Fully Coupled Thermo-Hydro-Mechanical Modeling by COMSOL Multiphysics, with Applications in Reservoir Geomechanical Characterization

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Abstract: In recent years, there has been a fundamental shift in the way researchers were looking at geomechanical and porous media. Because of the complex nature of geomaterials and presence of solid and fluid within a single system it is crucial to consider all the physics involved within the geomaterial system. As part of this research a fully coupled thermo-hydro-mechanical model based on COMSOL's built-in application modes and PDE application mode is developed. The model consists of a three-phase flow model designed as a set of coupled PDE application modes that when coupled with Heat Transfer Module and Structural Module, forms a thermo-hydro-mechanical model. The coupled application modes entail their own relevant boundary conditions depending on the analysis. A Transient elasto-plastic analysis from Structural Module along with necessary formulation is implemented to define the appropriate yield criteria for the shear and tensile failure of the rock. To account for inherent heterogeneity in rock properties, a probabilistic distribution of mechanical and hydraulic properties through external script and interpolation functions available in COMSOL is used. The integrated non-isothermal flow and geomechanical analysis, using the powerful COMSOL multiphysics interface, yields astonishing results indicating the importance of geomechanics in petroleum engineering problems. The results from the analyses demonstrate the impact of geomechanical properties on multiphase flow behavior and vice versa.

Keywords: Thermo-hydro-mechanical coupling, Geomechanics, Reservoir simulation, poroelasticity, multiphase flow

1. Introduction

The goal of geomechanical reservoir characterization is to describe the role of geomechanics on the whole reservoir characterization and to predict reservoir behavior under varying conditions of stresses and strains during various stages of exploration, development, production and completion. The purpose of this project is to explore the application of a new thermo-hydro-mechanical model in the practical problems in major areas of petroleum geomechanics.

As shown in Figure 1, stresses and strains in a reservoir, have a two-way link with temperature and flow of the fluid. Change in temperature during, for instance thermal recovery or hydraulic fracturing, would result in the development of thermal stresses in the porous material and the generated stresses can cause a failure in the reservoir rock and consequently altering its porosity, permeability, and thermal properties. This will not only progressively change the strength of the rock, but also will cause changes in the flow regime and rate. Fluid flow will also be affected by temperature variations directly through the change in the viscosity of the hydrocarbon. The flow of fluid in the pores of rock, on the other hand, can impact the effective stresses in the rock through the fluid's pressure. The effect will be more noticeable if the reduced effective stresses combined with thermal loads yield the rock and stimulate the existing discontinuities or cause abnormal porosities.

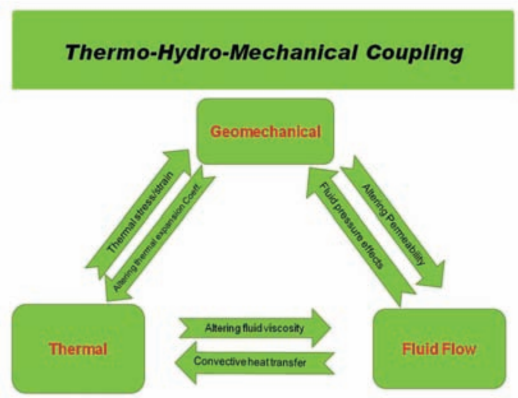

Figure 1. A thermo-hydro-mechanical flowchart

Therefore, it is critically important that for any petroleum geomechanical analysis such as well stability, reservoir subsidence or reservoir simulation, a coupled thermo-flow-geomechanical approach to be implemented. The most common approach to conduct this complex coupling simulation is a partially (loosely) coupled approach in which thermal flow and geomechanical analysis are conducted in separate simulators and the results are passed between them for each time step. However, with strong multiphysics capability in COMSOL, a fully coupled approach can be implemented to solve all set of equations for thermal, mechanical, and single/multiphase flow in the same simulator (COMSOL). In addition to fully coupled capability, COMSOL provides the advantage of access to other application modes such as electrical heating as well as general PDE application for flexible coupling of desired additional physics.

2. Governing Equations

Geomechanics, if defined as the mechanics of geomaterials, is in essence a multidisciplinary field of engineering. This is mostly because of the complex nature of geomaterials and the presence of multiple constituent in a heterogeneous system under various conditions of stress, temperature and flow history. Coexistence of solid and fluid within a single matrix with one ingredient (fluid) capable of moving or undergoing pressures different from solid phase and significant effect of fluid pressure on overall behaviour of rock matrix drives the requirement for considering other physics in mechanical analysis of a geomaterial system. In the scope of petroleum geomechanics, the most important physics to be simultaneously included in geomechanical modeling are fluid flow and heat transfer.

The fundamental equation for mechanical physics is the force equilibrium equation:

$$-\nabla.\sigma = F \quad \text{Eq. 1}$$

Where, σ is the total stress tensor and F is the external or body force.

The flow of fluid in the pores of rock can impact the stresses and strains in the rock through the fluid's pressure. This impact is best demonstrated and implemented by decomposing the stress tensor into effective stress s' and pore pressure p.

$$\sigma = \sigma' + \alpha p \quad \text{Eq. 2}$$

For the general case of three-phase flow, the concept of effective stress can be defined based on an average pore pressure:

$$\bar{p} = S_w p_w + S_o p_o + S_g p_g \quad \text{Eq. 3}$$

$$\sigma = \sigma' + \alpha \bar{p} \quad \text{Eq. 4}$$

Where the parameter α is called Biot-Willis coefficient.

