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A coupled geomechanical reservoir simulation analysis of CO_2 – EOR: A case study

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Abstract. Currently, there is a great interest in the coupling between multiphase fluid flow and geomechanical effects in hydrocarbon reservoirs and surrounding rocks. The ideal solution for this coupled problem is to introduce the geomechanical effects through the stress analysis solution and implement an algorithm, which assures that the equations governing the flow and stress analyses are obeyed in each time step. This paper deals with the implementation of a program (FORTRAN90 interface code), which was developed to couple conventional reservoir (ECLIPSE) and geomechanical (ABAQUS) simulators, using a partial coupling algorithm. The explicit coupled hydro-mechanical behavior of Iranian field during depletion and CO_2 injection is studied using the soils consolidation procedure available in ABAQUS. Time dependent reservoir pressure fields obtained from three dimensional compositional reservoir models were transferred into finite element reservoir geomechanical models in ABAQUS as multi-phase flow in deforming reservoirs cannot be performed within ABAQUS. The FEM analysis of the reservoir showed no sign of plastic strain under production and CO_2 injection scenarios in any part of the reservoir and the stress paths do not show a critical behavior.

Keywords: coupled; hydro-mechanical; FEM; plastic strain; stress path

1. Introduction

Reservoir production and injection causes changes in the stresses and strains within the reservoir and surrounding rocks. Such changes give rise to the so-called geomechanical effects, namely the effects observed in the system due to the change in pore pressure, characteristic of the extraction and injection of fluids in porous media. In a recent book, Herwanger and Koutsabeloulis (2011) illustrate some of these effects: subsidence of the surface or seafloor, slipping among stratigraphic planes, reactivation of faults, loss of seal integrity, compaction and expansion of the reservoir.

Enhanced oil recovery using carbon dioxide (CO_2-EOR) is a method that can increase oil production beyond what is typically achievable using conventional recovery methods while facilitating the storage of carbon dioxide (CO_2) in the oil reservoir. In principle, when CO_2 is

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injected in an oil reservoir, it mobilises oil not extracted by conventional methods either by interacting physically and chemically with the oil and the reservoir rock, or by regulating the reservoir pressure.

Past enhanced oil recovery efforts have shown that, geologic sequestration of CO_2 is a technically viable means of reducing anthropogenic emission of CO_2 from accumulating in the atmosphere (Solomon 2006, Preston *et al*. 2005, Wright 2007). Security of storage is one of the most important concerns with the long term injection of CO_2 in underground formations. Injection of CO_2 induces stress and pore pressure changes which could eventually lead to the formation or reactivation of fracture networks and/or shear failure which could potentially provide pathways for CO_2 leakage through previously impermeable rocks (Goodarzi *et al*. 2010, 2011). Therefore geomechanical modeling plays a very important role in risk assessment of geological storage of CO_2.

More recently, studies of actual CO_2 injection sites, such as the In Salah CO_2 storage project in Algeria, have shown that significant geomechanical changes may indeed occur, depending on the injection pressure and site specific geomechanical conditions (e.g., Rutqvist *et al*. 2010, Bissell *et al*. 2011, Verdon *et al*. 2011, Zhou *et al*. 2010). The importance of geomechanics has recently become more widely recognized as the possible magnitude and extent of pressure disturbance associated with large-scale CO_2 storage operations have become more apparent (Zoback 2010).

The numerical analyses that consider the geomechanical effects should consider the phenomena in a coupled way. According to Settari and Vikram (2008), coupled problems in geomechanics must take into account the interrelationship of hydraulic, thermal and mechanical variables in the solution of differential equations involved in each particular problem. In general, the mechanical problem is usually addressed by the finite element method and the flow problem by the finite difference method.

During CO_2 sequestration different physical processes that involve multiphase and multi-component fluid flow in a geologic system take place. In order to study the mechanical deformations during CO_2 sequestration, numerical modeling of fluid flow through porous medium coupled with a geomechanical analysis of the medium at different pore pressure distributions (Rutqvist *et al*. 2002, Settari and Mourits 1998, Settari and Walters 1999, Thomas *et al*. 2003, Vidal-Gilbert *et al*. 2009, Lynch *et al*. 2013, Lamy-Chappuis *et al*. 2014) is required. This coupling can be achieved either by a fully or partially coupled numerical simulation.

In the fully coupled simulation approach, the fluid flow through pores and elasticity calculations are carried out simultaneously. (Lewis and Sukirman 1993, Tortike and Farouq Ali 1987, Xikui and Zienkiewicz 1992) have presented formulations for the fully coupled approach, and (Gutierrez and Lewis 1998) have presented a fully coupled reservoir simulator. However, the complexity of a fully coupled physical system results in very high computational costs and thus the applicability of the fully coupled approach is limited (Inoue and Fontoura 2009).

Partial coupling approaches are based on an external coupling between separate numerical simulations. In general, a conventional reservoir simulator based on the finite difference (FD) method is used to process the fluid flow problem and a finite element (FE) model is used to solve the stress equilibrium equations, respectively. This method benefits from the latest developments in each field, has lower computational costs and hence the best simulator available can be employed. In general, partial coupling can be divided into two families: explicit and iterative coupling.

