

Article

An Efficient Numerical Model for the Evaluation of the Productivity Considering Depletion-Induced Plastic Behaviors in Weakly Consolidated Reservoirs

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Abstract: Efficient and accurate modeling of rock deformation and well production in weakly consolidated reservoirs requires reliable and accurate reservoir modeling techniques. During hydrocarbon production, the reservoir pressure is dropped, and rock compaction is induced. In such depletion-induced reservoir rock deformation, both elastic and plastic deformation can be generated. The numerical investigation of depletion-induced plasticity in shale oil reservoirs and its impact on coupled reservoir modeling helps provide insights into the optimization of horizontal well productivity. This study introduces a coupled flow and geomechanical model that considers porous media flow, elastoplastic deformation, horizontal well production, and the coupling between the flow and geomechanical processes. Simulation results are then provided along with numerical modeling parameters. Effects of relevant parameters, including depletion magnitude, rock mechanical properties, and hydraulic fracture parameters, jointly affect rock deformation, rock skeleton damage, and horizontal well productivity. Depletion-induced plasticity, stress, pressure, and subsidence are all characterized by the solution strategy. In addition, the implementation of direct and iterative solvers and the usage of full coupling and sequential coupling strategies are investigated, and the associated solver performance is quantified. It helps evaluate the numerical efficiency in the highly nonlinear numerical system. This study provides an efficient coupled flow and elastoplastic model for the simulation of depletion in weakly consolidated reservoirs.

Keywords: coupled flow and geomechanics; reservoir geomechanics; weakly consolidated reservoir; reservoir modeling; rock mechanics



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1. Introduction

The exploitation of weakly consolidated reservoirs requires an improved understanding of the complex multi-physical problems in the subsurface, including porous media flow and reservoir geomechanics [1,2]. Hydrocarbon depletion involves tightly coupled mechanisms associated with fluid flow and geomechanics [3,4]. Therefore, using modeling methods that only consider limited physical behaviors may negatively impact the reliability and accuracy of the modeling process. The implementation of efficiently and accurately

coupled flow and geomechanics models becomes important in understanding the system responses during the development of weakly consolidated reservoirs. Through adequate modeling techniques, depletion-induced elastic deformation, plastic deformation, rock skeleton damage, pressure drop, stress perturbation, and horizontal well productivity can be better quantified.

To better improve the modeling accuracy for such poromechanical behaviors, many coupled flow and geomechanics models have been presented based on poroelastic theories [5]. Such strategies often model the coupled physical behaviors between porous media flow, heat transfer, and geomechanical behaviors, which are all relevant factors in the understanding of depletion-induced reservoir responses [6–9]. During the process, pressure alteration and rock compaction/tension are jointly modeled, and for naturally fractured reservoirs, discontinuities and heterogeneities should also be considered in the coupling models [10]. The existence of discontinuities in reservoirs can complicate the physical modeling and numerical solution [11].

Coupled models were first derived based on simplified assumptions and linearized equations, and their applicability is sometimes limited. With the advancement of computational capabilities, more complex and realistic models have been developed [12,13]. Fully coupled models have been developed for the simultaneous solution to fluid flow, heat transfer, and mechanical deformation problems [14]. The models are generally based on mass conservation, momentum balance, and the first law of thermodynamics, and they can capture the complex and interconnected interactions between these processes [13]. The development of these models has been facilitated by computational techniques in recent decades, which have allowed for the simulation of larger and more complex problems. Uncertainty analysis techniques have also been developed to improve the comprehensiveness of the numerical solutions, as it is hard to directly obtain abundant reservoir data for accurate parameterization in realistic field studies. These considerations improved the reliability of modeling techniques for complex physical behaviors in the subsurface [5,15]. In the porous media, coupled modeling also considers thermal effects, phase changes, and injection effects such as enhanced oil recovery and gas hydrate exploitation. The associated rock physical and rock mechanical properties changes are quantified by analytical correlations and full geomechanical modeling. Rock mechanical failures and subsidence are also quantified in coupled modeling studies of depletion-induced system responses [16–19]. Guo et al. [20] extended this series of coupled modeling work to include the effects of heterogeneity and 3D dimensions in gas hydrate reservoirs. Nonuniform and anisotropic system responses are observed in their coupled models. The existing studies on coupled flow and geomechanics simulation techniques in porous media have provided insights into the behaviors in these systems. The previous studies enabled the characterization and prediction of reservoir performance and the optimization of exploitation techniques [21]. They can also help to assess the risks associated with these operations, such as geomechanical failure and depletion/injection-induced deformation in the hydrocarbon-bearing reservoirs. Hui et al. [22] applied coupled flow–geomechanics techniques combined with the Mohr–Coulomb criterion for fault reactivation assessment, where they quantified the induced plastic deformation related to faulting.

While significant progress has been made in the development of coupled flow and geomechanics simulation techniques for porous media, some problems associated with coupled modeling in the subsurface hydrocarbon-bearing reservoirs still need to be studied. One of the main challenges is how to address the numerical stability issues in these models, especially for large-scale reservoirs considering complex physical behaviors. This is due to the complexity of the equations and the need for high-resolution discretization to capture the small-scale features of the reservoir [23]. This challenge has been partially addressed

by the development of more efficient numerical methods and the use of high-performance computing [24]. In order to further improve the computational efficiency, structured grid-ding systems have also been proposed in some studies where the representation of complex fracture networks is treated for better simulation efficiency [25]. In the complex coupled system, porous media flow-related parameters and geomechanical parameters can all affect the solver performance in the numerical simulation runs. How these parameters affect the solution performance is directly related to the reliability of using numerical tools in understanding the physical processes during subsurface hydrocarbon exploitation [26–28]. Also, the effect of depletion-induced elastoplasticity and its relationship with solver performance has not been addressed in previous studies. In fact, depletion-induced plasticity can have a great impact on the geomechanical response in the reservoir and can largely affect the numerical solver performance. In certain cases, the emergence of plasticity in the system can lead to non-convergent solutions. Therefore, it is meaningful to carry out relevant numerical studies.

In this study, a coupled flow and geomechanics model for the simulation of production-induced pore pressure and rock deformation in a weakly consolidated hydrocarbon-bearing reservoir is first introduced. Single-phase porous media flow and both elastic and plastic rock skeleton deformation patterns are included in the fully coupled model. Then, simulation results for the reservoir system response are presented. The effect of relevant numerical parameters on the solver performance and the numerical simulation results are quantified and discussed. Convergent and efficient numerical solutions to the complex and coupled modeling problem are obtained in this study. The study provides a reference for the determination and optimization of numerical simulation parameters for coupled flow and geomechanical problems in weakly consolidated reservoir depletion. The results are especially relevant when plastic deformation is important in the coupled modeling system. The contribution of this work is primarily focused on the investigation of depletion-induced plasticity and its quantitative effect on the simulation of system responses.

2. Methodology

2.1. Governing Equations

In this study, the methodology is established to address the fully coupled problem of porous media fluid flow and geomechanics. This problem is addressed by employing a numerical framework, which includes Darcy's law for single-phase fluid flow in porous media and the theory of elasticity with soil plasticity considerations, where the Drucker–Prager yield criterion is employed to determine rock deformation and failure. The multi-physical model is achieved based on a finite element framework where time discretization and space discretization are involved. It provides a multi-physics model that allows for a dynamic coupling between fluid flow and solid deformation.

In the first place, the solution strategy is focused on modeling the single-phase fluid flow in the porous media. This phase is governed by Darcy's law for the porous media fluid flow, where the flow velocity is very low. This is based on the fundamental equation in reservoir engineering that describes the flow of a fluid through a porous medium. It quantifies the relationship between the discharge rate through the porous medium and the pressure gradient over the corresponding distance. Additionally, Darcy's law is combined with the principle of mass conservation. Therefore, they jointly establish the fluid diffusivity equation as shown in Equations (1) and (2).

$$\frac{\partial(\phi\rho_f)}{\partial t} + \nabla \cdot (\phi\rho_f u_{fs}) = \rho_f q_f \quad (1)$$

$$u_{fs} = -\frac{k}{\mu} \nabla p \quad (2)$$

where ϕ is rock porosity, unitless; ρ_f is fluid density, kg/m³; t is time, s; u_{fs} is fluid velocity, m/s; q_f is sink/source in unit volume, 1/s; k is permeability, m²; μ is viscosity, m/s; and p is pressure, Pa. Thus, the governing equations for fluid flow are implemented.

