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COMPARISON OF COUPLING STRATEGIES TO INCORPORATE RADIAL INFLUX EFFECTS IN WELL-RESERVOIR COUPLING

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Abstract. The coupling of well and reservoir is one of the most studied topics of petroleum engineering during the last 30 years. Although there are many models for coupling a vertical well with a reservoir, these models frequently do not consider pressure losses due to acceleration and frictional effects on the production zone, which is justified by the fact that these are small contributions, which is probably correct for most wells, but is unclear to determine which is the minimal length of a production zone to consider these effects important. This work was a first step on this kind of investigation since it focusses is to introduce 4 coupling strategies and to observes the reliability and the efficiency of each one of them. These 4 coupling strategies are a consequence of introducing production zone in the problem, since this region requires the existence of two coupling points the well was separated in two regions, and the order of simulation of these two regions as well as the number of loops in the iteration process were the points of differentiation between these 4 strategies. To evaluate the coupling strategies, 8 production scenarios were simulated, and an exploratory analysis of results was performed. The exploratory analysis shows that more important than the order of simulation is the number of loops in the process, strategies with one loop are less susceptible to numerical errors, and strategies with two loops required least iterations to advance a time-step.

Keywords: *Coupling strategy, well-reservoir coupling, petroleum production, two-phase flow*

1. INTRODUCTION

According to Redick and Gildin (2018) coupling is the process of simulating physically disparate assets as one system in order to determine overall project performance. In a petroleum field, reservoir, well and the surface facilities are connected, but they are physically disparate, so it is necessary to use a coupling technique to simulate the entire field. In order to couple, there are implicit and explicit strategies. As presented by Redick and Gildin (2018) and Schiozer (1994) the implicit strategies are divided in fully implicit and partially implicit, for fully implicit simulation it is necessary to adequate equations at boundaries and solve the system at the same computational time and for partially implicit method the reservoir and the surface system converge at an integration point.

In that work the surface system will not be addressed, so the focus will be on the well-reservoir coupling. In general, when coupling reservoir-well partially implicitly a point above the production zone is selected to be the integration point, this occurs because the pressure losses originated by friction and acceleration under that point are not considered. Although in general these losses are irrelevant for production, we are trying to develop a simulator that can be utilized as a tool to prevent liquid loading, and the onset of this phenomenon is a direct consequence of fluids behavior in production zone (Dousi et al., 2006).

That work will focus on developing a computer program that allows the integrated simulation of the well-reservoir system, requiring coupling these systems and the region under direct influence of both the production zone. To proceed with the coupling simulation, the model will be divided in three components that are separately simulated and combined by a sophisticated nodal analysis. These three systems are:

-Reservoir – it is simulated using the pressures in the wellbore as boundary condition in order to obtain the flow-rates of each fluid.

-Wellbore – it is defined as the region of the tube in the production zone and uses BHP – Bottom Hole Pressure as boundary condition with the well and flow-rates as boundary condition with the reservoir to get the distribution of pressures in the production zone. This definition is not largely utilized, but this work used it in order to facilitate the comprehension of the division assumed.

-Well – The region of tube that is not under flow from the formation. It uses BHP as a boundary condition with the wellbore and THP - Top Hole Pressure as a boundary condition with the wellhead.

Figure 1 presents that division and the important pressures in the boundaries of the systems.

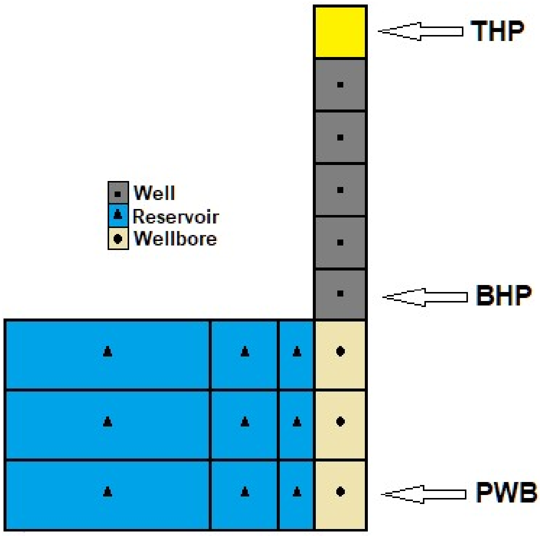


Figure 1. Division of the model

The purpose of work is to present four coupling strategies to simulate these three systems. To do that reservoir flows for each one of wellbore points, pressures at each wellbore point and the BHP should converge (technically the flow-rates at BHP point also should be checked, but they by mass balance if the flow-rates in the wellbore converge it will also converge).