In the explicit coupling approach, a reservoir simulator carries out fluid flow calculations at each time-step, however stress-displacement calculations are only carried out on selected time-steps, the choice of which depends on the variation in the accessible pore space due to the change in pore pressure, i.e., if the variation in pore space between time-steps is not significant, then geomechanical calculations may be ignored. Angus *et al*. (2015) applied an explicit coupling scheme to the Valhall reservoir using subsidence to calibrate the geomechanical model.

Once the change in pore space is considerable, the stress-displacement analysis is carried out (Minkoff *et al*. 2003, Settari and Walters 1999, Segura *et al*. 2011). This approach can significantly reduce the computation cost of the coupled analysis through reduced number of stress-displacement simulation runs (Dean *et al*. 2006). In the iterative coupling approach the two simulators are coupled at each time-step.

The present coupled reservoir simulation study utilizes a reservoir model for simulation of fluid flow through porous media using the commercial fluid flow simulator ECLIPSE 300 (ECLIPSE 2010) and the optimized finite element discretization using the commercial finite element solver ABAQUS (ABAQUS 2010) for the geomechanical analysis of rock deformation that is caused by the pore pressure difference associated to enhanced oil recovery using carbon dioxide (CO_2-EOR). First, a description of the problem and of the general methodology has been given by providing an overview of the workflow that has been developed. Next, the application of this approach to a realistic test case has been illustrated. Finally, we conclude with a discussion on the obtained results and the perspective for future work.

2. Geological background of studied area

The studied oil region is located in south west of Iran. The region has little folding, with numerous reservoirs. Sequence stratigraphy of the region, respectively, from top to the target depth includes Aghajari, Gachsaran, Asemari, Pabdeh, Gurpi, Ilam, Lafan, Sarvak, Kazhdumi, Darlyan, Gadvan, Fahliyan and Garau.

In this study Sarvak formation was the target reservoir. This reservoir is an anticline structure directed to north-south with no exposure and it was detected by geophysical (seismic) survey. No major faults and fractures have been reported in this reservoir.

The Sarvak formation (Cretaceous, thick 650-1100 m) is a thick carbonated unit that was deposited in ‘Neotethys southern margin of Zagros area. It is one of the most important hydrocarbon horizons in Iran. Laboratory and field observation lead to recognition of four facies environments: open marine, shale, and lagoon in coastal area of Fars, Khuzestan and Lurestan. The lower lithostratigraphic limit of Sarvak Formation, which is conformable and gradational, overlies the Kazhdumi Formation. Upper lithostratigraphic limit of that is secant with Ilam-Lafan Formation (Fig. 1). Also thickness and layers slope of Sarvak formation is approximately constant.

The reservoir depth is about 2700 m and has a thickness of approximately 110 meters. Limestone is the dominant rock type in this reservoir and also upper structure. The reservoir geometry has been indicated by five wells drilled in the structure and the information related to the distance between the wells and connection depth of them to Sarvak formation.

The reservoir upper surface was sketched by introducing the intersection points from wells and the formation in Surfer software. Finally, the reservoir geometry was determined by its upper surface and the thickness of layers.

The mechanical properties and initial stress profile is required to be added to the geomechanical model and coupled with the flow model in order to be able to study the mutual effect of pressure and stresses and the resulting effect on integrity and injectivity. The reservoir rock mechanical parameters including, uniaxial compressive strength, young modulus and poisson ratio was obtained from Dipole sonic imager (DSI) logs, laboratory tests and empirical relationships. The reservoir young modulus, poisson ratio and uniaxial compressive strength are 25 GPa, 0.20 and 60 MPa respectively.

Also the reservoir Initial pressure is around 4100 psi. Other characteristics of the reservoir layers are given in Table 1.

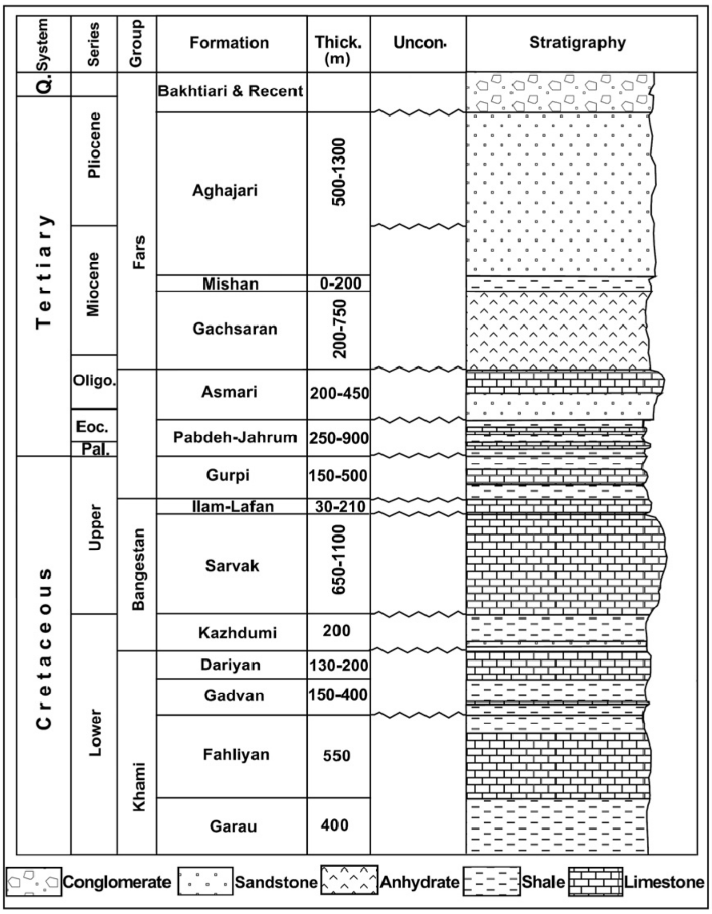

Fig. 1 Sequence Stratigraphy of the studied region (Alavi 2004)

