A NEW APPROACH FOR CALCULATING ANNULAR PRESSURE BUILDUP IN AN OFFSHORE WELL

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Abstract. The present work is concerned with the prediction of annular pressure buildup (APB) in an offshore well. APB is caused by the heating and expansion of the annular fluid trapped between the production line and the surrounding formation due to the production of heated hydrocarbons. To better predict this effect a mathematical model was developed to simulate the hydrodynamic and thermal processes along the production well, as well as the thermal and mechanical interaction with the surrounding formation. The model was developed to be as robust as possible so it can be used in different scenarios. The thermal model relied on the energy equation for the hydrocarbon mixture and on a thermal resistance network in the radial direction. The momentum and energy equations were solved coupled to determine the vapor mass fraction and the equilibrium temperature of the mixture along the well. An estimate of the annular pressure buildup was obtained by coupling the expansion of the trapped fluid with a structural deformation model of the concentric annuli. The results, which are compared against pressure and temperature field data for a 4700-m deep offshore well composed by three concentric annuli with a permanent downhole gauge (PDG) 3890-m deep, focus on the temperature, heat transfer rates per unit length and APB.

Keywords: Annular pressure buildup, heat transfer, offshore oil well.

1. INTRODUCTION

The continued demand for oil and its derivative boosts the industry to search for new reservoirs, forcing the exploration for oil and gas in harsh scenarios, such as those found in high pressure and high temperature (HPHT) wells, combined with extreme depths and high flow rates. These wells require special equipment to fully monitor its conditions and are at constant risk of failure caused by leaks, loss of productivity or even the total loss of the well (Oudeman and Kerem, 2004; Azzola et al., 2007; Pattillo, 2011).

A recurring problem that affects mainly high pressure and high flow rate wells during oil exploration and production is a phenomenon known as APB (Annular Pressure Buildup), which is the pressure increase caused by a thermal expansion of the fluid trapped within the annulus due to the upward flow of heated hydrocarbons. APB is one of the main possible issues occurring during the well construction and production due to its potential catastrophic consequences to the integrity of the well (Bradford et al., 2004). While several strategies have been developed to mitigate APB (Ellis et al., 2002; Ezell et al., 2010), there is still lack of robust models able to accurately predict the complex heat transfer, multiphase flow nature of the petroleum production process in order to support well design and construction.

The heat transfer process in oil and gas wells during production has been studied for over 50 years by several researchers worldwide (Ramey, 1962; Raymond, 1969; Shiu and Beggs, 1980; Arnold, 1990; Sagar et al., 1991; Alves et al., 1992; Hasan and Kabir, 1991-2012). A reference work in the field is reported by Hasan and Kabir (2002), and was later on compiled into a book. The first analytical model of heat transfer in petroleum wells was presented by...
Ramey (1962), who considered a single-phase flow for the well, steady-state heat transfer in the wellbore and transient in the rock formation (half transient model). More recent models have incorporated two-phase flow phenomena, variable physical properties and other effects, such as the change in kinetic energy variation and the Joule-Thomson coefficient, (Alves et al., 1992; Hasan and Kabir, 1994; Stone et al., 2002; Pourafshary et al., 2009).

The usefulness of measuring wellbore fluid temperature was pointed out as early as 1937 by Schlumberger et al. (Hassan and Kabir, 2002). The correct prediction of the temperature and pressure along the tubing string and in the annuli is of paramount importance in well design, since it is critical to (i) making decisions on flow assurance strategies, (ii) calculating corrosion and erosion rates and (iii) identifying potential risks associated with pressure buildup. This paper will focus on the accurately estimation of APB using a robust two-phase flow and heat transfer model of the well.

In the present study, the pressure and temperature of a 4700-m deep pre-salt production well composed by three concentric annuli are used to compare the results of the model proposed (Hafemann, 2015b). Phase equilibrium and physical properties were calculated by the commercial package Multiflash™, which was coupled to an in-house built well model based on Hafemann’s et al. (2015b). The model is solved from bottom hole to wellhead, where each new axial position of the wellbore is calculated based on the gradient obtained from the previous position, and the temperature and quality can be estimated by solving the energy and momentum equation. Radial heat transfer was modeled via a thermal resistance network approach and the annular pressure buildup was estimated using a new model, based on the analytical equation proposed by Oudeman and Kerem (2004).