2. COUPLING STRATEGIES

This section will address the problem on how coupling between reservoir, wellbore and well simulations work in order to simulate a system with boundaries of imposed wellhead pressure and no flux at reservoir external frontier. Four arrangements are presented to do coupling between the reservoir model, wellbore and well.

Two key questions are important to understand how the coupling works:

-What are the possible orders to simulate the coupling?

This is a logical question, if there are three systems it is possible to find a solution for two of them and then find a solution for the other system or search directly for a three-system solution. In case of find a two systems solution first, it is possible to solve wellbore-reservoir or well-reservoir systems, as the well simulator only considers the total flow from reservoir.

-How each system interacts with the results got by others?

For wellbore and well it is possible to know what pressures match for a determined set of flow-rates from the reservoir, but as theses flows are not necessarily induced by those pressures, it is necessary to guess a set of pressures that induces flows that match pressures. In order to do that it is necessary to implement an algorithm to guess these pressures.

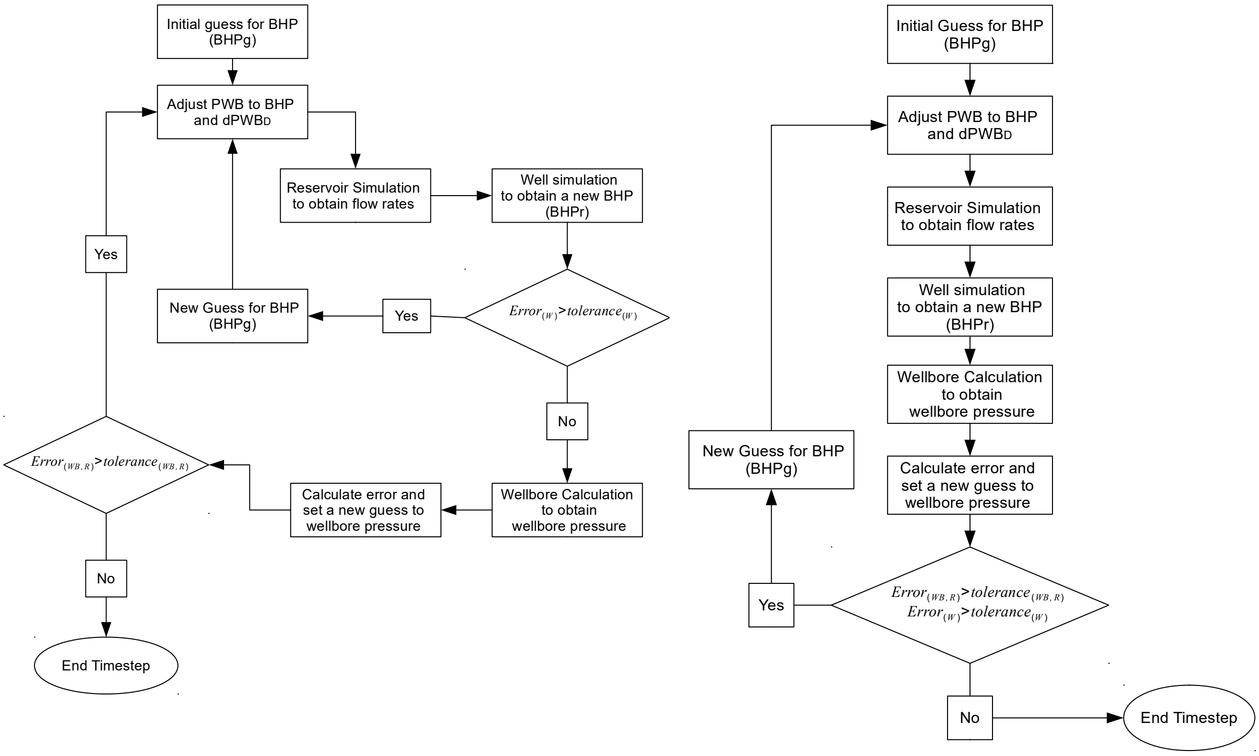
A third question that will be addressed in this work is how to use data from a time-step to simulate the next. In the four next subsections, the four strategies for coupling will be presented.

