A framework for full waveform modeling and imaging for CO_2 injection at the FRS project

Davood Nowroozi, Donald C. Lawton

ABSTRACT

The Field Research Station (FRS) is a project developed by CMC Research Institutes, Inc. (CMC) and the University of Calgary. It is a CO_2 injection and test site in the south east of Alberta, near Brooks. A well has been drilled to a depth of 550 m and a full set of well log data has been acquired. It is ready for the small volume of CO_2 injection in the shallow targets to be monitored using seismic and other survey types.

During the injection CO_2 in the target layer (300 m depth), dynamic parameters of the reservoir as pressure and phases saturation will change and they can be derived of fluid simulation result. For the project, strategy is five years' injection with constant mass of CO_2 equal to 1000 t/yr. In this case, the CO_2 saturation increases to a maximum of 70% in the injection zone adjacent to the well but is generally between 10 to 50 percent; the CO_2 plume shape is an ellipsoid with radius of 120 m radius and a thickness of 12 m. Based on well log data and dynamic reservoir parameters (CO_2 and brine saturation, and reservoir pressure) the P-wave velocity and density were determined through fluid substitution methods. The bulk modulus of dry rock, fluids, minerals and density after injection was calculated and saturated bulk modulus extracted using Gassmann's equation. Fluid substitution causes a change in acoustic impedance value in injection zone of reservoir.

Time-lapse seismic analysis of reservoir was assessed by seismic finite difference time domain (FDTD) modeling based on an acoustic velocity-stress staggered leapfrog scheme. The FDTD is 2nd order in time and 4th order in space on Central Finite Difference (CFD). The boundary conditions are set on all edges except surface, based on a perfectly matched layers (PML) approach. The effect of CO_2 substitution is a time delay in time domain seismic data under the reservoir because of velocity reduction and also a change in amplitude of reservoir reflections. Based on synthetic models, the difference between base model and time-lapse model after 5 years of CO_2 injection reveals a significant seismic result, because it is a near-surface reservoir. Given that the seismic resolution is high because of the shallow target depth and acquisition parameters, it is expected to improve that seismic monitoring will be an effective method to monitor the CO_2 injection.

INTRODUCTION

The project area covers 1*1 km and it is at a direct distance of 20 km from Brooks, Alberta and 10 km west of Lake Newell (the red squares shows the project area, Figure 1). The research plan is injection a very controlled and limited amount of CO_2 in the shallow layers to monitor migration and behavior of gas plume by seismic and other methods.

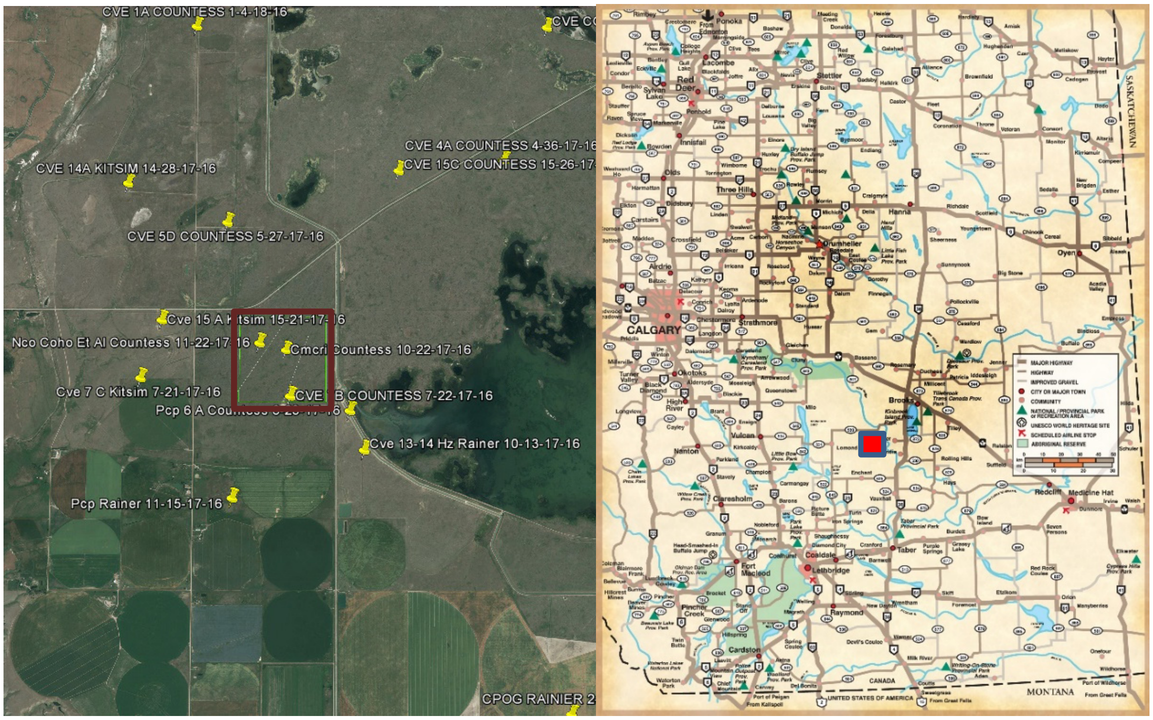

FIG. 1. Location of the project (satellite image from Google Earth)

This paper covers four parts of the research; they are:

- Making a geomodel
- Fluid simulation
- Rock physics study
- Seismic synthetic modeling

Over the next year, the field study will continue with CO_2 injection and seismic time lapse acquisition. Currently, all models are synthetic and these will be compared with real data to demonstrate a new method for higher accuracy and less error in seismic time-lapse monitoring.