Then, the solution strategy in the methodology is focused on the geomechanical behaviors of the porous medium. In weakly consolidated reservoirs, the porous media are reservoir rocks. The computation is established through the application of the theory of elasticity and the consideration of soil plasticity assumptions. To address plasticity, the Drucker–Prager yield criterion is used to determine whether the stress and strain states activate the failure of reservoir rocks and whether it has the capacity to handle plastic deformations and yield failures in these materials. Within the methodology, the Drucker–Prager yield criterion is integrated by setting up the elasticity matrix and yield function. The geomechanical behavior of the reservoir rocks is further characterized by defining relevant mechanical parameters such as cohesion, friction angle, and dilatancy angle. These are integrated with the common elastic parameters, such as Young’s modulus and Poisson’s ratio, as part of the material properties. Additionally, certain boundary conditions and initial conditions are defined to ensure consistency with the realistic constraints of the multi-physical system. Also, these conditions are important as numerical convergence can be achieved only when they are properly defined and prescribed. The momentum balance and yield criterion are described by Equations (3)–(5).

$$\nabla \cdot \sigma = 0 \quad (3)$$

$$f = \beta_f I_1 + \sqrt{J_2} - \kappa_f \leq 0 \quad (4)$$

$$g = \beta_g I_1 + \sqrt{J_2} - \kappa_g \leq 0 \quad (5)$$

In Equation (3), σ is the stress tensor, and the equation describes the momentum balance for the stress tensor. The stress components are in Pa. Equations (4) and (5) describe the Mohr–Coulomb and Drucker–Prager models for shear failure. In the models, f is the yield function, and g is the plastic potential function. I_1 is the first invariant, Pa; J_2 is the second invariant, Pa. κ_f , κ_g , β_f , and β_g are coefficients for the failure envelope.

Equation (6) presents the coupling between stress and pore pressure.

$$\sigma = \sigma_0 - b(p - p_0)\mathbf{1} + C_{dr} : \varepsilon \quad (6)$$

where σ_0 is the initial stress, Pa; b is the Biot coefficient for the coupling between fluid flow and geomechanics, unitless; C_{dr} is a stiffness tensor, and the component is in Pa; and ε is the strain tensor, and the component is unitless.

2.2. Coupling Strategies

The basic form of the coupled flow and geomechanical problem is a fully coupled scheme. In this strategy, the pressure and stress results are solved in the same system. Porosity change is used to relate the solid deformation with porous media flow.

The porosity change with stress and time is described as follows:

$$\frac{\partial \phi}{\partial t} = \frac{b - \phi}{K_s} \frac{\partial p}{\partial t} + (b - \phi) \frac{\partial \varepsilon_v}{\partial t} \quad (7)$$

where ϕ is the rock porosity, unitless; and ε_v is the volumetric strain, unitless. Thus, the time derivative of porosity can be related to bulk volume and pore volume.

Also, as a modification to Equation (1), the velocity can be expressed as

$$u = u_{fs} + u_s \quad (8)$$

where u_s is the deformation rate, and u is the interstitial velocity, m/s. Thus, the solid deformation field and the porous media flow problem are fully coupled.

Based on Equations (6)–(8), the poromechanical relationship between total stress, effective stress, and pore pressure is established. Also, the effect of rock deformation and rock stiffness properties on porosity alteration and fluid flow is quantified by these equations.

Another strategy to solve the coupled problem is the use of the sequential coupling method. In this strategy, the two separate problems are not solved simultaneously in the same system. Therefore, the solution termination criterion becomes different. The error estimate is as follows:

$$err_{j,k} < tol_j \quad (9)$$

$$err_{j,k} = \max(e_{j,k}^N, e_{j,k}^S) \quad (10)$$

where j and k represent solution groups; err is error; and tol is tolerance.

After the completion of the computations, the obtained computational results are post-processed within the simulation framework. The output data are then visualized for analysis and interpretation purposes. This methodology provides a framework to study the complex, interconnected, and coupled behaviors between fluid flow and geomechanics in the porous media.

To establish the numerical system, finite element methods are used for the space discretization, and the finite difference method and the backward Euler method are used for the time discretization. Quadratic shape functions are used for the discretization of the porous media flow problem and the geomechanical problem. The numerical system is solved by a multifrontal massively parallel solver (MUMPS). The entire numerical solution strategy is also presented in a flowchart in Figure 1.

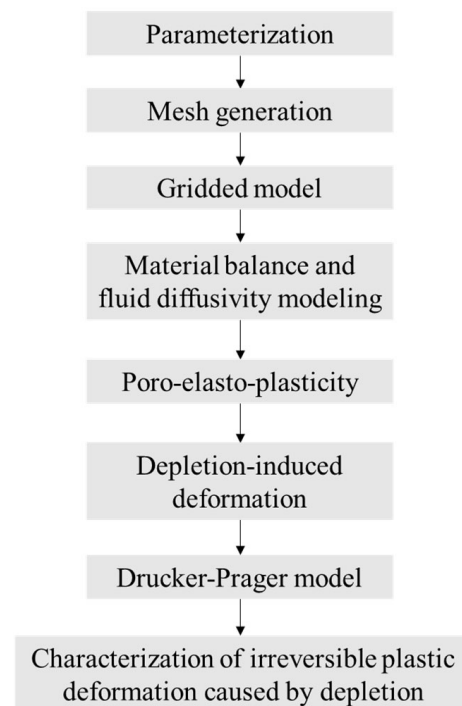


Figure 1. Solution strategy.

3. Numerical Simulation

The base case is established for the simulation of the coupled flow and geomechanics behaviors in a hydrocarbon-bearing reservoir where the formation strength is relatively low. The parameters used in this numerical study are adjusted from field cases with shallow depths and very soft formation rocks [29,30].

As shown in Figure 2, a 2D reservoir is established, and a wellbore with a length of 2 m is prescribed at the center of the model. The wellbore segment is located between $x = -1$ m and $x = 1$ m at $y = 0$ m. The 2D plane represents a vertical slice in a reservoir. The width and height of the 2D reservoir are 40 m. An unstructured grid is employed for the simulation. The modeling parameters are presented in Table 1. The model is focused on the reservoir surrounding the wellbore and is not extended to the full field due to the nonlinear nature of the numerical problem. The 2 m wellbore segment represents a producing interval for depletion. The porous media flow problem has four no-flow boundaries, and the geomechanical problem has roller boundaries and stress boundaries. They are presented in Equations (11)–(13).

$$\mathbf{v}_t \cdot \mathbf{n} = 0 \text{ on } \Gamma \quad (11)$$

$$\boldsymbol{\sigma} \cdot \mathbf{n} = \mathbf{t} \text{ on } \Gamma_1 \quad (12)$$

$$\mathbf{u} \cdot \mathbf{n} = 0 \text{ on } \Gamma_2 \quad (13)$$

where $\mathbf{v}_t$ is velocity of the fluid flow; $\mathbf{n}$ is the outward unit normal vector; $\mathbf{t}$ is the boundary traction; $\mathbf{u}$ is the displacement vector. Γ is the boundary for the domain of the fluid flow problem; and Γ_1 and Γ_2 are the traction boundaries and the roller boundaries for the geomechanical problem. The traction boundaries are at the right and the top, while the roller boundaries are at the left and the bottom.

