,90	69,74
GOR (Mscf/stb)	628,71	861,90	2712,14	2241,11

Is important to emphasize that this is a temporal analysis in other words, the data was obtained during the entire well production period. In the present work it was considered a production period of 5476 days, as it is shown on Tab. 2.

The layout production data were set in a way that could represent a typical offshore system scenario. Figure 1 shows the well's general scheme and the main variables needed to multiphase flow approach. This are presented on Tab. 3.

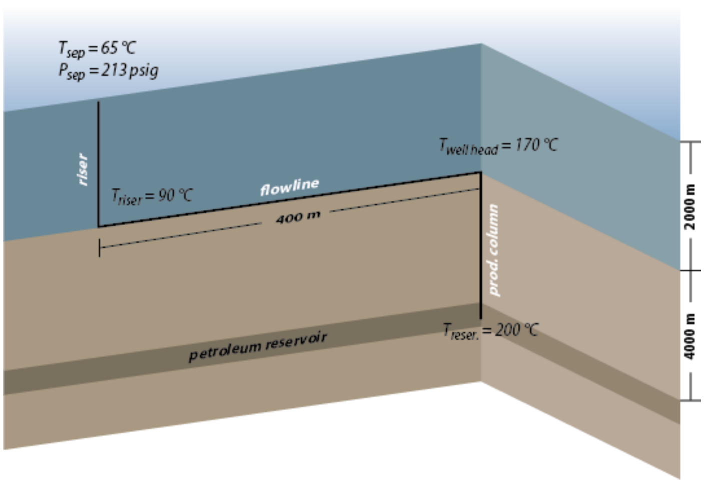


Figure 1. Dimensions and temperature for the system geometry and temperature at the separator vessel (out of scale)

Table 3. Production system data related to Fig. 1

Production system data	***Values***
Production Column Length (m)	4000
Flowline Length (m)	400
Riser Length (m)	2000
Perforation Temperature (°C)	200
Wellhead Temperature (°C)	170
Bottom Riser Temperature (°C)	90
Separator Vessel Temperature (°C)	65
Separator Vessel Pressure (psig)	213

As the flow pattern is significantly to the head loss calculation, the system modeling as a whole (production lines and column) could get very complex. In view of the exposed problem, the approach was based on small discrete pieces, large enough to allow the correct identification of the flow patterns inside each tubing section analyzed. In Both vertical (production column and riser) and horizontal (flowline) sections, Beggs & Brill (Beggs & Brill, 1973) methodology was applied. This correlation was chosen due to its history in several petroleum industry studies and the possibility to discretize the flow pattern in every tubing section (Tackacs, 2001). It was used the black oil approach specifically for three-phase systems with water-oil-gas. The MatLab software was chosen as a computational tool to implement the head loss calculation strategy of a production system, employing the literature models and correlations to predict phases' physical properties.

2.1. Black oil correlation

Black oil correlations were developed specifically for water-oil-gas systems and for this reason are very useful to predict phase behavior on the flow of petroleum wells. In this kind of correlation all different present phases are composed of only one component where this component is set with average properties. When used together with a set of calibration options, black oil correlations can produce precise behavior phase data with a minimum of input data Villela (2004).

Table 4. Fluid prediction methods and correlations

Properties	***Symbols***	***Method / Correlation***
Solubility Ratio	R_s	Standing (1981)
Oil Formation Volume Factor	B_o	Standing (1981)
Gas Formation Volume Factor	B_g	Gas law
Water Formation Volume Factor	B_w	Gould (1974)
Compressibility Factor	Z	Hall & Yarborough (1973)
Dead Oil Viscosity	μ_{od}	Beal (1946)
Crude Oil Viscosity	μ_{ob}	Beggs & Robinson (1975)
Gas Viscosity	μ_g	Lee, Gonzalez & Eakin (1966)
Water Viscosity	μ_w	Van Wingen (1950)
Oil Superficial Tension	σ_o	Baker & Swerdloff (1955)
Water Superficial Tension	σ_w	Baker & Swerdloff (1955)
Friction Factor	f_a	Swamee & Jain (1976)

2.2. Flow regime map

Beggs & Brill (1973) methodology aforementioned was used to check the major flow regime in each production column and production line piece. Thus it was necessary to calculate: Froude Number Eq. (1), No-slip holdup Eq. (2) and constants that defines regions on the flow regime map Eq. (3) to (6). Those parameters are necessary in order to obtain the flow regime in the pattern flow map proposed by Beggs & Brill (1973) as in Fig. 2. It's important to highlight that each flow regime covers a wide range of flow patterns as it can be seen on Tab. 5.

