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THM Modeling for Reservoir Geomechanical Applications

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Introduction

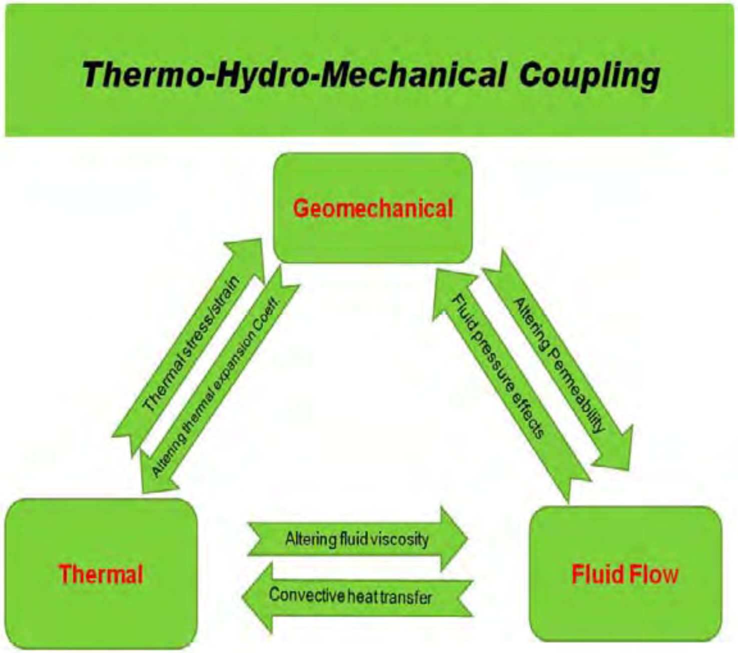
- Why THM important in geomechanics?
  - Dealing with “porous media” requires mechanical as well as fluido-dynamical physics (fully coupled)
  - Temperature can significantly influence the mechanical and hydraulic properties of porous media
- The THM will help simulate:
  - Wellbore stability; thermal well testing; Hydraulic fracturing; Thermal recovery methods such as steam injection, electrical and electromagnetic heating; Surface subsidence; stimulation techniques such as pressure pulse; and chemical applications such as CO2 sequestration

Why COMSOL Multiphysics?

- Fully coupled analysis capability
- PDE application mode can solve multiple, coupled, nonlinear physical models through their governing PDE's
- Compatibility with MATLAB provide extra control over the solution
- Built-in application modes
  - Electromagnetic
  - Chemical
  - Acoustic
- Spatial variability of parameters
- Transient parameter change

Thermo-Hydro-Mechanical Model

- THM deals with 3 physics:
  - Heat transfer (convection/ conduction)
  - Fluid flow (single/multi phase)
  - Mechanical stresses and strains (elastic/ elasto-plastic/ thermal elasto plastic constitutive model)



- Relative strength of coupling links varies (1^{st} /2^{nd} level)

Governing Equations

- Conservation of momentum
- Conservation of mass
- Conservation of energy

- Darcy's law
- Biot's poroelasticity

Governing Equations

- Two-phase Flow (o,w)
- Buckley-Leverett formulation (Pc=0)
- Three phase (o, w, steam), Two component(o,w)

- Thermal effects:
  - Generation of thermal stress
  - Conduction & convection equations
  - Conservation of thermal energy

Geomechanical Effects

- First-level Geomechanical Effects:
  - Lagrange porosity for isothermal condition:

$$\emptyset = \emptyset_0 + \alpha \Delta \varepsilon_v + c_s(\alpha - \emptyset_0)\Delta p$$

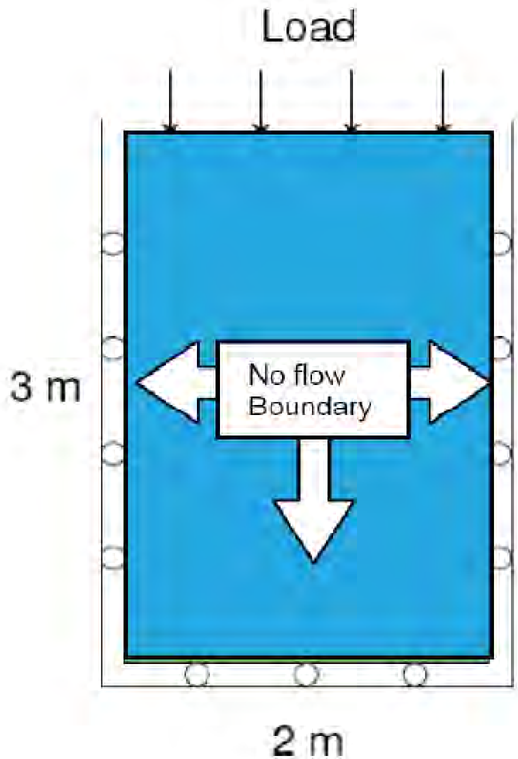
  - Euler's porosity for non-isothermal condition:

