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INNOVATIVE PSEUDO-TRANSIENT WELL RESERVOIR COUPLING

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Abstract. *A novel well reservoir coupling method is developed using a three phase, black-oil, transient reservoir simulator and a black-oil steady-state vertical well simulator. The integrated model is based on an imposed wellhead pressure and an initial pressure and saturation in the reservoir. The simulation than proceeds to advance the solution in the reservoir using a set of steady state solutions for the well until a converged solution is achieved for each time step. The reservoir is simulated with imposed internal boundary condition of pressure, set to be iteratively equal to the bottom hole pressure in the well, coupling the system. Also the mass flow rate is balanced explicitly at the interface between well and sand face. The convergence of interactions is obtained for each time step before advancing. Due to the lack of field data for testing some hypothetical situations are being tested. As preliminary results a demonstration of the capabilities of the program is presented, showing promising results.*

Keywords: *well reservoir coupling, numerical modeling, petroleum production, multiphase flow, integrated simulation*

1. INTRODUCTION

According to Constantini et al. (2008) the fundamental understanding of the dynamic interactions between two-phase flow in the reservoir and that in the wellbore remains surprisingly weak. The petroleum industry uses inflow performance relationships (IPR's) and tubing performance relationships (TPR's) to try understanding how the well and reservoir interact by means of the Nodal Analysis. This analysis however, is inaccurate. The IPR's, which derive from steady state data, are not suitable for transients may led to erroneous predictions Constantini et al. (2008).

The work of Souza et al. (2014) report an inherent difficulty of this type of approach is the multi-scale nature of the flow problem: the wellbore radius is generally much smaller than the first reservoir cell. Simulating the two systems coupled is particularly difficulty because the different nature of the two problems. The inertial difference for the flow to take pace in each domain brings instabilities to the simulation and requires adaptations in the traditional approach of simulating reservoirs to create consistent results. One such adaptation is that the traditional mesh in reservoir simulation is linear and in rectangular coordinates; the traditional integration direction is from the head to the bottom hole, in this case the most interesting integration direction is reverse, because the bottom hole pressure is one of the coupling parameters for the coupled simulation.

In this problem, a reservoir requires a logarithmically spaced mesh around the well, according to Ertekin et al. (2001) this type of mesh results in higher velocities as the area perpendicular to the flow along the radial direction becomes progressively smaller, and this necessitates smaller time steps to generate numerically stable results. On other hand, the well need to be integrated iteratively for the coupling and this demands a consistent model to ensure convergence.

2. COMPUTATIONAL PROCEDURE

The computational procedure relies on iterations between the reservoir and the wellbore, as the system needs an initial condition for the first timestep, the hydrostatic pressure gradient is assumed. An arbitrary bottom hole pressure (BHP) is imposed for the end of the first timestep of reservoir simulation and during this simulation the BHP is taken as a ramp. The results of that simulation for production data of each fluid are used to run the wellbore to obtain a new BHP. If the system has attained convergence the final condition of reservoir is considered valid and time is advanced. If no convergence is obtained, the original reservoir condition is simulated with that new bottom hole pressure and the process is repeated until convergence. Figure 1 presents the algorithm.