The total head loss was calculated using the Beggs & Brill head loss equation, Eq. (7) with Swamee-Jain (1976) friction factor equation, Eq. (8).

$$N_{Fr} = v_m^2 / gd \tag{1}$$

$$\lambda_L = v_{sL} / v_m \tag{2}$$

$$L_1 = 316.\lambda_L^{0,302} \tag{3}$$

$$L_2 = 0,000925.\lambda_L^{-2,468} \tag{4}$$

$$L_3 = 0,10.\lambda_L^{-1,452} \tag{5}$$

$$L_4 = 0,50.\lambda_L^{-6,738} \tag{6}$$

$$-\left(\frac{\partial P}{\partial L}\right)_{B\&B} = \frac{\left(\frac{f \rho_m v_m^2}{2d}\right) + (\rho_s g \sin\theta)}{1 - \left(\frac{\rho_s v_m v_{sg}}{P}\right)} \tag{7}$$

$$f = \left\{ (64/\mathrm{Re})^8 + 9,5\left[\ln\left(\varepsilon/3,7D + 5,74/\mathrm{Re}^{0,9}\right) - (2500/\mathrm{Re})^6\right]^{-16} \right\}^{0,125} \tag{8}$$

Where we can define:
N_{Fr} = Froude number
λ_L = Non-slip holdup
v_m = Mixture velocity
v_{sL} = Superficial liquid velocity
v_{sL} = Superficial gas velocity
d = Tube diameter
g = Gravity acceleration
ρ_m = Mixture density
ρ_s = Superficial density
L_i (i=1,2,3 and 4) = Map delimitations
Re = Reynolds number
P = Pressure

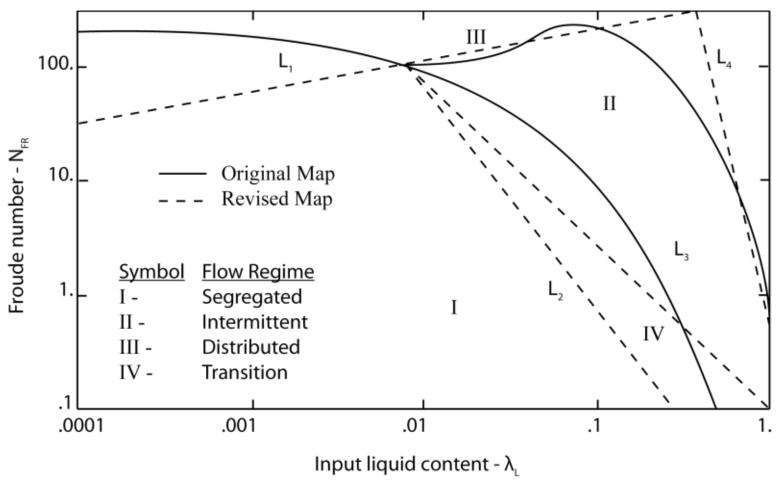


Figure 2. Regime flow map according to Beggs & Brill (1973)

Table 5. Flow pattern accordingly to Beggs & Brill (1973) for flow regime map

Flow Regime	***Flow Pattern***
Segregated	Stratified, Wavy and Annular flow
Intermittent	Plug and slug flow
Distributed	Mist and Bubble flow
Transition	

3. DISCUSSION AND RESULTS

With the aid of the reservoir simulation and the analysis of one particular well, is possible to obtain relevant data about production during the reservoir exploration period, therefore it was used the total production history of 5476 days. In order to achieve more comprehensive analysis, data were obtained in 1825 days intervals until 5476 days. The data, gas, oil and water flow rates and consequently BSW (Basic Sediments and Water) and GOR (Gas oil ratio) is described in Tab. 2. By means of setting fixed values of BSW and GOR, and varying fluid production rates accordingly to these variables, it was possible to obtain four TPR (Tubing Performance Relationship) in an effort to check the influence of those parameters (BSW and GOR) on system required pressure without any artificial lift method to lift the produced fluids from the perforation zone to the separator vessel.