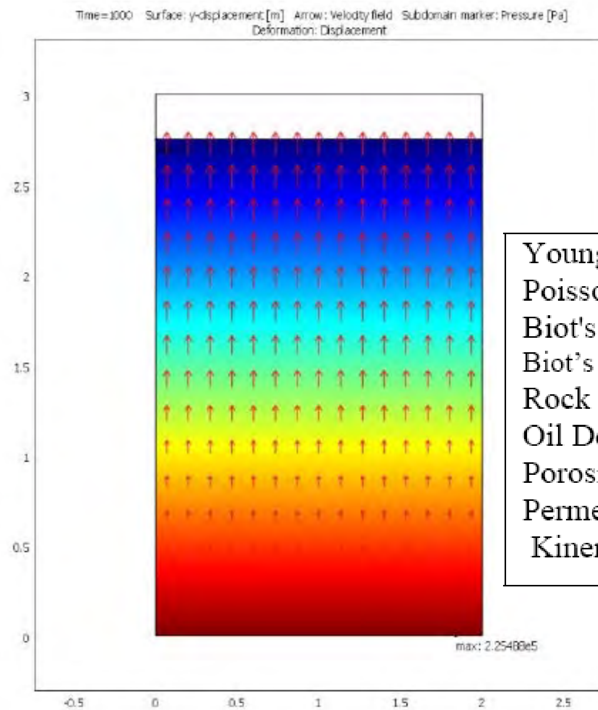
$$\emptyset = \frac{\emptyset_0 + \Delta \varepsilon_v - \alpha_T(1 - \emptyset_0)\Delta T}{1 + \Delta \varepsilon_v}$$

- Second-level Geomechanical Effects:

$$k = k_0 \frac{\left(1 + \frac{\varepsilon_v}{\emptyset_0} - \frac{\alpha_T(1 - \emptyset_0)\Delta T}{\emptyset_0}\right)^3}{1 + \Delta \varepsilon_v} \qquad k = k_0 e^{\left(\frac{5}{\emptyset}\varepsilon_v\right)}$$

Verifying the Model:
1) Uniaxial Compression



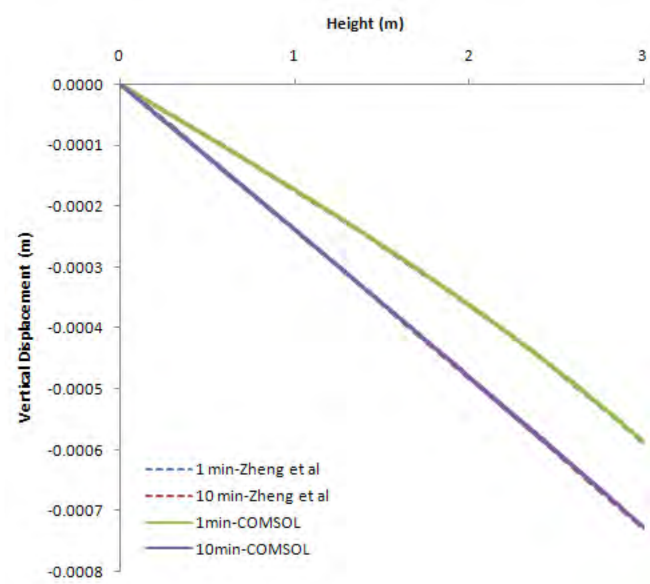


Young's Modulus	1.44×10^{4} MPa
Poisson's Ratio	0.2
Biot's Coefficient,	0.79
Biot's modulus(M)	1.23×10^{4} MPa
Rock Density	2000 kg/m^3
Oil Density	940 kg/m^3
Porosity	0.2
Permeability	2×10^{-13} m^2
Kinematic Viscosity	1.3×10^{-4} m^2/s

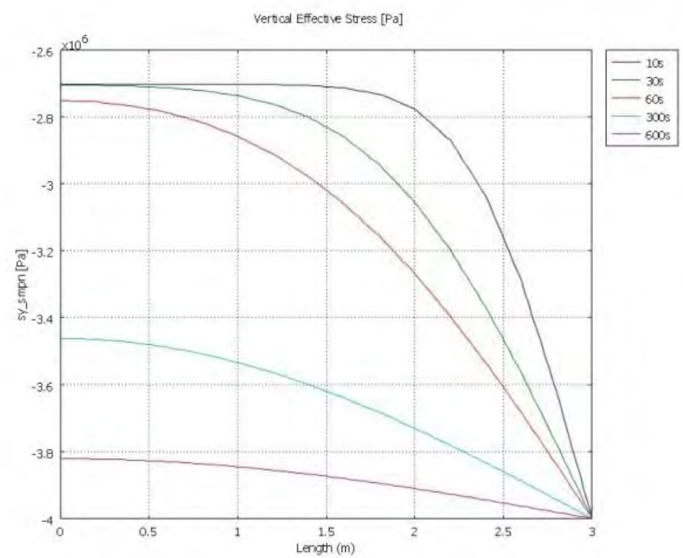
A saturated rock sample undergoing uniaxial compression

Upward water flux due to mechanical deformation.