By implementing the pore pressure into the mechanical equilibrium equation we will obtain:

$$-\nabla.\sigma = F - \alpha I \nabla p \quad \text{Eq. 5}$$

Flow of fluids in a reservoir can be single phase or multiphase. For single phase flow, two modes of fluid flow can be considered, Darcy and Brinkman. According to Darcy's empirical law (later derived mathematically from Stokes equations), the flow velocity is linearly proportional to pressure gradient.

$$u = -\frac{k}{\mu}(\nabla p - \rho g \nabla z) \quad \text{Eq. 6}$$

Where, μ is the dynamic viscosity of the fluid and k is the permeability of the rock matrix.

Brinkman equations on the other hand, describe fast-moving fluids in porous media. They indeed interpolate between the Navier-stokes equation and Darcy's law [1]:

$$\mu\nabla^2 u - \nabla p - \mu\alpha^2 u = 0 \quad \text{Eq. 7}$$

$$\nabla . u = 0 \quad \text{Eq. 8}$$

For the case of a single phase flow of a slightly compressible fluid in a compressible rock, Darcy's law can be used to derive the following transient parabolic equation:

$$\emptyset\rho C_t \frac{\partial p}{\partial t} = \nabla . \left(\frac{\rho k}{\mu}(\nabla p - \rho g \nabla z)\right) + q \quad \text{Eq. 9}$$

Where, C_t represents the total compressibility (rock and fluid).

Pore pressure from fluid flow can affect the stress state in the porous media. On the other hand, geomechanical deformations, can affect the fluid flow through the porous media. This hydro-mechanical coupling can in general be formulated according to poroelasticity theory as follows:

$$G\nabla^2 u + \left(K_d + \frac{G}{3}\right)\nabla . (\nabla u) = \alpha\nabla p \quad \text{Eq. 10}$$

$$\frac{1}{M}\frac{\partial p}{\partial t} - \nabla . \left(\frac{k}{\mu}(\nabla p - \rho_f g \nabla z)\right) = -\alpha\frac{\partial(\nabla . u)}{\partial t} \quad \text{Eq. 11}$$

Where M, Biot's Modulus is defined as:

$$\frac{1}{M} = \frac{\alpha - \emptyset}{K_s} + \frac{\emptyset}{K_f} \quad \text{Eq. 12}$$

K_f is the bulk modulus of the fluid and K_s is the bulk modulus of the solid. Mechanical deformation can also impact the fluid flow behavior within the rock by changing the permeability k. The change will be more obvious if the stresses caused by a combination of structural, flow, and thermal loads yield the rock and create discontinuities, fractures or abnormal porosities. This could happen during a thermal recovery process.

For multiphase flow, various conditions of two phase and three phase flow can occur in the reservoir. Basic equations for two phase (water and oil) flow are:

$$\frac{\partial(\emptyset\rho_\alpha S_\alpha)}{\partial t} = -\nabla . (\rho_\alpha u_\alpha) + q_\alpha , \alpha = w, o \quad \text{Eq. 13}$$

$$u_\alpha = -\frac{k_{r\alpha}}{\mu_\alpha}(\nabla p_\alpha - \rho_\alpha g \nabla z), \alpha = w, o \quad \text{Eq. 14}$$

$$S_w + S_o = 1 \quad \text{Eq. 15}$$

$$p_c = p_o - p_w \quad \text{Eq. 16}$$

For the case of modeling thermal recovery by steam, a three-phase (steam, water, oil) , two component (water and oil) flow is used. the water and steam in such a model constitute a single component with mass exchange between them and with no mass exchange between steam (gas) or water with oil (bitumen) component. Thus, the equation of conservation of mass for the water can be given as:

$$\frac{\partial}{\partial t}\left(\emptyset\left(\rho_w S_w + \rho_g S_g\right)\right) = -\nabla . \left(\rho_w u_w + \rho_g u_g\right) \quad \text{Eq. 17}$$

In an engineering model of a reservoir rock containing heavy oil or bitumen, temperature is a very important component of the system. Both rock and bitumen properties are strongly affected by heat. The transfer of heat, on the other hand, is influenced by other physics such as flow of a fluid through a material. This two-way coupling mechanism requires understanding and implementing the thermal energy and heat transfer in a geomechanical model through a multiphysics simulation.

Heat energy can transfers from one point to another in a porous media due to a difference in temperature by conduction, convection, or both. Conduction can occur in stationary solid or liquid by a temperature gradient through diffusion. Convection or the transfer of heat by a moving fluid can take place only in fluids or gases. In a porous rock as a material consisting of both solid and liquid the thermal energy can transfer by both mechanisms of conduction and convection.

According to Fourier's law the heat flows from regions of high temperature to regions of low temperature according to the following equation:

$$q = -k\nabla T \qquad \text{Eq. 18}$$

Where, k is the thermal conductivity of the media. By combining Fourier's law and energy conservation law, the heat transfer through conduction can be represented in the following mathematical form, called heat equation:

$$\rho C_T \frac{\partial T}{\partial t} - \nabla.(k_T \nabla T) = Q \quad \text{Eq. 19}$$

Where ρ is the density, C_T is the heat capacity, k_T is the thermal conductivity, and Q is the heat source or sink.