Our research method was defined in Figure 2. It demonstrates research elements and relation between them for optimizing data in a reservoir.

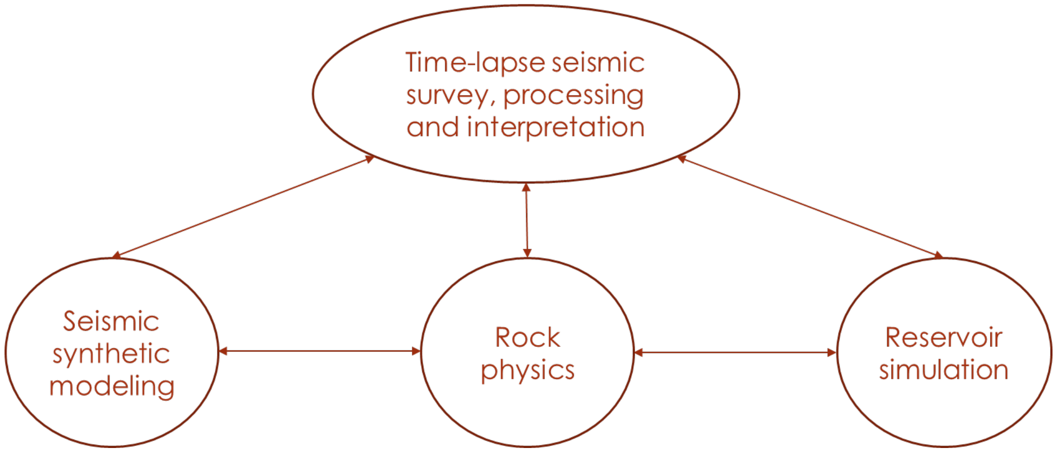

FIG. 2. Research routine for optimizing data quality in different disciplines.

GEOLOGY OF AREA

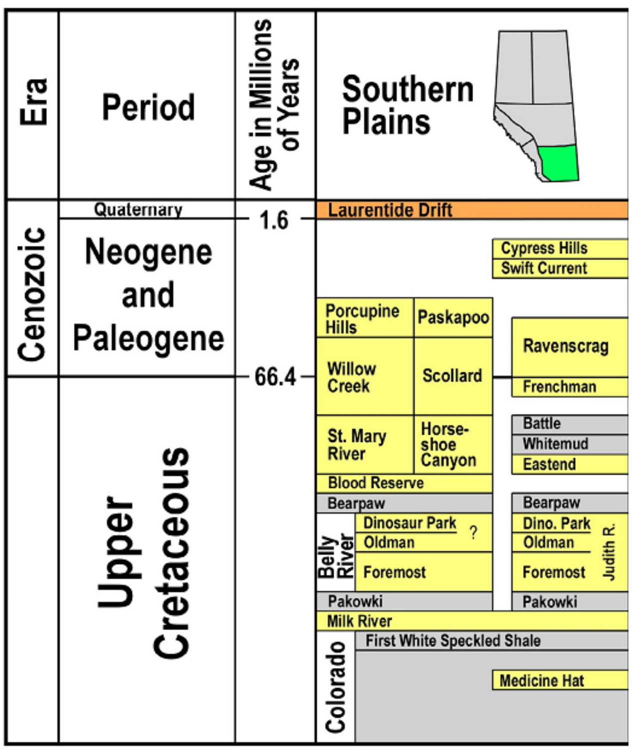

FIG. 3. Geological sequence in the project area (Alberta Southern plains), the first priority is injection in the Belly River sandstone.

The project area is located in southern plains, the injection well drilled from recent to Santonian stage's sediments in upper Cretaceous. In the first phase, the Basal Belly River Formation on the top of Pakowki Fm is the main injection target. The BRS is a continental sediment, primarily a deltaic sandstone. In a deltaic environment or channel deposited sandstone, porosity and permeability are guided by the direction and shape of the channels, which that should be considered in fluid simulation in high amount injection/production.

GEOMODEL

For the mass transfer's calculation and fluid simulation, it needs to collect data from different disciplines that included:

1- Geological set and studies
2- Seismic data and result of interpretation and UGC maps in depth domain
3- Well log data and petrophysical interpretation
4- Core analysis
5- Facies analysis

Procedure for analysis data are:

1- Permeability and porosity estimation
2- Make a suitable grid
3- Upscaling well logs
4- Variogram analysis
5- Final estimation by Kriging
6- Model validation

