

INFLUENCE OF FLUID-MECHANICAL COUPLING IN GAS GENERATION IN UNDERSATURATED PETROLEUM RESERVOIRS

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Abstract. Among the several mechanisms of producing an oil reservoir, the gas expansion mechanism is an important primary recovery process. During the depletion of the reservoir, the pore pressure may reach values below the bubble pressure of the oil, allowing the gas release. From the geomechanical point of view, the change in pore volume, due to production, changes the dynamics of gas generation, since it is dependent upon the change in pore pressure. Studies considering the fluid-mechanical coupling show the relationship between variations of fluid pressure and porous structure of the reservoir. This work aims to study the influence of the fluid-mechanical partial coupling (one and two-way) in the process of gas release during recovery of hydrocarbon. It was used the partial coupling methodology developed by ATHENA/GTEP – PUC-Rio. The model called “A” has only one producing well, while the model called “B” has four injection wells, besides the producer. Initially, the oil present in the reservoir is in undersaturated condition. In model “A” was observed that the pressure drop of fluid is more accentuated, until it reaches the bubble pressure, when considering the two-way coupling. Consequently, the gas release initiation occurs earlier than one-way coupling scheme. After starting gas generation, the rates of pressure change in both partial coupling scenarios tend to equalize. In terms of compaction and subsidence, it was observed most significant displacements values in two-way coupling, highlighting the rigorous consideration of the geomechanical effects in the applied methodology. In model “B”, it was observed that the consideration of the two-way coupling resulted in a recovery scenario without generation of gas, unlike the results shown by the one-way coupling in which gas was generated during 40% of total simulation time. In geomechanical terms it was observed, as presented previously, that the values of vertical displacement were greater in the two-way coupling. The methodology used in this paper proved to be capable of simulating coupled process in a blackoil reservoir, as could be observed by the results. Furthermore, the use of one-way partial coupling scheme, which is widely used in the oil industry, showed results quite different in terms of gas liberation, when are compared with the two-way partial coupling scheme, which was developed in a more rigorous way.

1 INTRODUCTION

A petroleum reservoir may contain fluids in various configurations of phases, and depending on the state of pressure and temperature that found, there may be a predominance of one over the other phases. The properties of the fluids contained in hydrocarbon reserves, as well as their relationship with the types of existing reservoirs, consists of a theme widely presented and discussed in classical and modern literature, see [1, 2, 3].

The combination of fluid properties can be made from theoretical and experimental evaluations, using thermodynamic laws and PVT test results, leading to predictions about the behavior of the reservoir during its production life. It is denoted, however, that currently interests are not solely directed to hydraulic point of view of oil extraction, but also to effects of this extraction on the geomechanical behavior of reservoir. Such effects have great practical relevance, as have been reported in recent publications on this subject [4, 5, 6, 7].

In the context presented, it is observed the importance of the jointly evaluation of geomechanical effect in the reservoir and the changes in produced fluid phase, since both are a result of the pressure gradient resulting from the reservoir development. Using concepts from fluid-mechanical coupling, associated to production mechanisms involving gas release, it becomes possible to establish a panorama of geomechanical action on the dynamics of the phases present in the system.

2 GAS GENERATION IN BLACKOIL RESERVOIRS: AN OVERVIEW

Among the various mechanisms of producing an oil reservoir, the solution gas drive is an important primary production process. According to [8], this mechanism is favourable to the production of oil reserves with dissolved gas, since the pressure drop in the reservoir, induced during production, can generate gas release. From the geomechanical point of view, the liberation of dissolved gas due to pressure relief caused by production is not independent of geomechanical effects, since the consideration of these effects causes substantial variations in the pressure state of the reservoir [5, 6].

Figure 1, adapted from [2], shows two situations in which an oil reservoir may be found: (a) shows a condition of undersaturated oil (fluid pressure higher than bubble pressure) and (b) shows a condition in which the fluid pressure falls below the bubble pressure.