In the case of heat transfer by convection and conduction, a convective term indicating the heat transfer through convective velocity u must be added to the equations above:

$$q = -k\nabla T + \rho C u T \qquad \text{Eq. 20}$$

$$\rho C_T \frac{\partial T}{\partial t} - \nabla.(k_T \nabla T + \rho C u T) = Q \qquad \text{Eq. 21}$$

Materials change volume with temperature causing thermal strains to develop in the materials. If the material cannot freely deform in response to the volume change, thermal stresses will develop in the material depending on the thermal expansion capacity, modulus of elasticity and the degree of constraint. Therefore, in a mechanical system under structural loads with varying temperatures the total stress will be the combination of structural and thermal stresses. For an elastic material, we will have:

$$\sigma_{\text{elastic}} = D[\varepsilon - \alpha_T(T - T_0)] \quad \text{Eq. 22}$$

Where α_T is the thermal expansion coefficient and D is the elasticity matrix.

The stresses generated by thermal energy can cause a failure in rock structure and consequently change the porosity and permeability. This will not only progressively change the strength of rock, will cause changes in the flow regime and rate. Fluid flow will also be affected by temperature variations directly. The viscosity of a fluid is an indication of its resistance to flow or deform itself. Temperature is by far the most important variable affecting viscosity and as a result the resistance of fluid to flow. Fluid flow on the other hand, can help transfer the heat through convection according to the following equation (u is the velocity from fluid flow):

$$\rho C \frac{\partial T}{\partial t} - \nabla.(k\nabla T + \rho C u T) = Q \qquad \text{Eq. 23}$$

In a petroleum engineering context, flow in a porous media can be isothermal (flow to a well) or non-isothermal (thermal recovery). The basis for non-isothermal flow formulation is the conservation of energy law. Using this law, the following energy equation for a general three-phase flow can be obtained:

$$\frac{\partial}{\partial t}\left(\emptyset \textstyle\sum_{\alpha=w}^{g} \rho_\alpha S_\alpha U_\alpha + (1-\emptyset)\, \rho_s C_s T\right) + \nabla.\textstyle\sum_{\alpha=w}^{g} \rho_\alpha u_\alpha H_\alpha - \nabla.(k_T \nabla T) = 0 \qquad \text{Eq. 24}$$

Where, U_α is the specific internal energy per unit mass of phase α, C_s is the specific heat capacity of the solid, H_α is the enthalpy of the a phase, and k_T is the thermal conductivity.

In addition, to account for the change in porosity and permeability as a result of volumetric strains developed in the rock by temperature and pressure, the following equations are used in the models:

$$\boldsymbol{\emptyset = \emptyset_0 + \alpha\Delta\varepsilon_v + c_s(\alpha - \emptyset_0)\Delta p} \qquad \text{Eq. 25}$$

$$\boldsymbol{k = k_0 e^{\left(\frac{5}{\emptyset}\varepsilon_v\right)}} \qquad \text{Eq. 26}$$

With $\boldsymbol{\varepsilon_v}$ being the volumetric strain, the first equation is from reference [1] and the second equation is from reference [4] and [5].

3. Examples and Verification

The examples provided in this section serve two purposes, first to demonstrate the application of the poroelastic, single-phase and two-phase hydro-mechanical model and second, to verify the results obtained from the model by comparison to analytical and numerical solution available in literature.

3.1 Uniaxial Single-phase Hydro-mechanical Model

The first example by Zheng et al [2] is a 2D rock sample 2m x 3m (Figure 2. undergoing a uniaxial compression. The rock is fully saturated with oil and the fluid can only flow through the top boundary. Confined by roller constraints at bottom and sides, a 4 MPa uniform load is applied on the top boundary.

A coupled hydro-mechanical analysis was conducted through transient pressure analysis from Darcy's law in Earth Science Module coupled with transient elasto-plastic plain strain analysis from Structural Module. To match the results from source, no change in porosity or permeability was taken into account in the analysis.

The sample configuration is shown in Figure 2 and the input parameters are given in Table 1. The governing equations for coupling mechanical and hydraulical equations were Eq. 10 and Eq. 11. Some modifications in storage term of the transient flow formulation were necessary to make it compatible with Biot's modulus in Eq. 11.

The vertical displacement of the top of the sample after 1 minute and 10 minutes is shown in Figure 4 . As it can be seen from this figure, the results are perfectly matched with the work done by Zheng et al [2]. Also the effective stress in the sample directly obtained from hydro-mechanical analysis is shown in Figure 5 and as it can be seen from the chart, the effective stress approaches the applied load as water pressure in the sample dissipates.

Table 1. Poroelastic and fluid flow parameters for the first example [2]

Young's Modulus	1.44×10^4 MPa
Poisson's Ratio	0.2
Biot's Coefficient,	0.79
Biot's modulus(M)	1.23×10^4 MPa
Rock Density	2000 kg/m^3
Oil Density	940 kg/m^3
Porosity	0.2
Permeability	2×10^{-13} m^2
Kinematic Viscosity	1.3×10^{-4} m^2/s

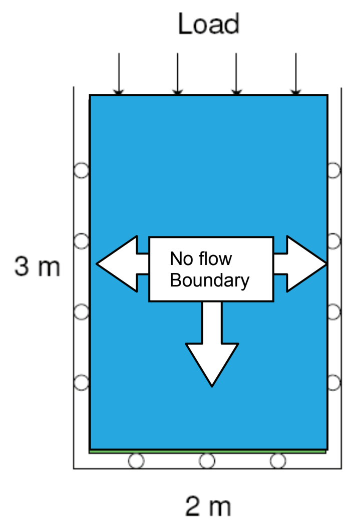

Figure 2. A saturated rock sample undergoing uniaxial compression

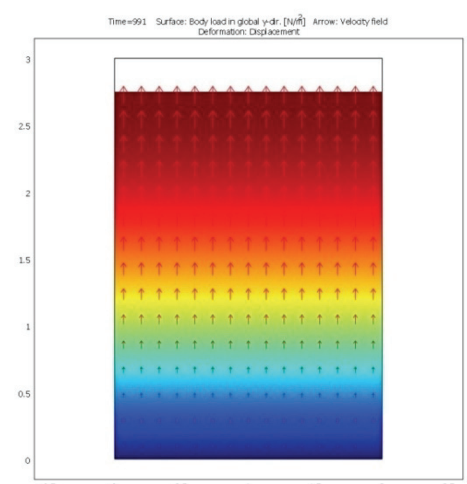

Figure 3. Upward water flux due to mechanical deformation.

