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MODELING AND INTERPRETING TRANSIENT DATA UNDER NON-ISOTHERMAL CONDITIONS IN A COUPLED, STRATIFIED, WELLBORE-RESERVOIR SYSTEM

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Abstract. *Well formation tests are usually performed to determine rock properties of a reservoir and the obtained data has often been interpreted based on an assumption that the reservoir is homogeneous in the vertical direction and described by a 1-D model. However, many reservoirs are found to be composed by layers that have different characteristics. Production wells in such reservoirs may receive oil from more than one layer. In stratified reservoir system, the pressure and temperature behavior are not necessarily the same as in single layered system, and rarely reveals the same average properties of the entire system. The prediction of the characteristics of the individual layers is important to describe properly the reservoir and improve production management. This work presents a numerical transient-thermal model for a coupled wellbore/2D-reservoir considering Joule-Thompson heating/cooling, adiabatic fluid expansion/compression, conduction and convection effects for both wellbore and reservoir for a single-phase fluid flow. The two-dimensional reservoir model allows the analysis of stratified zones and barriers. The model allows cross flow between the adjacent layers with different rock properties. Wellbore temperature and pressure at a certain gauge depth are evaluated along the time. Results show how pressure transient analysis (PTA) and temperature transient analysis (TTA) can be used to characterize different configuration of stratified reservoirs.*

Keywords: *Non-isothermal, coupled wellbore-reservoir, stratified reservoir, temperature transient analysis*

1. INTRODUCTION

Well test is used to characterize the reservoir in order to improve production management. The test consists in the analysis of the pressure transient behavior inside the wellbore after successive opening and closing of the production valve, usually known as Drawdown and Buildup periods, respectively. Specifically, multilayer well test is used to determine geological properties of individual layer in stratified reservoir. Commonly, the well test assumes an isothermal fluid flow into the reservoir; i.e., temperature change is neglected, as presented by Park and Horne (1989). However, this assumption can lead to misinterpretation of pressure signal and as a consequence errors in the reservoir characterization especially in reservoirs at high transmissibility, as discussed by Galvao *et al.* (2020). In the last decades, temperature measurement technologies have improved, providing measurement with high accuracy and a good resolution. Therefore, several recent studies, such as Sui *et al.* (2008) , Onur and Cinar (2017) and Onur *et al.* (2017), have proposed combined analyses of transient pressure and temperature data to enhance the information obtained from downhole gauges, to better characterize near-wellbore and far-field reservoir parameters.

The main objective of this work is to develop a computational model for analysis of transient fluid flow and heat transfer phenomena that occur between a production well and its adjacent stratified reservoir area. The model is used to analyze the effect of individual reservoir layer properties in the transient pressure and temperature data. The results can be used in the development of formation test for stratified reservoirs. The two-dimensional treatment of the reservoir allows to represent a stratified reservoir with barriers and faults. Pressure transient analysis (PTA) and Temperature transient analysis (TTA) are provided for different configuration of stratified reservoirs.

2. MATHEMATICAL AND NUMERICAL FORMULATION

The mathematical formulation comprises of a coupled wellbore/reservoir model, consisting of a fully coupled reservoir/casing/tubing system. In the reservoir, the mass and energy transient conservation equations in two dimensions are solved, Equations (1-2). The wellbore model consists of mass, momentum and energy transient conservation equation, Equations (6-11). The coupled wellbore/2D-reservoir system was solved by using an accurate finite difference method, considering appropriate boundary and coupling conditions.

2.1 Reservoir model

The reservoir model used in this work is based on the model presented by Onur and Cinar (2017) for one dimension and extended to two-dimensional reservoir. The reservoir is heterogeneous, i.e. the values of permeability and porosity may vary as function of "z" and "r" coordinates, as shown in Fig. 1. The following hypotheses are considered:

- Flow in two dimensions (radial and vertical);
- Single-phase oil with immobile connate water saturation;
- Reservoir may be heterogeneous, isotropic, or not;
- Fluid flow is governed by Darcy's Law, both for radial and vertical directions;
- Density and porosity are function of pressure and temperature. Others fluid properties are constant;
- Wellbore is vertical and fully penetrates the reservoir;
- Solid matrix is in local thermal equilibrium with surrounding fluids (oil and water);
- The reservoir is thermally isolated on the bottom and top boundaries;
- There is no fluid flow from upper and lower boundaries;
- Gravity effects are considered.