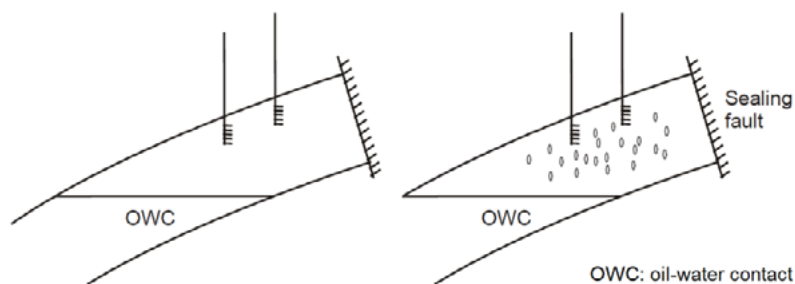


Figure 1: Solution gas drive reservoir (a) above the bubble point pressure; (b) below bubble point pressure

These production scenarios consider that the fluid is trapped by a sealant layer, and that the water influx in production is not relevant, in such a way that the boundaries do not permit flow in either direction. It should be emphasized that, because of the condition of flow isolation, the reservoir will undergo a gradual reduction of pressure during production, resulting in the

expansion of the fluids present in the formation and the compaction of mineral skeleton of reservoir rock [8]. These phenomena contribute to the expulsion of fluid from the reservoir, allowing the production. Nevertheless, the pressure reduction may even result in the phase change of the dissolved gas, which upon become free, configures an important agent in this mechanism of production. It is therefore evident the interrelationship between the geomechanical effects and behavior of fluid in production as well as the need to perform a separate evaluation for possible situations, with and without free gas together with the oil.

In the undersaturated condition, the interaction between the compressibilities values of the components influences on the production capacity of the reservoir, mainly because there is no predominance of one phase over the other, in terms of compressibility. In this case the influence of variation of the pore volume due to geomechanical effects affects the system response front of the change of pressures resulting from the production.

In the situation where the oil pressure is below the bubble point pressure, the solution gas present in the oil is released and a gas saturation in the free form is developed in the reservoir. The compressibility of the gas, according to [2], can be two orders of magnitude higher than the value of the water compressibility, and about thirty times the compressibility of the porous structure. Thus, it is observed that the geomechanical effect in the reservoir may be differentiated in situations with and without free gas into the fluid, due to the difference between the magnitudes of phases compressibilities.

Assuming the compressibility of the system as being governed primarily by gas compressibility, it is assumed that the variation of pore volume resulting from the change in the stress state of rock due to production, does not significantly interfere on the gas pressure as occurs on pressure of the fluid in the liquid state. In terms of fluid-mechanical coupled analysis, this consideration is equivalent to saying that, upon fluid pressure reaching the bubble point, the phenomenon of coupling changes its nature, since gas is more compressible and the production mechanism does not refer solely to reservoir compaction.

3 PANORAMA OF THE FLUID-MECHANICAL COUPLING SCHEME

Studies conducted by the Computational Geomechanics Group – ATHENA/ GTEP – PUC-Rio showed substantial influence of geomechanical effects on the history of fluid pressures during the development of a reservoir, and also on other aspects such as subsidence and compaction. The simulated cases and reported in the literature [5, 6] considered no free gas, falling on the condition of undersaturated oil. In such situations, the use of iterative techniques in the fluid-mechanical coupling, i.e. with exchanging information between the flow and stress simulators, gave results of better quality than explicit coupling, when compared to full coupling, since the fluid and the pore structure compressibilities influence the production process. The use of partial coupling in the simulations with complete saturation of fluids in porous media has led to significant changes in rates of pressure change over time. However, studies involving coupled simulations with the presence of free gas in the porous medium should be performed taking into account that the gas has a high compressibility value regarding to other components, and the observed behavior must be distinct from complete saturation liquid.

The coupling methodology developed by the ATHENA/ GTEP – PUC-Rio consists of a one and two-way partial coupling scheme, where the flow variables (pore pressure and saturation of the phases) and the stress variables (displacement field, stress and strain state) are calculated separately and sequentially, by a conventional reservoir simulator and a stress

analysis program, respectively. The coupling parameters are exchanged at each time step until reaching the convergence. The quality of this methodology was ensured by the rigorous development of a coupling parameter which approximates the geomechanical response to the fully coupled behavior. In this work, it will be shown just the equations of the flow problem and the stress analysis problem. For more details about the development of the formulation see [6].

The flow equation can be obtained by combining the mass conservation equation and the Darcy's law. The law of mass conservation is a material-balance equation written for a component in a control volume. In hydrocarbon reservoirs, a porous medium can contain one, two and three fluid phases. The governing flow equation for the conventional reservoir simulation and the governing equation used in the fully coupled scheme are given by Eq. (1) and Eq. (2), respectively. In the conventional reservoir simulation, the porosity is related to pore pressure through the rock compressibility using a linear relation, and in the fully coupled scheme, the porosity equation is composed of four components that contribute to the fluid accumulation term.

$$(c_f \phi^0 + c_r \phi^0) \frac{\partial p}{\partial t} - \frac{k}{\mu} \nabla^2 p = 0 \quad (1)$$

$$[c_f \phi^0 + c_s (\alpha - \phi^0)] \frac{\partial p}{\partial t} - \frac{k}{\mu} \nabla^2 p = -\alpha \frac{\partial \varepsilon_v}{\partial t} \quad (2)$$

where ϕ is the porosity, p is the pore pressure, t is the time, k is the permeability, μ is the viscosity, c_f is the fluid compressibility, c_s is the solid matrix compressibility, c_r is the rock compressibility, α is a Biot's coefficient and ε_v is the bulk volumetric strain.