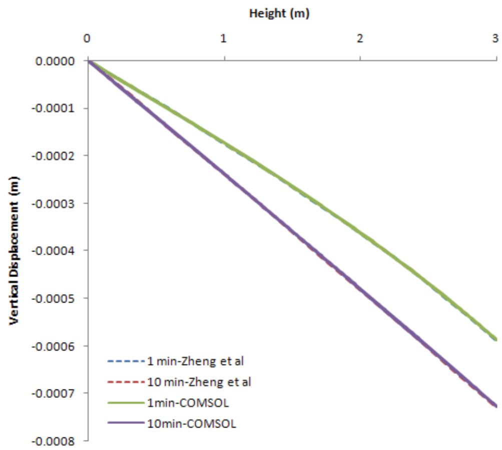

Figure 4. Vertical displacements along the sample at different times after loading

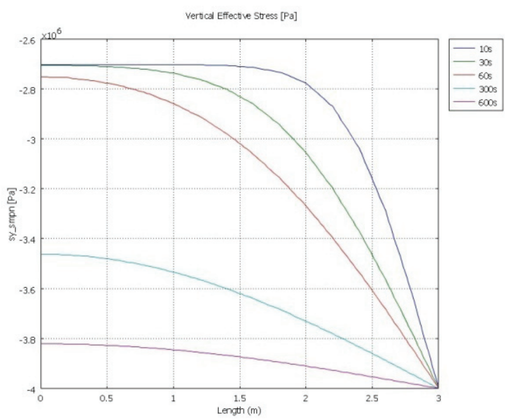

Figure 5. Effective stress along the sample at different times after loading directly from fully coupled hydro-mechanical model.

3.2 Water Flooding Two-Phase Hydro-Mechanical Model

The second example by Mainguy et al [1] is a cylindrical rock sample 1.5m length and 0.5m diameter (Figure 2. undergoing a water flood test. The rock is originally saturated with oil and while confined by roller constraints on all sides a constant water influx is imposed at the top. The input parameters are given in Table 1 and the sample configuration is shown in Figure 6.

The hydro-mechanical model for this example is a set of PDE application modes for two-phase flow coupled with transient elasto-plastic plain strain analysis from Structural Module. The coupling mechanical and hydraulical properties are based on Eq. 10 and Eq. 11 with appropriate modification in compressibility terms. The change in porosity during the simulation as a result of mechanical strains is calculated based on Eq. 25. Although, the original analysis by Mainguy and Longuemare [1] is based on a coupled 1D flow coupled with geomechanics the current study is based on 2D flow and stress analysis. Nonetheless, the oil production results for both reservoir simulation and fully coupled method (Figure 8 and Figure 9) are very close to their results.

Table 2. Mechanical and fluid flow parameters for the second example [1]

Oil viscosity	0.500 Pa·s
Water viscosity	0.001 Pa·s
Intrinsic permeability	5×10^{-14} m^2
Initial porosity	0.30
Initial oil density	950 $kg\cdot m^{-3}$
Initial water density	1000 $kg\cdot m^{-3}$
Water compressibility	4 x 10^{-10} Pa^{-1}
Oil compressibility	0.000 Pa^{-1}
Water top influx	0.02 $kg\cdot m^{-2}\cdot s^{-1}$
Drained elastic modulus	3 x 10^{9} Pa
Poisson's ratio	0.3
Drained bulk modulus	2.5 x 10^{9} Pa
Rock shear modulus	1.15 x 10^{9} Pa
Biot's coefficient	1
Total displacement	0.000 m
Relative permeability of water	S_w^2
Relative permeability of oil	S_h^2

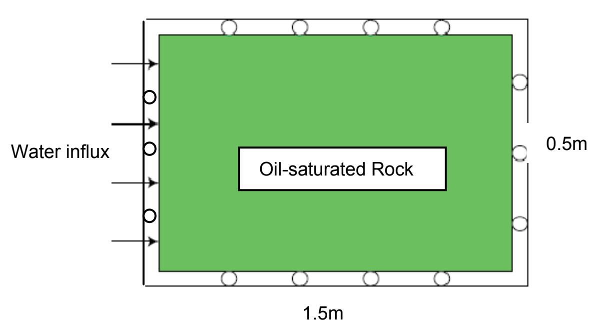

Figure 6. A confined oil-saturated rock sample subject to constant water influx on one side