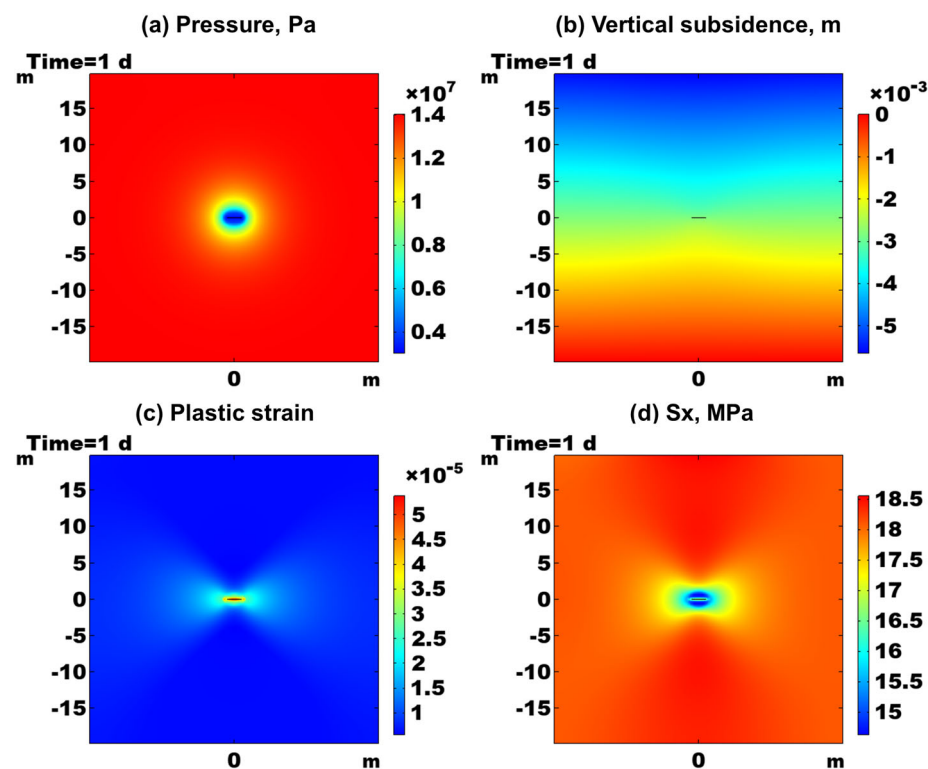


Figure 2. Two-dimensional distributions of (a) pressure, (b) subsidence, (c) plastic strain, and (d) S_x after 1 day of production in the wellbore.

Table 1. Modeling parameters for the base case.

Parameter	Value
Grid size	40 m by 40 m; x and y coordinates are both from −20 m to 20 m
Wellbore length	2 m
Horizontal well location	From (−1 m, 0 m) to (1 m, 0 m)
Initial pore pressure	14 MPa
Fluid density in the porous media	1000 kg/m ³
Dynamic viscosity	1 MPa-s
Permeability	1 mD
Porosity	0.15
Compressibility	1×10^{-10} 1/Pa
Rock Young's modulus	40 GPa
Rock Poisson's ratio	0.2
Initial horizontal stress	18 MPa
Initial vertical stress	20 MPa
Rock density	2600 kg/m ³
Rock cohesion	0.3 MPa
Internal friction angle	14°
Horizontal well production pressure	3 MPa
Production time	30 days

Note that the plasticity-related parameters in Table 1 are constant. This is the assumption employed in this numerical study as it does not consider the change in plastic models during the development of the hydrocarbon-bearing reservoir. This assumption is based on the rock mechanical properties of the weakly consolidated reservoir and the numerical convergence performance, and it may not be generalized if relevant reservoir geomechanical behaviors are different. The simulation time of 30 days is determined by multiple initial simulation attempts as it does not result in significant boundary effects, and the combination of the 40 m by 40 m model size and the 30-day simulation time is suitable for the prevention of boundary effects.

The general simulation results after 1 day of production are shown in Figure 2, and the results after 30 days of production are shown in Figure 3. They can provide the spatial and temporal evolution patterns of pressure, deformation (in terms of subsidence), plastic strain, and the x component (in the horizontal direction) of the total stress tensor.

The results in Figures 2a and 3a are discussed in the first place. After 1 day of production, the depletion induced by depressurization in the wellbore is noticeable at and around the wellbore. The lowest pressure magnitude is 3 MPa at the wellbore. The pressure depletion pattern is nearly elliptical as the depletion is achieved through the horizontal wellbore segment. However, the effect of pressure depletion is highly localized around the wellbore: pressure is insignificantly affected 5 m away from the wellbore. After 30 days of production, the majority of the 2D domain is disturbed by the depletion induced by the horizontal wellbore segment at the center. A contrast is that the depletion pattern is no longer elliptical as on day 1, and the pattern becomes more radial. It indicates that the depletion pattern evolves with production time. The far-field is also slightly depleted as the disturbance is propagated. It is noted that the depletion progresses relatively fast

during 30 days, as the production boundary condition prescribed at the horizontal wellbore segment is a Dirichlet boundary with constant pressure. It can induce relatively drastic depletion effects.

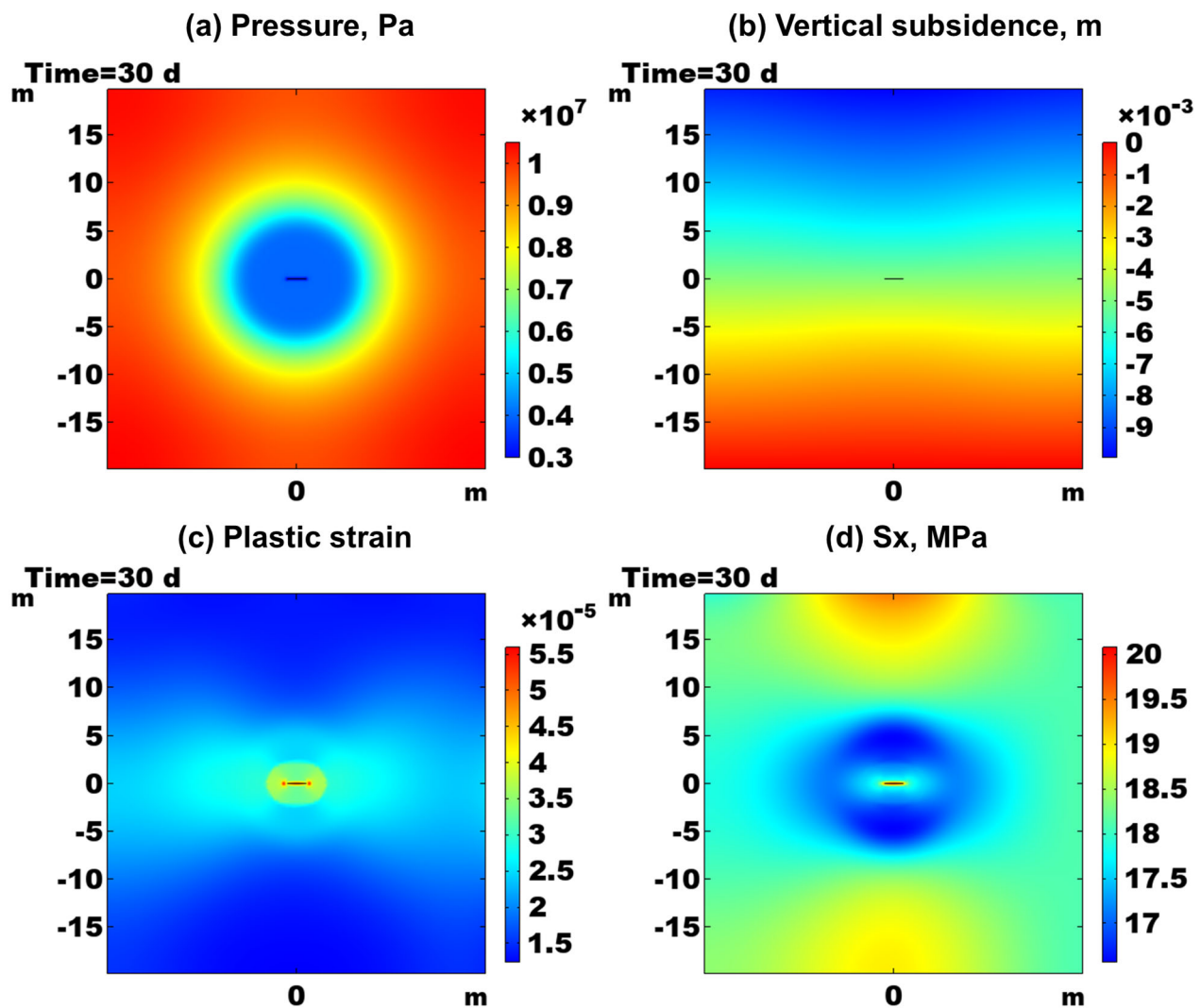


Figure 3. Two-dimensional distributions of (a) pressure, (b) subsidence, (c) plastic strain, and (d) S_x after 30 days of production in the wellbore.