The formulation of the geomechanical problem takes into account the equilibrium equations, stress-strain-displacement equations, rock-flow interaction and the boundary conditions. The governing equation of the geomechanical problem may be written as indicated in Eq. (3).

$$G \nabla^2 \mathbf{u} + \frac{G}{1-2\nu} \nabla \nabla \cdot \mathbf{u} = \alpha \nabla p \quad (3)$$

where G is the shear modulus, \mathbf{u} is the nodal displacement and ν is the Poisson ratio.

The methodology used herein for the coupling between flow and stress problem was described in [5, 6]. The coupling is achieved through a convenient approximation between of the flow equation of the conventional reservoir simulation and the flow equation of the fully coupled scheme. In this methodology, the effect of solids compressibility is removed from the fully coupled scheme and the effect of volumetric strain of the porous medium is added to conventional reservoir simulation.

The parameters responsible for the coupling, which honor the fully coupling equation, are the porosity ϕ and the pseudo-compressibility c_p , presented in Eq. (4) and (5) respectively. These parameters are updated during each iteration through the coupled analysis.

$$\phi = \phi^o + \alpha (\varepsilon_v - \varepsilon_v^o) + \frac{1}{Q} (p - p^o) \quad (4)$$

$$c_p = \frac{\varepsilon_v^{n+1} - \varepsilon_v^n}{\phi^o (p_i^{n+1} - p_i^n)} \quad (5)$$

Furthermore, the partial coupling between the stress analysis program and the conventional reservoir simulator is reached using a staggered procedure, implemented in a C++ code [6].

The fact that the gas is more compressible than other medium components as well as being in process of gradual release of its dissolved state, it provides more significant production rates than those caused by the reduction of the pore volume, given the smallest variations of pressure and consequent changes in stress state. Therefore, the use of an iterative coupling scheme in this particular situation probably does not lead to substantial differences in the rate of change of pressure, since the variation of the pore volume would not be the dominant mechanism in the recovery of hydrocarbons. The use of a fluid-mechanical coupling scheme, to perform the analysis of the transition between undersaturated and saturated oil configurations, consists of a relevant study, since denoted the influence of geomechanical effects on the pressure variation in the cases where the fluid has not reached the bubble point pressure. Such assessments will be conducted via blackoil models built in this study, as presented in the following sections.

4 COUPLED SIMULATIONS IN BLACKOIL SCENARIOS

4.1 Scenarios

The simulations were performed using two different numerical models, based on model presented by [5, 6, 7]. The first model, called A, consists in a simplified reservoir with one producer well placed in its center. The second model, called B, presents the same configuration aforementioned, however, it was added four injector wells. Figure. 2 shows these two configurations.

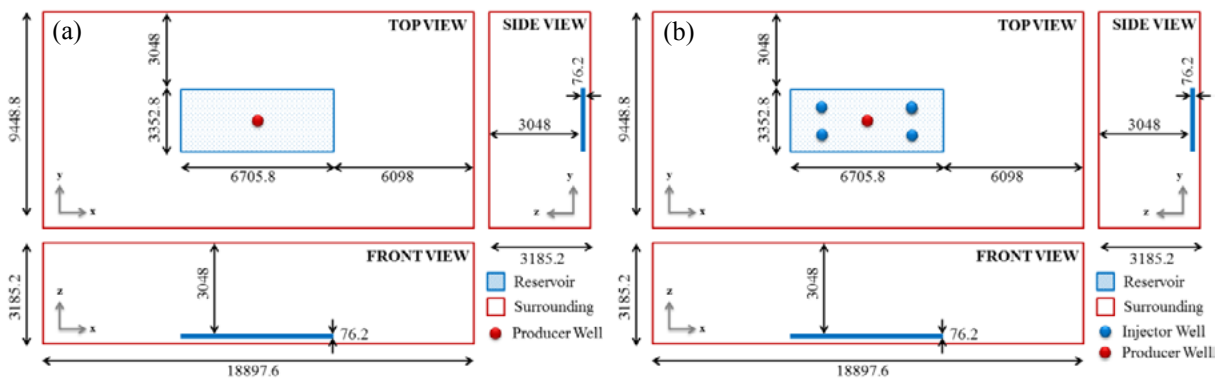


Figure 2. Blackoil reservoirs, (a) model A and (b) model B

It should be noted that the analysis time for the models A and B was 1200 and 5000 days respectively. The simulation time for the model B was longer than model A because the interest was observe the influence of the injection in long-term. Table 1 presents the geomechanical and fluid properties adopted for both models. The PVT data were adopted according to a real reservoir available.