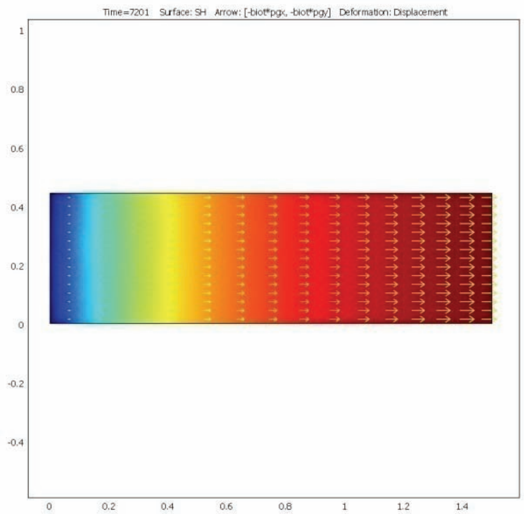

Figure 7. Oil saturation in the sample two hours after water flooding

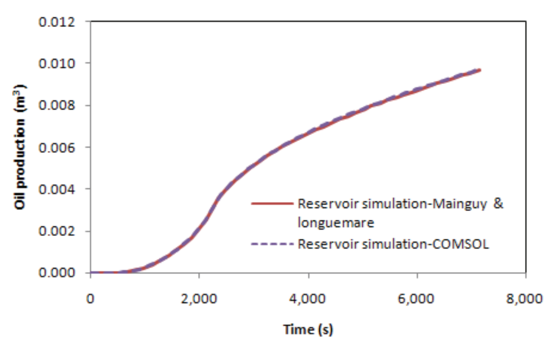

Figure 8. Comparison of oil production from reservoir simulation model , Mainguy & longuemare and COMSOL

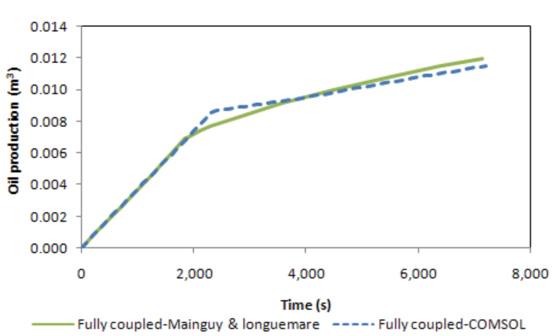

Figure 9. Comparison of oil production from fully coupled model , Mainguy & longuemare and COMSOL

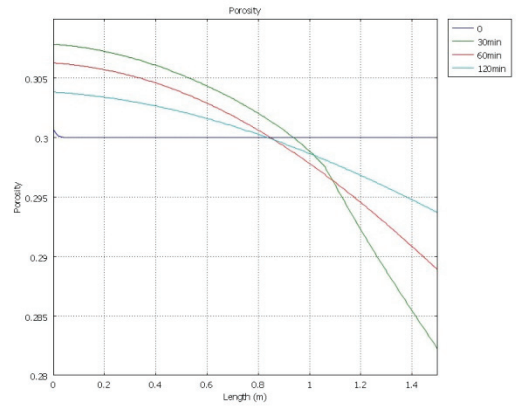

Figure 10. Porosity in the sample 30, 60 and 120 minutes after water injection from fully coupled COMSOL model.

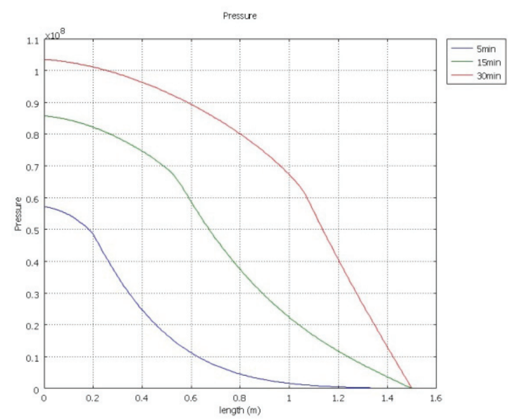

Figure 11. Pressure in the sample 5, 15 and 30 minutes after water injection from fully coupled COMSOL model.

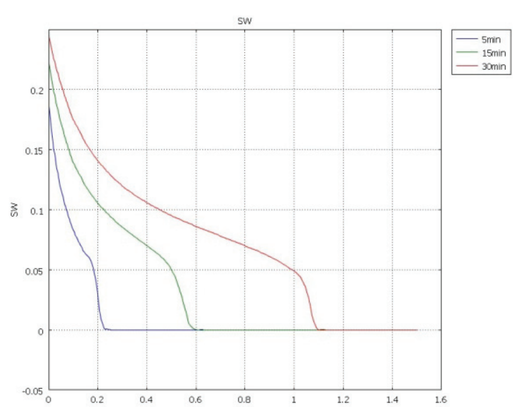

Figure 12. Water saturation in the sample 5, 15 and 30 minutes after water injection from fully coupled COMSOL model.

4. Practical Reservoir Geomechanical Applications

By implementing the thermo-hydro-mechanical model developed in COMSOL, geomechanics of three major petroleum engineering problems; surface subsidence, fluid injection for hydraulic fracturing, and steam injection for SAGD thermal recovery are explored in this section. The impact of geomechanics through various coupling links and their impact on non-isothermal single phase and two phase flow pattern are explored. In addition, change in porosity and permeability as a result of mechanical strains is considered. Only poroelastic behaviour is implemented within this paper and elasto-plastic (poroplastic) behavior will be covered in future publications. Also, the models can be analyzed based on a stochastic set of input parameters to account for heterogeneity.