Verifying the Model:
1) Uniaxial Compression

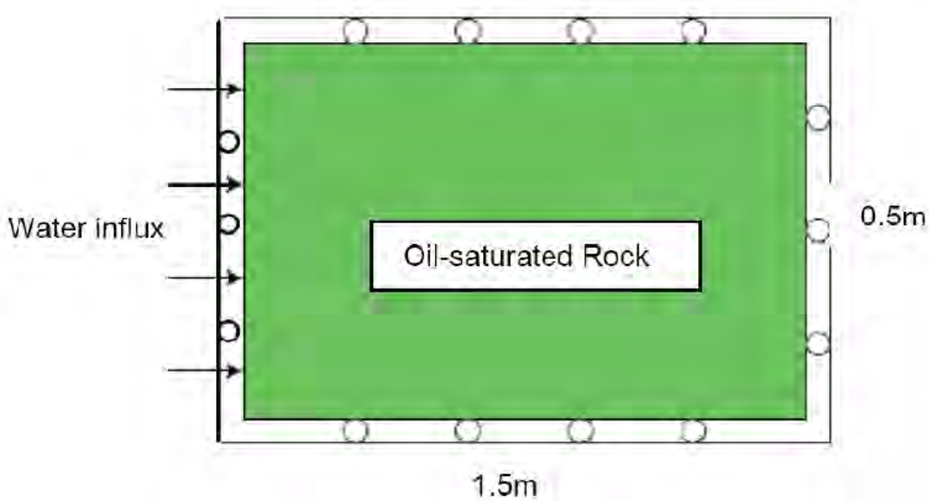


Vertical displacements along the sample at different times after loading

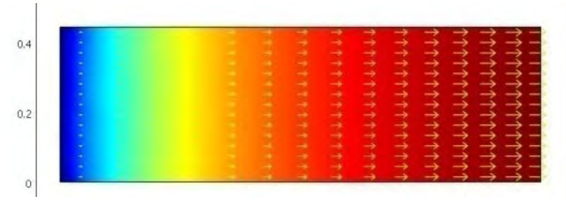


Effective stress along the sample at different times after loading directly from fully coupled hydro-mechanical model.

Verifying the Model: 2) Water Flooding



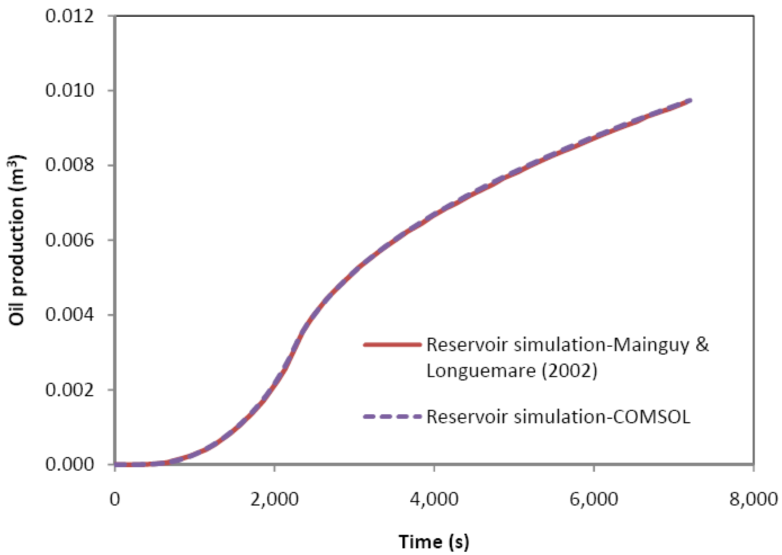
Oil viscosity	0.500 Pa·s
Water viscosity	0.001 Pa·s
Intrinsic permeability	5×10^{-14} m^2
Initial porosity	0.30
Initial oil density	950 kg·m^{-3}
Initial water density	1000 kg·m^{-3}
Water compressibility	4×10^{-10} Pa^{-1}
Oil compressibility	0.000 Pa^{-1}
Water top influx	0.02 kg·m^{-2}·s^{-1}
Drained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



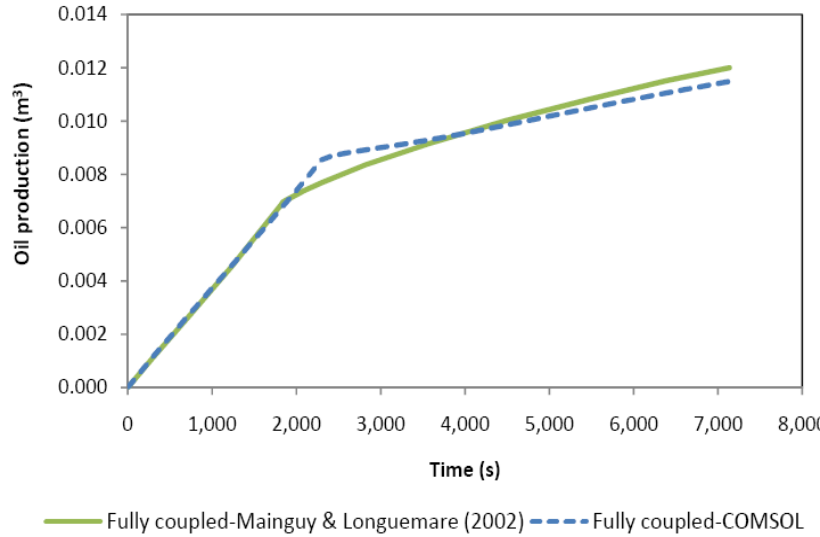
A confined oil-saturated rock sample subject to constant water influx on one side

Oil saturation in the sample two hours after water flooding

Verifying the Model:
2) Water Flooding

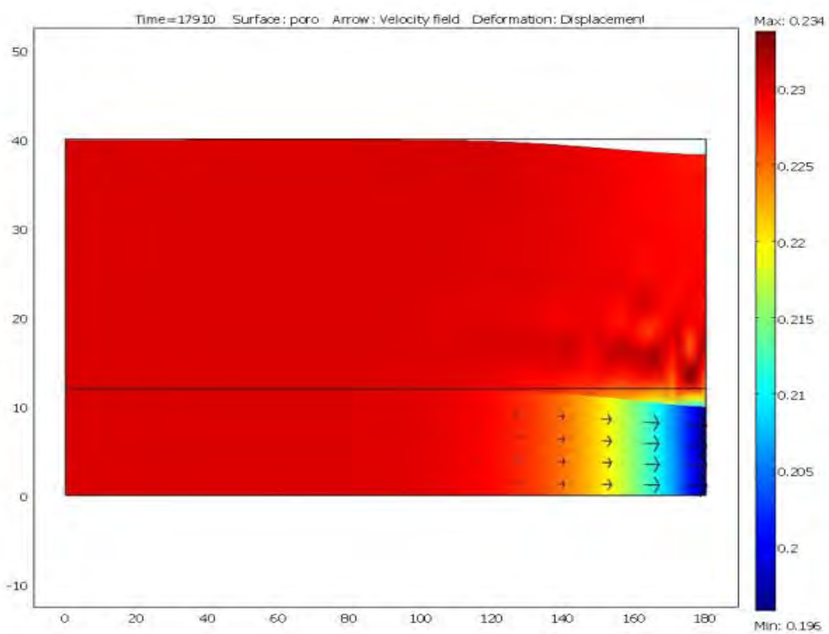


Comparison of oil production from reservoir simulation model , Mainguy & Longuemare (2002) and COMSOL