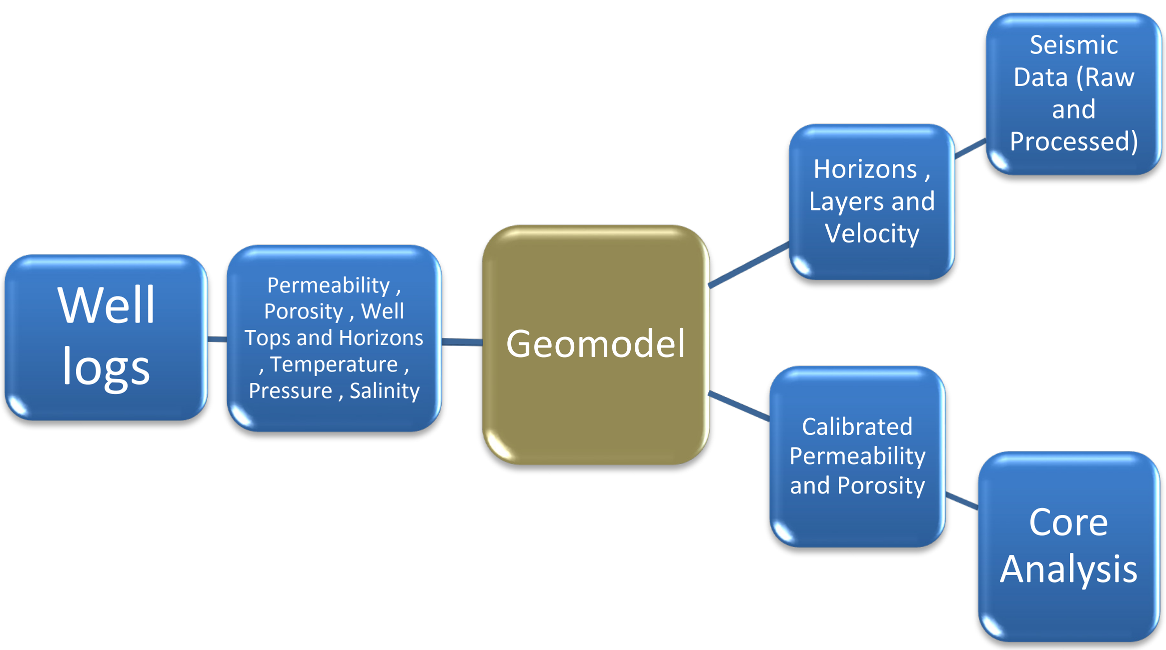

FIG. 4. Procedure for make the FRS geomodel.

For the permeability modeling, Timur-Coates (KTIM) and the Schlumberger-Doll-Research (KSDR) models from NMR log were available and KTIM was used for Kx,y modeling. Because of layering and rapid change in the vertical permeability (or perpendicular to the geological layers), Kz was considered to be 10% of KTIM. Also an average of the porosity logs was considered for geostatistical porosity model.

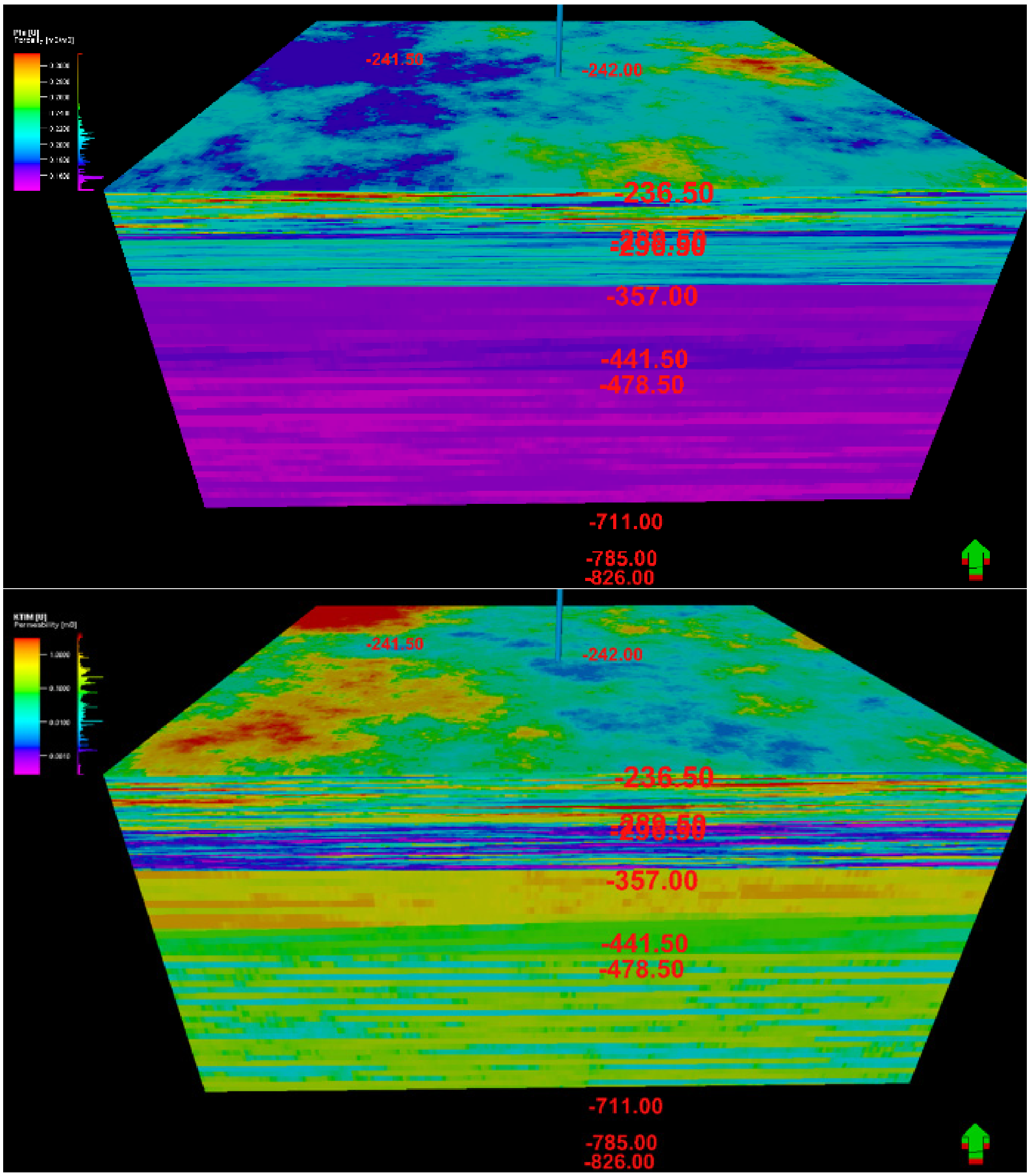

FIG. 5. Porosity (up) and Permeability (X, Y) (down) models, size of geomodel is 1*1 km.