Table 1 Mechanical properties of the reservoir layers

Layer	Thickness (m)	Porosity	Permeability (md)	Water saturation (%)	Density (Kg/m^3)
1	5	0.01	2	0.9	2600
2	20	0.1	40	0.15	2600
3	30	0.14	40	0.2	2600
4	60	0.1	40	0.45	2600
5	5	0.01	2	0.9	2600

3. Construction of the flow and geomechanical model

3.1 Reservoir modeling

The results of the standard reservoir studies carried out for the management of the field production provide part of the inputs necessary for a geomechanical finite element analysis. The typical workflow of a reservoir study consists of a "static" study and a "dynamic" study.

The "static" model includes the detailed reconstruction of the geological structure of the reservoir (e.g., the shape of the layers and the trend of the faults), the definition of the mineralized volumes and the attribution of the petrophysical parameters (initial porosity and permeability) as a function of the location. The result of a static study is a 3D model of the reservoir and of the surrounding region, describing all its geological, lithological, stratigraphical and petrophysical aspects. Fig. 2 shows the geometry of the oil reservoir, where the number of reservoir grid blocks in X, Y and Z directions is 25, 70 and 5 respectively. So the reservoir is divided into a number of 8750 cells in ECLIPSE software.

The "dynamic" model is built with the flow simulator (ECLIPSE 300), which is a fully implicit, multi- phases, 3D finite difference code. The dynamic model takes as input all the information of the static model and, by introducing a series of additional parameters regarding the characteristics of the fluids, the rock and the well system, provides the information required for the field management, such as the dynamic reserve evaluation injection and the production profiles as a function of the development scenarios. As an example, in Fig. 3 the finite difference discretization of a dynamic model for the oil field is shown.

The dynamic model provides as output sets of data that are used in the geomechanical finite element simulation: the grid discretization of the reservoir and of the surrounding areas; the initial values of porosity and permeability; the evolution of the fluid pressure as a function of space and time. As explained in detail in the following section, all these information are converted with an interface code and used to build the ABAQUS FE model.

3.2 geomechanical modeling

A FORTRAN90 interface code that provides an automated link between the flow model and

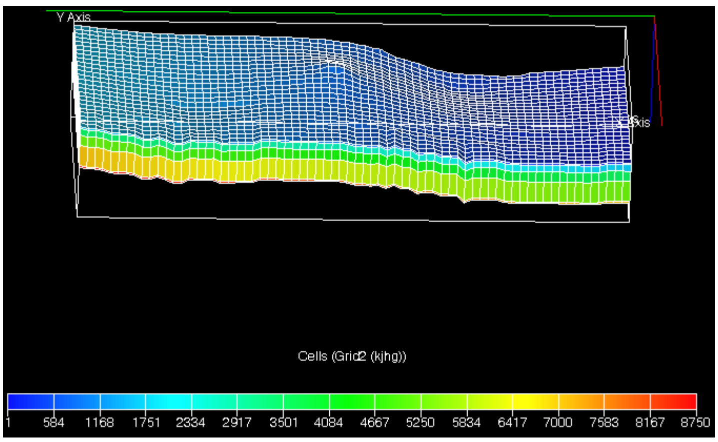

Fig. 2 3D static model: representation of a geological horizon

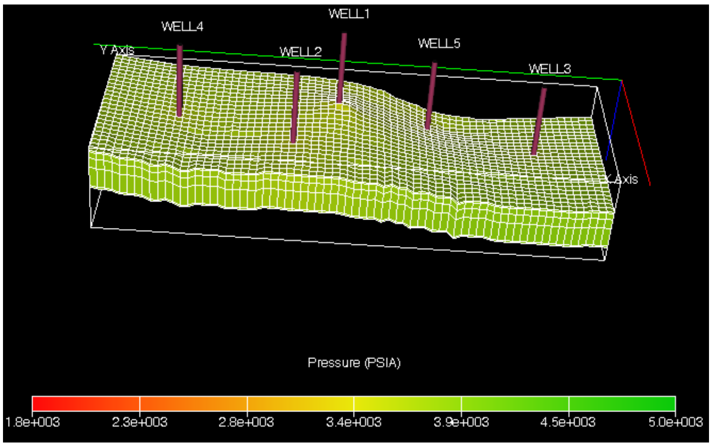

Fig. 3 Flow model: grid discretization, well system and initial pressure distribution

ABAQUS has been developed. Files with the results of the flow simulation are processed and the needed information is re-written as input files to run ABAQUS.

The geometrical information of the ECLIPSE 3D corner point grid are directly extracted from the relevant output files of the flow model and processed to build the FE mesh in the reservoir region. This approach allows for the definition of a FE model which is fully consistent with the reservoir FD model.