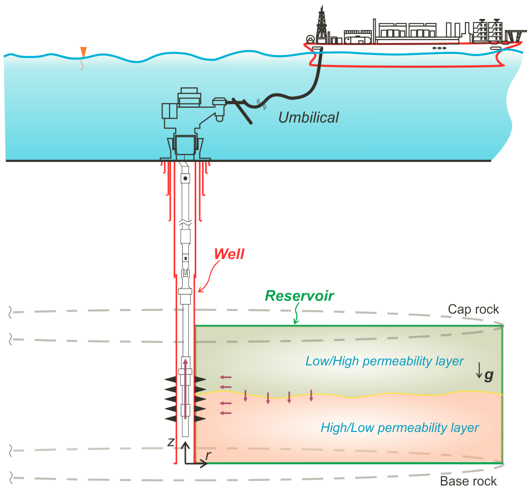

Figure 1. Schematic drawing of the coupled wellbore/2D-reservoir system.

Mass conservation equation:

$$\phi\left[C_{tot}\frac{\partial p}{\partial t}-\beta_{tot}\frac{\partial T}{\partial t}\right]=-\frac{1}{r}\left[\frac{\partial}{\partial r}(rv_{ro})+rv_{ro}\left(C_o\frac{\partial p}{\partial r}\right)-rv_{ro}\left(\beta_o\frac{\partial T}{\partial t}\right)\right]$$
$$-\frac{\partial}{\partial z}(v_{zo})-v_{zo}\left(C_o\frac{\partial p}{\partial z}\right)+v_{zo}\left(\beta_o\frac{\partial T}{\partial t}\right) \tag{1}$$

In Equation (1), v_{ro} and v_{zo} represents Darcy's Law, C is the compressibility of the phase, and β is the thermal expansion. The subscripts "tot" and "o" are the oil+water+rock phase and oil phase only respectively.

Energy conservation equation: Assuming the local thermal equilibrium between the solid matrix and fluid phase, including the Joule-Thomson coefficient (ε_{JTo}), considering that porosity is function of temperature and pressure and using the definitions of isothermal compressibility and isobaric thermal expansion coefficients of the rock, the energy conservation for a two-dimensional reservoir in cylindrical coordinates can be expressed as:

$$\frac{\partial T}{\partial t}-\varphi^*\frac{\partial p}{\partial t}+C_{pRo}\left(\frac{-K_r}{\mu}\frac{\partial p}{\partial r}\right)\left(\frac{\partial T}{\partial r}\right)+C_{pRo}\left(\frac{K_z}{\mu}(\frac{\partial p}{\partial z}-\rho_o g)\right)\left(\frac{\partial T}{\partial z}\right)-$$
$$C_{pRo}\varepsilon_{JTo}\left(\frac{-K_r}{\mu}\frac{\partial p}{\partial r}\right)\left(\frac{\partial p}{\partial r}\right)+C_{pRo}\varepsilon_{JTo}\left(\frac{K_z}{\mu}(\frac{\partial p}{\partial z}-\rho_o g)\right)\left(\frac{\partial p}{\partial z}\right)-$$
$$\frac{1}{r}\frac{\partial}{\partial r}\left(r\alpha_t\frac{\partial T}{\partial r}\right)+\frac{\partial}{\partial z}\left(\alpha_t\frac{\partial T}{\partial z}\right)=0. \tag{2}$$

$$\varphi^*=\frac{(\rho c_p\varphi)_{tot}+\phi p C_r}{(\rho c_p)_{tot}+\phi p\beta_r}. \tag{3}$$

$$C_{pRo} = \frac{\rho_o c_{po}}{(\rho c_p)_{tot} + \phi p \beta_r}. \tag{4}$$

$$\alpha_t = \frac{\lambda_t}{(\rho c_p)_{tot} + \phi p \beta_r}. \tag{5}$$

Where φ^* is the effective adiabatic-expansion coefficient of the fluid-saturated porous medium, C_{pRo} is the coefficient associated to convective-heat transfer velocity, α_t is the thermal diffusivity, ρ, ϕ and C_p are the density, porosity and heat capacity.

2.2 Wellbore model

In the wellbore system the conservative equations are based on models presented by Sui *et al.* (2008) and Onur *et al.* (2017). It considers the following assumptions:

- Axial flow of slightly compressible single phase fluid;
- Wellbore storage is considered;
- Heat transfer to the surroundings occurs due to radial diffusion. There is no axial heat diffusion;
- Density is function of temperature and pressure. Others fluid properties are constant;
- Wellbore materials have constant thermal conductivities.