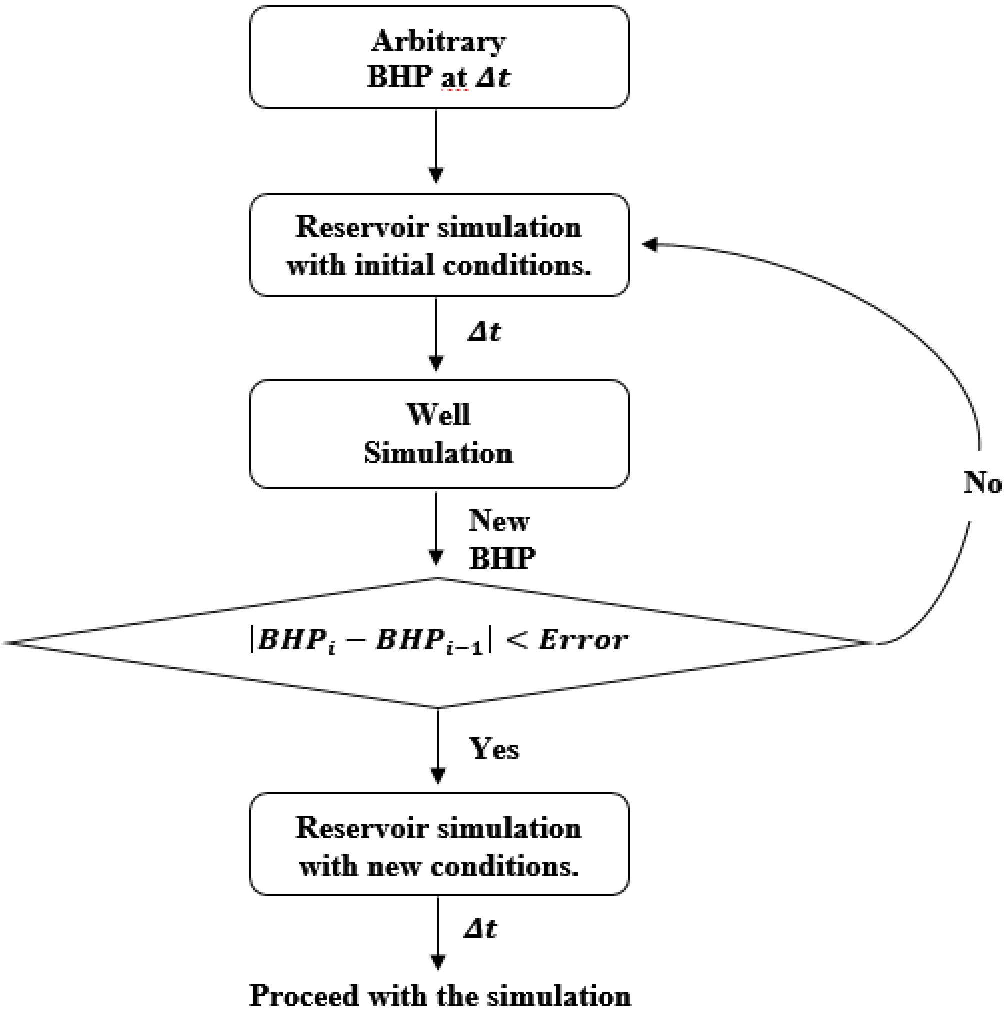

Figure 1: Algorithm to simulating reservoir wellbore coupling

For this work, the error is 13789.5(2 *psi)*, for the wellhead pressure the converge is assumed when the well simulation results in some value between the wellhead pressure minus 6894.76 Pa(1 *psi)* and the wellhead pressure plus 6894.76 Pa (1 *psi)*.

3. RESULTS AND DISCUSSION

The chosen production situation is based on the work of Schietz (2009), that developed equations for reservoir start-up with a transient simulation. The graphic representation of this simulation for tubing head pressure (THP) and BHP for optimize the start-up of a reservoir. This data allows to determine the influence of start-up for long time simulation introducing transient THP or BHP until the production stabilization, after it the time step increases, THP is fixed and the pseudo-transient simulator is more physically consistent.

The reservoir has two hydrocarbon layers of different characteristics. The two zones initially contain under saturated oil, with a 30.48*m* (100 *ft)* water column and are assumed to be not communicating. The well length is simulated from the top of reservoir to the surface, between the two reservoir layers the oil hydrostatic pressure gradient is assumed to increase the well pressure for simulation of the second layer.

Table 1-Layers Properties (modified from Schietz, 2009)

Property	Layer A	Layer B
Formation-top	2100.0 m(6890 ft)	2240.2 m(7350 ft)
Height	140.2 m(460 ft)	204.2 m(670 ft)
Permeability, k_{xy} & k_z	$2.96*10^{-13}$ m² (300 mD) & $9.86*10^{-14}$ m² (100 mD)	$3.94*10^{-13}$ m² (300 mD) & $4.93*10^{-14}$ m² (100 mD)
Porosity	0.25	0.27

As the two layers of reservoir are not communicating the simulation process assumes two different reservoir systems and ignored possible geomechanic effects. In addition, the pseudo-transient state crossflow is not considered, the sum of the production of the two reservoir zones is assumed as the flowrate at the bottom of the well.