Another important point is related to the number of cells originally describing the flow model. In some cases the huge number of FD grid cells, and the fact that the FE final grid must also include over-, under-, and side-burden, makes it impossible to maintain the same discretization. The interface code that generates the FE grid allows for a merging of grid cells in the vertical and in the horizontal direction to reduce the number of dof (degree of freedom). The FD grid, however, is the result of a detailed study of the field that considers information coming from seismic surveys, well data, geological knowledge of the area and reservoir development program. The vertical discretization is of upmost importance to correctly describe the material properties of the porous medium and the pressure drawdown. Therefore, when a vertical merging is needed, a comprehensive analysis must be executed in order to lump layers with similar properties and CO_2-EOR histories.

The result of this process is a FE grid which discretizes the field region, including all the mineralized area and the surrounding aquifers if any. This model is then extended in the horizontal direction to describe the side-burden, up to the surface to describe the over-burden and down to a fixed basement to describe the under-burden. This external part of the grid, needed to correctly simulate the geomechanical behavior of the system, is automatically built by the interface code, provided that the final model size is given. The element type attributed to the reservoir regions is 8-node brick stress/displacement/pore pressure (C3D8P), while 8-node brick stress/displacement (C3D8) is assigned to the external regions.

3.3 Prescribed conditions

The initial effective stresses are generated in the ABAQUS subroutine, SIGINI.

The initial geostatic stress field must be in equilibrium with the applied loads and boundary conditions. Ideally, the loads and initial stresses should exactly equilibrate and produce zero deformations. This state is obtained performing an initial ABAQUS analysis fixing all displacements degree of freedoms. Calculated reaction forces written to the ABAQUS output file are then used to create nodal point forces, which are applied in the first step of the actual ABAQUS analysis.

The pore pressure depletion and injection history within the reservoir is transferred from the ECLIPSE reservoir model to ABAQUS utilizing the user subroutine DISP. A file containing the pore pressure in each ECLIPSE block is read for each time step analyzed by ABAQUS.

The initial porosity distribution is transferred from the ECLIPSE reservoir model to ABAQUS utilizing the user subroutine VOIDRI for reading initial porosity in ABAQUS. The initial void ratio e_0, defined as the ratio between the pore volume and the solid volume, is related to the porosity n through: $e_0 = n/(1-n)$.

The boundary condition for the fluid flow model is that there is no flow across the boundary of the reservoir. The constraints for the geomechanical model are as follows. The right, left, front and back sides of the model are fixed in the *x*-direction and *y*-direction so there would be no displacement in the *x* and *y* directions. The bottom side of the model is fixed in all directions and the top of the model is free to move in all directions.

4. Results and discussion

The reservoir information was used to build the “dynamic” model. As shown in Fig. 3 the reservoir was targeted by five wells. Production conditions and restrictions are as follow:

- Oil production rate of each well is 3,500 stb/day (standard barrels per day) and the minimum bottom hole pressure is 1450 Psi.
- Oil production of each well will be terminated if the well production rate is less than 500 stb/day or GOR (reservoir gas and CO_2 oil ratio) is greater than 20 mscf/stb.

Also production and injection strategies are as:

Oil production of all wells was started at 1 January 1997. If any of the wells production was terminated (because of mentioned restrictions) the well will be used as a CO_2 injection well. Injection strategy involves the injection of 200,000 mscf/day (Million standard cubic feet per day) and a maximum bottom hole pressure of 7000 Psi

The reservoir production rate is shown in Fig 4. As shown, at the beginning, each well production rate is 3,500 stb/day. Because of reservoir pressure reduction, the oil production rate will be decreased gradually. After about 3410 days from the start of production the production rate of well No.1 falls under 500 stb/day, so its production will be halted and it will be prepared for CO_2 injection rate of 200000 mscf/day.

After CO_2 injection the reservoir pressure gradually increased and so the rate of production in four other production wells will increase. Due to increased GOR > 20 mscf/stb, the production of well No. 5, well No. 4 and well No. 3 will be terminated at 5985, 12125 and 14397 days after production beginning respectively. Also well No. 2 production will be terminated at 6695 days after production beginning because the well oil rate is below limit (500 stb/day). Rate of reservoir pressure change is shown in Fig. 5.

Due to the difference between the reservoir pressure and pressure at the bottom of injection well, CO_2 flow path is from bottom of the injection well to around it. In spite of production from