The results in Figures 2b and 3b present the spatial and temporal evolution of depletion-induced subsidence in the vertical direction. On both day 1 and day 30, an upheaving pattern of the vertical subsidence profile is observed around 5 m below the center of the horizontal wellbore. A cause of this effect is the rock skeleton compaction induced by pore pressure drop. Since the boundary at the bottom is fixed, the induced compaction below the wellbore contributes to the upheaval around 5 m below the wellbore segment. For the area above the horizontal wellbore segment, as it moves closer to the center, the subsidence magnitude increases. The greatest subsidence on day 1 and day 30 is always observed at the top and the magnitude at the top increases from 5 mm to 9 mm.

In Figures 2c and 3c, the depletion-induced plastic deformation is quantified. The results represent production-induced formation damage in terms of irreversible and permanent deformation in the rock skeleton. After 1 day of production, the induced plastic regime is primarily at and near the wellbore. It is also noted that the areas near the two ends of the horizontal wellbore enter the plastic regime as well. This is because the pressure drop in these areas leads to changes in both normal stress components and shear stress components.

When the evolved stress state activates the failure criterion in Equations (4) and (5), the corresponding areas start to accumulate plastic strain. From day 1 to day 30, the greatest plastic strain magnitude increases from 5.2×10^{-5} to 5.5×10^{-5} . It indicates that, as long as the depletion is induced in the horizontal wellbore, instant formation damage (in terms of plastic deformation) is obtained, while the damage gradually evolves with time. The comparison between the plastic strain distributions on day 1 and day 30 indicates that the area experiencing plastic deformation expands with time: on day 1, the areas right above and below the center of the horizontal wellbore segment do not have significant plastic strains; on day 30, the same areas experience elevated plastic strain magnitudes. These results show that the depletion-induced formation damage can actually accumulate instantaneously as long as the production starts, and the depletion-induced plastic regime evolves drastically with time.

The temporal and spatial evolving patterns of S_x are shown in Figures 2d and 3d. It presents the change in the x component of the total stress tensor in the x direction. This stress component consists of both effective stress on rock skeletons and pressure saturated with reservoir fluids. After 1 day of production, the stress at and around the wellbore drops due to the significant pressure depletion. However, certain areas beyond the wellbore experience slight increases in S_x above the initial stress magnitude of 18 MPa. This is primarily because these areas do not experience instantaneous pressure drop caused by the horizontal wellbore depletion, while the depletion-induced rock skeleton compaction has impacted these areas. As a result, these areas are not drained while the rock compaction magnitude has already increased. The total stresses in these areas increase. After 30 days of horizontal well depletion, the areas surrounding the wellbore no longer have significant stress increases above 18 MPa. This is because the depletion during 30 days has effectively drained these surrounding areas, and the total stress drops below the initial value of 18 MPa. However, areas near the boundaries experience a slight stress increase. It indicates that, in these areas, the effect of depletion-induced rock compaction outweighs the effect of depletion-induced pressure drop, resulting in an increase in stress magnitude. This phenomenon is also related to the geomechanical boundary conditions: the bottom and the left are roller boundaries, and the top and the right are traction boundaries. Compared to 2D domains confined by four fixed/roller boundaries, this type of mixed setup allows for more rock compaction, which contributes to the increase in effective stress and, ultimately, the increase in total stress.

After the temporal and spatial characterization of pressure, subsidence, plastic strain, and S_x in the 2D domain, the evolutions of displacement and plastic strain at three monitoring points of (0 m, 0 m), (5 m, 0 m), and (10 m, 0 m) are plotted in Figure 4. At the three monitoring points, displacement (in both horizontal and vertical directions) gradually increases with time. It is noted that although the depletion is initiated at the center of the wellbore, it does not result in the greatest displacement magnitudes. The monitoring point closer to the right boundary (traction boundary with a constant compressive boundary stress) experiences the highest displacement profile. This is due to the fact that the traction boundary allows for rock compaction induced by pressure depletion. Since the constant depletion pressure is instantly prescribed at the wellbore at time 0, it induces instantaneous displacement (representing deformation) at and near the wellbore within the domain. This instantaneous response is also observed in the temporal evolution of plastic strain. Once the simulation of depletion starts, instant plastic strain starts to accumulate at the three locations, indicating that plastic damage in the weak formation can be generally induced by the exertion of a constant low production pressure at the horizontal wellbore segment. Since the depletion is the most drastic at the wellbore, the wellbore location experiences the greatest plastic strain magnitudes. It also implies that the wellbore location has the greatest

production-induced formation damage. For the two points away from the wellbore, the one closer to the well has the higher plastic strain profile, indicating that the effect of wellbore depletion on formation damage attenuates as it moves away from the wellbore. The lowest plastic strain profile is observed at the point close to the right boundary.

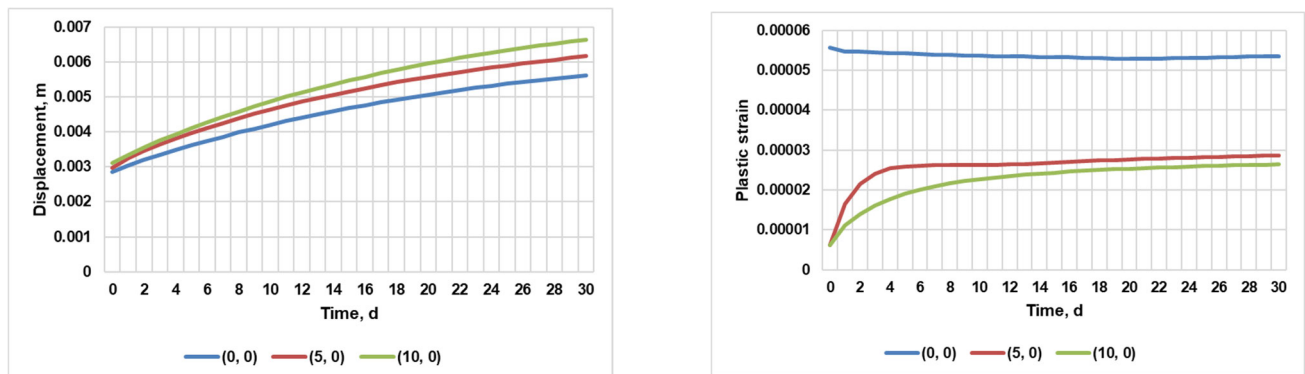


Figure 4. The temporal evolutions of displacement and plastic strain at three monitoring points of (0 m, 0 m), (5 m, 0 m), and (10 m, 0 m).

The production-related reservoir response is also discussed. In Figure 5, the cumulative production in the simulation time is compared against the average depletion-induced plastic strain and the average depletion-induced displacement in the reservoir. The two average values are calculated based on the plastic strain and displacement distribution results in the entire 2D domain. It is clear that the prolonged production contributes to the monotonically increasing plastic strain and displacement. The cumulative production is sustained at a relatively constant slope throughout the simulation time, while a decrease in production rate can be observed in the early days. Correspondingly, the slope of the average plastic strain curve is the highest at the beginning, while it starts to drop with production time. A similar trend is also observed in the average displacement curve. This indicates that the continuous production in the wellbore leads to a fast accumulation of plastic strain and depletion-induced displacement in the reservoir, while the accumulation becomes less progressive with time. The results in Figure 5 also indicate that the accumulation of plastic strain (irreversible rock skeleton damage) also has an impact on the drop in production rate (the slope of the cumulative production curve).