2.1 Coupling Strategy 1 (COUP1)

This strategy solves reservoir-well in a loop inside the main loop, or in other words, it strategy solves first get a bottom hole pressure that match the reservoir for a determined pressure at wellbore deepest point and then check the validity of the last wellbore solution, if wellbore solution do not match then a new guess is set for it and the reservoir-well loop is solved. This process repeats until a guess for wellbore respect the tolerance, Figure 2(a) represents this algorithm.

2.2 Coupling Strategy 2 (COUP2)

This strategy solves reservoir-well-wellbore in the same loop, this loop starts with reservoir simulation, then well is simulated to obtain a response value to BHP, finally it uses this response and reservoir flows to simulate wellbore. If this process does not reduce the error to a value less than the tolerance it sets a new guess for BHP, Figure 2(b) represents this algorithm.



(a) (b)

Figure 2. (a) Algorithm for Coupling Strategy 1, (b) Algorithm for Coupling Strategy 2

2.3 Coupling Strategy 3 (COUP3)

This strategy solves reservoir-wellbore-well in the same loop, this loop starts with reservoir simulation, then wellbore is simulated to obtain wellbore pressure distribution, finally well is simulated to get new BHP. The difference between this strategy and strategy 2 is the use of the old BHP instead of new to simulate wellbore. Figure 3(a) represents the algorithm for this coupling.

2.4 Coupling Strategy 4 (COUP4)

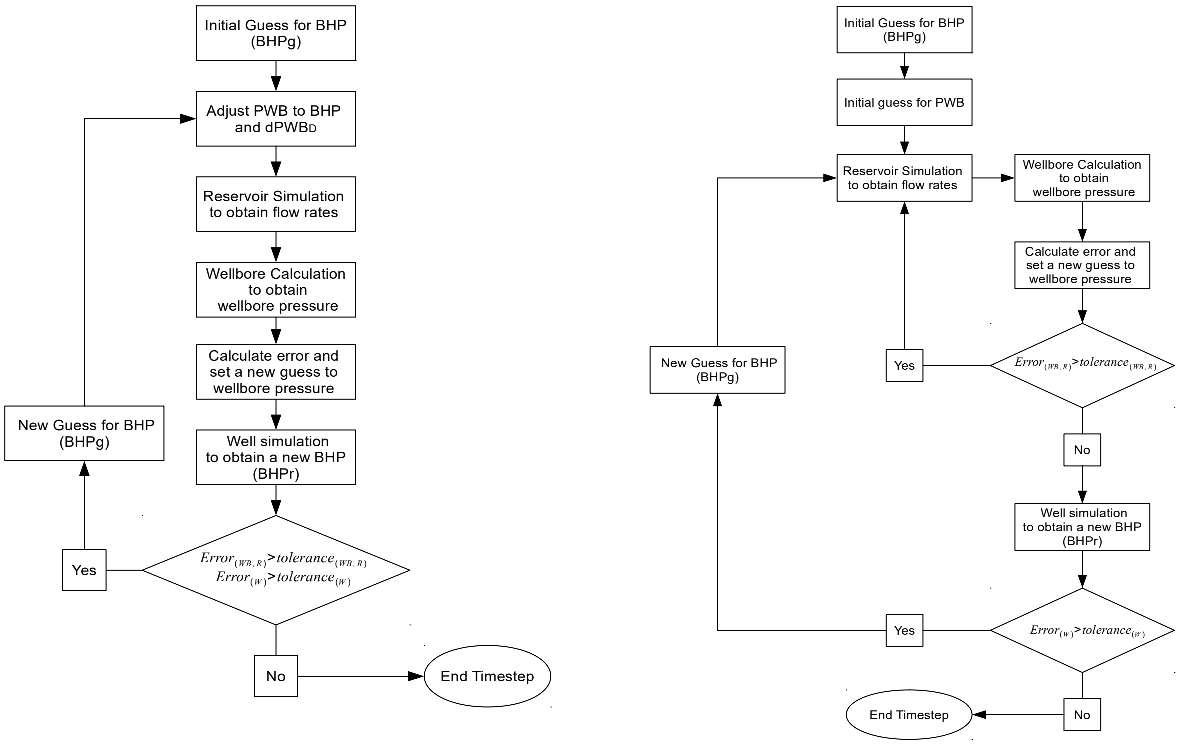
This strategy solves reservoir-wellbore in a loop inside the main loop, or in other words, it solves to obtain wellbore pressures that match the reservoir for an determined bottom hole pressure and then check the validity of this pressure, if BHP does not match then a new guess is set for it and the reservoir-wellbore loop is solved. This process repeats until respect tolerance; Figure 3(b) represents this algorithm.