Mass conservation equation:
Introducing the volumetric flow rate, q, and considering positive the upward flow direction

$$\frac{\partial p}{\partial t} + \frac{q}{AC_o}\frac{\partial p}{\partial z} - \frac{\beta_o}{C_o}\frac{\partial T}{\partial t} - \frac{q\beta_o}{AC_o}\frac{\partial T}{\partial z} + \frac{1}{AC_o}\frac{\partial q}{\partial z} + \frac{q_s}{\rho C_o} = 0 \tag{6}$$

$$q_s = \frac{2(\rho_{ro} v_{ro})}{R} \tag{7}$$

Where q_s is the source term related to mass input coming from each layer of the reservoir. In the wellbore, the pipe is considered rigid with a cross-sectional area A shown in Equation (6).

Momentum conservation equation:
The flow is one dimensional (only "z" direction, vertical) in the wellbore, so, in the "r" (radial) direction momentum is neglected.

$$\frac{1}{A}\frac{\partial q}{\partial t} + \frac{q}{A^2}\frac{\partial q}{\partial z} + \frac{1}{\rho_o}\frac{\partial p}{\partial z} + \frac{fq|q|}{2A^2 D} + gsin(\alpha) = 0 \tag{8}$$

In Equation (8) the angle (α) is referent to the angle that the wellbore makes with the horizontal and here is considered a vertical well so $\alpha = 90^o$. The variable D is the inside diameter of the pipe, and f represents the Darcy Weisbach friction factor.
For laminar flow, it is a function of the Reynolds number Re:

$$f = \frac{64}{R_e}. \tag{9}$$

For turbulent flow (Re>4000), the friction factor is given by Colebrook (1939).

$$\frac{1}{\sqrt{f}} = -2.0log\left(\frac{\delta/D}{3.7} + \frac{2.51}{R_e\sqrt{f}}\right), \tag{10}$$

where: δ/D represents the relative roughness of the tube.

Energy conservation equation:

The energy balance equation for a wellbore control volume takes account the conductive heat loss to the formation (Q), the convective energy transport into and out of the control volume, z is positive in the upward direction. The energy-balance equation is written taking account to the lost energy to the formation and the convective energy transport into and out to the control volume. The energy conservation model used in the present work is similar to the one presented by Hasan and Kabir (2005). The final form of the energy equations, written in terms of flow rate (q):

$$\rho_o A C_{po}(1 + C_T)\frac{\partial T}{\partial t} = \rho_o q C_{po} L_R\Big[T_{ext}(z) - T(z,t)\Big] - \rho_o q C_{po}\left(\frac{\partial T}{\partial z} - \varphi(z,t) + \frac{gsin(\alpha)}{C_{po}}\right) + q_e \tag{11}$$

The term q_e in Eq. (11) is correlated with the source term related to convective energy and it come from each layer of the reservoir, and is given by:

$$q_e = \frac{2}{R}\frac{\rho_{ro}v_{ro}}{\rho_{wo}}\frac{1}{C_{po}(T_r - T_w)} \tag{12}$$

The term $T_{ext}(z)$, in Eq. (11) is correlated with the geothermal gradient and L_R is the relaxation-distance parameter that contains the overall heat-transfer coefficient. The parameter $\varphi(z,t)$ consider the Joule-Thomson effect and the kinetic-energy contribution. The subindex r and w are related to reservoir and wellbore, respectively.

$$T_{ei}(z) = T(z=0) - zg_t sin\alpha, \tag{13}$$

$$\varphi(z,t) = \varepsilon_{JTo}\frac{\partial p}{\partial z} - \frac{q}{(A)^2 C_p}\frac{\partial q}{\partial z}, \tag{14}$$

$$L_R = \frac{2\pi r_{to}U_t\lambda_e}{\rho_o q c_{po}\left[\lambda_e + r_{to}U_t f_D(t_D)\right]}, \tag{15}$$

$f_D(t_D)$ is the dimensionless heat transfer function. The approximation given by Hasan *et al.* (2002)is used in the present work.