4.1 Surface Subsidence

Total external stress over a rock element underground is carried partly by the solid framework of the solid and partly by the fluid in the pores of the rock. This means, overburden pressure is supported by both rock matrix and pore fluid pressure. Mathematically this can be demonstrated by introduction of effective stress (σ') in the $\sigma = \sigma' + \alpha\bar{p}$ Eq. 4 ($\sigma = \sigma' + \alpha\bar{p}$)

During production the fluid is removed from the pores, reducing p and consequently the share of pore fluid from the total overburden pressure. This forces the rock framework to have to carry more load. More load on rock matrix causes compression strains and consequently compaction of the reservoir. The compaction of the reservoir can result in the subsidence of the ground surface above the reservoir formation. In addition to the problem that may be caused for the amenities on the surface, compaction can impact the wellbore integrity and result in problems for drilling and production equipment.

In order to evaluate the likelihood and amount of subsidence, a fully coupled hydro-mechanical model based on theory of poroelasticity and transient single-phase flow (Eq. 10 and Eq. 11) is used to demonstrate the scenario. The poroelastic and fluido-dynamical input parameters are given in Table 3 and the output is presented in Figure 13 and Figure 14.

Table 3. Mechanical and fluid flow parameters for surface subsidence

Oil viscosity	0.1 Pa·s
Reservoir permeability	5×10^{-13} m^2
Overlying layer’s Permeability	5×10^{-14} m^2
Initial porosity	0.23
Oil density	970 kg·m^{-3}
Rock density	2000 kg·m^{-3}
Production rate	0.005 m/h^{-1}
Elastic modulus	1×10^{10} Pa
Poisson’s ratio	0.25
Biot’s modulus (M)	1.3×10^{10} Pa
Biot’s coefficient	0.85

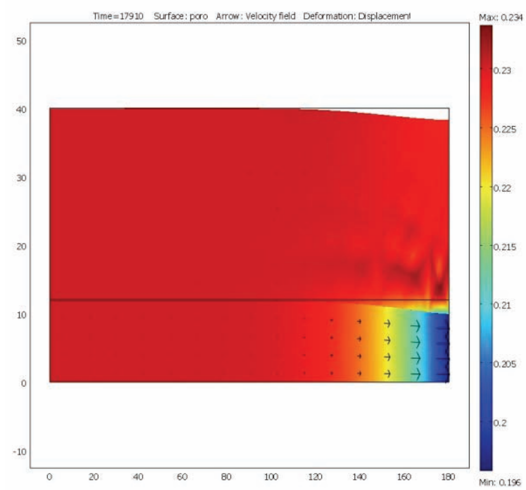

Figure 13. Surface subsidence as a result of oil production from a reservoir

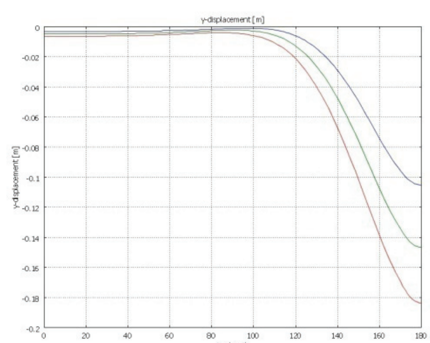

Figure 14. Surface subsidence 2, 3, and 4 hours after production

4.2 Non-isothermal Fluid Injection into a well

Non-isothermal fluid injection into a well is a thermo-hydro-mechanical process that could happen during for instance hydraulic fracturing projects or enhanced oil recovery methods. The injection could be single phase if the formation is dry or saturated with the same liquid or two-phase if the formation is saturated with another immiscible fluid. The capability of COMSOL in thermo-hydro-mechanical modeling of both cases is discussed in this section.

i) Single-phase thermal fluid injection

By coupling transient Darcy's flow, Convection & conduction, and structural mechanics, it is possible to build a thermal fluid injection model for a deformable rock. The input data for this model is presented in Table 4 and some output from the model is shown in Figure 16 and Figure 18. It should be mentioned that only an elastic behavior is considered in this exampled and possible failure and elasto-plastic behavior is not taken into account.

Table 4. Input data for single phase fluid thermal fluid injection

Permeability	5×10^{-13} m^2
Injection Pressure	5×10^7 Pa
Initial porosity	0.23
Initial fluid density	980 kg·m^{-3}
Rock density	2800 kg·m^{-3}
Elastic modulus	3×10^9 Pa
Poisson's ratio	0.25
Biot's modulus (M)	1.3×10^{10} Pa
Biot's coefficient	0.85
Vertical in-situ stress	5.9×10^6 Pa
Horizontal in-situ stress (Max)	6.11×10^6 Pa
Horizontal in-situ stress (Min)	4.89×10^6 Pa
Original temperature	293 K
Injection temperature	283 K
Viscosity: initial temperature	1.03×10^{-3} Pa·s
Viscosity: injection temperature	1.34×10^{-3} Pa·s
Heat Capacity	1140-1160J/kg/K
Thermal expansion coefficient	6.64×10^{-6} /K
Thermal conductivity	2.63 W/m/K
Well radius	0.1 m

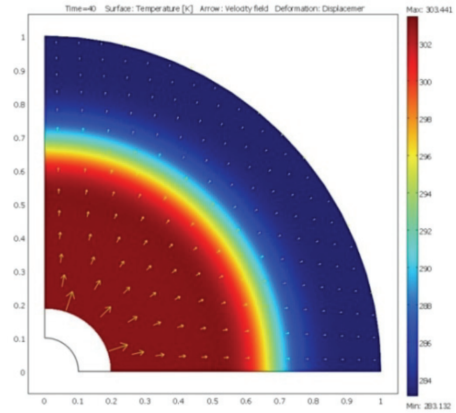

Figure 15. Temperature distribution and wellbore deformation 40 s after water injection