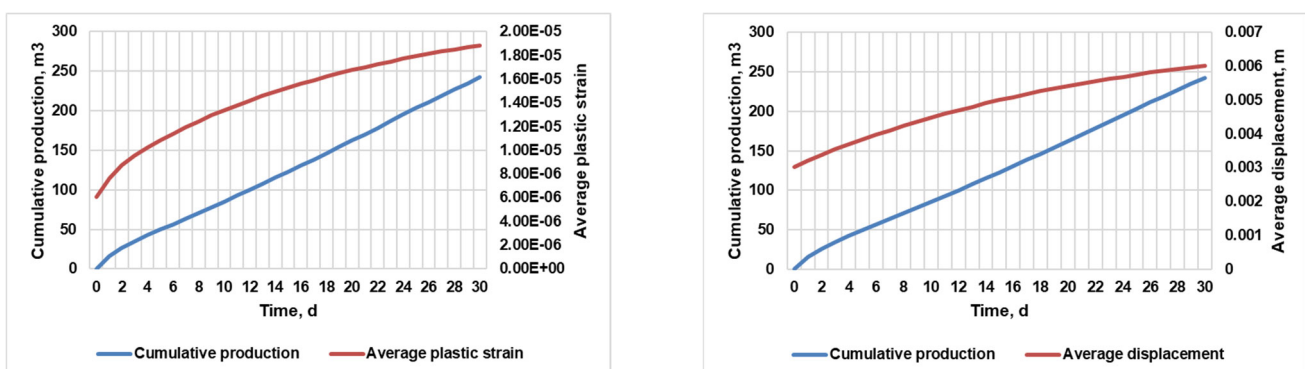


Figure 5. Cumulative production in the wellbore against depletion-induced plastic strain and displacement in the reservoir.

The production constraint is a key parameter to control during the exploitation of reservoir fluids. Apart from the production parameter in Table 1 (horizontal well production pressure of 3 MPa), another two production pressure values of 2 MPa and 4 MPa are

investigated so that the effect of horizontal well production on the elastoplastic reservoir response can be better understood. Geomechanics-related system responses and horizontal well production are reported and discussed.

In Figure 6, the depletion-induced subsidence after 30 days of production is plotted for three different production pressure values. Intuitively, the simulation scenario with a constant production pressure of 4 MPa leads to the lowest subsidence as the magnitude of production is the smallest. The scenarios with production pressure values of 2 MPa and 3 MPa both lead to greater subsidence distributions. The local subsidence above the wellbore center and the local upheaval below the wellbore center are also observed in the case with a 2 MPa production pressure, as in Figures 2b and 3b. However, compared to the base case, the 2 MPa production pressure scenario leads to more significant local subsidence and upheavals, which is also explained by the enhanced coupled flow and geomechanical effect exerted by a lower production pressure. Also, the roller boundary at the bottom of the domain always leads to 0 subsidence, and this is the effect of the boundary condition used in this study. Generally, the distribution patterns in the three scenarios are very similar, while the difference is noted in the subsidence magnitudes. This is caused by the same depletion boundary in the 2 m wellbore segment at the center of the domain.

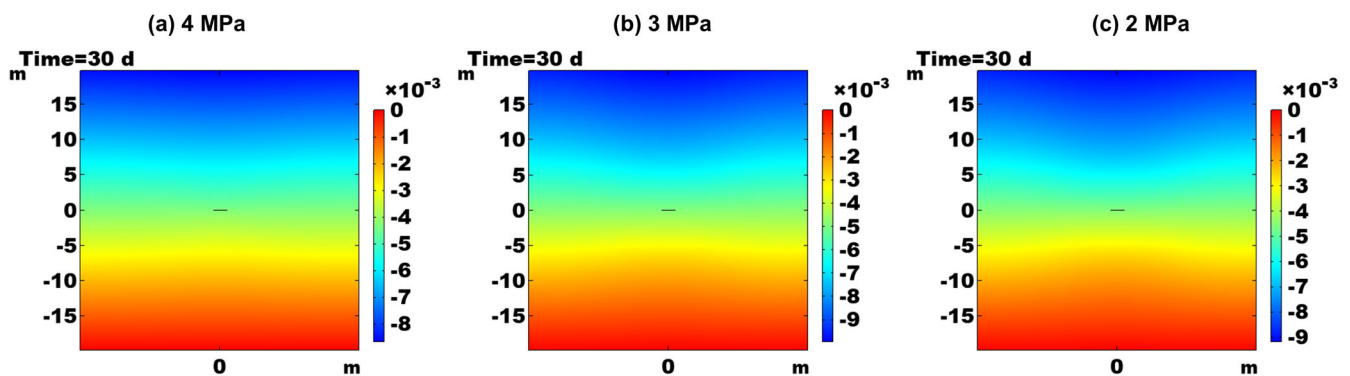


Figure 6. Depletion-induced subsidence after 30 days of production with a constant horizontal wellbore depletion pressure of (a) 4 MPa, (b) 3 MPa, and (c) 2 MPa.

Figure 7 then quantifies the temporal evolution patterns in these three scenarios at the monitoring point of (0 m, 20 m). Since the initial reservoir pressure is 14 MPa, the production pressure difference of 12 MPa corresponds to a production pressure of 2 MPa; the production pressure difference of 11 MPa corresponds to a production pressure of 3 MPa; the production pressure difference of 10 MPa corresponds to a production pressure of 4 MPa. Typically, as the production pressure difference increases, the subsidence at the top of the model also increases.

In Figure 8, the depletion-induced formation damage is quantified for the three investigated scenarios after 30 days of production. The damage is characterized by the geomechanical responses of plastic strain. The result in Figure 8b is from the base case, and it serves as a reference so that the effect of changing the production pressure to 2 MPa and 4 MPa can be better visualized. In the scenario with a 4 MPa production pressure after 30 days in Figure 8a, the induced plastic strain has lower magnitudes and smaller plastic regime areas. It is also like the result in Figure 2c, where the plastic strain is induced after 1 day with a production pressure of 3 MPa. This phenomenon indicates that the magnitude and extent of the plastic regime are both governed by the production time and production pressure in the horizontal wellbore. When the production pressure is decreased to 2 MPa, the plastic strain response becomes more significant, and the maximum plastic strain reaches 6×10^{-5} at and near the wellbore. Although the far-field is not drastically affected, the near-well area generally experiences greater plastic strain responses.

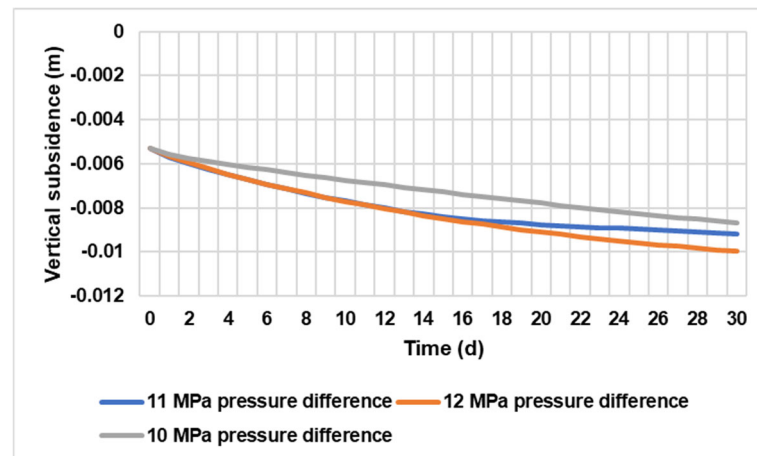


Figure 7. Depletion-induced subsidence during 30 days of production with a constant production pressure difference of 12 MPa, 11 MPa, and 10 MPa.