Results of 8 simulations are presented; some differences between the behaviour assumed for the start-up and different time procedures are presented in Table 2 with the characteristics of all simulations. The number of timesteps presented is for well-reservoir coupling, for the reservoir they are 15 times smaller than those. If the simulation of the reservoir is instable, the program developed can overcome this reducing the time step, the timestep for the coupling is maintained for these cases.

There are three types of start-up utilized:

-THP FORCED- Uses the data of THP from Figure 2 to make the start-up the pressure of bottom hole is calculated, but this is not a physical process, because the well would be transient.

-BHP FORCED- Uses the data of BHP from Figure 2 to make the start-up, the pressure of the top is calculated, because the well would be transient.

-SIGMOID- Uses the equation 1 from (Schietz, 2009) to make the start-up, in the equation t represents the time in seconds and THP is obtained in *psia*.

$$THP = 737.52 - \frac{0.85979\left(\frac{t}{60}\right)}{\exp\left(-0.039084\left(\frac{t}{60}\right)-120.53\right)} \qquad (1)$$

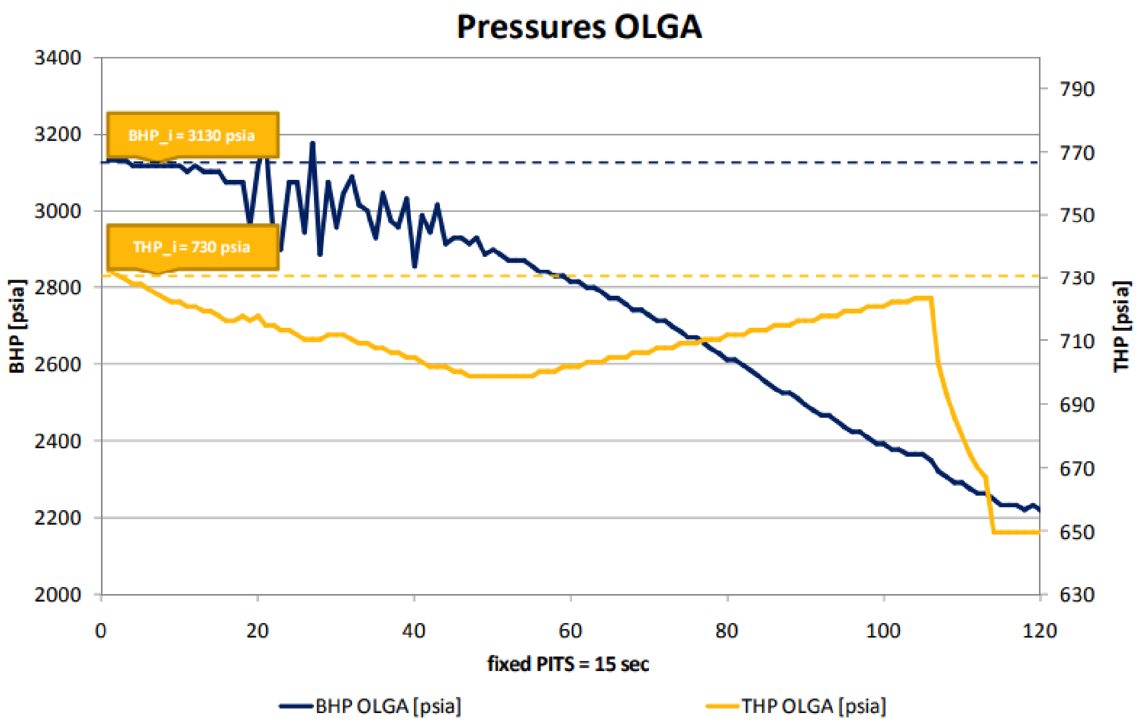

Figure 2: Pressure vs. step plot for optimized all-oil/no WC run using fixed PITS (Pipe-It time-step) (Schietz, 2009)