2.5 Description of reservoir, wellbore and well models

In order to perform coupling simulation each of the system components must first be solved independently. As the modeling of each one of them is based on different equations and there some alternatives to solve these equations, it is necessary to make it clear which approaches are used in this work.

It performs the reservoir solution by a three-phase flow homemade simulator, that is only capable of represent cylindrical coordinates, this coordinates system facilitates the use of wellbore pressures as a boundary condition, Equation 1 represents flow of a phase α that is also dissolved in phase β in porous medium, more detail about this equation could be found in Alves (2020) . The model is based on the black oil model with simultaneous solution during the Newton-Raphson iteration presented by Chen et al. (2006) and the discretization of equations is due the finite volume method.

$$\phi \frac{\partial}{\partial t}\left(\frac{S_\alpha}{B_\alpha} + \frac{Rs_\beta S_\beta}{B_\beta}\right) = \frac{1}{r}\frac{\partial}{\partial r}\left[r\left(\frac{k_\alpha K_r}{\mu_\alpha B_\alpha}\frac{\partial p_\alpha}{\partial r} + \frac{Rs_\beta k_\beta K_r}{\mu_\beta B_\beta}\frac{\partial p_\beta}{\partial r}\right)\right] + \frac{\partial}{\partial z}\left[\frac{k_\alpha K_z}{\mu_\alpha B_\alpha}\left(\frac{\partial p_\alpha}{\partial z} - \rho_\alpha g\right) + \frac{Rs_\beta k_\beta K_z}{\mu_\beta B_\beta}\left(\frac{\partial p_\beta}{\partial z} - \rho_\beta g\right)\right] \tag{1}$$



(a) (b)

Figure 3. (a) Algorithm for Coupling Strategy 3, (b) Algorithm for Coupling Strategy 4

The wellbore is simulated using the Ouyang (1998) homogenous model that incorporates multiphase flow and the influence of radial influx on losses due acceleration and frictional effects, equation 3 represents the pressure drop in wellbore region. The wellbore is simulated using first order Euler Method to advance the solution of mass and momentum balance equations.

$$\frac{dp}{dx} = \left(\frac{dp}{dx}\right)_{acc,I/O} + \left(\frac{dp}{dx}\right)_{acc,exp} + \left(\frac{dp}{dx}\right)_{fric} + \left(\frac{dp}{dx}\right)_{grav} \tag{2}$$

The well advance the solution using a fourth order Runge-Kutta Method, the energy conservation is considered as well as the mass and momentum that are also considered for the well, well behavior could be represented by equation 3 without the first term on the right side. In order to understand if the well model is relevant to coupling results, four models are implemented for the well, they are different in their concepts. These models are:

-The classical correlation of Hagedorn & Brown (H&B) as presented in Hagedorn and Brown (1965).

-Barbosa & Hewitt (B&H) mechanistic model as presented by Barbosa and Hewitt (2006).

-Chexal & Lellouche (C&L) model as presented by Chexal et al. (1992) for gravitational losses combined friction losses predicted by Friedel (1979).

-Beggs & Brill (B&B) correlation as presented by Beggs and Brill (1973).

3. SIMULATION CASES

To understand how efficient each coupling strategy is, there will be performed 8 simulation scenarios, for these simulations r_w = 4.53 cm, r_e = 457 m and the length of production zone is 6.1 m. The information about fluids properties, reservoir initial conditions and rock properties are presented in Table 1, these characteristics are the same for all simulations. Well length is assumed to by 1500 m for 4 simulations and 2000 m for the other 4, it will use each well model in 2 simulations.