Table 1. Rock and fluid properties for both models

Properties	Values
API (°)	27.5
Initial rock compressibility	$3,33 \times 10^{-4} \text{ psi}^{-1}$
Horizontal permeability	$9.86 \times 10^{-14} \text{ m}^2$
Vertical permeability	$9.86 \times 10^{-15} \text{ m}^2$
Initial porosity	0,25
Young's modulus (reservoir)	0,689 GPa
Young's modulus (surrounding rock)	6,89 GPa
Poisson's ratio	0,25
Production rate – <i>model A</i>	50000 BBL/day
Production rate – <i>model B</i>	6500 BBL/day
Injection rate – <i>model B</i>	9000 BBL/day

In the following items will be discussed the results (pore pressure, gas release, compaction and subsidence) obtained from the numerical models aforementioned.

4.2 Results

This section is divided in two distinct parts. In the first one, it will be presented the results obtained considering the model with one producer well (*model A*). In another part, it will be discussed the results of the model with injectors and producer wells (*model B*).

- *Model A*

Figure 3 shows the comparison between the conventional reservoir simulation (IMEX) and the simulation partially coupled ABAQUS-IMEX in two-way. It was evaluated the pore pressure distribution over time and the produced gas rate in reservoir conditions. It can be mentioned that the bubble pressure for oil is 5000 psi.

It can be seen that the pore pressure decay rate was higher considering ABAQUS-IMEX two-way coupling than the conventional reservoir simulation (IMEX). In this case, gas generation occurs 160 days before the reservoir simulation, highlighting the importance of geomechanical effects. Besides that, it was observed that after gas release within reservoir, the pore pressure decay rate is quite similar in both methodologies compared, noting that fluid-mechanical behavior is also affected by this process. The pore pressure decay rate curves are presented in Figure 4.

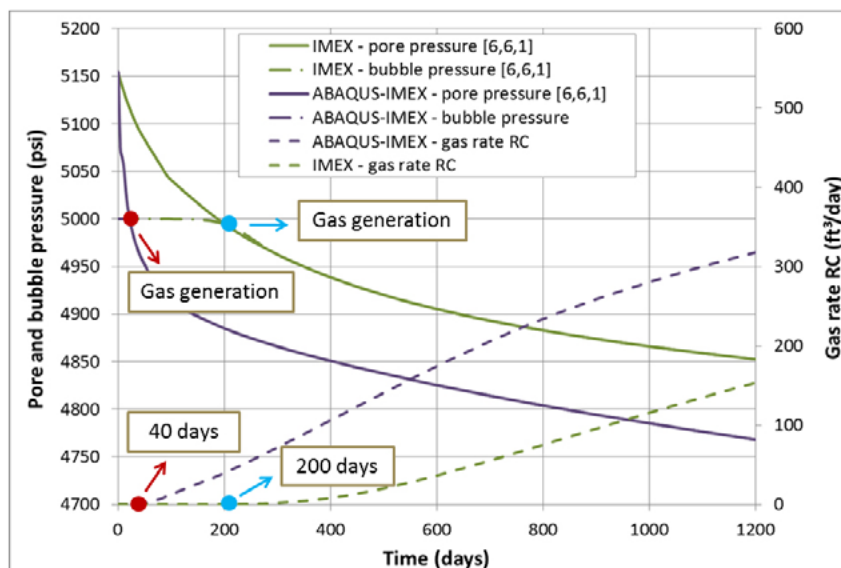


Figure 3. Pore pressure variation and gas generation over production time for conventional reservoir simulation and partially coupled scheme – model A