2. MODELING

Figure 1 shows a schematic diagram of the vertical well with its lithological map. A more detailed description of the well can be found in Ferreira et al. (2016). The well has a total depth of 4700 m, where the water column accounts for the first 1387 m. The hydrocarbon fluid flow occurs in the internal tubing, while the region between the tubing and casing consists of a closed annular space. The first annular is filled with a 2419 m long nitrogen column, pressurized at approximated 8 MPa. Sea water fills the rest of the first annulus. The other annuli are filled with a water/glycerin mixture to imitate a real oil based annular fluid. In the radial direction, the model also considers a cemented region followed by the rock formation. Values for the formation properties can be found in the literature (Eppelbaum et al., 2014 and Jaeger 1979).

![Figure 1. Well geometry and lithography.](image_url)
The momentum balance equations for the steady-state, one-dimensional flow in the tubing can be written as follows (Brill and Mukherjee, 1999):

\[
\frac{dP}{dz} = \left( \frac{dP}{dz} \right)_f + \left( \frac{dP}{dz} \right)_g + \left( \frac{dP}{dz} \right)_{acc}
\]

(1)

where \( P \) is the pressure in kPa, and \( z \) is the axial distance in m. The terms on the right side of Eq. (1) represent friction, gravity and acceleration pressure drop terms, respectively. According to Brill and Mukherjee (1999), the gravitational pressure drop is dominant in wells, accounting for 80 to 95% of the pressure gradient, while friction losses normally represent 5 to 20% of the total pressure drop, and the acceleration term is negligible, being only relevant in particular cases.

If the thermodynamic conditions at the position are such that the flow is single-phase liquid, then the single-phase frictional pressure gradient is calculated using the Colebrook friction factor. As the local pressure decreases due to friction and gravitational head, the flow becomes two-phase and the modified Hagedorn and Brown (1965) correlation is used to calculate the two-phase pressure drop. This robust correlation was used due to its large experimental data base, allowing an accurate pressure loss prediction in many different scenarios.

The energy equation is implemented in the same way presented by Hasan and Kabir (2002):

\[
\frac{dH}{dz} + g \cdot \sin \alpha + v \frac{dv}{dz} = \pm \frac{Q}{w}
\]

(2)

where \( H \) denotes the enthalpy, \( g \) is the gravity, \( \alpha \) the wellbore inclination, \( v \) the velocity, \( w \) mass flux and \( Q \) is the heat transfer rate per unit length of wellbore, which is defined in terms of an one-dimension radial overall heat transfer coefficient and temperature difference between the fluid inside the production tubing and the wellbore/formation interface, as shown in the following equation:

\[
Q = -2 \pi r_o U_w \left( T_f - T_{wb} \right)
\]

(3)

where \( r_o \) denotes the outer radius of the tubing, \( U_w \) the overall-heat-transfer coefficient based on the tubing outer surface area, \( T_f \) is the flowing fluid temperature and \( T_{wb} \) is the interface wellbore/formation temperature.

To calculate the heat transfer rate per unit length, the transient model used by Hafemann et al. (2015b) was adopted. This model considers all the different layers of the wellbore (cement, casing, tubing and annular) and the local formation properties. Each layer is associated with a thermal resistance and the model is solved by calculating the overall thermal resistance and the integration of the energy equation. This idea is based in the simplifications made by Hasan and Kabir (2012), making the heat transfer equation accounts for the transient effect of the wellbore/formation interface temperature by using a relaxation parameter that is based in a dimensionless temperature function proposed by Hasan and Kabir (1991).