As the simulations are computed with the data of Figure 2 some considerations of Schietz (2009) are adopted for guarantee the similarity between the works. Two remarkable considerations are that the bubble point pressure is assumed constant with $1.379*10^7$ Pa(2000 *psi),* when the original idea of the program developed is to be applied with a variable bubble point, and to imitate the pressure drop across the perforation the intercellular horizontal transmissibility for fluid flowing from the reservoir into the wellbore has been reduced and set to 0.2 *rb-cp / day-psi (5.2214*10^{-14}m³* in the reservoir conditions) (Schietz,2009). The production zones are in the 6.096 m (20 *ft)* of each layer top.

Table 2- Simulations Characteristics

Simulation Number	Start-up Type	Timesteps
1	THP FORCED	240 timesteps of 15 s; 24 timesteps of 1h; 60 timesteps of 1d; 770 timesteps of 5d
2	THP FORCED	240 timesteps of 15 s; 24 timesteps of 1h; 830 timesteps of 5d
3	THP FORCED	120 timesteps of 15 s; 973 timesteps of 5d
4	THP FORCED	120 timesteps of 15 s; 120 timesteps of 1h; 120 timesteps of 1d; 723 timesteps of 10d
5	SIGMOID	240 timesteps of 1h; 120 timesteps of 10d; 25 timesteps of 100d
6	SIGMOID	240 timesteps of 1h; 120 timesteps 10d; 334 timesteps of 20d
7	BHP FORCED	120 timesteps of 15 s; 120 timesteps of 1h; 120 timesteps of 10d; 317 timesteps of 20d
8	BHP FORCED	120 timesteps of 15 s; 120 timesteps of 1h; 120 timesteps of 1d; 723 timesteps of 10d

Simulation 8 is a basis for comparing, it is obtained with the results for transient BHP for the first 30 minutes and with the pseudo-steady state simulator after, this is a physically coherent basis for analysis; long timesteps are also avoided, because of possible instabilities in the reservoir simulation the results are presented in figures 2 to 4. Information about the reservoir fluids, initial conditions of reservoir and the well are showed in Table 3.

Table 3- Well-Reservoir Characteristics

Fluids	
API	35.38
Gas Specific Gravity	0.367
Reservoir	**Initial Condition**
Pressure (at the bottom of reservoir)	$2.4821*10^7$ Pa(3600 psi)
Initial Oil Saturation, Production Zone	0.90
Initial Water Saturation, Production Zone	0.10
External Radius	400.81 m(1315 ft)
Well	
Diameter	0.04445 m (0.14583 ft)
Initial depth	2100 m (6890 ft)
Wellhead Pressure after start-up	$2.4821*10^6$ Pa (630 psi)

The figure 3 shows that the regime is practically a steady state after the start-up process. A drop in the pressure of wellbore is expected when the production time increases, but the application of reduced transmissibility induces a re-pressurization from the bottom of each reservoir, as this transmissibility is not high when compared with vertical transmissibility.