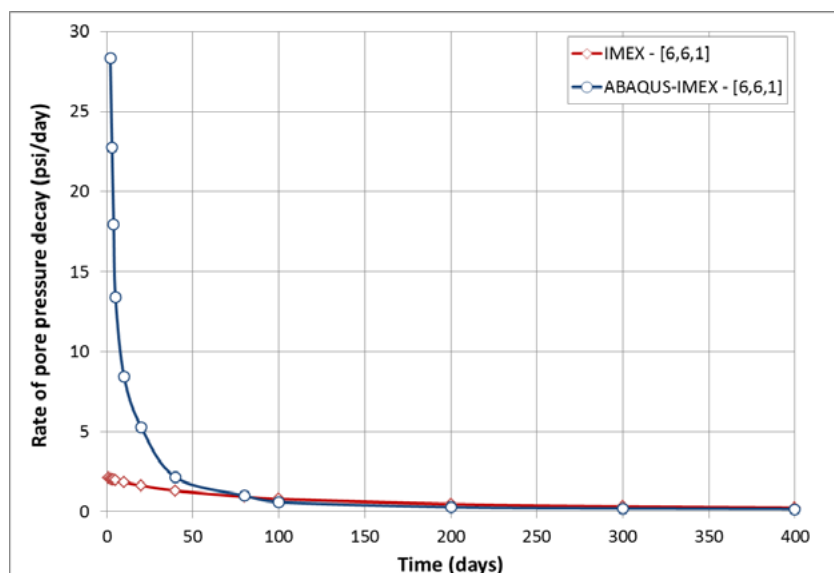


Figure 4. Pore pressure decay rate over production time for conventional reservoir simulation and partially coupled scheme – model A

It was evaluated also, the average pore pressure within reservoir considering one and two-way fluid-mechanical coupling schemes. It should be noted that one-way coupling simulation presents the same results when compared with conventional reservoir simulation, once the geomechanical effect does not affect the flow simulation, as discussed in [5, 6]. Figure 5 presents the average pore pressure behavior considering one and two-way coupling. It was clear that the correct information interchange between simulators (two-way coupling ABAQUS-IMEX) resulted in a higher pore pressure drop over production time. This fact makes sense physically, by virtue of the increased stiffness of system due consideration of surrounding rocks.

Figure 6 shows a set of outlook of pore pressure distribution considering one and two-way

coupling methodologies. It can be seen that in the iterative simulation, the variation of pore pressure was broadest than the simulation performed by one-way coupling (see Figure 6). Figure 6 is composed by a set of images, which are: top view, cross section through the producer well and tridimensional.

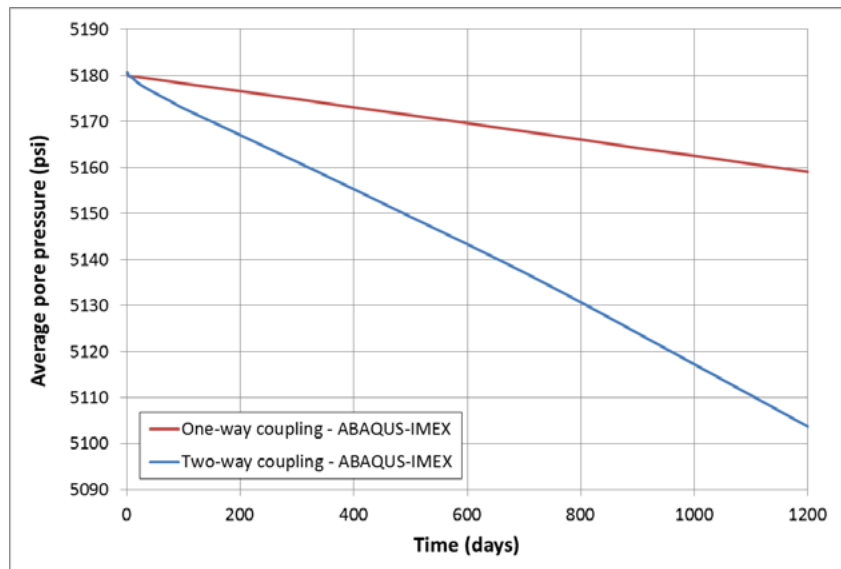


Figure 5. Average pore pressure over production time for one and two-way coupling schemes – model A

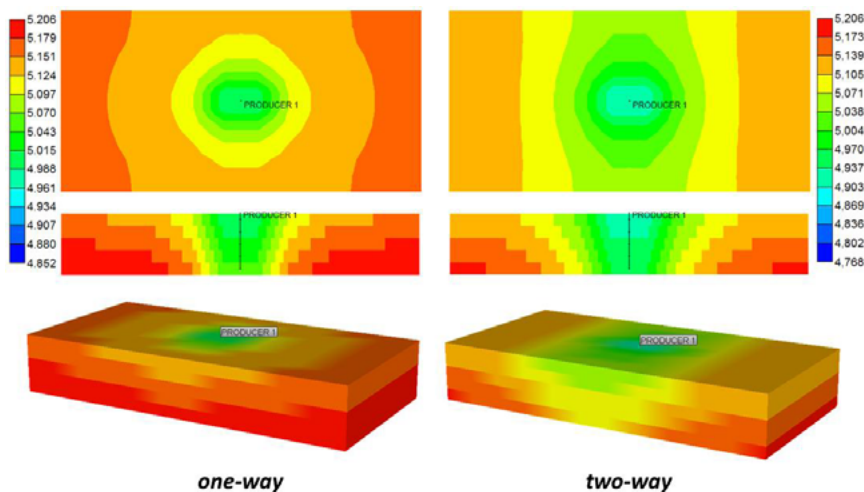


Figure 6. Outlook of pore pressure variation after 1200 days of production considering one and two-way coupling schemes – model A