$$f_D(t_D) = ln\left[e^{-0.2t_D} + \left(1.5 - 0.3719e^{-t_D}\right)\sqrt{t_D}\right], \tag{16}$$

t_D is the dimensionless time, defined by: $t_D = (\alpha_{te}/r_{co}^2)t$, where α_{te} is the effective/total thermal diffusive constant of earth. U_t is the overall heat transfer coefficient, which determines the heat transfer from the wellbore to the surroundings. This was presented by Sagar *et al.* (1991) the model is derived from the steady-state energy equation that considers the heat-transfer mechanisms found in a wellbore, and if flow occurs inside a tubing, is given by:

$$U_t = \frac{1}{r_{ti}}\left[\frac{ln\left(r_{ci}/r_{co}\right)}{\lambda_{an}} + \frac{ln\left(r_{wb}/r_{co}\right)}{\lambda_{cem}}\right]^{-1}, \tag{17}$$

r_{ti} is the inside tubbing radius
r_{to} is the outside tubbing radius
r_{ci} is the inside casing radius
r_{co} is the outside casing radius
r_{wb} is the wellbore radius
λ_e is the thermal conductivity of the earth
λ_{an} is the thermal conductivity of material in anulus
λ_{cem} is the thermal conductivity of cement

2.3 Coupling and boundary condition of the wellbore-reservoir system

The coupling condition between the wellbore and the reservoir where:
- At the bottom-hole, the wellbore and the reservoir have the same pressure, temperature, and flow rate;
- Contact region between the wellbore and the reservoir have the same pressure and temperature;
- The mass and energy source terms of the wellbore will be determined directly through the flows- from the reservoir.

The boundary condition related to flow rate is defined at the top of the wellbore. During the drawdown, the flow rate is set to a constant value q; during the buildup, it is set to zero, $q = 0$. In the reservoir boundaries, far away from the wellbore (right side), we have the geothermal gradient for the temperature and hydrostatic gradient for the pressure. The top and the bottom boundaries are isolated, both for heat and flow.

2.4 Initial condition of the wellbore-reservoir system

Before the wellbore top valve is opened, it is assumed the wellbore is fully filled with oil, so initial pressure condition is considered to be the hydrostatic gradient. Along the reservoir thickness, it is also considered the same hydrostatic condition. The wellbore-reservoir system is also assumed to be in local equilibrium with the neighborhood. Therefore, the initial temperature of the reservoir and the wellbore will be the geothermal gradient.

3. RESULTS

3.1 Input data and operation conditions

This section will present the properties of the fluid, reservoir, well and operating conditions. The wellbore high was 512.5m measured from bottom of reservoir, the flow rate was set in the upper boundary of the wellbore, $800m^3$/day. The Drawdown and Build up periods were both 48 hours. The average permeability used was $K = 100mD$.

Table 1. Reservoir properties

Property	**Units**	**Value**
p_i	MPa	49.03
T_i	K	334.0
r_e	m	25,000.0
ϕ	fraction	0.12
c_r	cm^2 / kgf	3.0e-5
s_w	fraction	0.15
g_t	K/m	0.03
c_pr	$J/m^3/K$	2.347e+6
λ_r	J/m/K	1.396e+4
λ_e	J/m/K	1.396e+4
α_e	m^2/h	5.894e-3

Table 2. Fluid properties

Property	**Units**	**Oil**	**Water**
B	$m^3/stdm^3$	1.4	1.0
c	cm^2/kgf	1.10e-4	3.96e-5
μ	cP	0.9	1.0
λ	$J/m//h/K$	5.833e+2	2.229e+3
ρ	Kg/m^3	770.0	998.2
β	K^{-1}	1.11e-3	5.27e-4
c_p	$J/Kg/K$	2252.9	4209.35
ε_{JT}	$K/Kgf/cm^2$	-3.374e-2	-1.921e-2
φ	$K/(Kgf/cm^2)$	2.279e-2	4.132e-3

Table 3. Reservoir constants

Constant	**Units**	**Value**
λ_t	$J/m/h/K$	1.238e+4
ϕ_t^*	$K/(Kgf/cm^2)$	1.874e-3
α_t	m^2/h	5.342e-3

Table 4. Wellbore Properties and dimensions

Properties	**Units**	**Value**
r_w	m	0.156
r_{co}	m	0.12224
r_{ci}	m	0.10839
r_{to}	m	0.06985
r_{ti}	m	0.05931
λ_{cem}	$J/m/h/K$	6.833e+3
λ_{wall}	$J/m/h/K$	1.617e+5
$\lambda_{wall-cem}$	$J/m/h/K$	9.995e+3
λ_{an}	$J/m/h/K$	5.833e+2
Skin factor		0
θ	$degree$	90^0

3.2 Stratified reservoirs

The results of pressure and temperature for three different cases of reservoirs configurations with the same total transmissivity (KH): homogeneous, stratified with communication between layers (crossflow reservoir) and another stratified without communication between layers (commingled reservoir), were compared during drawdown and buildup periods in an attempt to find a signature that differentiated these reservoirs, Fig. 2. Although the graphs present different levels of pressure and temperature, no signature that could characterize a type of reservoir can be observed in a first analysis.