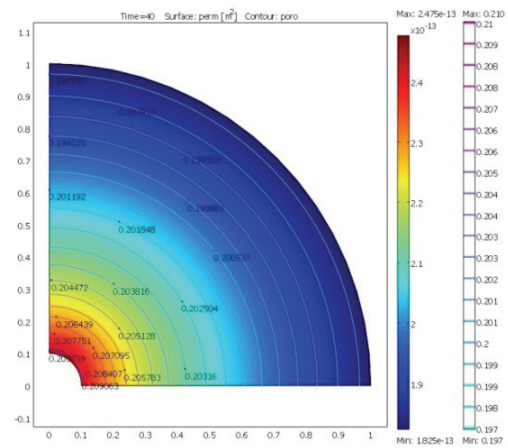

Figure 16. Permeability and porosity change as a function of volumetric strain

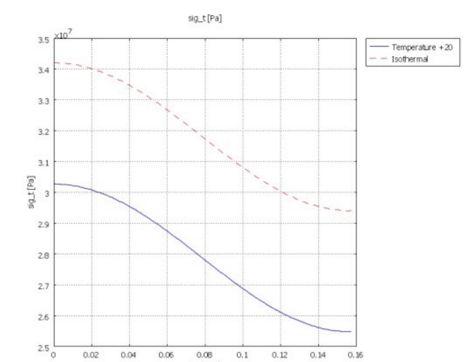

Figure 17. Tangential stress around the wellbore for isothermal and non-isothermal fluid injection

ii) Two-phase thermal fluid injection

The verified two-phase hydro-mechanical model introduced in water flooding example (section 3.2) can be transformed into a THM model to simulate the injection of water into an oil saturated reservoir. The coupling mechanical and hydraulic properties are based on Eq. 10 and Eq. 11 with appropriate modification in compressibility terms. The change in porosity and permeability during the simulation as a result of mechanical strains is accounted for using Eq. 25 and Eq. 26.

The example presented here is the injection of water with constant rate into an oil saturated reservoir. The model can be developed further to simulate the hydraulic fracturing in the reservoir. A summary of the input parameters used in this example are shown in Table 5. Figure 18 to Figure 20 show some of the results obtained from this practical example.

Table 5. Input data for two phase fluid injection

Initial Permeability	5×10^{-14} m^2
Injection flux	0.02 $kg\cdot m^{-2}\cdot s^{-1}$
Initial porosity	0. 3
Initial oil density	950 $kg\cdot m^{-3}$
Initial water density	1000 $kg\cdot m^{-3}$
Rock density	2400 $kg\cdot m^{-3}$
Elastic modulus	3×10^9 Pa
Poisson's ratio	0.3
Biot's coefficient	0.9
Drained bulk modulus	3×10^9 Pa
Vertical in-situ stress	6×10^6 Pa
Horizontal in-situ stress (Max)	6.6×10^6 Pa
Horizontal in-situ stress (Min)	5.4×10^6 Pa
Original temperature	293 K
Injection temperature	293 K
Initial Oil viscosity	0.500 Pa·s
Initial Water viscosity	0.001 Pa·s
Thermal expansion coefficient	1×10^{-5} /K
Thermal conductivity	2.63 W/m/K
Relative permeability of water	S_w^2
Relative permeability of oil	S_h^2
Water compressibility	4×10^{-10} Pa^{-1}
oil compressibility	1×10^{-10} Pa^{-1}
Pore compressibility	1×10^{-9} Pa^{-1}
Wellbore radius	0.1 m
Cohesion (C)	5×10^5 Pa
Friction angle	30^o
Yield criterion	Drucker-Prager

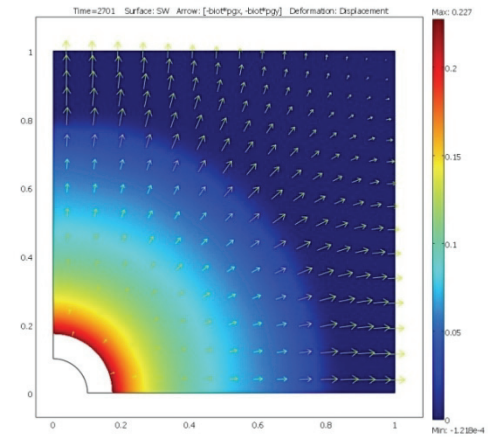

Figure 18. Saturation of injection fluid (water) into an oil saturated reservoir 45min after injection

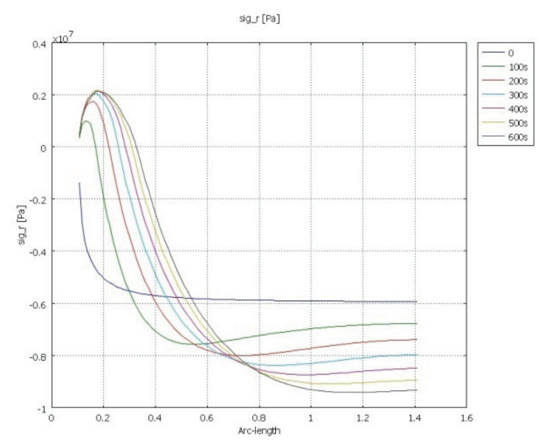

Figure 19. Radial effective stress at different times after injection

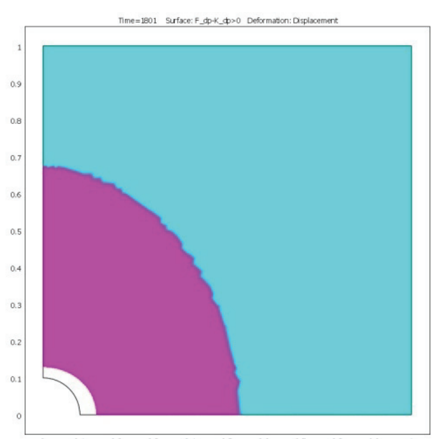

Figure 20. Plastic zone based on Drucker-Prager yield criterion 30min after injection