The result of geostatistical analysis on well and seismic data yielded a geomodel that is the basis for fluid simulation. An accurate geomodel can guarantee a precise result for fluid simulation.

RESERVOIR SIMULATION

Reservoir simulation is a direct method to model fluid flow in a reservoir or more generally in porous media. One side of simulation is for managing and optimizing production/recovery (in this study injection) rate and reduction in production/injection cost.

For hydrocarbon reservoir simulation, the continuity equation is a main aproach. The conservation law in reservoir (conservation of mass, energy and momentum) is essential of mass balance and the continuity equation. In simple form, for each cell a combination of Darcy's law and material balance are solved.

Darcy's law:

$$\mathbf{q} = -\frac{\mathbf{k}}{\boldsymbol{\mu}}\nabla\mathbf{P} \qquad (\mathbf{eq.1})$$

Material Balance:

$$-\frac{\partial \mathbf{J_x}}{\partial \mathbf{x}} - \frac{\partial \mathbf{J_y}}{\partial \mathbf{y}} - \frac{\partial \mathbf{J_z}}{\partial \mathbf{z}} - \mathbf{q} = \frac{\partial \mathbf{C_l}}{\partial \mathbf{t}} \qquad (\mathbf{eq.2})$$

or:

$$-\nabla.\boldsymbol{M} = \frac{\partial}{\partial t}(\emptyset\boldsymbol{\rho}) + \frac{\boldsymbol{Q}}{\boldsymbol{\rho}} \qquad (\mathbf{eq.3})$$

and simulator flow equation:

$$\nabla.[\boldsymbol{\lambda}(\nabla\boldsymbol{P} - \boldsymbol{\gamma}\nabla\boldsymbol{z})] = \frac{\partial}{\partial t}\left(\frac{\emptyset}{\boldsymbol{\beta}}\right) + \frac{\boldsymbol{Q}}{\boldsymbol{\rho}} \qquad (\mathbf{eq.4})$$

Black-oil and compositional models are two approach for simulation. The black oil simulator that is used in this paper is suitable for three component and three phases that their properties are function of pressure and for cases that composition not change in reservoir.

The compositional simulator can support multi-component and multi-phase reservoirs based on the equation of state (EOS) modeling that may may generate new components due to chemical reactions as miscible gas injection. The compositional method is expensive and takes a longer time compared with a black oil simulator.

For a Black oil simulation, geometry and property, fluid property and well production/injection are needed. Geometry and properties is for grid and cell coordinates and size and static properties of each of them (for example porosity). Other parameters are fluid properties that cover phase viscosities, solution gas-oil ratio (R_s) and relative permeability. Wells production/injection schedule is the end part, in this section effect of production or injection will enter to simulation as our last term of material balance or simulator flow equation (Fanchi,2006).

FLUID SIMULATION

Primary data for simulation

For the simulation, some data as PVT table, injection strategy, relative permeability, water salinity and rock compressibility constitute the essential information. The pressure and temperature of reservoir calculated by log data and temperature gradient as Figure 6.

For the relative permeability, a study about CO_2 in sandstone formations in Western Canada was available and used for the calculation (Bachu,2013).

Water salinity also assumed a very light amount as 1000 ppm.

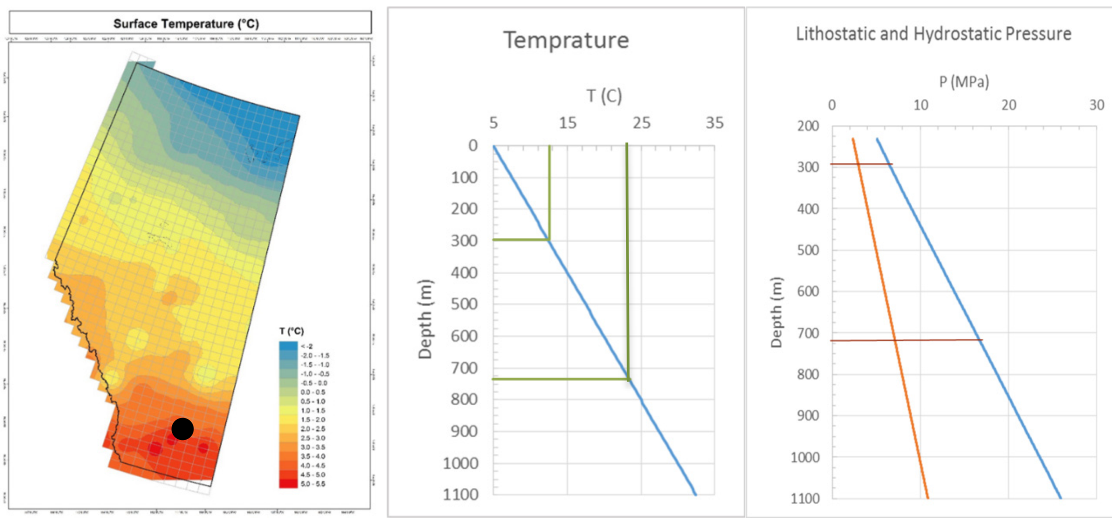

FIG.6. Surface temperature in Alberta (dark circle is on the project area) and underground temperature according to temperature increase rate as 23.5 °C per Km, third shape is lithostatic pressure according to well log data and hydrostatic pressure.