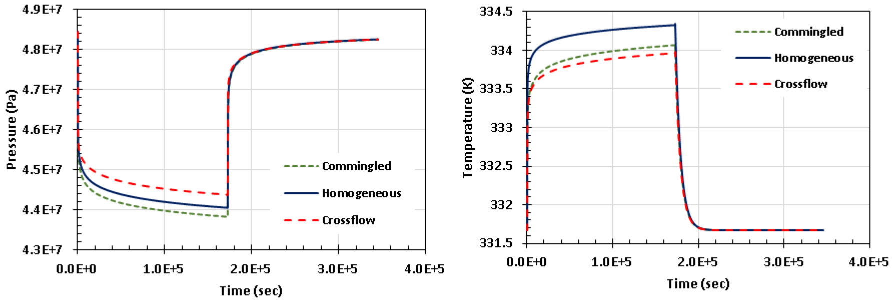

Figure 2. Pressure and temperature for homogeneous and stratified reservoir with and without crossflow ($z = 78m$).

The same results were analyzed using Bourdet derivative graphs, separately for the drawdown (Fig 3), and buildup periods Fig. (4).

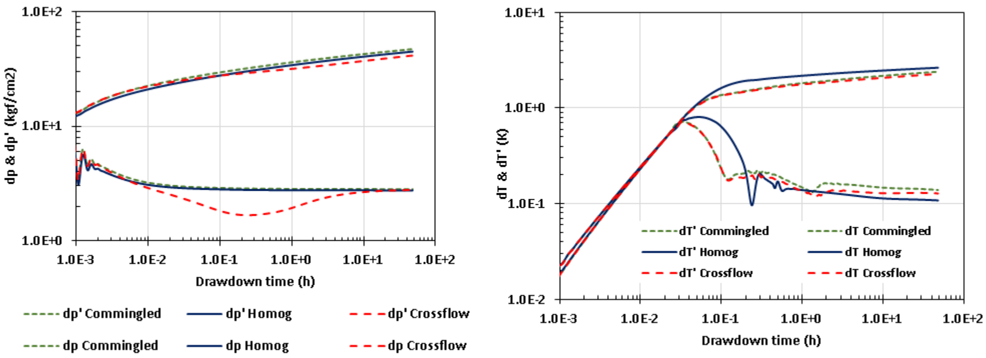

Figure 3. Pressure and temperature derivatives for homogeneous and stratified reservoir with and without crossflow during drawdown period ($z = 78m$).

The use of the Bourdet derivative for the interpretation of pressure results during drawdown test reveals the presence of heterogeneity, characteristic of stratified reservoirs, a minimum in the pressure derivative appears for the stratified reservoir with communication between layers (red in discontinuous line), however, a signature of stratification do not appear in cases of homogeneous (blue in continuous line) and reservoirs without cross flow (green in discontinuous line). The use of Bourdet derivatives for temperature reveals a different behavior for homogeneous reservoirs and stratified

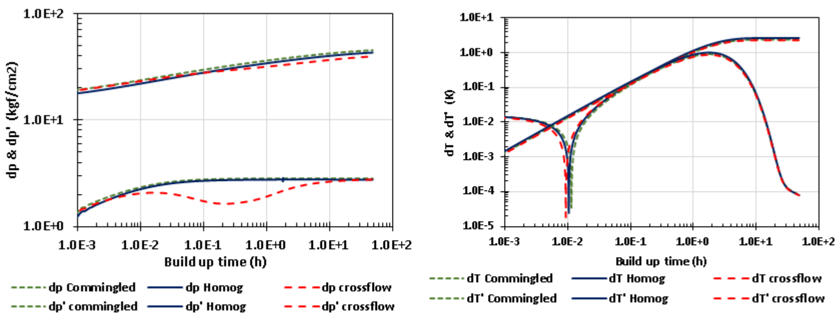

Figure 4. Pressure and temperature derivatives for homogeneous and stratified reservoir with and without crossflow during buildup period ($z = 78m$).

reservoirs both in the case of commingled and crossflow reservoirs and the use of the pressure and temperature derivatives together allows the identification of the stratified reservoir.

During the buildup, the signature resulting from the heterogeneity of the stratified reservoirs appears on the pressure derivative graphs, however the same does not happen with the temperature derivative graphs, so we will focus our analysis only on the drawdown periods.