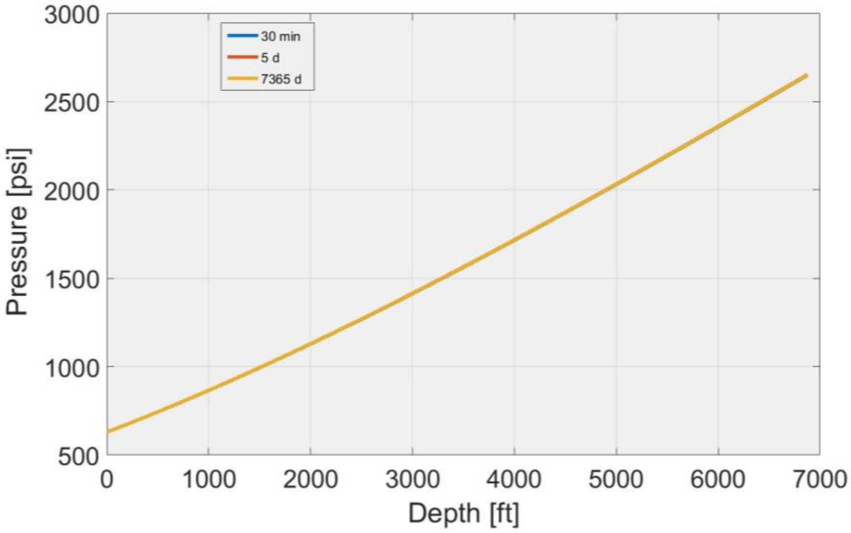

Figure 3: Well Pressure Behavior at three different times

Figure 4 shows an oscillatory aspect for the production in some intervals, this is probably a consequence of the following steps, the pressure in the well drop a little, due to some numerical instability or real unstable flow in the reservoir. When the BHP decreases the production increases, in next timestep the pressure increases because of the increased production, THP is fixed and pressure losses increases. The red and yellow lines mark respectively the end of 1h timesteps and 1d timesteps, an initial supposition is that the change of timestep causes the oscillatory aspect, but clearly this is not true.

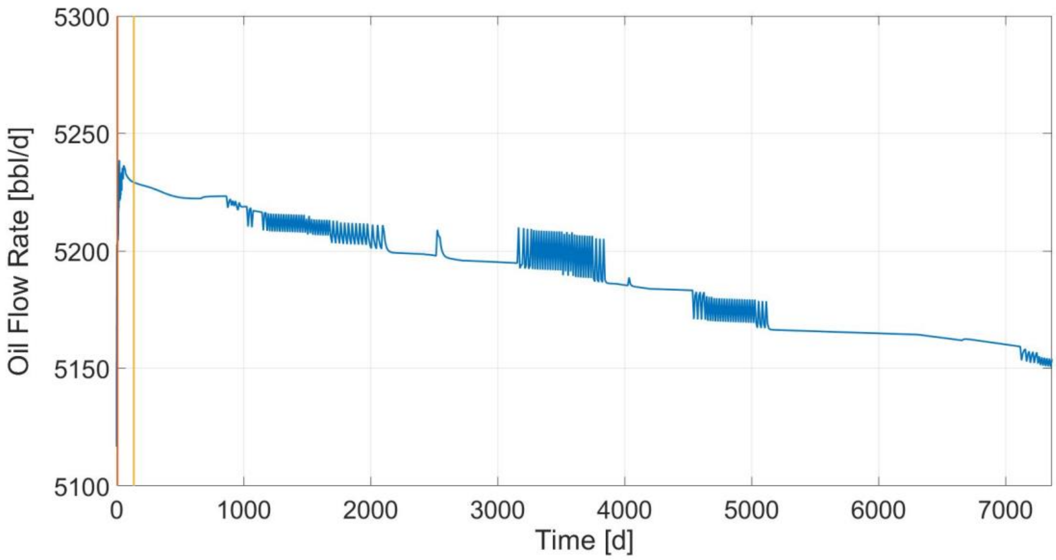

Figure 4: Oil Flow Rate vs. Production Time

Figure 5 shows the all system pressure drop, in the reservoir the production zone of the two major layers is subdivided in 4 layers of *1.524 m* (5 *ft)* each. The aspect of curves of the reservoir pressure does not indicate steady state, but as explained before some re-pressurization is obtained from the bottom layers, despite the increase of water concentration near the well it remained immobile. The effects of the re-pressurization also made the layer 4 of both production zones have a little pressure drop in the radius direction.