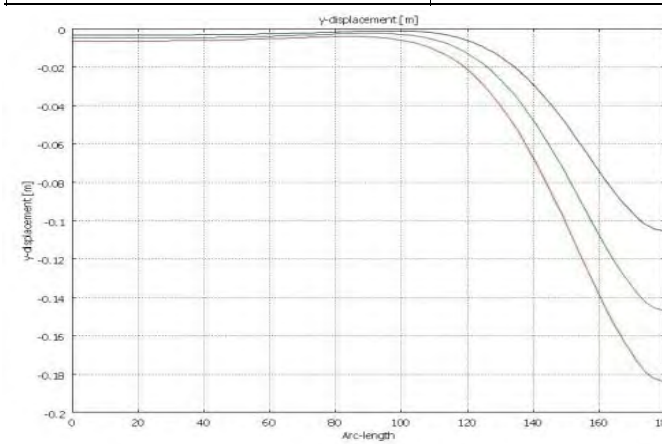
Comparison of oil production from fully coupled model , Mainguy & Longuemare (2002) and COMSOL

Application 1: Surface Subsidence



Surface subsidence as a result of oil production from a reservoir

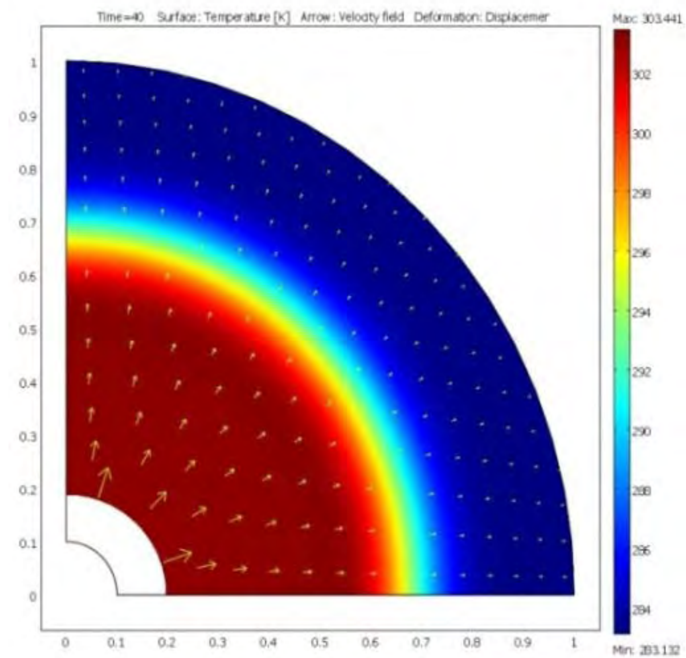
Oil viscosity	0.1 Pa·s
Reservoir permeability	$5x10^{-13}$ m^2
Overlying layer's Permeability	$5x10^{-14}$ m^2
Initial porosity	0.23
Oil density	970 $kg{\cdot}m^{-3}$
Rock density	2000 $kg{\cdot}m^{-3}$
Production rate	0.005 m/h^{-1}
Elastic modulus	1 x 10^{10} Pa
Poisson's ratio	0.25
Biot's modulus (M)	1.3 x 10^{10} Pa
Biot's coefficient	0.85