The injection strategy is considered as a constant mass amount of CO_2 equal to 1000 tonne/years for five years.

Pressure and saturation

The CO_2 saturation amount is related to trapping efficiency (Bachu, 2013) and irreducible water amount. For the low permeability area as the injection target in sandstone, trapping efficacy can be up to 65 percent (Bachu, 2013). The irreducible water amount can be calculated by using difference of total saturation (by Archi's equation) and free fluid from the NMR log.

However, the simulation for a selected injection strategy shows that maximum saturation in the injection point can reach to maximum 70% and the reservoir pressure is may increase to values higher than fracture pressure equal to 140 bar. The numerical simulation result is going directly to the next part for the rock physics study and velocity/density/acoustic impedance calculation.

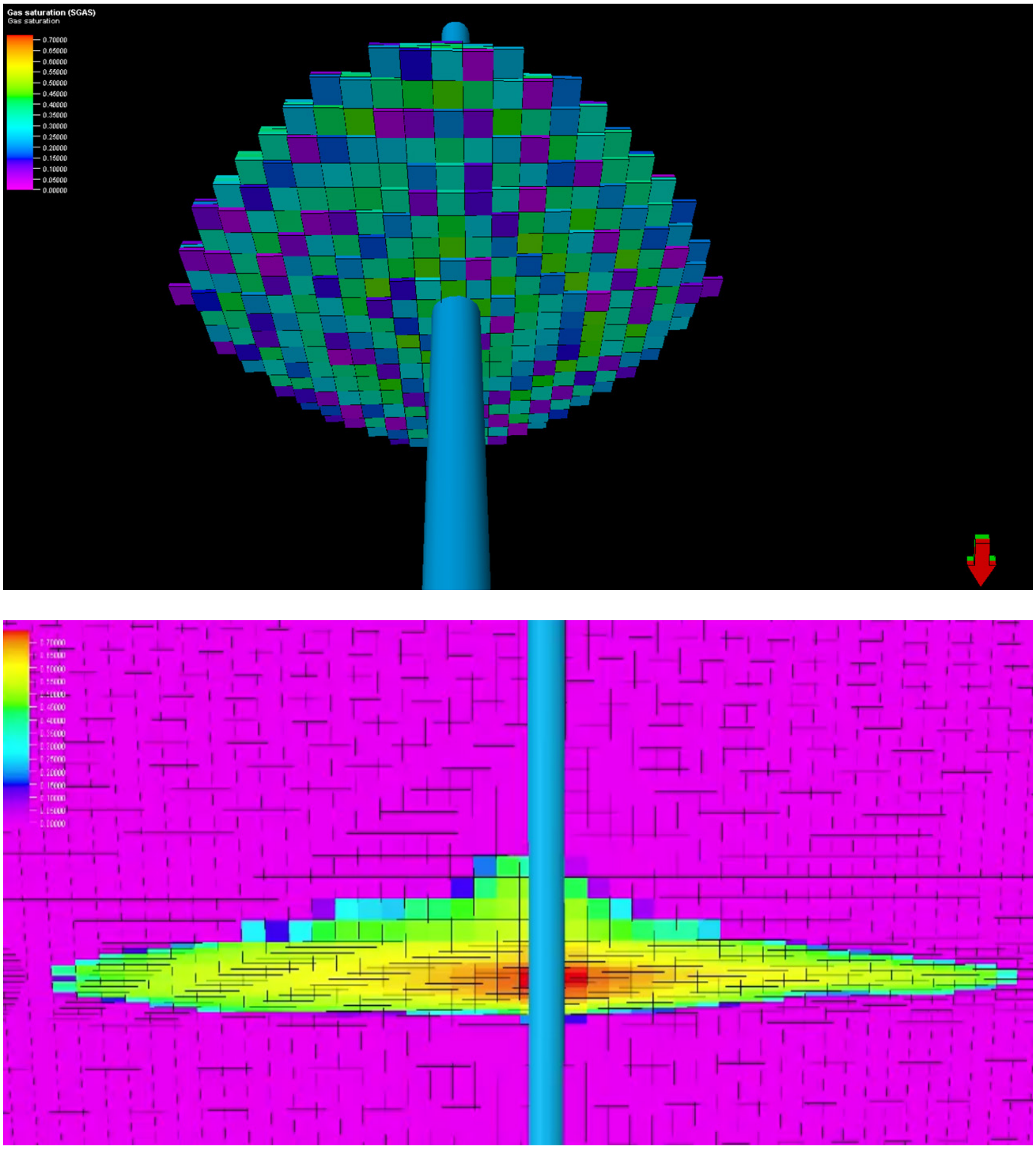

FIG 7. CO_2 gas saturation distribution after five years' injection

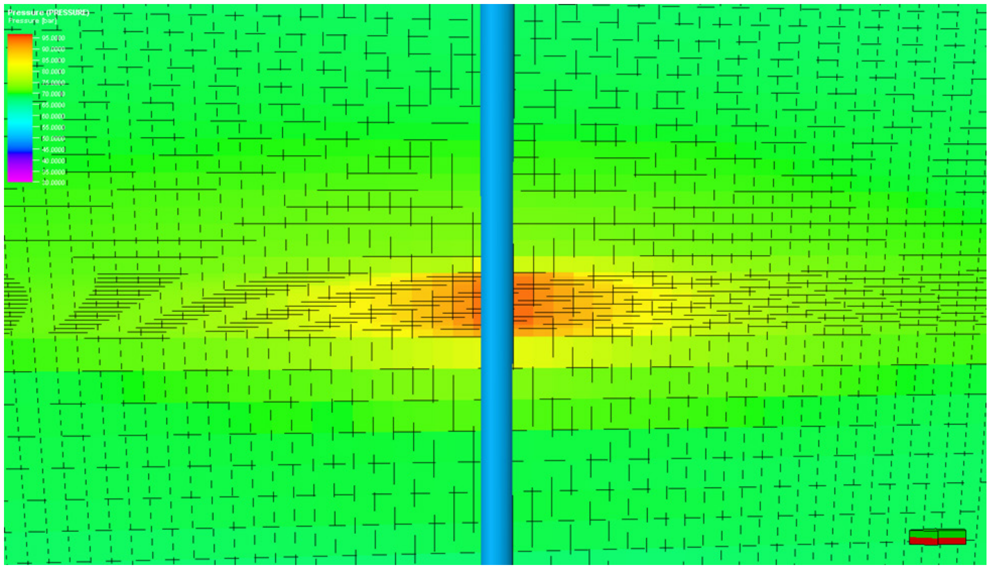

Fig.8. Reservoir pressure after five years CO_2 injection

Velocity change due to fluid substitution

Fluid substitution in a porous media can change physical properties. Velocity and density are two parameters that change during fluid substitution and they are manifested by changes in seismic signature of the rock. Gassmann's equation is a theoretical approach that relates saturated bulk modulus to bulk modulus of mineral matrix (mono mineral), bulk modulus of the fluid, bulk modulus of the porous rock frame and porosity. The first part of Gassmann's equation can be stated as:

$$K^* = K_d + \frac{\left(1-\frac{K_d}{K_m}\right)^2}{\frac{\varphi}{K_f}+\frac{1-\varphi}{K_m}-\left(\frac{K_d}{K_m^2}\right)} \qquad \text{(Eq. 5)}$$

K^* = The saturated bulk modulus (undrained of pore fluids)

K_d = The bulk modulus of the dry porous rock = frame

K_m = The bulk modulus of the solid rock matrix material

K_f = The bulk modulus of the fluid saturating the porous rock

Φ = The porosity of the rock.

P and S waves are controlled by shear (μ) and bulk modulus (K) as following formula:

$$vp = \sqrt{\frac{K+\frac{4}{3}\mu}{\rho}} \quad , vs= \sqrt{\frac{\mu}{\rho}} \qquad \text{(Eq. 6)}$$

For the two last formulae, if velocity is km/s and density in gm/cc, K and G will be in GPa. It is assumed that in the fluid substitution procedure, shear modulus stays constant.

Other form of Gassmann's equation is useful for the direct velocity calculation for the fully fluid saturated porous rock is as following (Gerritsma, 2005):

$$V_P = \left[\frac{K_d + 4\mu_b/3 + n^2 M}{\rho_{sat}} \right]^{1/2} \qquad \text{(Eq.7)}$$

$$V_S = \left[\frac{\mu_b}{\rho_{sat}} \right]^{1/2} \qquad \text{(Eq.8)}$$

where

$$M = \frac{1}{\frac{\Phi}{K_f} + \frac{1-\Phi}{K_m} - \frac{K_d}{K_m^2}} \qquad \text{(Eq.9)}$$

$$n = \left(1 - K_d/K_m\right) \qquad \text{(Eq.10)}$$

in which

K_d, K_m , K_f, Φ described in Gassmann's main equation

$\mu_d = \mu_{sat}$ = the shear modulus of the dry porous rock

$\rho_{sat} = \rho_b$ = the density of the saturated rock; $\rho_{sat} = \Phi\rho_f + (1-\Phi)\rho_m$

ρ_f = the density of the fluid saturating the porous rock

ρ_m = the density of the solid matrix material.