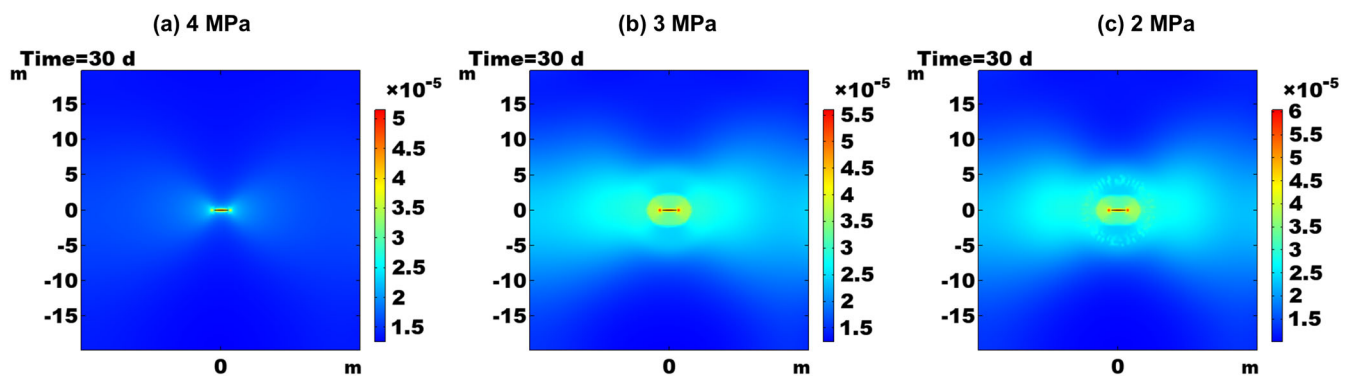


Figure 8. Depletion-induced plastic strain after 30 days of production with a constant horizontal wellbore depletion pressure of (a) 4 MPa, (b) 3 MPa, and (c) 2 MPa.

In Figure 9, the depletion-induced stress response is characterized by the three investigated scenarios. Specifically, the distribution of S_x is asymmetric with $y = 0$ m due to the consideration of gravity in the numerical model: the effect of gravity facilitates the downward porous media flow, and the induced coupled flow and geomechanical response tend to be stronger in the upper half of the reservoir domain. In addition, the distribution of S_x is generally symmetric with $x = 0$ m, while slight asymmetric patterns are observed, especially on day 30. This is caused by the asymmetric exertion of the boundary condition in the geomechanical problem. Another observation is that the magnitude of the induced S_x does not change monotonically with production pressure. Within the entire domain, the greatest S_x is recorded in the case with 3 MPa production pressure. In this response, total stress is determined by both pressure and effective stress. Pressure is governed by the fluid flow problem, and effective stress is governed by the depletion-induced geomechanical response. The decrease in pressure and the induced increase in effective stress jointly control the S_x response. An annular shape of S_x with the lowest S_x magnitude is observed in both Figure 9b,c. This pattern is caused by the fact that the pressure in this area is effectively depleted, leading to significant decreases in total stress. The upper and lower areas near the top and bottom of the domain have relatively high total stress values. The local increase in total stress is caused by the transmission of depletion-induced effective stress from the wellbore to the far-field areas. During this process, the pressure drop behavior is mainly localized around the wellbore (as in Figures 2a and 3a), which has a very limited impact on the pressure drop near the upper and lower boundaries. Thus, the total stress values in these areas can become greater than the initial stress values due to this effect.

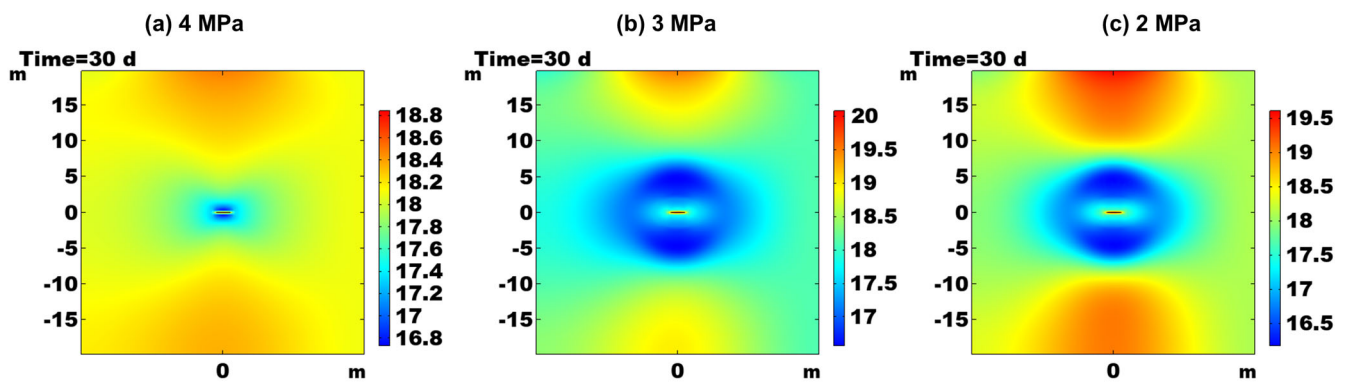


Figure 9. Depletion–induced S_x after 30 days of production with a constant horizontal wellbore depletion pressure of (a) 4 MPa, (b) 3 MPa, and (c) 2 MPa.

Another system response investigated is the correlation between the cumulative production profile and the production-induced plastic strain in the reservoir in the three cases. In Figure 10, the cumulative production profiles and the induced plastic strain against time are reported. Note that the induced plastic strain results are the average values over the entire 2D domain. The comparison of cumulative production results indicates that the lowest production pressure leads to the greatest productivity. It is also noted that the difference between the 3 MPa and 4 MPa scenarios is not as significant as the difference between the 2 MPa and 3 MPa scenarios. This means that dropping the production pressure to 2 MPa can effectively improve productivity, while the incremental plastic strain is not much greater than the 3 MPa case.

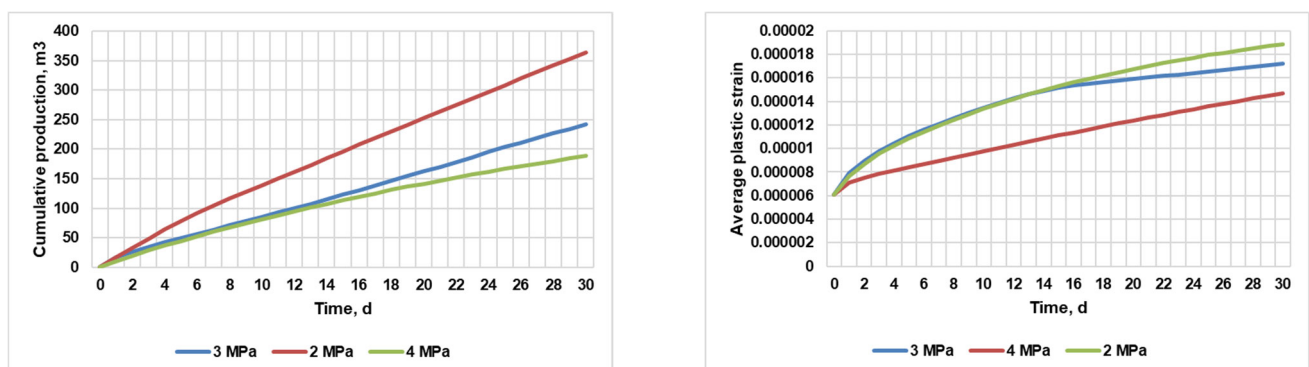


Figure 10. Cumulative production and average plastic strain in the reservoir induced by horizontal well production with a constant pressure of 2 MPa, 3 MPa, and 4 MPa.

4. Numerical Performance of the Simulator

4.1. Evaluation of the Solver Performance Using the Fully Coupled Strategy

To examine the performance of the solver in the numerical simulator, except for the base case simulation, another three simulation cases are also carried out considering different scenarios: (1) the simulation with a finer mesh, (2) the simulation with a greater depletion in the well, and (3) the simulation with stiffer reservoir rocks. Note that the fully coupled strategy simultaneously solves for pressure and displacement in the numerical system.