It was evaluated also, the compaction of reservoir and the subsidence of seafloor, as can be seen in Figure 7. The measurement elements chosen were placed in the producer well position in relation to reservoir and overburden. Again, the behavior observed is quite similar those analyzed previously, i. e, both results present important differences between methodologies, in which two-way coupling shows values of compaction and subsidence higher than the one-way scheme. Thus, these results suggest that one-way coupled analyses could provide geomechanical forecasts against the security.

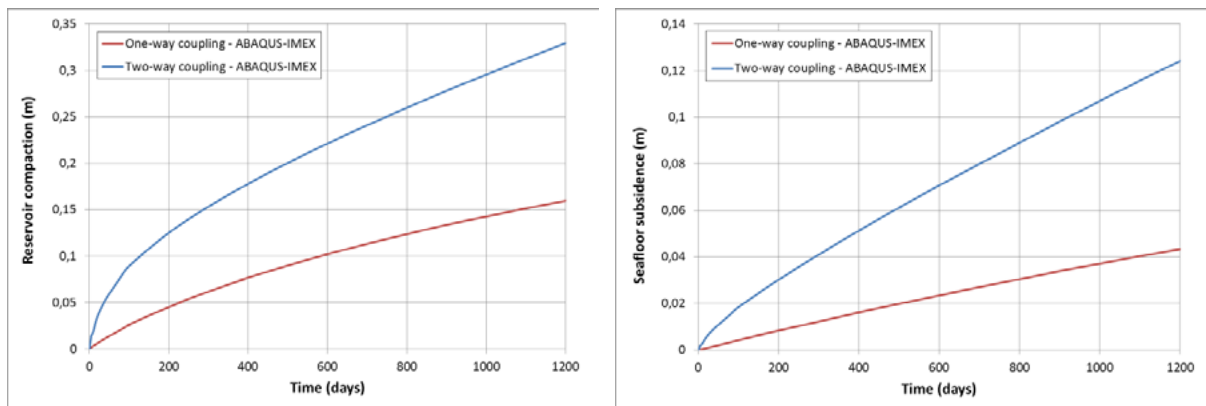


Figure 7. Compaction of reservoir and subsidence of seafloor for one and two-way coupling schemes – *model A*.

Therefore, in a general way, the analyses performed considering the influence of a rigorous fluid-mechanical coupling in a blackoil production scenario proved to be fundamental when the aim is to determine geomechanical behavior. As aforementioned, one-way coupling can forecast results against the security, once the pore pressure, compaction and subsidence obtained were less than the iterative coupling. Furthermore, considering gas release, two-way analyses provided a larger gas volume when compared with one-way analyses, highlighting its importance for field operations.

- *Model B*

As presented for the previously model, Figure 8 shows the comparison between the conventional reservoir simulation (IMEX) and the simulation partially coupled ABAQUS-IMEX in two-way. It was evaluated the pore pressure distribution and the produced gas rate in reservoir conditions after 5000 days for injection and production. The flow rates (producer and injectors wells) are presented in the Table 1.

It can be observed that pore pressure behavior, for two methodologies, present some similarities, i. e, both curves present decrease in the beginning of the analyses and start to increase when the influence of injector wells reaches the producer well. Nevertheless, there is a quite difference in the gas generation behavior. The consideration of iterative fluid-mechanical coupling led to an increase in pore pressure, due injection, were not fast enough to generate gas in the reservoir, in contrast to conventional reservoir simulation, in which was observed gas release during around 2000 days. In other words, the effect of injection, as production presented previously, is affected strongly by consideration of the geomechanical effect, i. e, in the production scenario, the pore pressure decrease faster than one-way coupling and in the scenario when injection prevails, the increase of pore pressure also is observed, by the system, faster than the one-way coupled analyses.