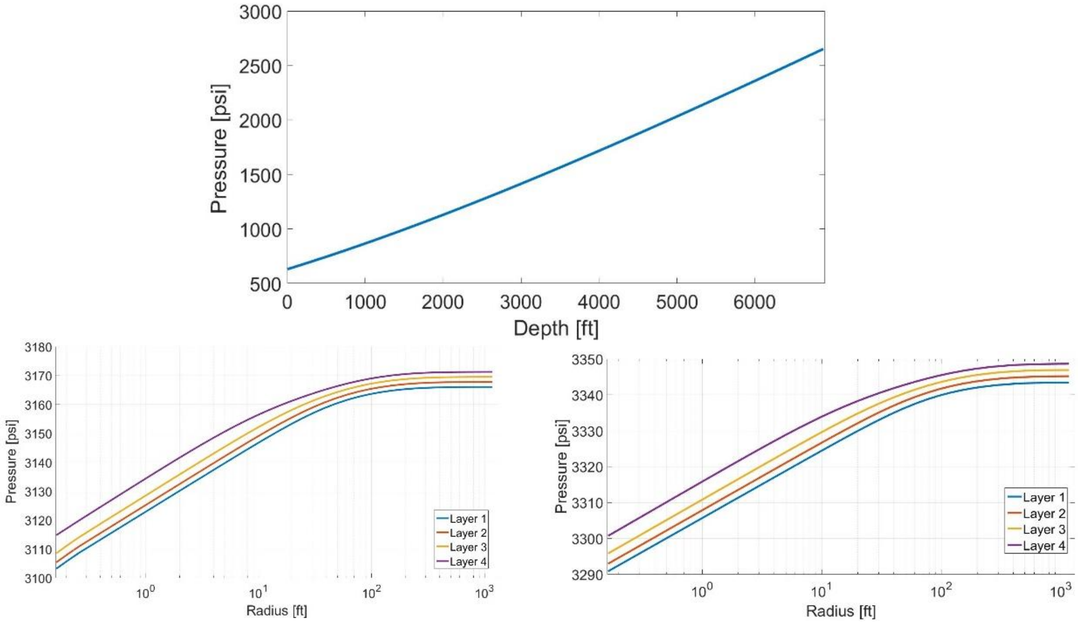

Figure 5: Pressure Behavior after 1000 timesteps. (a) Pressure x Well Depth;
(b) Layer A- Pressure x Reservoir Radius (C) Layer B- Pressure x Reservoir Radius

Figures 6 and 7 present the results for all simulations. Figure 5 focus on the start-up process and some simulations obtained the same results, as for example for simulations 7 and 8. The huge production when BHP FORCED is used maybe result of the coupling difference between this work and the point assumed for Schietz (2009). The start-up process with the sigmoid is slower than with the other conditions, this is showed by the results of simulations 5 and 6. Immediately after the start-up the production results are virtually constant for all simulations.

Figure 8 shows again the oscillatory aspect, presenting some peaks and the start of each oscillatory period some simulations look delayed in relation with others, this is probably an effect of time step. The simulation, with greater timesteps result in an aspect of more spaced peaks and lose the oscillatory effects presented by other curves. Simulations 7 and 8 with BHP FORCED resulted in greater drop of production, especially the simulation 7 and this demonstrated that the timestep influences the results for production. It is impossible with a single comparison of two results understand the relation. The production results are very similar, results tested with other BHP presented the same aspect but a different oil flow rate average, these results are not included because of the lack of confidence about start-up process.

The results demonstrated three points: the start-up process chosen for the production does not made great difference in production, but the wellhead pressure after it is essential for the production results; the production shows oscillatory behaviour, this possibly lead to instabilities or some loss of information for elevated timesteps, for instance, the 100 days simulation induced the reservoir for reduce the internal timesteps and the computational time grew substantially; the difference between the bottom hole pressure instantly before and after the end of start-up is big, this indicate that when the production stabilizing the well condition is not permanent in terms of composition.