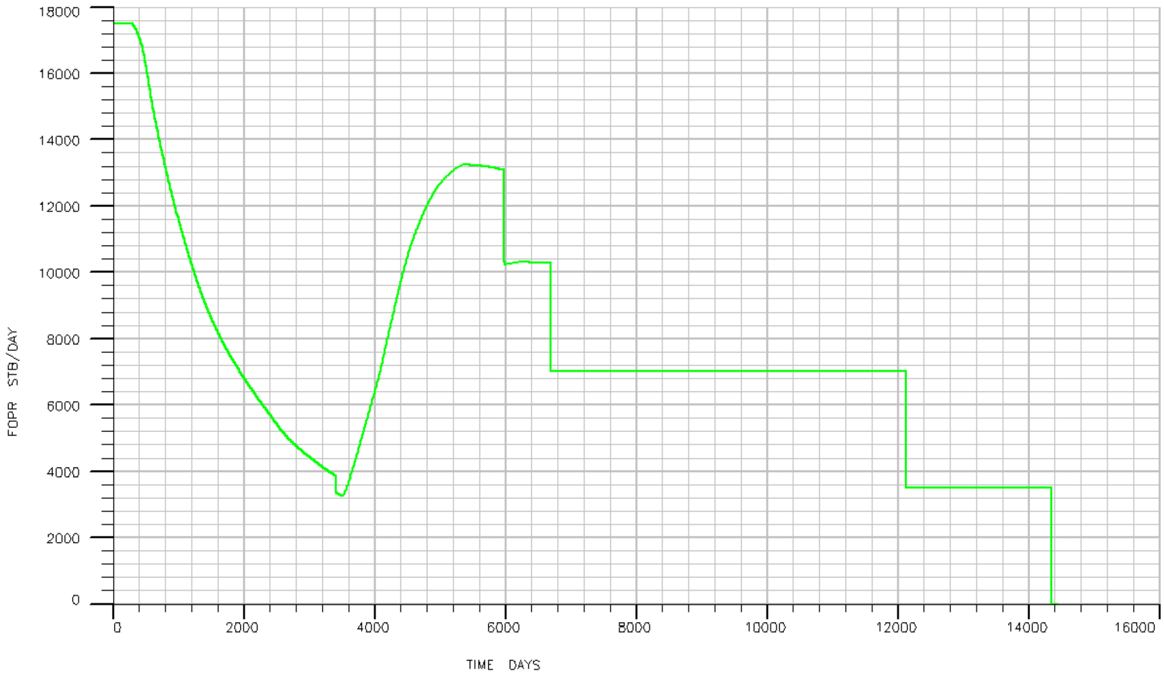

Fig. 4 Reservoir oil production rate

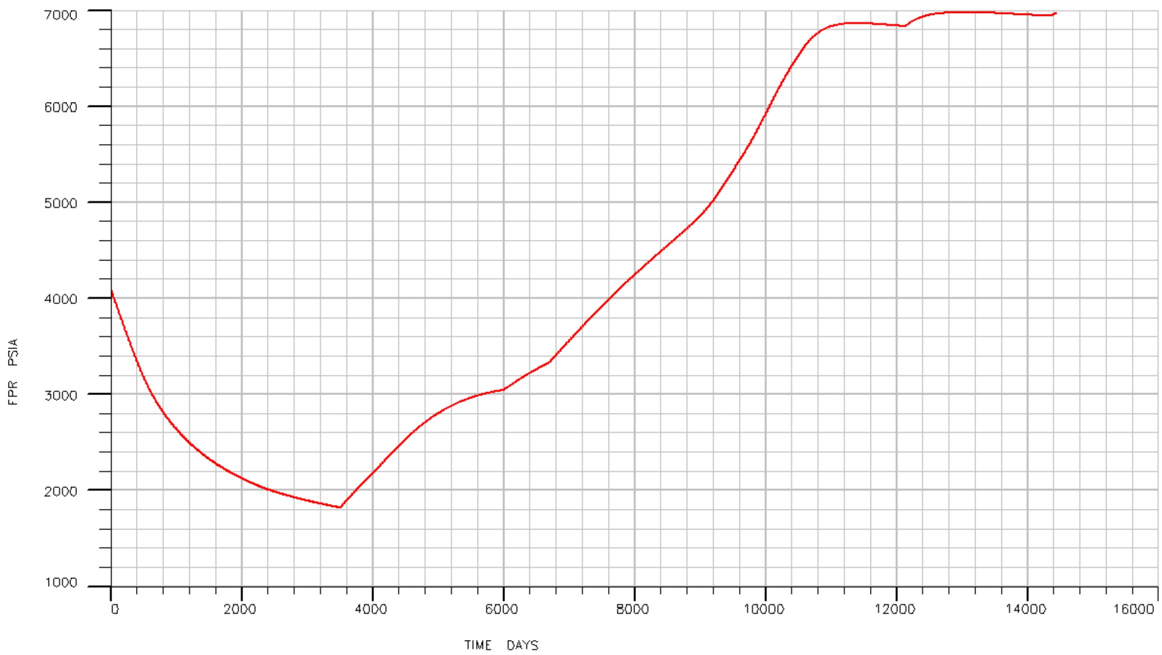

Fig. 5 Reservoir pressure rate

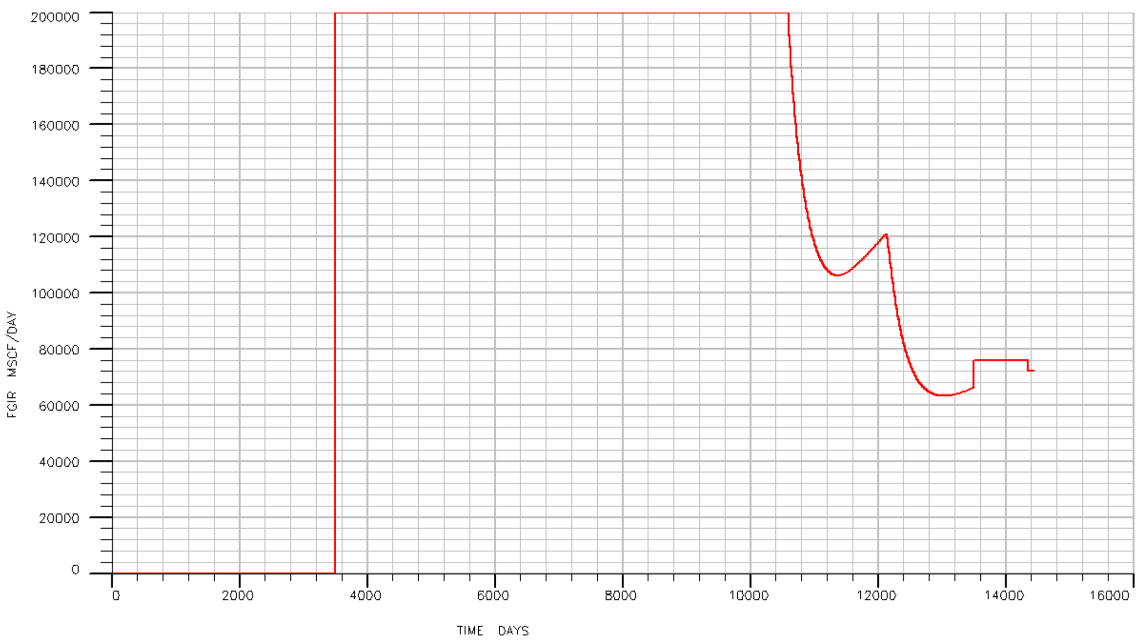

Fig. 6 Well No.1 gas (CO_2) injection rate

the four wells (No. 2, 3, 4 and 5) by increasing the time of CO_2 injection from the well No. 1, the reservoir pressure gradually increases and by reduction of difference between the reservoir pressure and injection pressure the CO_2 injection rate decreases. Therefore the slope of the reservoir pressure changes rate will be reduced. The reservoir CO_2 injection rate is shown in Fig. 6.

The in-situ stress regime for the case study is NF stress regime with stress ratio (k) of 0.41 and