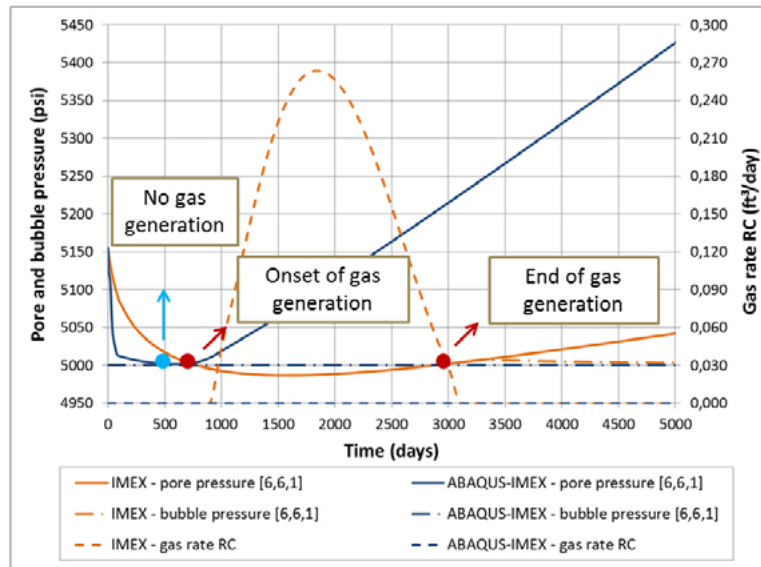


Figure 8. Pore pressure variation and gas generation over production time for conventional reservoir simulation and partially coupled schemes – *model B*

The average pore pressure behavior within reservoir was evaluated considering one and two-way fluid-mechanical coupling schemes (see Figure 9). The pore pressure increases in a higher rate when the two-way scheme is compared to one-way coupling. It was expected once the injection rate is higher than production rate and the geomechanical effect has a fundamental importance in the behavior, as discussed in the former analyses.

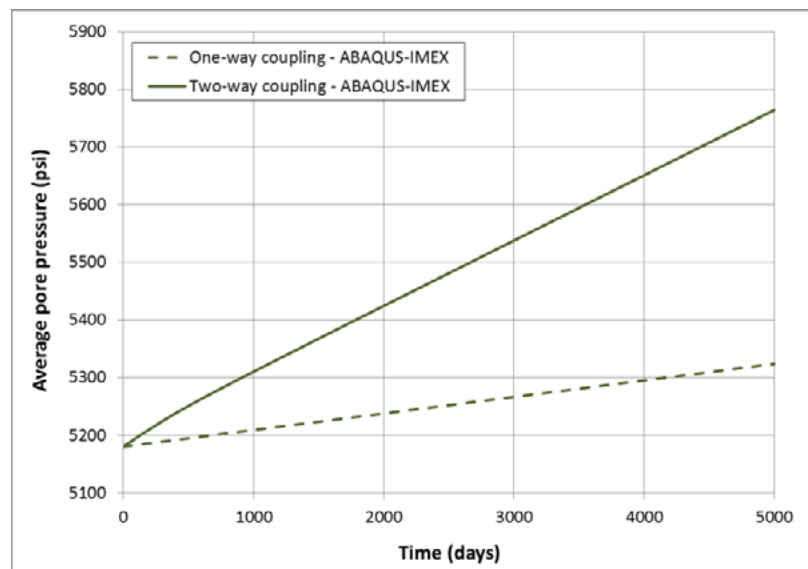


Figure 9. Average pore pressure for one and two-way coupling schemes – *model B*.

As already performed to *model A*, Figure 10 shows a set outlook of pore pressure distribution considering one and two-way coupling methodologies. Again, it can be seen that in the iterative simulation, the variation of pore pressure was broadest than the simulation performed by one-way coupling. Besides that, the pore pressure gradients around the wells are higher in the two-way scheme than one-way scheme. Figure 10 is composed by a set of

images, which are: top view, cross sections through the producer/injector wells and tridimensional.