Surface subsidence 2, 3, and 4 hours after production

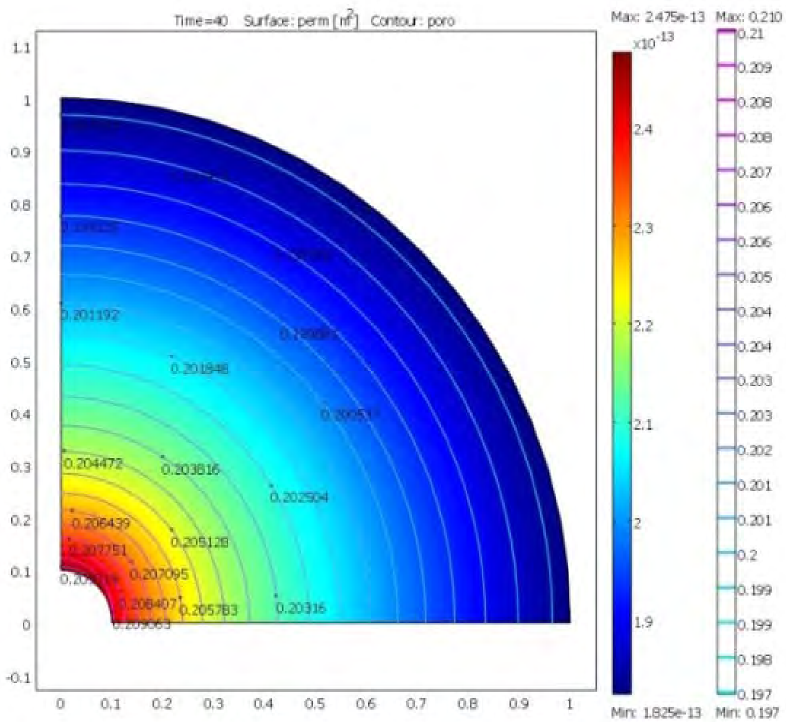
Application 2: Fluid Injection I

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

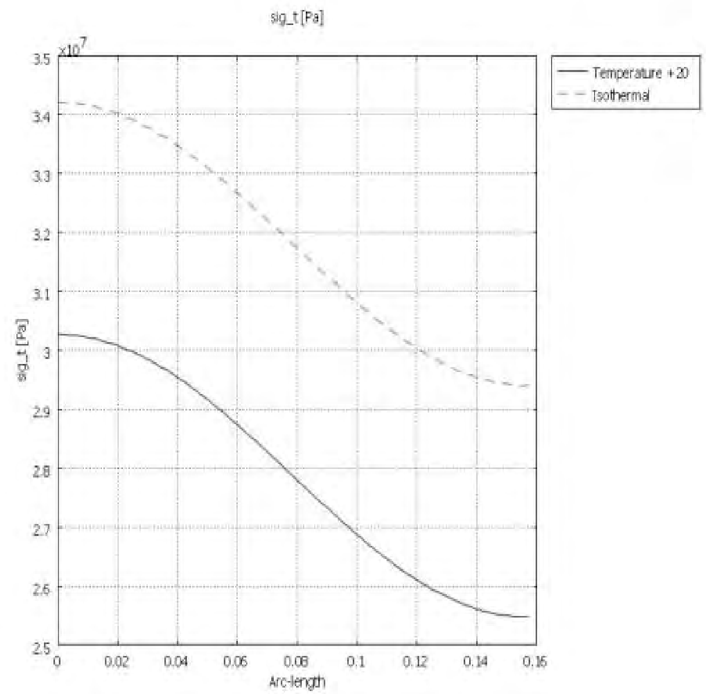


Temperature distribution and wellbore deformation 40 s after water injection

Application 2: Fluid Injection I



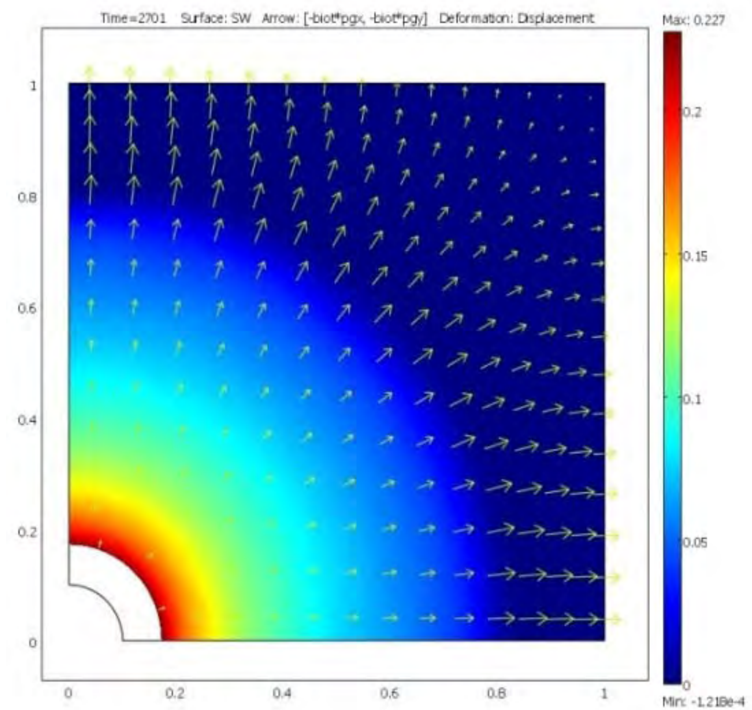
Permeability and porosity change as a function of volumetric strain