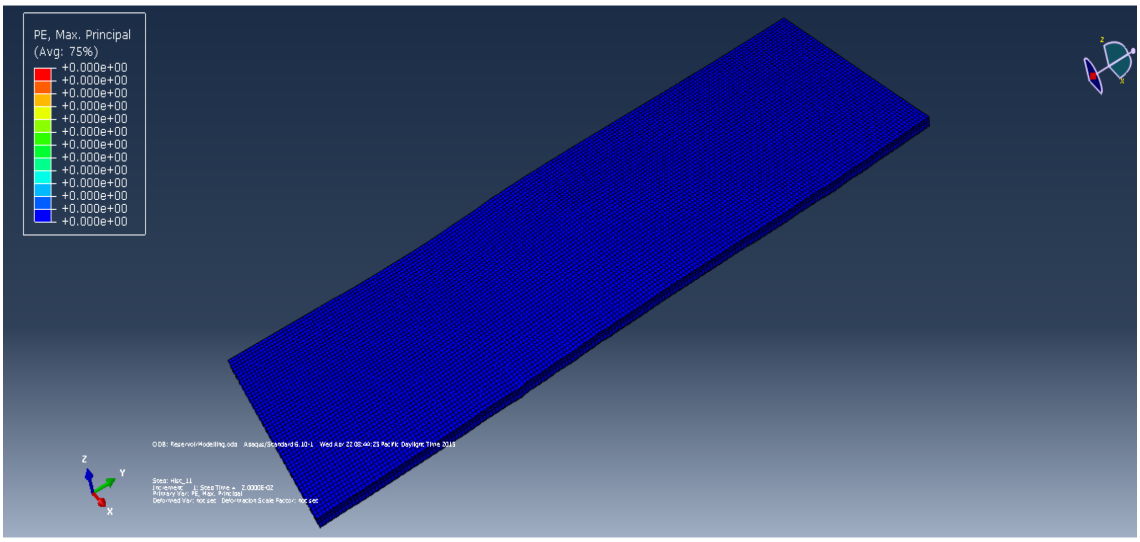

Fig. 7 Maximum plastic strain in the reservoir

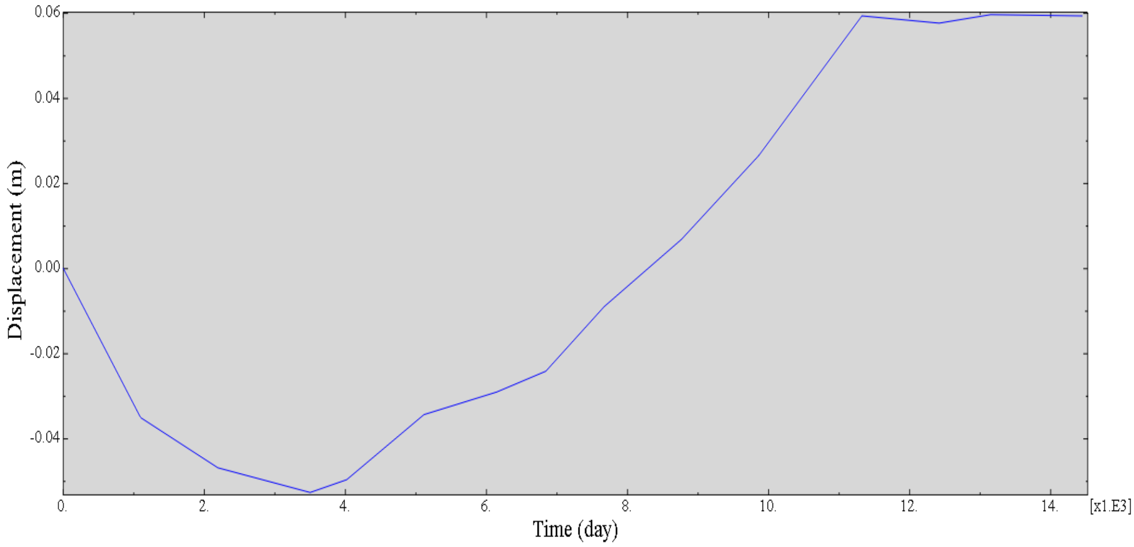

Fig. 8 Vertical displacement changes around the well No. 1 during production and injection scenarios

Mohr-Coulomb elasto-plastic criterion was used for geomechanical simulation of the reservoir during CO_2-EOR. The FEM analysis of the reservoir showed no sign of plastic strain under production and gas injection phases in any part of the reservoir (Fig. 7). During depletion and before the injection scenario of well No. 1, the reservoir