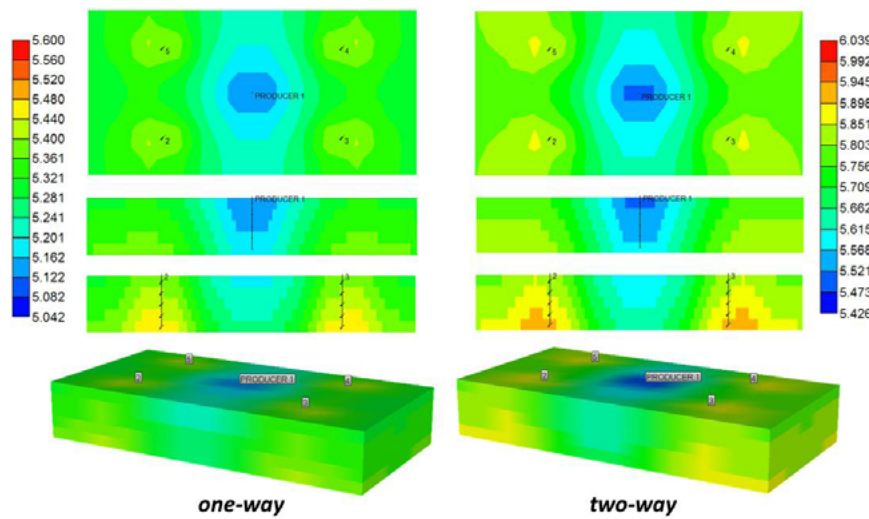


Figure 10. Outlook of pore pressure variation after 5000 days of production and injection considering one and two-way coupling scheme.

Since the effects of injection are prevalent in a global way, it was observed that curves decrease to negative values which indicate expansion in the reservoir and overburden (see Figure 11). It can be noted also, that in the beginning of the analyses, there is a small value of compaction. This fact is related to a time necessary to injection effect reach the measurement point, once this point was adopted in the location of producer well. As observed in *model A*, both results present important differences between methodologies, in which two-way coupling shows values of compaction (reservoir expansion) and subsidence (seafloor expansion) higher than the one-way scheme.

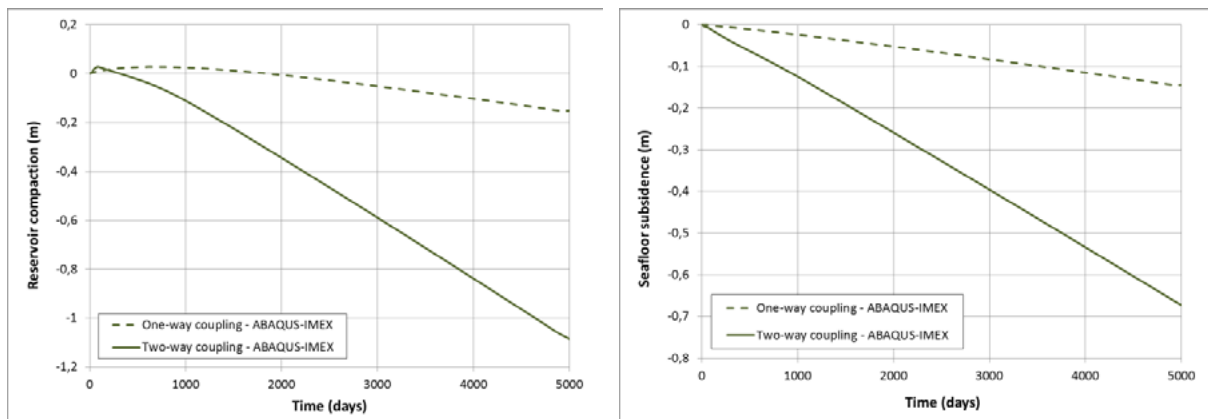


Figure 11. Compaction of reservoir and subsidence of seafloor for one and two-way coupling schemes – *model B*.

As concluded for a production scenario, the consideration of a rigorous fluid-mechanical coupling in reservoir simulation proved to be primordial when the aim is to predict

geomechanical behavior. As already discussed, one-way coupling can forecast results against the security, once the pore pressure, compaction and subsidence obtained were less than the iterative coupling. Moreover, considering gas generation within reservoir, two-way analyses did not predict any gas release during 5000 days of field development, unlike the analyses presented by one-way coupling scheme, which predicted around 2000 days of gas release. Thus, the use of one-way coupling should be done carefully, once its results can have a quite significant impact in field activities.

6 CONCLUSIONS

After analyses presented in this work, some conclusions can be done in relation to the influence of fluid-mechanical coupling in gas generation in undersaturated petroleum reservoirs. It should be highlighted that the use of the strong coupling methodology, as the one developed by ATHENA/GTEP-PUC-Rio, has fundamental influence in a forecast of reservoir geomechanical behavior.

For a production scenario, it can be concluded that when the porous medium is filled by fluid (composed by a mixture of gas and oil), the influence of coupling methodology is not fundamental, once the production mechanism is ruled by the gas expansion within the reservoir. On the other hand, for scenarios that combines injection and production, the iterative coupling methodology presents more accurate results when compared with one-way coupling scheme. Furthermore, the choice of coupling methodology must be careful, mainly when the purpose is to predict the time and volume of gas released when the pore pressure drop below the bubble point pressure.

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