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

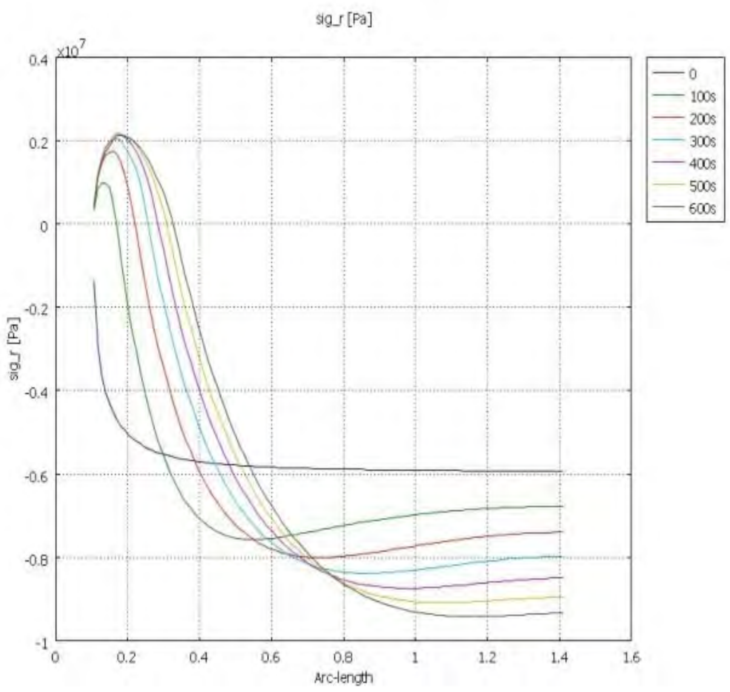
Application 2: Fluid Injection II

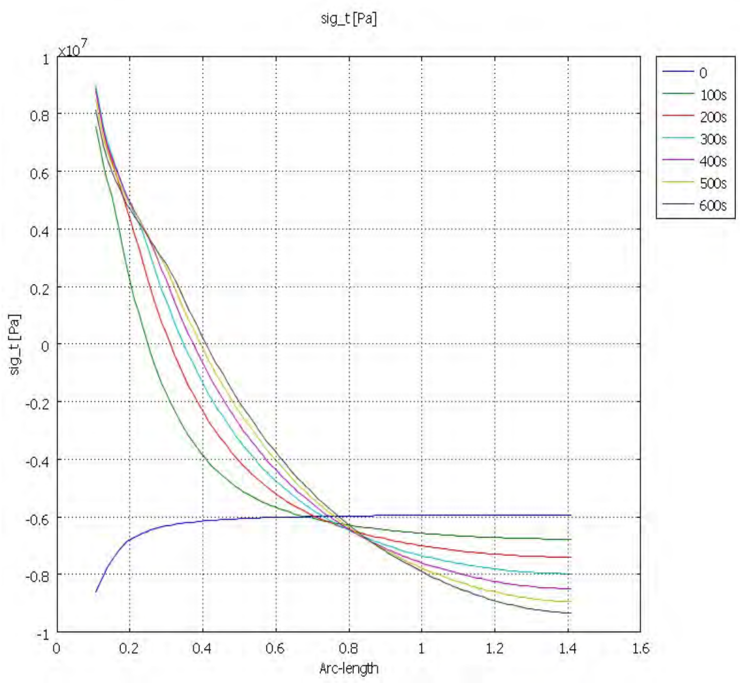
Initial Permeability	$5\text{x}10^{-14}$ m^2
Injection flux	0.02 kg·m^{-2}·s^{-1}
Initial porosity	0. 3
Initial oil density	950 kg·m^{-3}
Initial water density	1000 kg·m^{-3}
Rock density	2400 kg·m^{-3}
Elastic modulus	3 x 10^9 Pa
Poisson's ratio	0.3
Biot's coefficient	0.9
Drained bulk modulus	3 x 10^9 Pa
Vertical in-situ stress	6 x 10^6 Pa
Horizontal in-situ stress (Max)	6.6 x 10^6 Pa
Horizontal in-situ stress (Min)	5.4 x 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	$1\text{x}10^{-5}$ /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 x 10^{-10} Pa^{-1}
oil compressibility	1 x 10^{-10} Pa^{-1}
Pore compressibility	1 x 10^{-9} Pa^{-1}
Wellbore radius	0.1 m
Cohesion (C)	5 x 10^5 Pa
Friction angle	30°
Yield criterion	Drucker-Prager



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

Application 2: Fluid Injection II

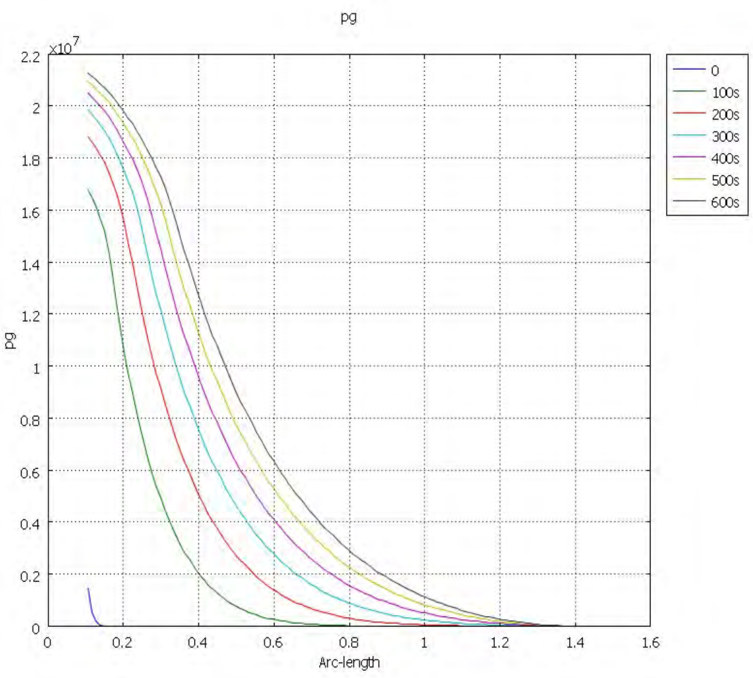




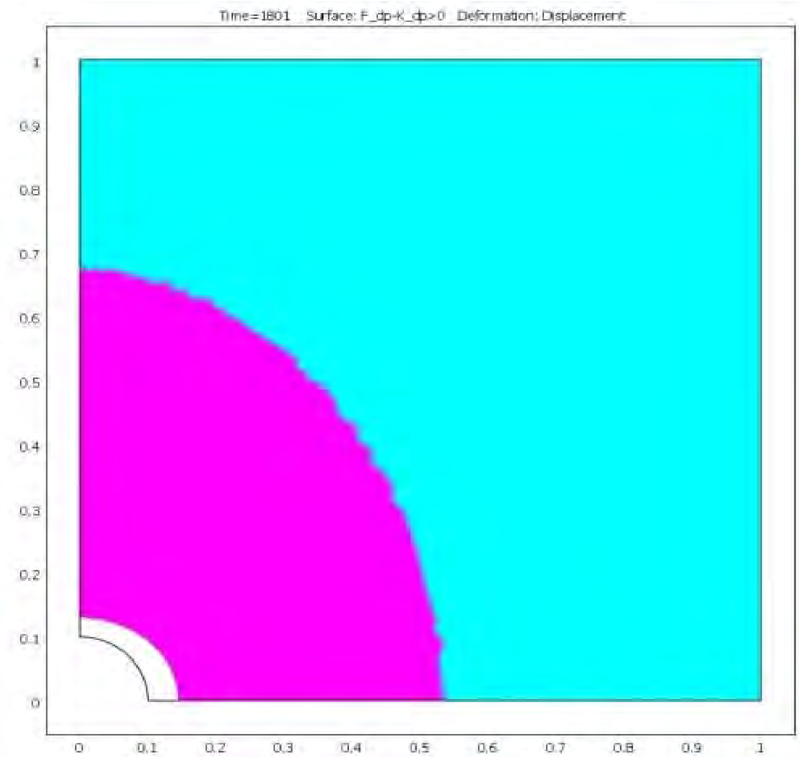
Radial effective stress at different times after injection