The time-steps utilized for all simulations are determined by the equation (3). The wellhead will be started using a sigmoid function to reduce oscillations in fluid flow during these initial times. This start-up process was suggested by Schietz (2009). After that start-up process, if the oil flow rate for a time-step is lower than 1000 barrels a day, it reduces THP 0.345 MPa (50 psi) until it reaches 4 MPa (580 psi), that is the minimum wellhead pressure considered. The reservoir only produces using its natural energy, or without artificial lift or injection methods.

$$\Delta t = \begin{cases} 1000\, s, & if\ TS < 100 \\ 1\, d, & if\ 100 \le TS < 200 \\ 2\, d, & if\ 200 \le TS < 300 \\ 3\, d, & if\ 300 \le TS < 400 \\ 4\, d, & if\ 400 \le TS < 500 \\ 5\, d, & if\ 500 \le TS < 700 \\ 10\, d, & if\ 700 \le TS < 800 \\ 20\, d, & if\ 800 \le TS \end{cases} \quad (3)$$

Table 1 – Reservoir basic characteristics

Fluids Densities	
°API	37.29
Gas Specific Gravity (γ_g)	0.367
Air density (Standard Condition)	1.2238 kg/m³
Water density (Standard Condition, ρ_{ws})	1009.5 kg/m³
Reservoir Initial Condition	
Pressure (at the bottom of reservoir, p_i)	24.82 MPa (3600 psi)
Bubble Point Pressure	13. 79 MPa (2000 psi)
Oil Saturation	0.80
Water Saturation	0.20
Reservoir Height	140.20 m (460.0 ft)
Temperature	323 K
Rock Properties	
Porosity (at 24.82 MPa, ϕ)	0.25
Rock compressibility (C_R)	0.681 x 10^{-10} Pa^{-1}

4. RESULTS

The results are presented in three complementary ways, Table 2 shows the reason why each one of simulations ends, the ideal result for this is “No operation point reached”, this implies that the simulation works but physically is impossible to sustain production using reservoir natural energy. The second way of present the results is presenting a brief description on how the simulation ends. Finally, the number of iterations required by each coupling are compared. It is important to clarify that no limit was put in iterations of each step; it stopped the process when the computational time to progress a time step take over 10 hours.

Table 2 shows that COUP1 and COUP4, both strategies based on two iterations loops, presented the same causes for simulation endings, these causes are different of the causes found for COUP2 and COUP3, strategies with only one loop. Although at first glance the two loops strategies are more secure, since they simulate 5 of 7 cases until the end of reservoir productive life, the failures presented by strategies 2 and 3 are a consequence of very low flow rates (a characteristic of simulations with Chexall & Lellouche correlation). The description of simulations that resulted in numerical failures or generated an unclear situation (the simulations are identified by their position in Table 2) help to clarify the information encountered.

Table 2- Coupling strategies results for 8 simulation cases

	Well Length (m)	*COUP1*	*COUP2*	*COUP3*	*COUP4*
H&B	1500	Numerical Failure	Unclear	Unclear	Numerical Failure
H&B	2000	Numerical Failure	Unclear	Unclear	Numerical Failure
B&H	1500	No operation point reached	No operation point reached	No operation point reached	No operation point reached
B&H	2000	No operation point reached	No operation point reached	No operation point reached	No operation point reached
C&L	1500	No operation point reached	Numerical Failure	Numerical Failure	No operation point reached
C&L	2000	No operation point reached	Numerical Failure	Numerical Failure	No operation point reached
B&B	1500	No operation point reached	No operation point reached	No operation point reached	No operation point reached
B&B	2000	Production did not start	Production did not start	Production did not start	Production did not start

Simulation (1,1)- The coupling strategy failed to advance to time step 1013, it failed to reduce wellbore residue, it probably occurred because the solution to wellbore pressures oscillates between two vectors. BHP was stable for time step 1012 and total oil flow rate swings between 1.12751 x 10^{-3} m³/s and 1.12752 x 10^{-3} m³/s (612.732 and 612.736 bbl/d).