3.3 Impacts on PTA interpretation results.

Pressure transient analysis (PTA) is usually used to characterize reservoirs. However, only pressure data is not enough, there are different reservoir configurations that lead to similar pressure signal. As an example of this affirmation here will

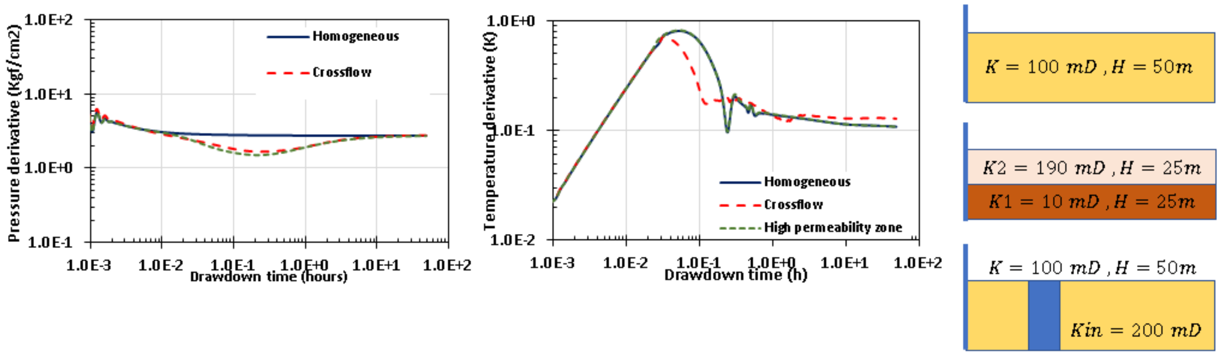

Figure 5. Derivative plot during drawdown for: a) pressure b) temperature.

Table 5. Table of parameters of a reservoirs with a central region of high permeability.

Property	Value
K_1 (mD)	100
Ky_1 (mD)	100
K_2 (mD)	200
Ky_2 (mD)	200
r_i (m)	16.92
r_f (m)	43.92

be tested three different reservoir configurations: homogeneous (case1), stratified (case2) and another vertically homogeneous reservoir with internal region of high permeability in the radial direction (case3), as shown in the upper side of Figure 5. All data are measured at the certain gauge depth in the wellbore above the reservoir. Pressure transient behavior of case 2 and case 3 are similar and can lead to a misinterpretation, as shown in Figure 5(a). This misinterpretation can be avoided by evaluating the temperature derivative data, as shown in Figure 5(b). Case 2 and case 3 have different behavior and the combined use of pressure and temperature can be explored to estimate the correct configuration of the reservoir.

The heterogeneity along the radial direction with a high permeability region does not change the temperature derivative plot, which makes the differentiation with respect to the stratified case easy to be observed. Therefore, temperature transient analysis (TTA) in a two-dimensional reservoir coupled with a wellbore can be used to distinguish different reservoir configuration in addition to pressure transient analysis (PTA).

The table (5) shows the geometric and permeability values for the analyzed cases.

3.4 Transient cross-flow analysis

Figure 6 and 7 shows a sequence of surface plots of pressure and vertical velocity fields inside the reservoir at intervals that vary from the early times to the end of the test.

As soon as the reservoir starts to produce, the difference in permeability between the two layers leads to a stronger pressure gradient in the radial direction in the less permeability layer (bottom). As a consequence, a pressure gradient in the vertical direction is created, driving flow from the less permeable to the more permeable layer. As the flow progresses, the pressure stabilizes, and the flow in vertical direction vanishes. After this stabilization, the reservoir behavior is similar to a homogeneous reservoir, since there is no vertical flow.

The pressure difference between two layers of a stratified reservoirs was monitored during a drawdown test inside the reservoir, at a position 1.5 meters far from the wellbore. In the beginning of the test (early times), the stratified reservoir behaves as if there was no flow between layers, as time goes up, due to the differences in radial velocities between the layers, there is the appearance of a pressure differential greater than the hydrostatic gradient and this gives rise to a vertical