has shown subsidence. However by injection of well No. 1 and production from other four wells, at the same time, the reservoir displacement reversed (Fig. 8). Though, such displacements are ignorable because of less potential for instability of the reservoir.

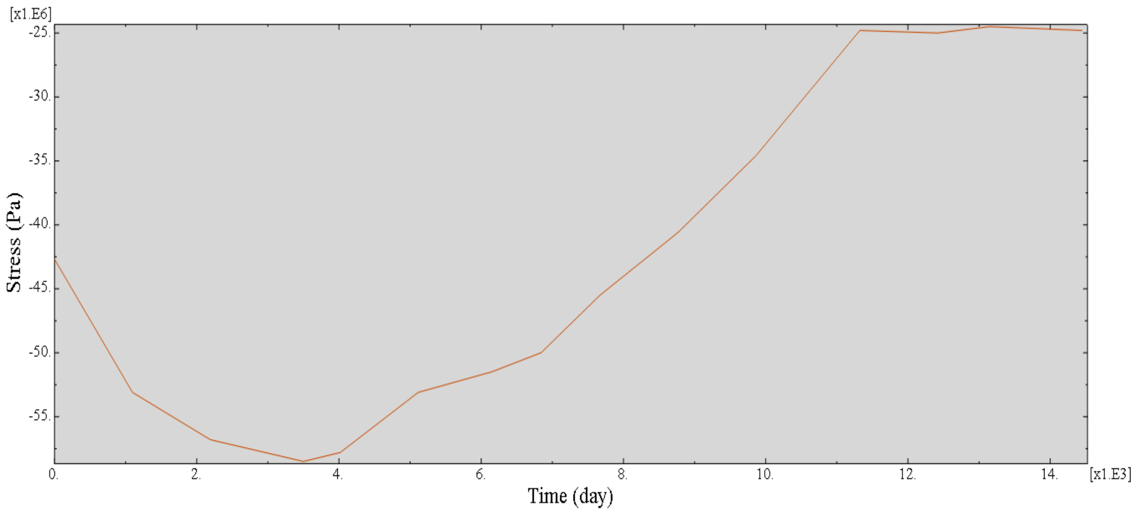

Fig. 9 The maximum principal stresses changes around the well No. 1 during production and injection scenarios

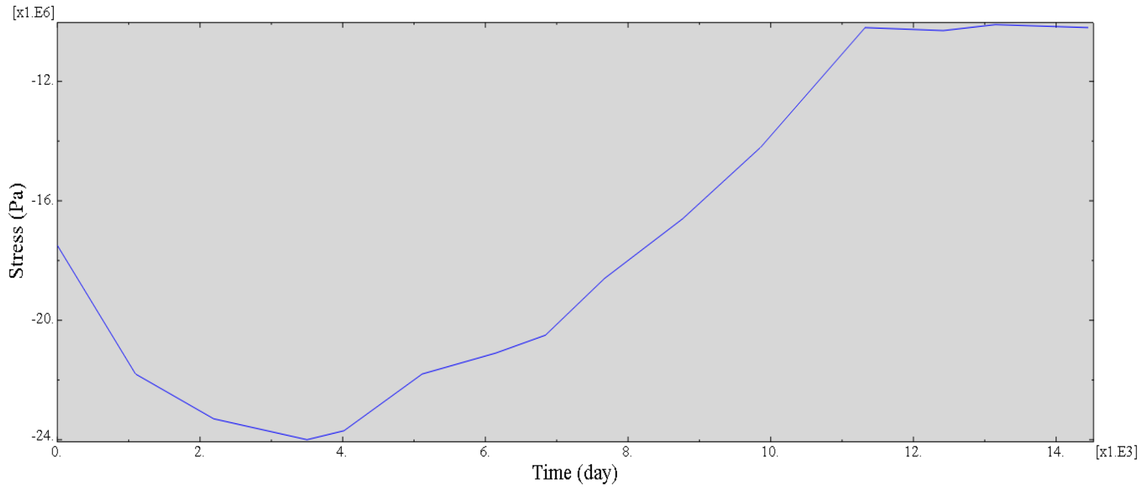

Fig. 10 The minimum principal stresses changes around the well No. 1 during production and injection scenarios