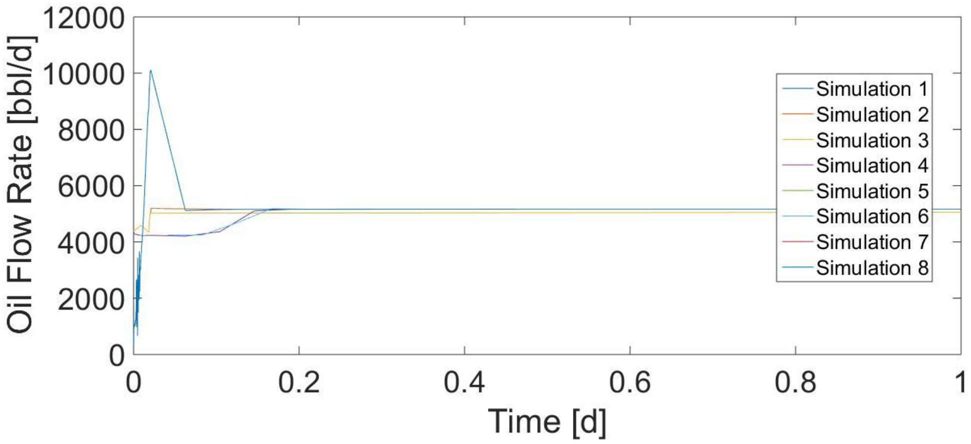

Figure 6: The first day of production for all simulations

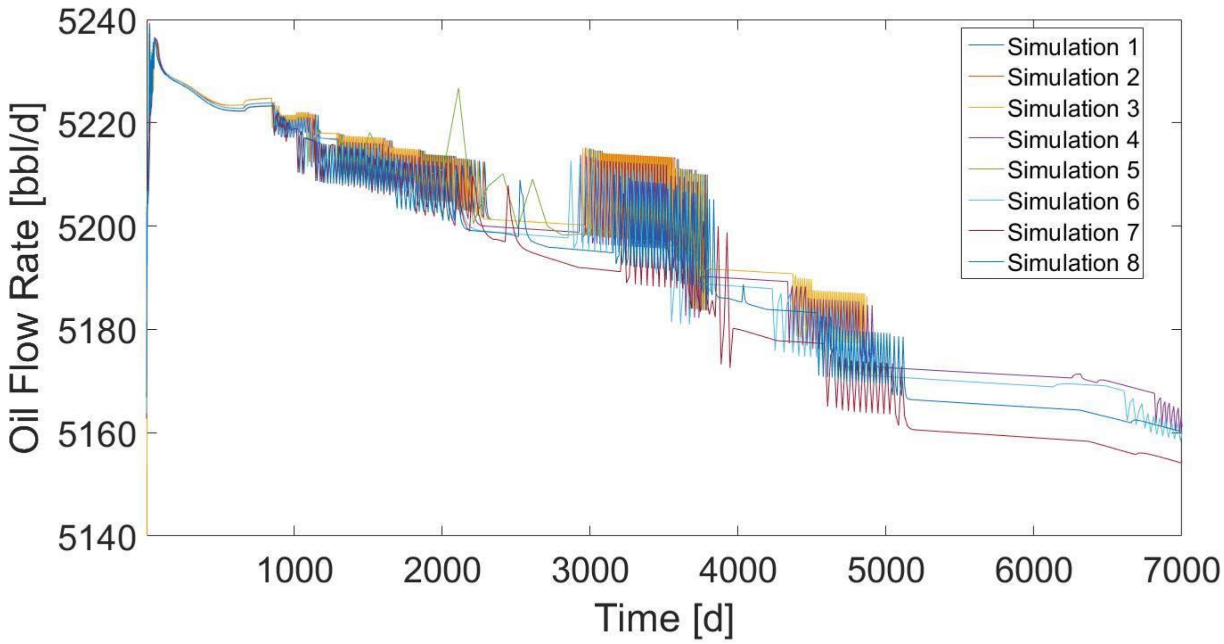

Figure 7: Long time production for all simulations

4. CONCLUSIONS

The proposed method for coupling obtained reasonable results. It is also clear the part of the process still need to be investigated in depth. When the convergence was obtained the simulation results were consistent with the theoretical and practical knowledge of production systems. This demonstrates a possible application on real situations with a upgrade of method applied in this work, perhaps indicating that the use of a real transient simulation in the well is necessary.

5. ACKNOWLEDGMENTS

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