Simulation (1,2)- The coupling strategy failed to advance to time step 2067, the numerical strategy for guess BHP was frequently inducing great production and consequently a numerical error in the well results, but when the guess is good the producing point was not found, so it is unclear if it is a numerical fail or the end of production.

Simulation (1,3)- The coupling strategy failed to advance to time step 2069, the failure can be described as on Simulation (1,2).

Simulation (1,4)- The coupling strategy failed to advance to time step 1449, the failure can be described as on Simulation (1,1), except for this case oil flow rate swings between 9.34902 x 10^{-4} and 9.34917 x 10^{-4} m³/s (508.063 and 508.071 bbl/d).

Figure 4 presents the number of iterations (reservoir simulations) to advance a time-step in each coupling strategy for the first row of Table 2, in the first step COUP1 and COUP4 take more iterations to reach the operation point than the one loop strategies, but after that they generally keep their iterations below 10. It is possible to observe that when COUP4 closes to time-step of failure, the number of iterations increases significantly, this indicates a change in reservoir behavior.

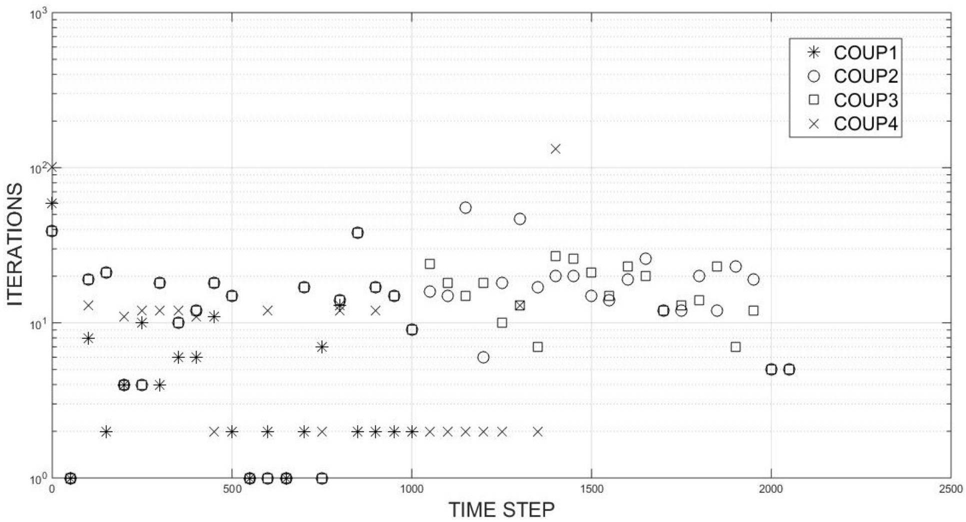


Figure 4. Iterations of coupling strategies for Case 1 every 50 time-steps

Simulation (2,1)-The coupling strategy failed to advance to time step 227, the failure apparently occurs because the strategy is incapable of reduce wellbore flow rates errors, this can be a consequence of iterate well and reservoir and after that include wellbore.

Simulation (2,2)-The coupling strategy failed to advance to time step 4673, the failure can be described as on Simulation (1,2).

Simulation (2,3)-The coupling method failed to advance to time step 4676, the failure can be described as on Simulation (1,2).

Simulation (2,4)-The coupling method failed to advance to time step 4493, although it is possible to produce more, as presented by other methods results, there is no sign of numerical failure that makes convergence impossible. The BHP value got can satisfy the tolerance, therefore, a value in wellbore was considered intolerable.

In Figure 5 it is possible to observe that COUP4 presents a similar pattern to that presented in Case 1, the start-up requires over 100 iterations and after that the number of iterations stay low. COUP1 struggles to obtain a solution for time-step 200 and then fails in time-step 227. COUP2 and COUP3, in general, need significantly more iterations than COUP1 and COUP4 to advance a time-step.