The pressure and the temperature of the reservoir fluid are calculated by a one-dimensional axial model, where the liquid production rate is known. The model was implemented in Matlab® and the thermodynamic and transport properties of the fluids (hydrocarbon mixture and annuli fluids) were computed using Multiflash™. The energy and momentum equations are solved from the bottomhole to the wellhead through a 4th order Runge-Kutta method, where each new position of the wellbore is calculated based on the gradient obtained from the previous position. Phase equilibrium and physical properties are updated at each axial step. At each position increment, the Runge-Kutta method returns the local pressure and enthalpy, which are the inputs of an equilibrium flash that return the mixture composition in the liquid and vapor phases, the saturation temperature and the quality. These are used as inputs in the closure relationships required in the momentum and energy balances. The global solution algorithm is shown in Fig. 2.
The pressure buildup in the annular was estimated based on the Oudeman and Kerem (2004) approach, which takes into account three contributions: (i) thermal expansion, that generates an increase in pressure when the annular volume does not increase enough to accommodate this expansion; (ii) change of the annular volume, by thermal expansion, “ballooning” or compression of the casings; (iii) the change in the amount of fluid in the annulus caused either by leak-off to formation or fluid influx into the annulus, and is represented according to the following equation:

$$\Delta P = \frac{\beta_a}{\kappa_a} \Delta T - \frac{\Delta V_a}{V_a \cdot \kappa_a} \Delta T + \frac{\Delta V_l}{V_l \cdot \kappa_a}$$

(4)

where $\kappa$ denotes the coefficient of isothermal compressibility of the annular liquid, $\beta$ is the coefficient of thermal expansion, $T$ is the temperature, $V$ is the volume and the subscript $a$ denotes the annulus and $l$ is the annulus liquid.

The APB calculation presented in this model is similar to that of Oudeman and Kerem (2004), but with a simplification to consider each annulus as pressure vessel where the pressure buildup results from the fluid expansion caused by the temperature increase due to heat transfer from the reservoir fluid to the formation. According to Oudeman and Kerem (2004) and Hasan et al. (2010), the first term in Eq. (4) correspond to 70 to 80% or more of total pressure increase. The temperature increase in the annuli can be calculated by comparing the annular temperature before and after the production starts. Before production, the well is considered to be in equilibrium with the formation temperature, i.e., the geothermal gradient. Knowing the annular fluid composition, the initial temperature and the annular volume, the average fluid density in each annulus can be easily calculated with Multiflash™.

Since the annular volume change is disregarded in the first part of the mechanical model, the average fluid density in the sealed annulus will remain constant because fluid leakage is not considered. Due to the very small compressibility of water-based fluids, the isochoric increase in annular temperature is accompanied by a massive increase in pressure in the annuli, as demonstrated by Ellis et al. (2002) and as can be seen in Fig. 3.
The average temperature of each annulus at every time step is obtained by the heat transfer model. Considering that the compositions of the annular fluids do not change, Multiflash™ can calculate the pressure increase inside each annulus by comparing the annular temperature at each time step with the initial temperature, before production.

This pressure increase will result in an annulus volume variation. The casing/tubing displacement model of Halal and Mitchel (1994) was used, considering radial symmetry and homogeneous isotropic (Hafemann et al., 2015a).

Halal and Mitchel (1994) and Hafemann et al. (2015a) calculated local variations of the annulus volume along the well, which is the correct approach when variable formation properties are considered. In the mechanical model proposed in the present paper, each annulus is treated as an integral volume, so that the annular pressure change caused by every local volume variation is transmitted through all the annulus instantly. That way, even though local volume deformations are computed, the calculated APB value is an overall parameter for each annular, updated at every time step.

With the overall annulus volume change, the overall annular fluid density will change, thereby correcting the annular pressure increase resulted from the temperature variation. This way an iterative solution is needed so that the first and second contributions of Eq. (4) converge to a proper APB value, as can be seen in the mechanics model of Fig. 2. With an increase in the annular pressure, the properties of the fluids in the annuli will change, affecting the thermal model, so another iterative loop is needed, but now between mechanic and the thermal model.