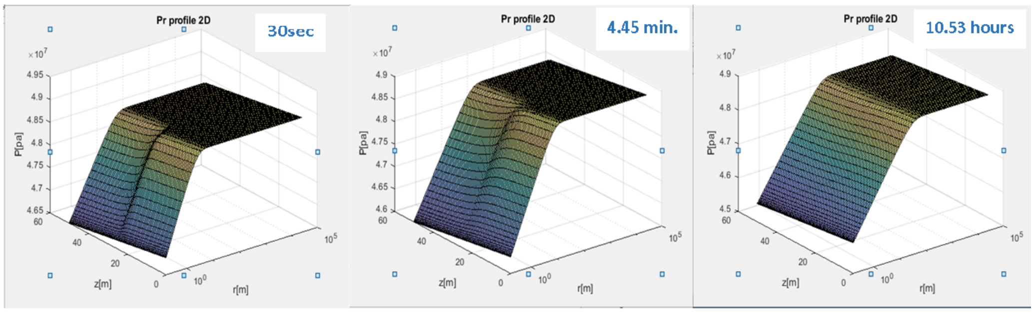

Figure 6. Pressure evolution inside the reservoir

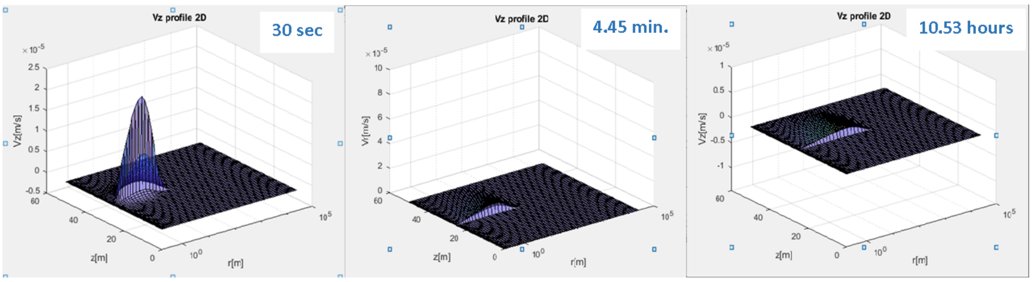

Figure 7. Crossflow evolution inside the reservoir

flow between the layers. Advancing a little more in time, the hydrostatic gradient, which dominates the well's behavior, is also extended to the reservoir, ceasing the vertical flow. At this point, the reservoir starts to behave as it were homogeneous . The higher the vertical permeability, the faster the reservoir approaches the hydrostatic gradient and inversely, the lower the vertical permeability, more time the reservoir needs to equilibrate the pressure. Figure 8 shows the evolution of the pressure differential over time, this test was repeated for similar reservoirs, but only with different vertical permeabilities.

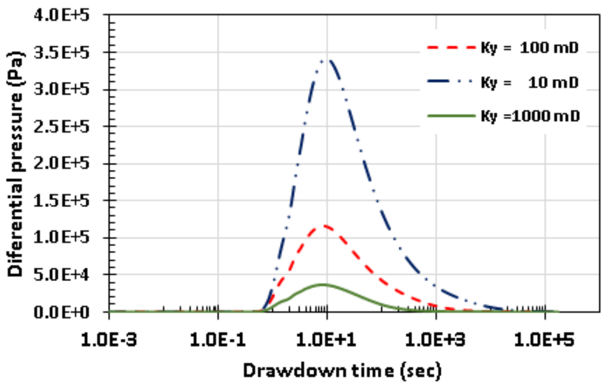

Figure 8. pressure differential in the reservoir as a function of vertical permeability.

The position where the minimum in the pressure derivative appears in stratified reservoir changes to the left as the vertical permeability value of each layer increase, as shown in Fig. 9(a). The table 6 shows the analyzed reservoirs and the variation in vertical permeability.

Table 6. Table of properties of a stratified reservoirs with different vertical permeability.

Case	K1 (mD)	K2 (mD)	Ky1 (mD)	Ky2 (mD)	H1 (m)	H2 (m)
Case 1	100	100	100	100	25	25
Case 2	10	190	10	190	25	25
Case 3	10	190	0.1×10	0.1×190	25	25
Case 4	10	190	0.5×10	0.5×190	25	25
Case 5	10	190	1.5×10	1.5×190	25	25
Case 6	10	190	3×10	3×190	25	25

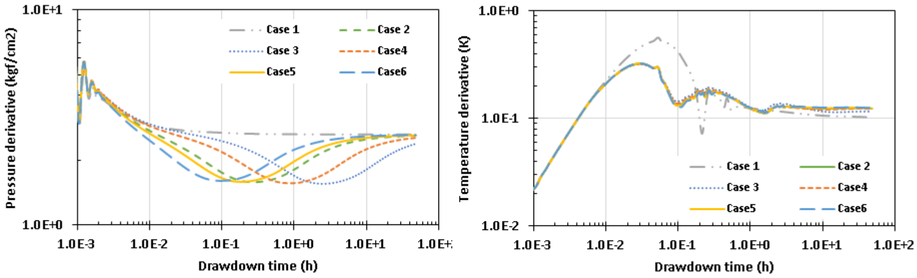

Figure 9. Effect of the vertical permeability value on the pressure(a) and temperature(b) derivative graph

As discussed later, this shift is associated with the vertical flow between the layers with different permeability's. Low vertical permeability delays the flow communication between the layers of a stratified reservoir, shifting the valley to longer times.