In the simulation case with a finer mesh, the generation of the 2D mesh is modified so that more elements are created. The minimum element size is 0.0075 m, and the maximum element size is 2 m. They result in 373,803 degrees of freedom and 10,660 domain elements in the mesh. As a comparison, the base case has a minimum element size of 0.015 m and a maximum element size of 4 m, which results in 94,887 degrees of freedom and 2774 domain

elements in the base case mesh. In the simulation case with a greater depletion in the well, the well production pressure is decreased from 3 MPa to 2 MPa. In the simulation case with stiffer reservoir rocks, a Young's modulus of 60 GPa is used, while the base case has a Young's modulus of 40 GPa.

In addition to the base case, the three different cases examine the solver with a greater nonlinear system (the case with a finer mesh with more nodes and degrees of freedom), a more rapid system response, and more physical changes (the case with a lower well production pressure or a greater depletion), and a greater stiffness in the solid mechanical field (the case with a greater reservoir rock stiffness).

Figure 11 shows the comparison of the solver parameters of four different cases during the simulation time of 30 days. Compared solver performance parameters include the residual evaluation number, the Jacobian evaluation number, the solution evaluation number, and the linear error. The residual evaluation number, the Jacobian evaluation number, and the solution evaluation number indicate the times the solver computes during the convergence attempt, and higher numbers indicate more attempts and slower convergence rates. The linear error is the error in the matrix calculation in a certain linear system, and a lower value indicates better solution accuracy during the convergence attempts.

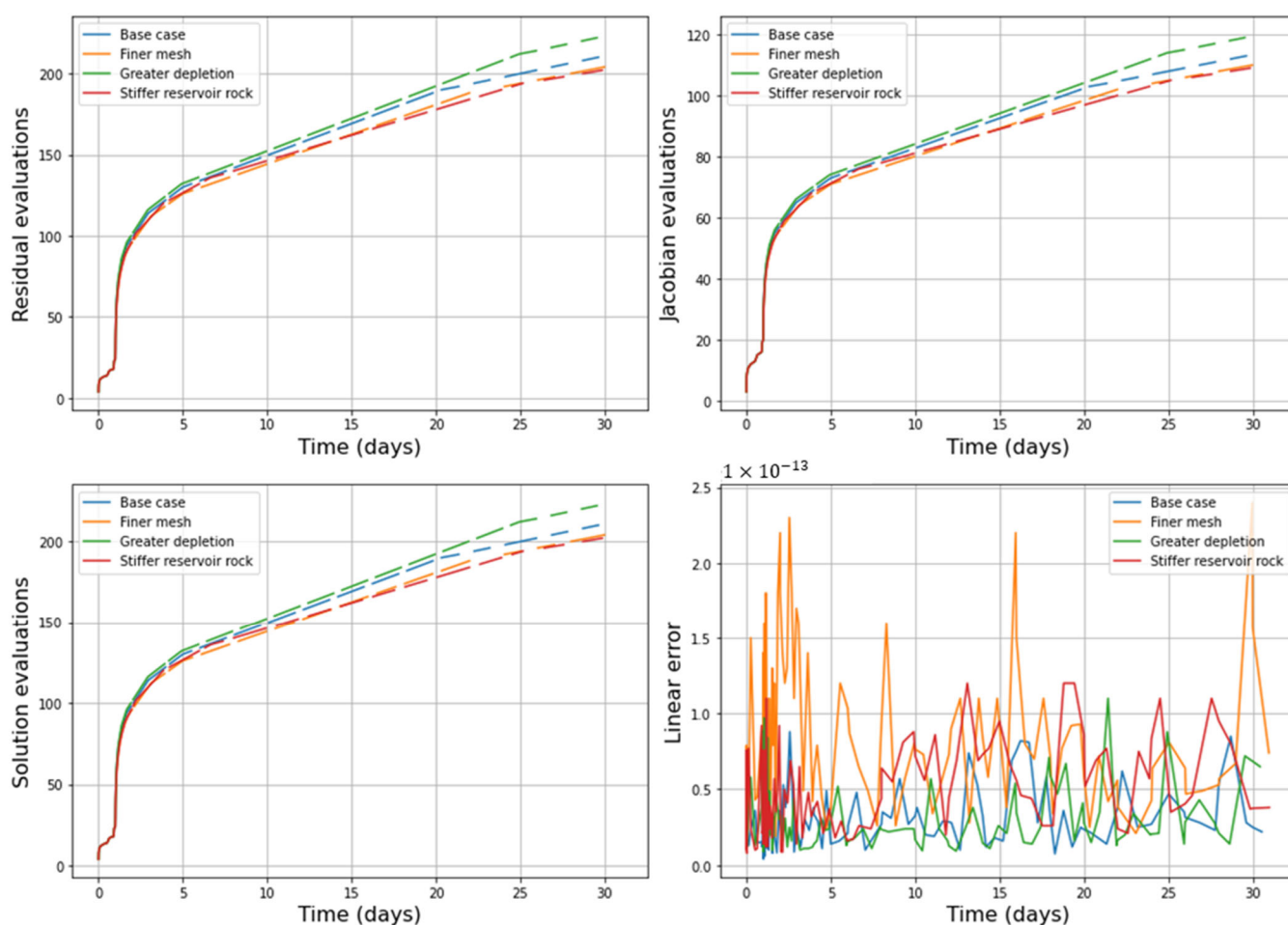


Figure 11. Comparison of solver performance of four different cases. The four cases are the base case, the case with a finer mesh, the case with a greater depletion magnitude in the well, and the case with stiffer reservoir rocks. Compared solver performance includes the residual evaluation number, the Jacobian evaluation number, the solution evaluation number, and the linear error.

In the solver performance results, the sudden increases in residual, Jacobian, and solution evaluations are obtained in the first 2 days of simulation. This means that it is

hard to obtain convergence at this time period, and multiple solver convergence attempts are made. After 5 days, since the system response becomes relatively stable, residual, Jacobian, and solution evaluations evolve with simulation time in nearly linear patterns. After 25 days, the slopes of these three curves start to decrease, indicating that the system response becomes even more stable near and at the end of the simulation time. The linear error curves oscillate significantly. This is because each matrix solution in the linear system converges with different errors. Although these errors are very low, they oscillate as the matrices at each solution vary.

In the residual evaluation, Jacobian evaluation, and solution evaluation curves, the simulation case with the greater depletion always has the highest profiles. This indicates that the solver convergence is negatively affected by the decrease in well production pressure. This is intuitive as a greater depletion results in stronger system responses in the geomechanical and porous media flow fields, and the solver must make more attempts to trial the intermediate solutions and achieve convergence. These three curves of the base case have the second-highest profiles. When using a finer mesh, the convergence becomes faster as the profiles of the three curves become lower. This is because a finer mesh indicates smaller element sizes, and the gradients over the 2D domain become more accurate during the solution. The simulation case with stiffer reservoir rocks also leads to low residual evaluation, Jacobian evaluation, and solution evaluation. This is related to the nature of the coupled flow and geomechanical problem: well depletion reduces pore pressure in the reservoir rock, and the solid rock skeleton becomes more compressive, and a stiffer rock slows down this process. As a result, the changes in pore pressure and displacement caused by poromechanical effects become weaker in the solution to the coupled system. Thus, the convergence of the solver is improved.

In the linear error results, highly oscillatory curves are obtained, and it is harder to obtain certain monotonic patterns. However, it can be observed that the largest linear error magnitudes are in the simulation case with the finer mesh. This can be explained by the fact that this case has the most nodes and degrees of freedom, indicating that the solution vector has the largest size among all the four simulation cases. Since the linear error here is evaluated over the entire solution vector, a larger vector can have greater overall errors.