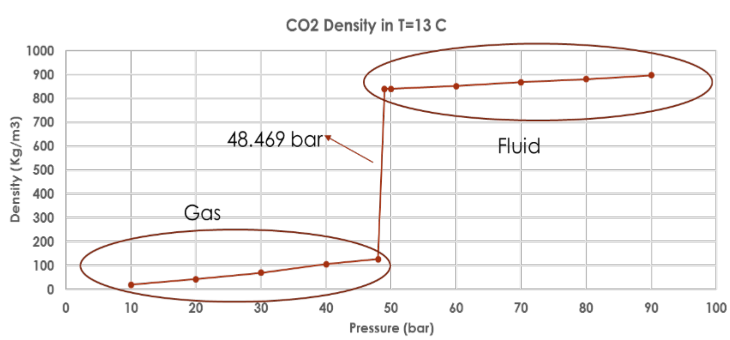

FIG. 9.CO_2 Phase change during the injection because of pressure change

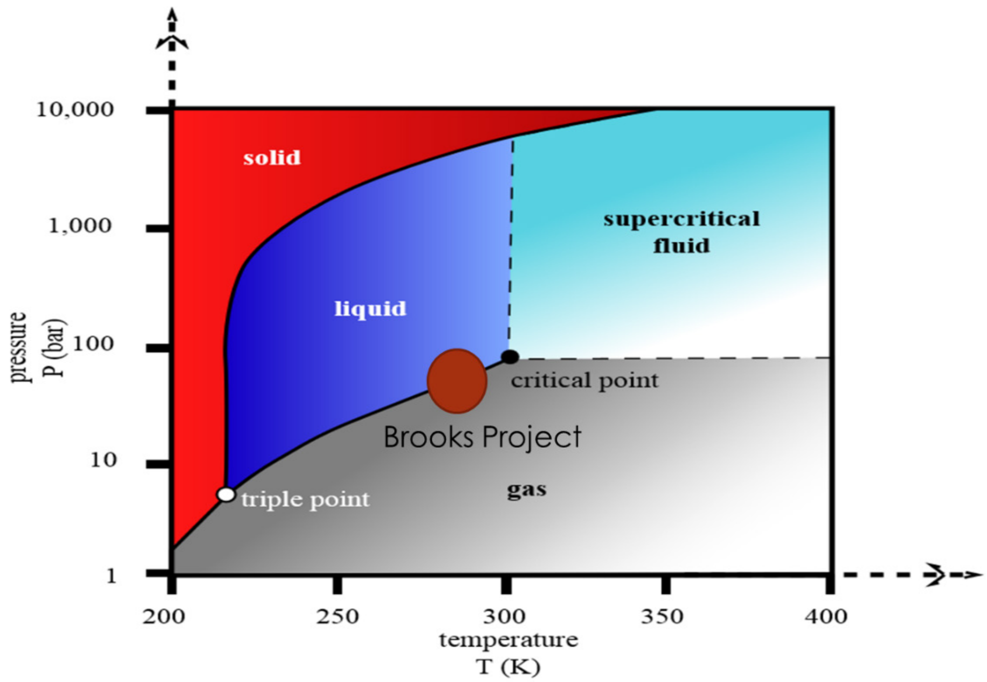

FIG. 10. CO_2 phase diagram (red circle shows the FRS reservoir condition during injection)

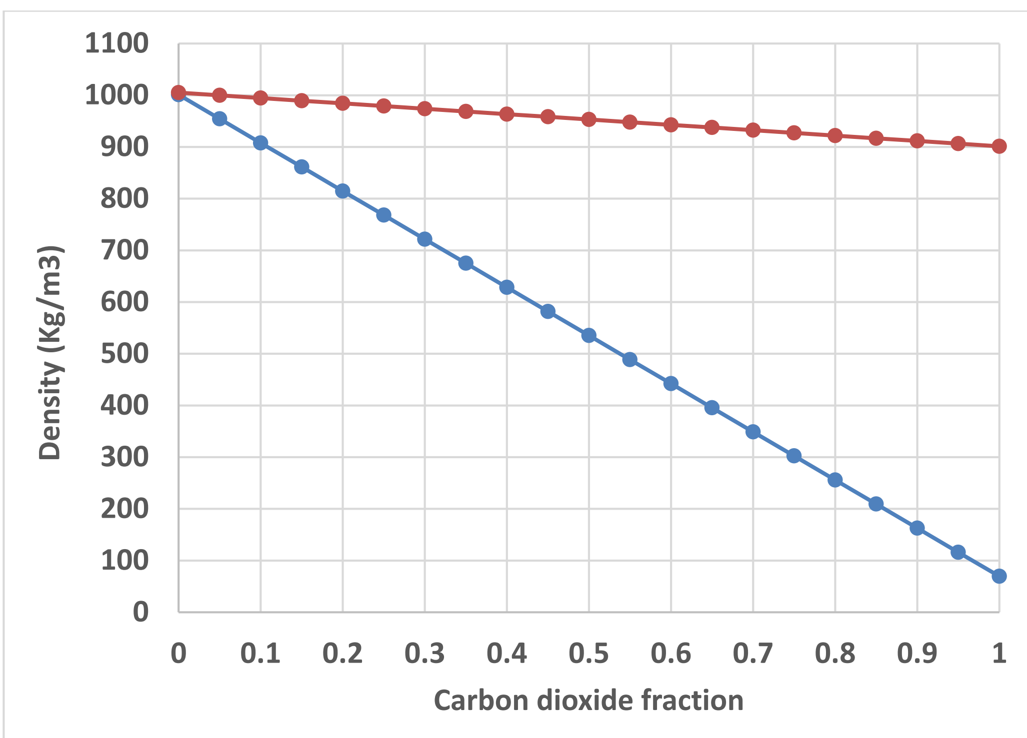

FIG. 11. CO_2 Phase density for brine and CO_2 mix during injection for the pressure less than 48.469 bar for CO_2 in gas phase (blue line) and higher for liquid phase (red)