Figure 3 shows pressure gradient along the well production history. This curve reflects the temporal fluctuation of BSW and GOR. Is possible to notice BSW prevails on ranges between 1 and 1826 days and between 3651 and 5476 days. Notwithstanding, between 1826 and 3651, is possible to verify a significant increase on GOR and therefore a reduction on the required flowing pressure. This behavior is due essentially to the hydrostatic pressure drop acting as the main cause of the head loss on vertical production systems. It`s worth mentioning that the horizontal flow section, referred as the flow line, shows negligible pressure fluctuation when compared to the rest of the system, in every considered production period.

Figure 4 shows the four TPR for the previously defined temporal intervals, 1, 1826, 3651 and 5476 days. It`s possible to notice that BSW fluctuations is more significantly than GOR fluctuations along the well production life, especially when high oil production rates are being taken on account. This is due to great increase in the water production over time requiring high bottom flowing pressure derived from the hydrostatic pressure drop. Nevertheless, as can be observed from Figure 3, between 1826 and 3651 days there is a significantly increase on GOR requiring small bottom hole flowing pressure at small oil flow rates. That can be explained due to the small gas density and, accordingly to that, small hydrostatic pressure drop.

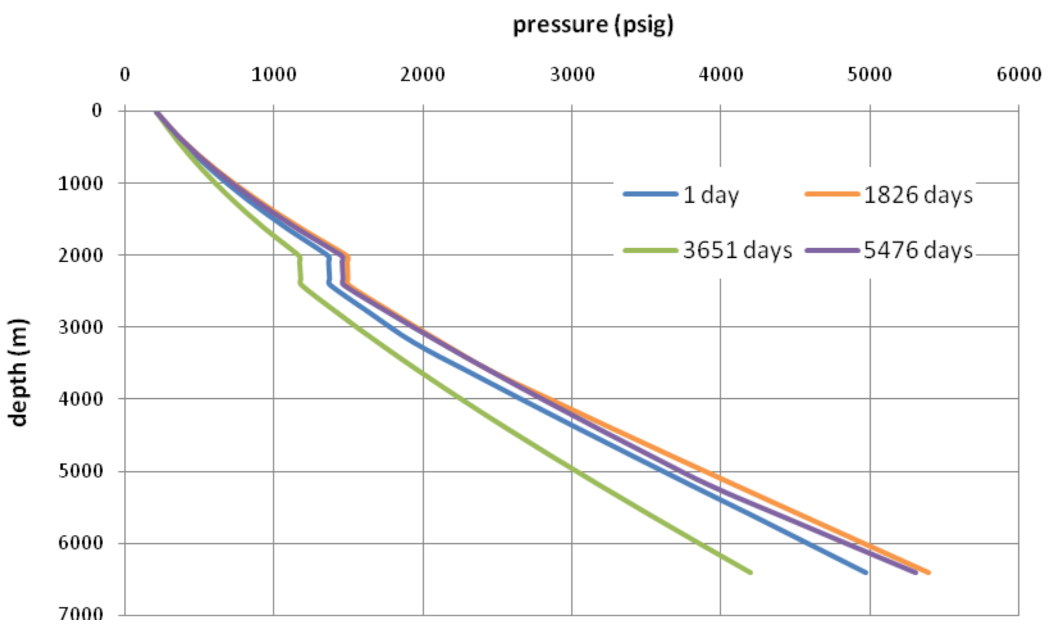


Figure 3. Pressure gradient

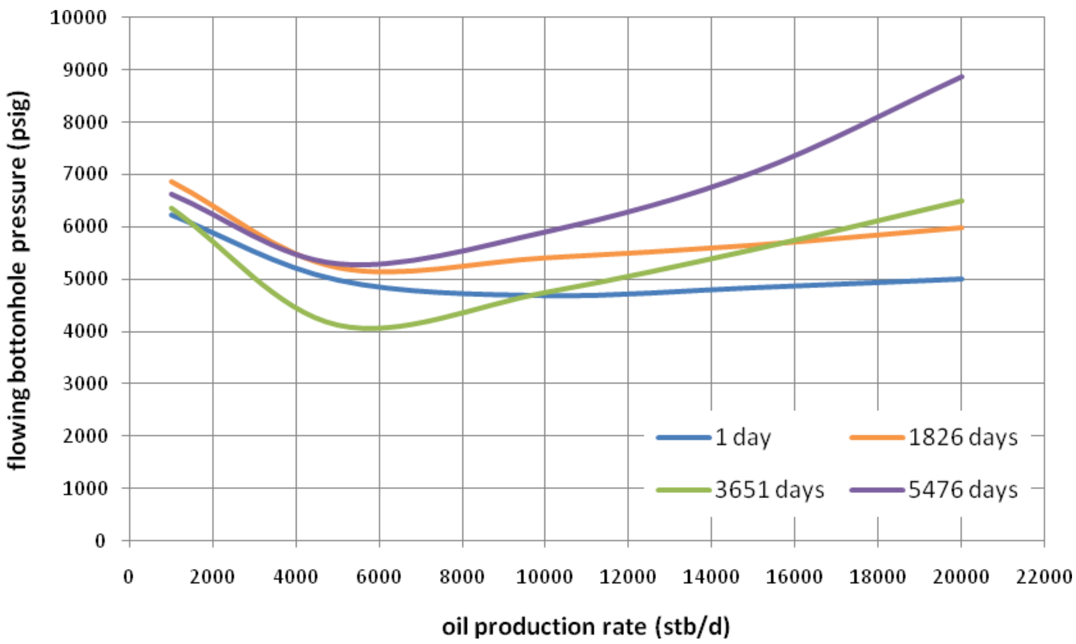


Figure 4. System Tubing Performance Relationship during the analyzed production period

The main flow pattern in each production column section and its influence on the system head loss, were realized with the results obtained from the simulator and particularly to the 1826 days TPR curve shown on Figure 4.