4.3 Steam Injection for Thermal Recovery

Steam Assisted Gravity Drainage (SAGD) is one of the best thermal recovery methods originally developed for oil sands in Alberta. In this method, two horizontal wells are drilled one above the other. Hot steam is injected through the top well into the reservoir to heat up the bitumen and make it mobile. During a SAGD process, stress state within the reservoir is significantly altered due the thermal stresses and steam pressure. As a result geomechanics becomes an important part of SAGD process as the new stress state can impact the multiphase flow of steam and bitumen by enhanced permeability or stimulated fractures.

A multiphase flow for a SAGD process can be modeled through a three-phase (steam, water, oil) and two-component (water and oil) formulations with mass transfer between steam and water (Eq. 17 and see [12]). The example model presented here illustrates the THM modeling of steam injection into a reservoir. For clearness, the production well is not modeled and in-situ stresses are ignored. The input values for the steam injection model is presented in Table 6 and typical results from the analysis are shown in Figure 21 to Figure 23.

Table 6. Input data for steam injection model

Initial Permeability	$9.82\text{x}10^{-13}$ m^2
Injection Pressure	1.084×10^6 Pa
Initial reservoir pressure	9.825×10^5 Pa
Initial porosity	0. 32
Initial oil density	1010 kg·m^{-3}
Initial water density	1000 kg·m^{-3}
Rock density	2800 kg·m^{-3}
Elastic modulus	1.4×10^9 Pa
Poisson's ratio	0.3
Biot's coefficient	1.0
Vertical in-situ stress	0.0 Pa
Horizontal in-situ stress (Max)	0.0 Pa
Horizontal in-situ stress (Min)	0.0 Pa
Original temperature	273 K
Injection temperature	436 K
Thermal expansion coefficient	$1.2\text{x}10^{-5}$ /K
Thermal conductivity	2.5 W/m/K
Water compressibility	4×10^{-10} Pa^{-1}
oil compressibility	1×10^{-10} Pa^{-1}
Pore compressibility	1×10^{-9} Pa^{-1}

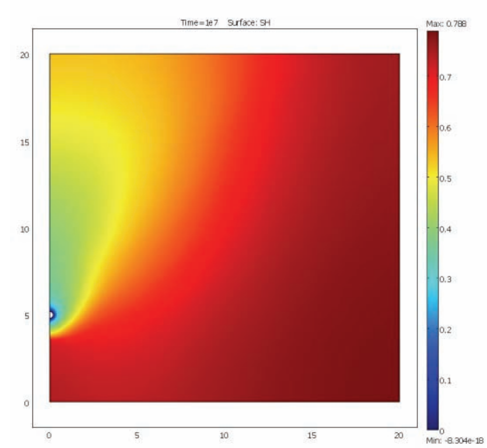

Figure 21. Distribution of oil saturation 115 days after injection

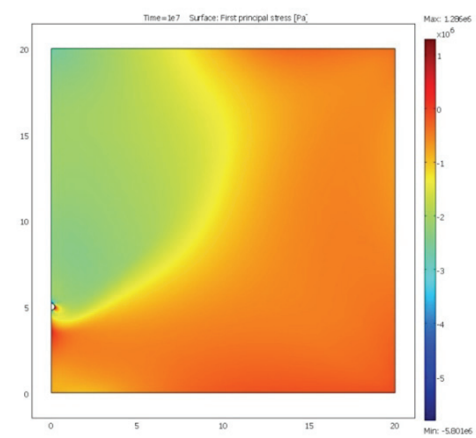

Figure 22. First principle stress distribution generated by steam pressure and temperature

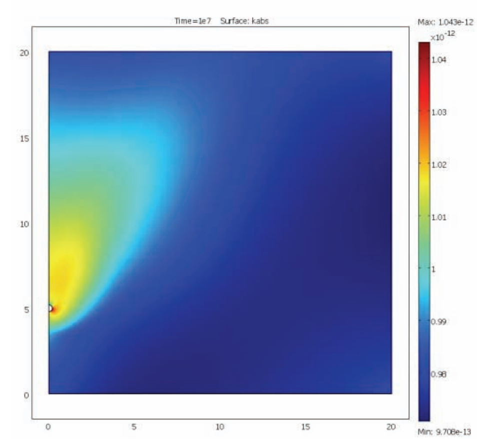

Figure 23. Permeability change as a result of volumetric strains

5. Conclusions

Fully coupled thermo-hydro-mechanical modeling for single phase and multiphase flow is successfully implemented in a number of reservoir geomechanical problems through the built-in and PDE application modes available in COMSOL Multiphysics. The models are verified by comparison to the numerical and analytical solutions available in the literature. An integrated non-isothermal flow and geomechanical analysis, using the powerful COMSOL multiphysics platform, yields astonishing results indicating the importance of geomechanics in petroleum engineering problems. The results from the analyses demonstrate the impact of geomechanical properties on single phase and multiphase flow behavior and vice versa.

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7. Acknowledgements

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