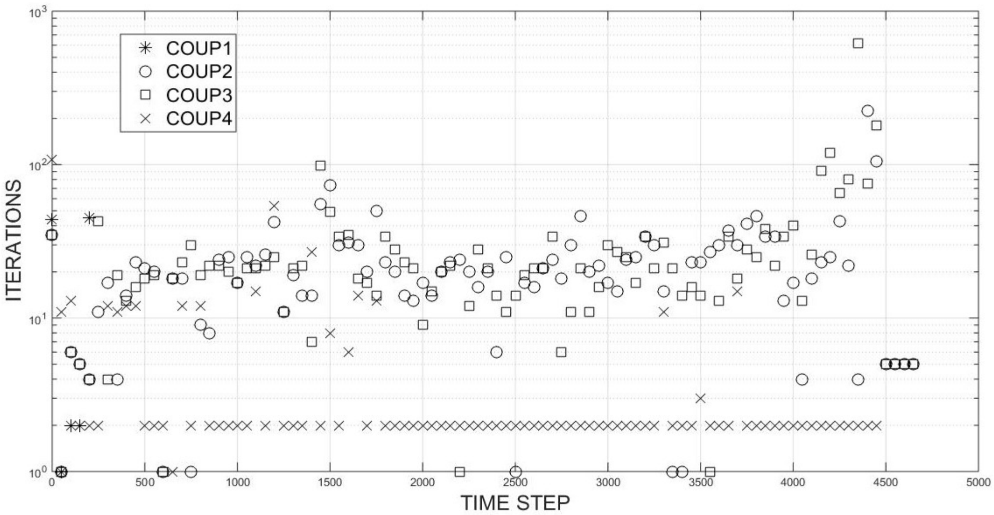


Figure 5. Iterations of coupling strategies for Case 2 every 50 time-steps

Simulation (5,1) - The coupling strategy failed to advance to time step 709, it failed to find a viable BHP.

Simulation (5,2) - The coupling strategy failed to advance to time step 559, it failed due to guess a BHP that induces a high flowrate from reservoir.

Simulation (5,3) - The coupling strategy failed to advance to time step 581, it is unclear how the strategy failed, but it is probable that it induces injection flow rate after 844 iterations.

Simulation (5,4) - The coupling strategy failed to advance to time step 707, it failed to find a viable BHP.

Figure 6 shows an increase in the number of iterations when the reservoir energy is reduced. For this case relevant information about failures can be obtained observing the oil flow rates results around the time that coupling strategies 2 and 3 failed, during these simulations is possible to observe that production is below 1.5 x 10^{-4} m³/s (80 bbl/d) with oscillations. The two loops strategies presented more consistency on this oscillation, one loop strategies do not present a pattern in that oscillation, so it possible this random behavior, combined with low flow rates, induced these methods failures.

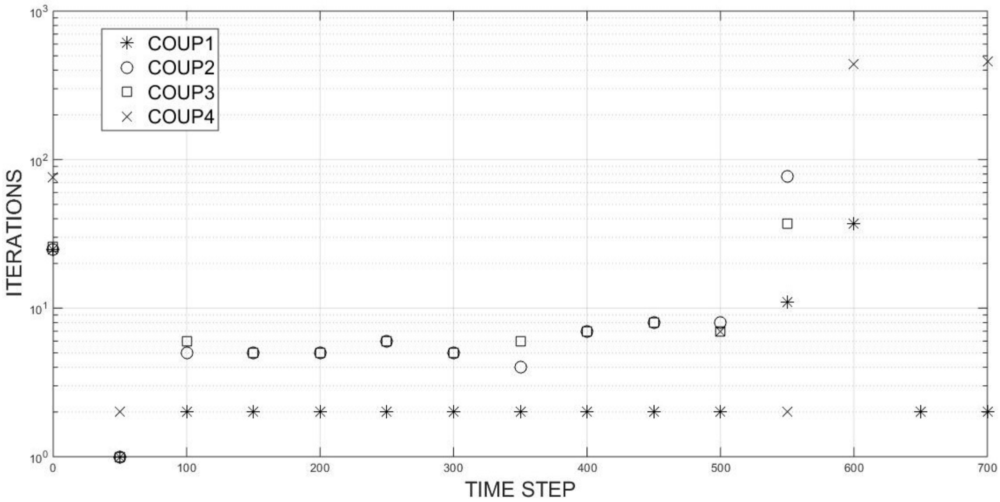


Figure 6. Iterations of coupling strategies for Case 5 every 50 time-steps.

Simulation (6,1) - The coupling strategy failed to advance to time step 717, it failed to find a viable BHP.

Simulation (6,2) - The coupling strategy failed to advance to time step 598, it is probable that the strategy induced injection flow rate after 539 iterations.