Tangential effective stress at different times after injection

Application 2: Fluid Injection II



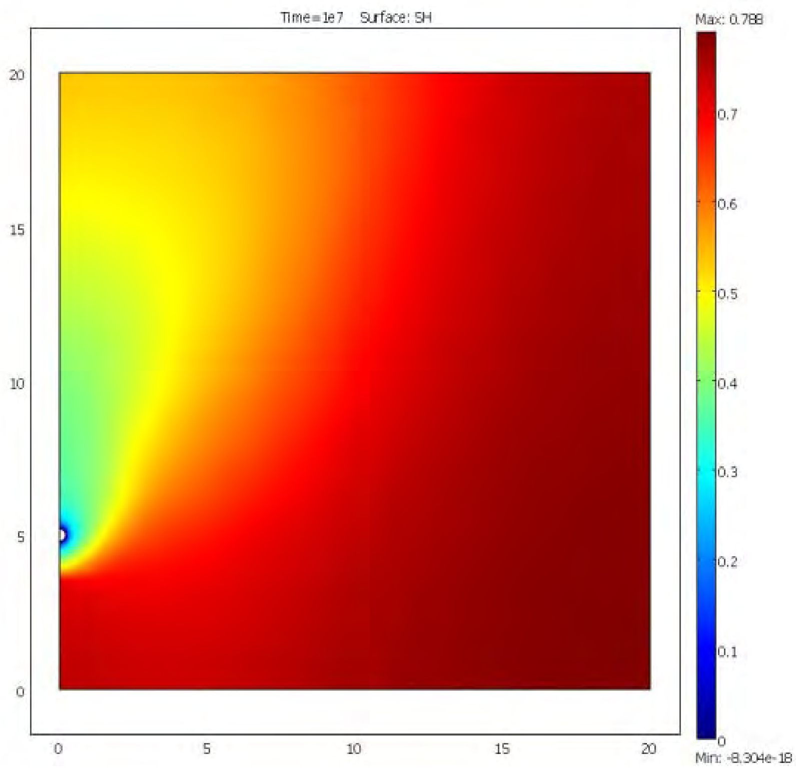
Fluid pressure at different times after injection



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

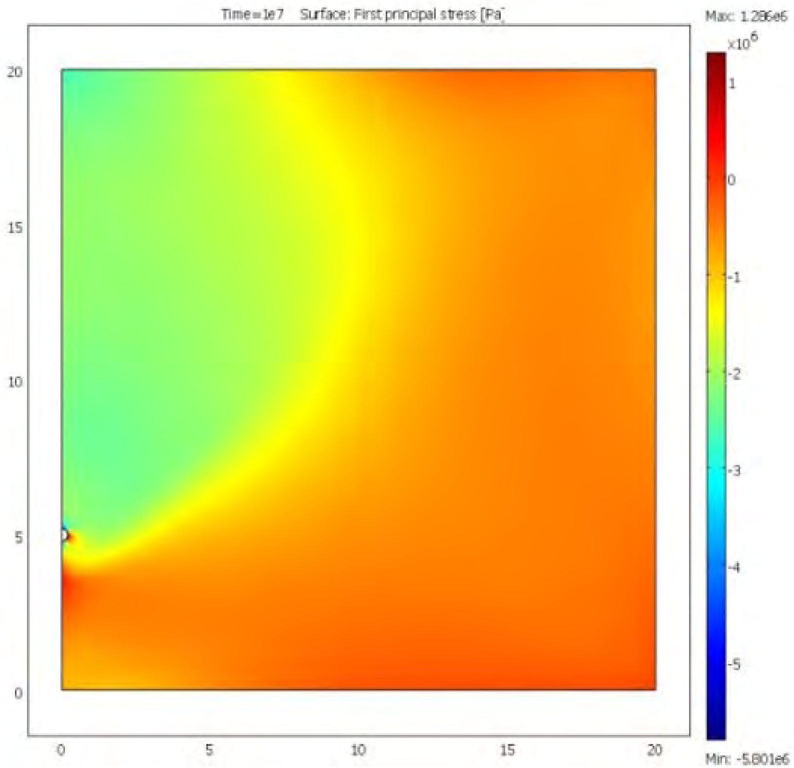
Application 3 : Steam Injection

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 $kg{\cdot}m^{-3}$
Initial water density	1000 $kg{\cdot}m^{-3}$
Rock density	2800 $kg{\cdot}m^{-3}$
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}