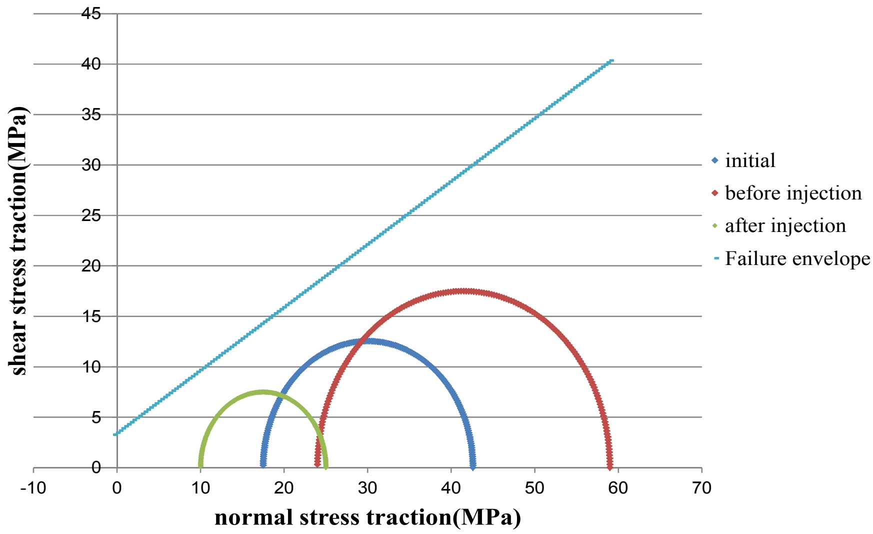

Fig. 11 Stress path for the reservoir for production and injection scenarios

The geomechanical analysis of the reservoir showed that the uplift is somewhat restricted by the overburden stiffness as the reservoir maximum vertical displacement is about 5.9 cm at the top of the injection zone, but attenuated to an uplift of about 4.5 cm of the ground surface.

The variations of the maximum and minimum principal stresses due to CO_2 injection are shown in Figs. 9 and 10 respectively.

Evolution of stress perturbations within the reservoir can be conveniently analyzed by plotting the stress path diagrams for the characteristic locations in the model (Fig. 11).

For the reservoir rock, the stress path diagrams show an increase of both the normal effective stress and the shear stress for depletion and an equally large decrease of both stresses for injection

(Fig. 11). In both cases the stress paths do not show a critical behavior, i.e. the paths are not converging towards the Mohr-Coulomb failure envelopes plotted for the shear strength parameters. It is noted that deformation is elastic. In addition, the reservoir stress path for injection is fully reversible with reference to the stress path for depletion.

5. Conclusions

The full-field analysis of the Iranian south west's oil region utilizes an external coupling between the reservoir simulator ECLIPSE and ABAQUS that has been established. Initial pressure, initial porosity variation and simulated pressure history are transferred from ECLIPSE to ABAQUS by FORTRAN utilizing the user subroutine facilities in ABAQUS. The ECLIPSE reservoir geometry is imported into ABAQUS/CAE by incorporating geometry information directly in the MATLAB file that generates the ABAQUS model. This kind of simulations is necessary to evaluate the hydro-mechanical assessment for a given production or injection site and to calculate the safety factors for a given scenario

According to the analysis carried out, it can be concluded that:

- At the start, each well production rate is 3,500 stb/day. Due to reservoir pressure reduction, the oil production rate will be decreased gradually. The production rate of well No.1 falls under 500 stb/day after about 3410 days from the start of production, so its production will be halted and it will be prepared for CO_2 injection.
- After CO_2 injection, the reservoir pressure gradually increased and so the rate of production in four other production wells increased. Due to increased GOR > 20 mscf/stb the production of wells No. 5, 4 and 3 terminated at 5985, 12125 and 14397 days after production beginning respectively. Also well No. 5 production will be terminated at 6695 days after production beginning because the well oil rate is below the limit.
- The pressure is maximum in the injection zone with a distance inferior to 100 m from the injection wellbore. This zone can be considered as the most critical part of the system. Beside this distance, the pressure decreases significantly.
- As soon as fluid injection starts, changes in reservoir stresses and strains can quickly propagate laterally within the injection zone, along with an expanding fluid pressure. The pressurization causes vertical expansion of the reservoir and changes in the stress field. These induced changes are, in general, proportional to the magnitude of the pressure increase, ΔP, and depend on the geometry and geomechanical properties of the reservoir and surrounding medium.
- The FEM analysis of the reservoir showed no sign of plastic strain under production and CO_2 injection scenario in any part of the reservoir. Also the displacements in both production and injection scenarios are small and no reservoir instability occurred.
- The uplift is somewhat restricted by the overburden stiffness; the vertical displacement is about 5.9 cm at the top of the injection zone, but attenuated to an uplift of about 4.5 cm of the ground surface.
- In both depletion and injection cases the stress paths do not show a critical behavior. However, this shear failure mechanism can be activated for high injection pressure levels. It is noted that deformation is elastic and the reservoir stress path for injection is fully reversible with reference to the stress path for depletion.

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