3. MODEL APPLICATION

Given the complex multiphysics phenomena involved in the simulation, it is fundamental to compare the model results against field data. However, it is important to keep in mind that, differently from heavily instrumented laboratory-based experimental apparatuses, petroleum systems often rely on limited instrumentation. Therefore, the present study relied on pressure and temperature measurements obtained at the Wellhead (WH) located at a depth of 1387 m, and permanent downhole gauge (PDG), installed 3890 m deep.

Pressure and temperature field data from the production test report supplied by Petrobras are shown in Figure 4 as a function of time for nearly 170 hours of measuring. The production was initiated roughly 40 hours after the measurements started. Once operational, the initial flow caused an increase in the wellhead temperature, which approached a quasi-steady state value of 373 K after approximately 40 hours of production. Also noticeable is that the temperature at the PDG tends to reach nearly constant values of 397 K almost immediately after production start. For elapsed times longer than 90 hours, all measured data have reached nearly steady operational conditions – note that the pressure measurements still varies slightly, however, the rate of change is small compared with the absolute pressure value, and they maintain values close to 18.28 MPa and 33.29 MPa for the WH and PDG respectively.
Figure 4. Temperature and pressure reading with time.

Figure 5 shows the variation of the temperature and pressure along the wellbore. Four different production times were simulated in order to analyze the transient behavior of the model: instantaneous production \((t=0)\), 1 day \((24 \text{ h})\), 2 days \((48 \text{ h})\), 5 days \((120 \text{ h})\) and 10 days \((240 \text{ h})\). In order to have a graphic comparison of the model results, the experimental temperature and pressure data measured at the PDG and WH, which are taken for Figure 4, are shown in Figure 5. As expected, both pressure and temperature decrease towards the wellhead. As can be seen, the pressure distribution does not have a great impact in the axial pressure distribution, unlike the temperature, which is highly affected by the production time, but only for the initial time. For \(t = 0\) a temperature drop of approximately 40 K is observed through the tubing string, while a temperature drop of approximately 22 K is observed for the other times. This happens due to the heating of the formation that can be seen in Figure 6.

Another fact that can be observed in Figure 5 is the localized drop in temperature for \(t = 0\) at a depth of 3050 m (distance of 840 m). This is due to the small thermal resistance associated with the H2O-glycerin discontinuity in the third annular, which enables a more direct thermal contact between the production hydrocarbons and the formation. For the other production times this discontinuity is diminished due to the heating of the formation. It also can be observed the very good agreement between the field data and the model results, which serves to infer consistency of the model implemented.

Figure 5. Pressure and temperature distribution along the well with production time.
The discontinuities presented in Figure 6 are caused by different rock properties and the well geometry. They are a result of a lack of axial heat transfer in the formation and also became evident in the heat transfer rate per unit length along the well, presented in Fig. 6. Both discontinuities increase with production time in Figure 6, but the discontinuity caused by the well geometry decreases in Figure 7, mainly due to the heating of the formation.
The initial time results in high heat transfer rates, mainly due to the low initial formation temperature (geothermal gradient). With the continued production, the heat transfer rate decreased due to the heating of the formation, but that did not affect the ever-increasing annular temperature, which continued to rise with production time as shown in Figure 8. More specifically, the APB in the first annular is less critical than the others annuli because its filled with a gas. On the other hand, the outermost annular has the largest APB value due to the large thermal gradient between the upper part of the well and the formation.

Figure 8. APB value with producing time.

4. CONCLUSION

A model to calculate pressure drop and heat transfer along an offshore well is presented in order to estimate annular pressure buildup.

The formation heating tendency is addressed by the formulation of a transient interface temperature. The influence of formation heating could be clearly observed on heat flux rate.

Results were compared to field data to validate the heat transfer and pressure drop models. Heat and wellbore/formation interface temperature are analyzed to identify transitions observed due to the well geometry and formation mechanical properties.

APB is calculated based on annular fluid expansion and the well string deformation as a result of well heat transfer and annular heating.

5. REFERENCES


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