Simulation (6,3) - The coupling strategy failed to advance to time step 596, the numerical error was unclear. It obtains some negative oil flow rates during the iterations.

Simulation (6,4) - The coupling strategy failed to advance to time step 727, it cannot find a viable BHP.

Figure 7 shows a difference in pattern of COUP1 and COUP4 results, in Case 6 their iterations do not increase, this is probably a consequence of the reservoir energy that is greater than in Case 5. A relevant observation about Chexall & Lellouche simulations is that two loops found operations points even for 5.5 x 10^{-6} m³/s (3 bbl/d) oil flow rate, this is almost certainly an unrealistic result, so the fact that they simulated these scenarios are not necessarily an advantage in relation to COUP2 and COUP3.

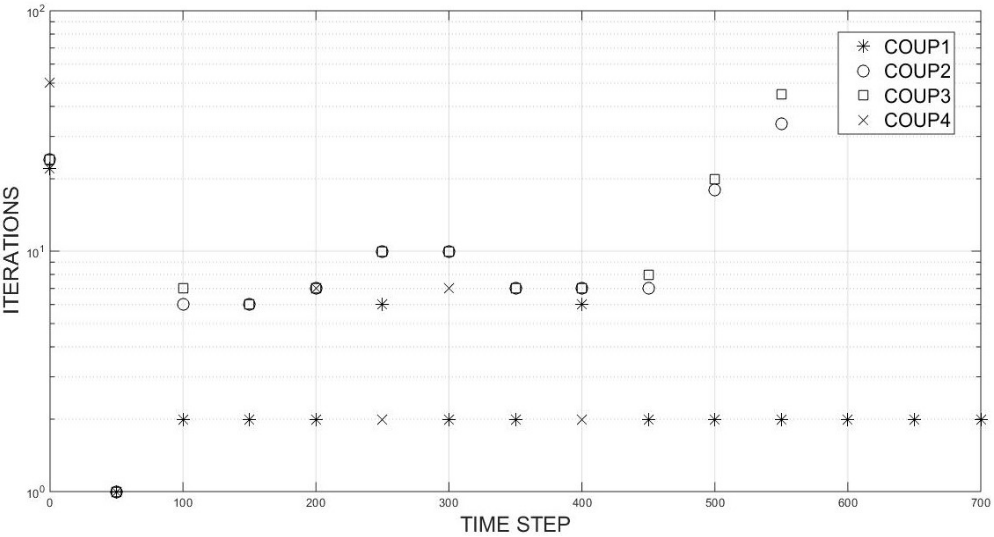


Figure 7. Iterations of coupling strategies for Case 6 every 50 time-steps.

The combination of all observations results is key observations:

-COUP1 and COUP4 presented similar results.

-COUP2 and COUP3 presented similar results.

-One loop coupling requires more iterations than two loops coupling.

-One loop coupling performs better to the start-up and are more probable to advance a time-step than two loops coupling.

-One loop coupling requires an improvement in safety but are considerably more efficient in terms of iterations.

5. CONCLUSION

This work developed a well-reservoir coupling simulator for vertical simulations using a transient reservoir simulator and a steady-state well simulator. Both methods were successfully programmed and got satisfactory results. The well simulator was broken in two simulators during this work development, each one using a specific approach, the first was the region of well that do not receive influx direct from the reservoir (that region simulator sustain the name "well")

As the well model was broken in two simulators, 4 strategies were developed to couple the reservoir and these two simulators, the differences between these methods were the simulation order and if they were integrated using one or two loops. The four coupling methods were used to simulate eight production cases and the results permitted two main observations:

-The strategies that utilizes two loops (COUP1 and COUP4) needed fewest iterations to advance a time-step.

-The strategies that utilises one loop (COUP2 and COUP3) are less susceptible to numerical errors.

As recommendations for future work, a few topics of interest were identified:

-About coupling methods an important evolution that could be developed is a combination of two and one loop methods that uses two loop methods to reduce iterations and one loop methods to increase the probability of convergence.

-To test a coupling method with well and wellbore models unified using only the pressures and flows at the wellbore as values to be tested during iterations, this will also reduce the necessity of data exchange between well and wellbore models.

6. ACKNOWLEDGEMENTS

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