The temperature derivative is not very sensitive to changes in vertical permeability, as can be seen in Fig. 9(b).

3.5 Gauge position effect.

Pressure and temperature measurements are taken at different gauge positions along the wellbore, above the reservoir. As can be seen in Figure 10 (a) and (b). The pressure derivative plots are similar for any gauge position, but the temperature derivative plots exhibit the differences caused by the influence of the relationship between the flows of the layers and their temperature.

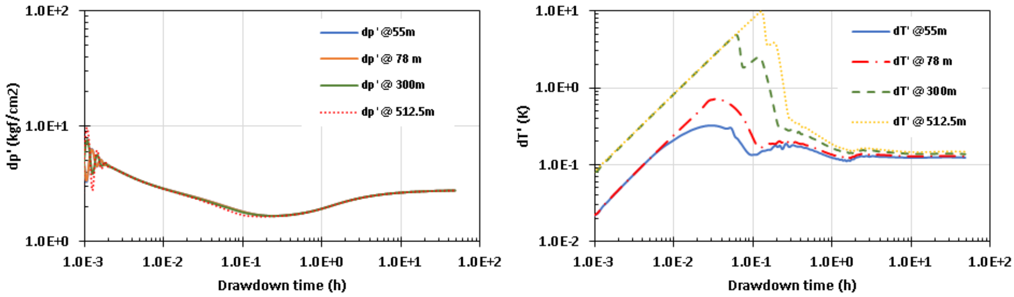

Figure 10. Effect of gauge position on pressure(a) and temperature(b) derivative graphs.

The difference between the derivative temperature plots for homogeneous and stratified reservoirs is minimized as we evaluate the temperature in gauge positions away from the reservoir. The heat exchange by thermal diffusion between the wellbore and the neighborhood is the most significant thermal phenomenon in the wellbore and becomes more accentuated as we go up. To prevent the heat exchange effects by diffusion along the wellbore from overlapping the thermal effect due to stratification, positions along the wellbore, just above the reservoir, are ideal for identifying the reservoir.Figure (11)

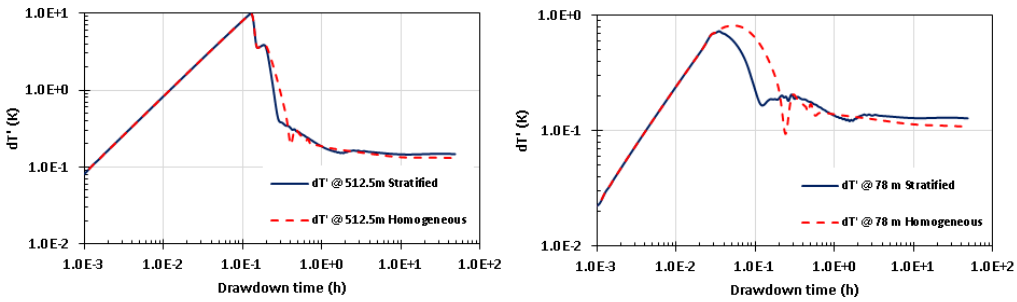

Figure 11. Effect on temperature derivative graphs near the wellbore (a) at 78 m and at the top of the wellbore (b).

4. CONCLUSION

This work presented a numerical modeling for a coupled wellbore-stratified reservoir system. The reservoir is treated in a two-dimensional way and the presence of heterogeneity in the vertical direction can be analyzed. A non-isothermal modeling was used, where the effects of conduction, convection, adiabatic fluid expansion-compression and Joule-Thompson were considered. Density and porosity were treated as a function of pressure and temperature.

The proposed model allows to identify and understand the behavior of the fluid inside stratified reservoirs and, based on this knowledge, to analyze the derivative graphs.

The analysis of the temperature transient together with the analysis of the pressure transient can help in the identification of stratified, double porosity or reservoirs with heterogeneities.

The best gauge positions to characterize the reservoir are those located just above it.

5. ACKNOWLEDGEMENTS

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