4.2. Evaluation of the Solver Performance Using Different Numerical Strategies

The previously discussed base case uses a multifrontal massively parallel solver (MUMPS) and a fully coupled mechanism to solve for dependent variables. The solver is essentially a direct solver, and the governing equations are solved simultaneously in one system. In numerical solutions, it is also possible to utilize iterative solvers and sequential coupling techniques to reduce the numerical system to be solved. However, using iterative solvers and sequential coupling strategies can reduce the solver convergence rate and the numerical stability in certain cases. Therefore, various numerical solution strategies can lead to different simulation results and solver performance.

This section provides a comparison between different coupling and solution strategies, which can also provide a quantitative understanding of the effects of numerical strategies on the solver performance. In this section, four cases are discussed: (1) the base case with a direct solver (MUMPS) and a fully coupled strategy; (2) the case with an iterative solver (GMRES) and a fully coupled strategy; (3) the case with a direct solver (MUMPS) and a sequential coupling strategy; (4) the case with an iterative solver (GMRES) and a sequential coupling strategy.

Figure 12 shows the comparison of the residual evaluation number, Jacobian evaluation number, solution evaluation number, and linear error over time. Similar to the previous observation, all three evaluation parameters drastically increase at the beginning of the

depletion. It is attributed to the significant physical changes, especially the depletion-induced near-well plasticity in the first two days.

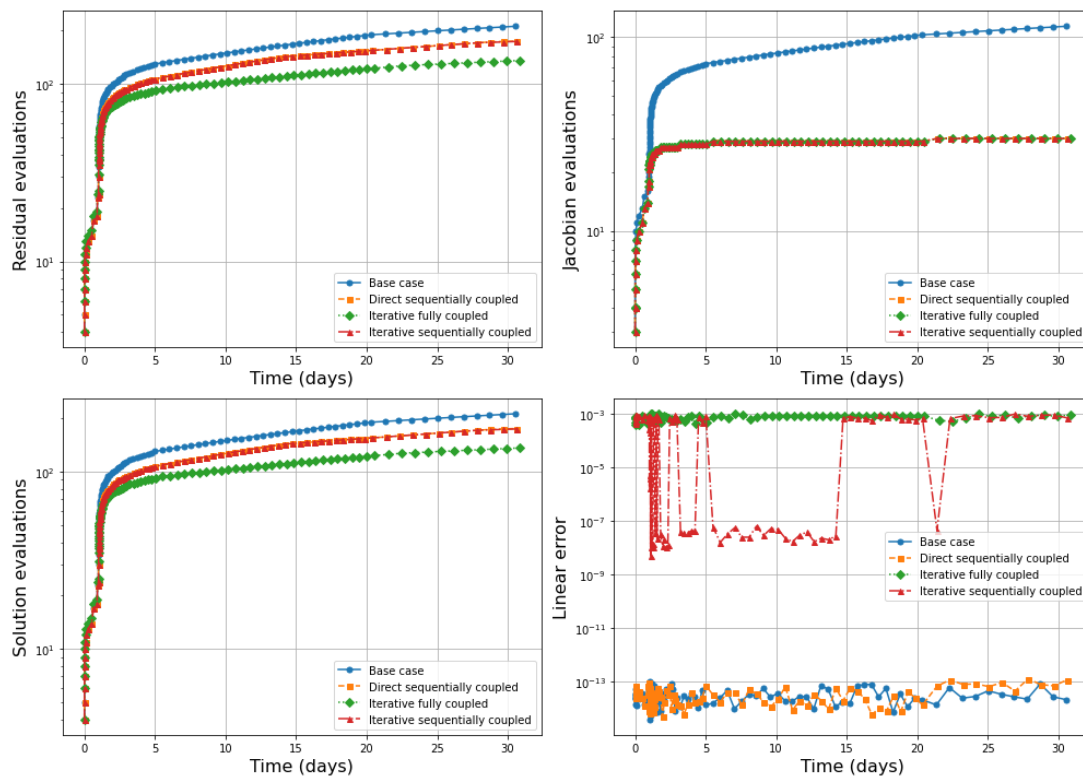


Figure 12. Comparison between solver performance parameters for the four cases: the base case with a direct solver and full coupling, the case with a direct solver and sequential coupling, the case with an iterative solver and full coupling, and the case with an iterative solver and sequential coupling.

Overall, the base case using a direct solver of MUMPS and the full coupling strategy leads to the greatest evaluation numbers. This indicates that the nonlinearity and complexity in the coupled problem increase the number of attempts of the direct solver to reach convergence. However, the base case has the lowest linear error profile, indicating that the direct solver can lead to accurate solutions over time. The case using an iterative solver of GMRES and the sequential coupling strategy has the lowest evaluation curves, indicating that this combination of strategies leads to faster convergence in the numerical solution. However, it results in high linear errors, implying a tendency toward inaccurate solutions. In the numerical system, it manages to converge with accurate solution approximations. The case using a direct solver of MUMPS and the sequential coupling strategy has intermediate residual and solution evaluation numbers and low Jacobian evaluation numbers and linear errors. This means that this combination can preserve accuracy and maintain relatively fast convergence rates. Its performance is similar to that of an iterative solver of GMRES and a sequential coupling strategy. The only difference is that the other case has greater linear errors over time.

Based on the comparison, it can be concluded that the selection of the solver type and the coupling strategy can affect the convergence and accuracy of the coupled flow and elastoplastic simulator. Although the direct solver with a full coupling strategy takes more attempts to converge, its linear errors are kept at a low level. In a full coupling strategy with an iterative solver, the system converges fast while the associated linear errors are high. These results indicate that the simulator performance is jointed and governed by the multi-physical fields (mass balance and momentum balance in this study) and the selection of solver types and coupling strategies.

4.3. Recommendation of Well Placement

In addition to the solver performance, the numerical simulation results can be used as a reference for the optimization of production strategies. Based on the results, the evolution of pore pressure depletion and effective stress alteration can be observed within the entire 2D domain, indicating that the placement of the horizontal wellbore in the center can lead to overall system responses. That is to say, for the setup in this numerical study, the domain can be effectively drained. Another important consideration is the depletion-induced formation subsidence. The greatest subsidence can reach around 0.5 cm in this relatively soft formation 20 m above the wellbore. This consideration helps optimize the prediction of reservoir deformation and well placement vertically.

5. Conclusions

This study presents a coupled simulator that considers depletion and depletion-induced pressure and geomechanical changes in the reservoir. New observations are obtained in this numerical study regarding the effect of depletion-induced plasticity, horizontal wellbore productivity, and its quantified influence on the solver performance. Also, the coupling strategies of full and sequential coupling and the solver selection of direct and iterative solvers are all analyzed in terms of numerical efficiency. The solution strategy proposed in this study is efficient and accurate for solving the coupled behaviors in weakly consolidated reservoirs in the specific cases presented in this study.

In conclusion:

- (1) The drastic system response at the beginning of depletion leads to significant increases in the solver evaluation numbers on its way to reaching convergence. This effect is largely magnified when the near-well reservoir region enters plasticity. When the depletion-induced system response becomes stable, it becomes easier for the solver to reach convergence;
- (2) Depletion-induced pore pressure change, effective stress change, plastic deformation, and formation subsidence are quantified by the model. Highly coupled behaviors are captured in the spatial and temporal evolution results. Direction-dependent and very non-monotonic behaviors are observed. Specifically, after 30 days, the subsidence can reach 5 mm to 9 mm; the plastic strain can reach 5.2×10^{-5} to 5.5×10^{-5} ; the total stress can become either greater than or lower than the initial stress magnitude due to the poromechanical effect;
- (3) Solver types and coupling strategies can have impacts on the solver convergence and efficiency. The use of the direct solver MUMPS is suggested if the linear error needs to be kept at a very low level, while its usage is not suggested if fast convergence is the priority. In contrast, the iterative solver GMRES can lead to relatively fast convergence;
- (4) In the coupled porous media flow and elastoplastic problem, the full coupling strategy can always lead to low linear errors during the numerical solution. The use of the sequential coupling strategy results in relatively higher linear errors. In the specific problems simulated in this study, these strategies can all lead to convergent and accurate numerical solutions.

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