Figure 5, Fig. 6 and Fig. 7 shows the flow patterns at some particular conditions, with each schematic draw being representative of the main flow regime inside the production system. Figure 5 represents the flow regime at the 1826th day for the operation conditions exposed on Tab. 2. It`s possible to observe that the bottom hole flowing pressure fluctuation along the analyzed production period affects significantly the predominant flow regime at each tubing section. Furthermore, during the earlier production days, it`s also possible to verify that at high bottom hole flowing pressures bigger will be the distributed flow regime prevalence, or rather, bigger will be the section needed to accrete and expand the gas bubbles dissolved in the oil. As time goes by as well as with the bottom hole flow pressures reduction, the fluid prevailing pressure becomes closer to the saturation pressure favoring the previous dissolved bubbles to expand, and hence increasing the intermittent flow regime prevailing. The distributed flow regime recurrence between 3651 and 5476 days is consequence of the GOR reduction between this time intervals.

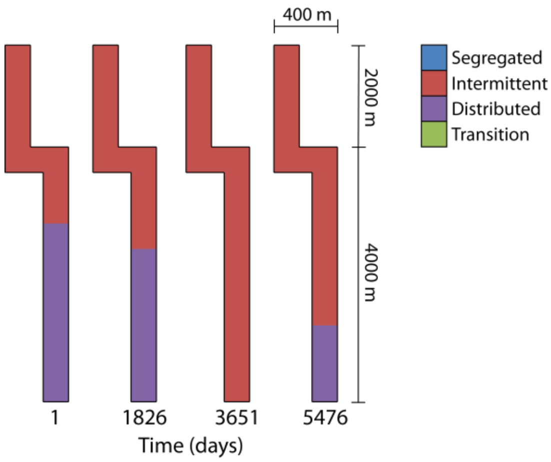


Figure 5. Flow regime along the well production history at the 1st, 1826th, 3651th and 5476th day

Figure 6 represents the flow regimes obtained through stipulated conditions in order to obtain the TPR curve at the 1826th day. Each column illustrate the flow regime at some particular oil production rate for defined values of BSW and GOR of 58,90% and 2712,14 Mscf/stb respectively. By observing Fig. 6 is possible to verify that with small oil production rates the transition flow regime becomes widespread through the production system, principally near the surface. The transient flow regime increase significantly the system head loss requiring higher bottom hole flow pressures. In addition to what was exposed, it can be noticed in Fig. 6 that from the moment the pressure drop due to hydrostatic becomes predominant, or rather when the system required pressure increase concomitantly with the oil flow rate, the condition at which the fluid is imposed becomes farther than the saturation pressure, increasing the distributed regime influence and decreasing the intermittent influence.