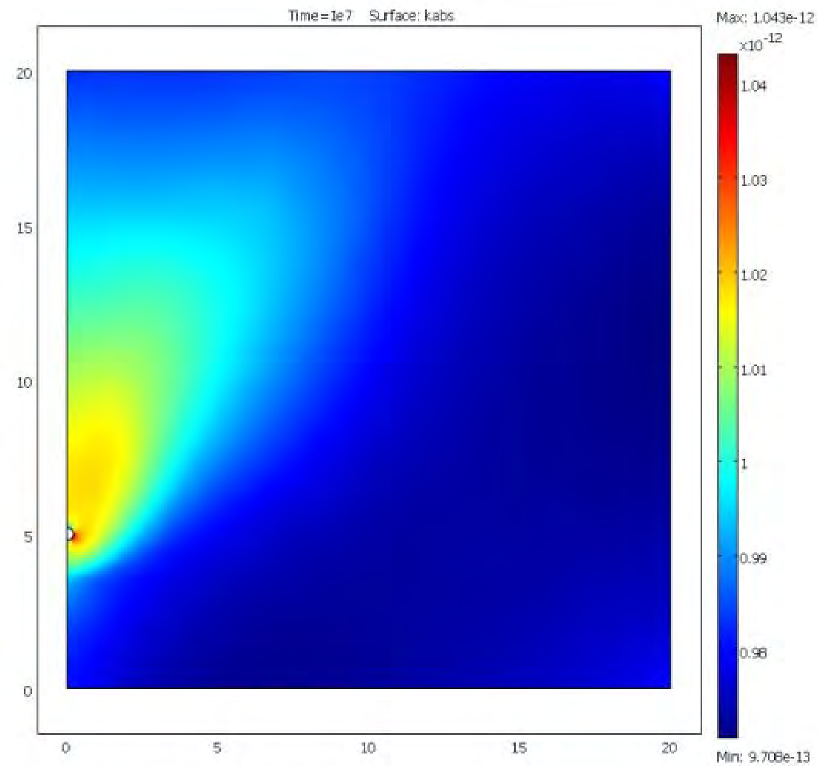


Distribution of oil saturation
115 days after injection

Application 3 : Steam Injection

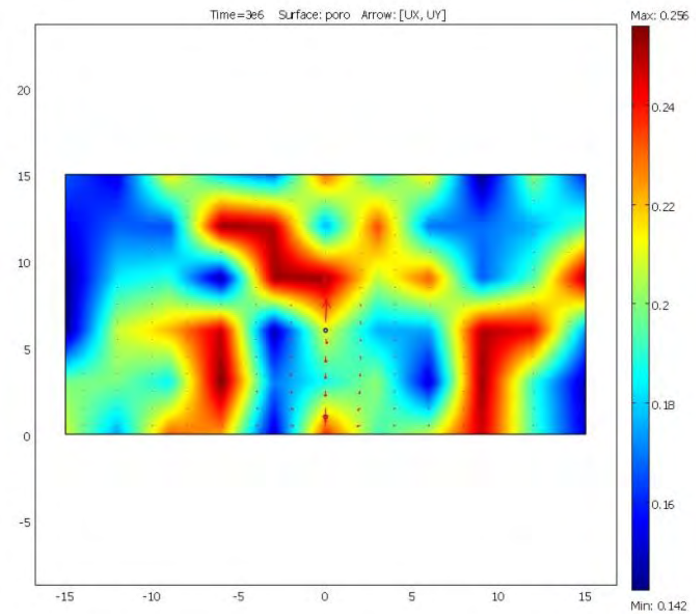


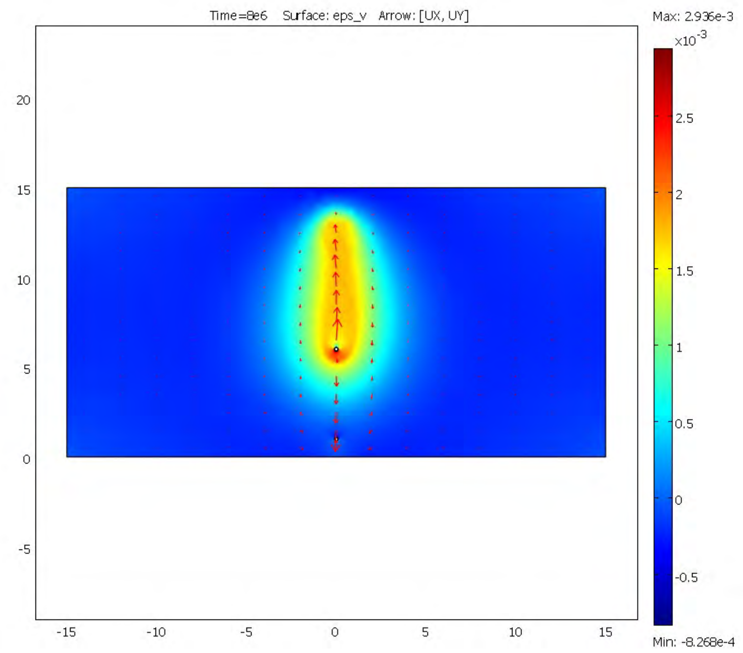
First principle stress distribution generated by steam pressure and temperature



Permeability change as a result of volumetric strains

Application 4 : SAGD





Heterogeneity in reservoir porosity, permeability and mechanical properties

Volumetric strains as a result of steam injection

Future Work

- Examining a Thermal elasto-plastic (TEP) constitutive model for the material
- Electrical recovery
- Electromagnetic heating
- THM-Chemical for CO_2 sequestration or other applications
- Pressure pulse technique
- Stochastic method for modeling heterogeneity

THM Modeling for Reservoir Geomechanical Applications

THANK YOU!