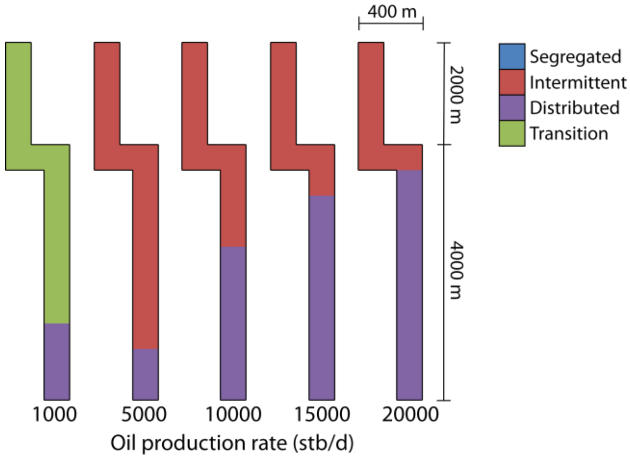
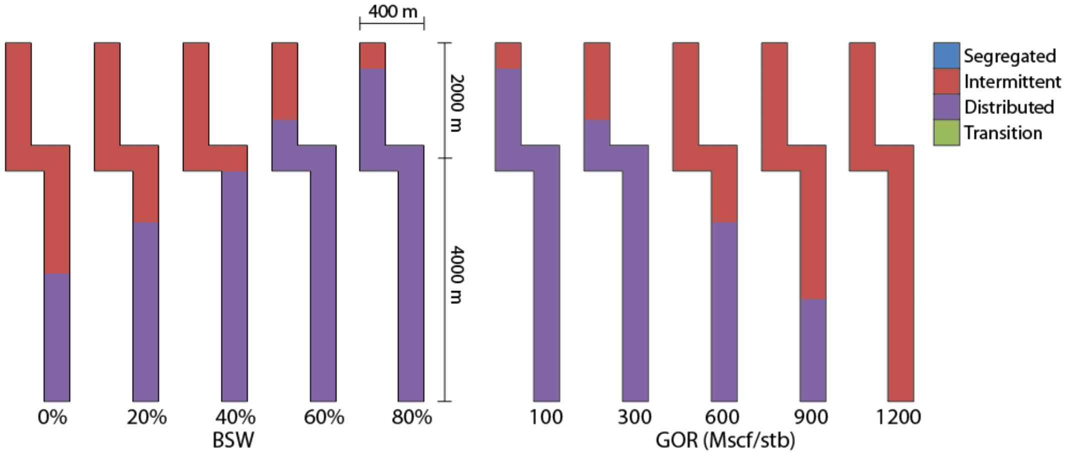


Figure 6. Flow regime at the 1826th production

Figure 7 had the purpose of pointing the individual influence of BSW and GOR on the flow regimes along the production system. In order to achieve that, in Fig. 7a it was ranged up the BSW setting the others production operation conditions constant, and similarly to the GOR in Fig. 7b. The data is shown on Tab. 6. In the Fig. 7a is possible to observe that for small GOR distributed flow regime prevails along the production system. The distributed flow regime preponderance decrease as the GOR increase and the intermittent flow regime becomes prevalent. This behavior is due the fact that high GOR denote high gas production and consequently favoring accretion and expansion of the gas bubble previously dissolved in the oil. Alternatively Fig. 7b shows an inverse behavior when compared to Fig. 7a, in other words, as the BSW increase the distributed flow regime becomes prevalent and consequently the liquid phase becomes prevalent on the pressure gradient.

Table 6. Operation conditions for Fig. 7

	Oil production rate (stb/d)	***BSW (%)***	***GOR (Mscf/stb)***
Figure 7a	10000	0, 20, 40, 60 e 80	600
Figure 7b	10000	20	100, 300, 600, 900 e 1200



(a) (b)

Figure 7. Flow regime for BSW (a) and GOR (b)

4. CONCLUSIONS

Submarine production system head loss is strongly influenced by the preponderant flow pattern. This flow pattern is highly related to the produced fluid properties and the production layout characteristics. Production layout optimization should be accomplished in order to exploit the reservoir without the need of artificial elevation. With this purpose, technical and economical viability research studies should be realized in order to fulfill these objectives.

The present work enabled the observation of the BSW and GOR influence in the flow pattern in each tubing section and consequently the system head loss. Furthermore it was observed that the distributed and intermittent flow regimes prevailed in the present analysis for the proposed production system. Nonetheless, those results are not generalist, since those results are tied to the proposed production system. Is important to highlight that the data used in the present work was obtained through a simulation of a reservoir model thus the next step would be realize the same analysis with real field data in order to investigate the validity of the analysis.

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