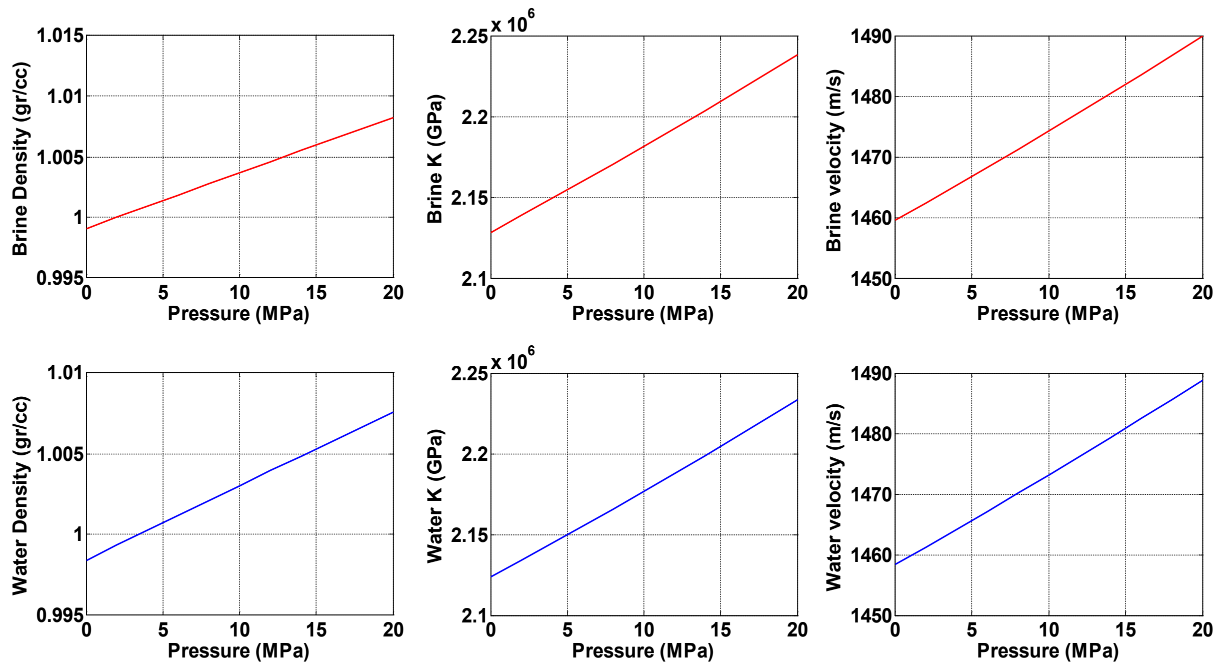

FIG.12. Water and Brine physical properties (Bulk modulus (K), Velocity, Density) in the reservoir condition (T=13, P=4-20 MPa, Salinity 1000 ppm)

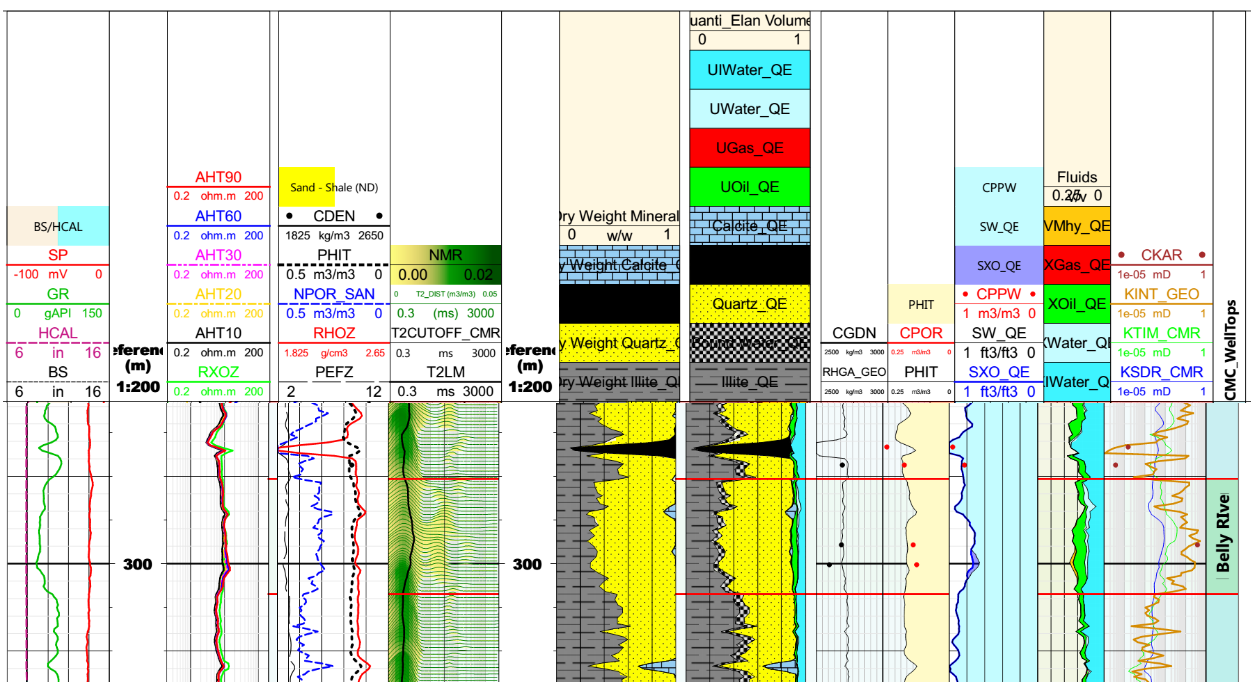

FIG. 13. Lithology of the injection zone by petrophysical interpretation (Schlumberger)

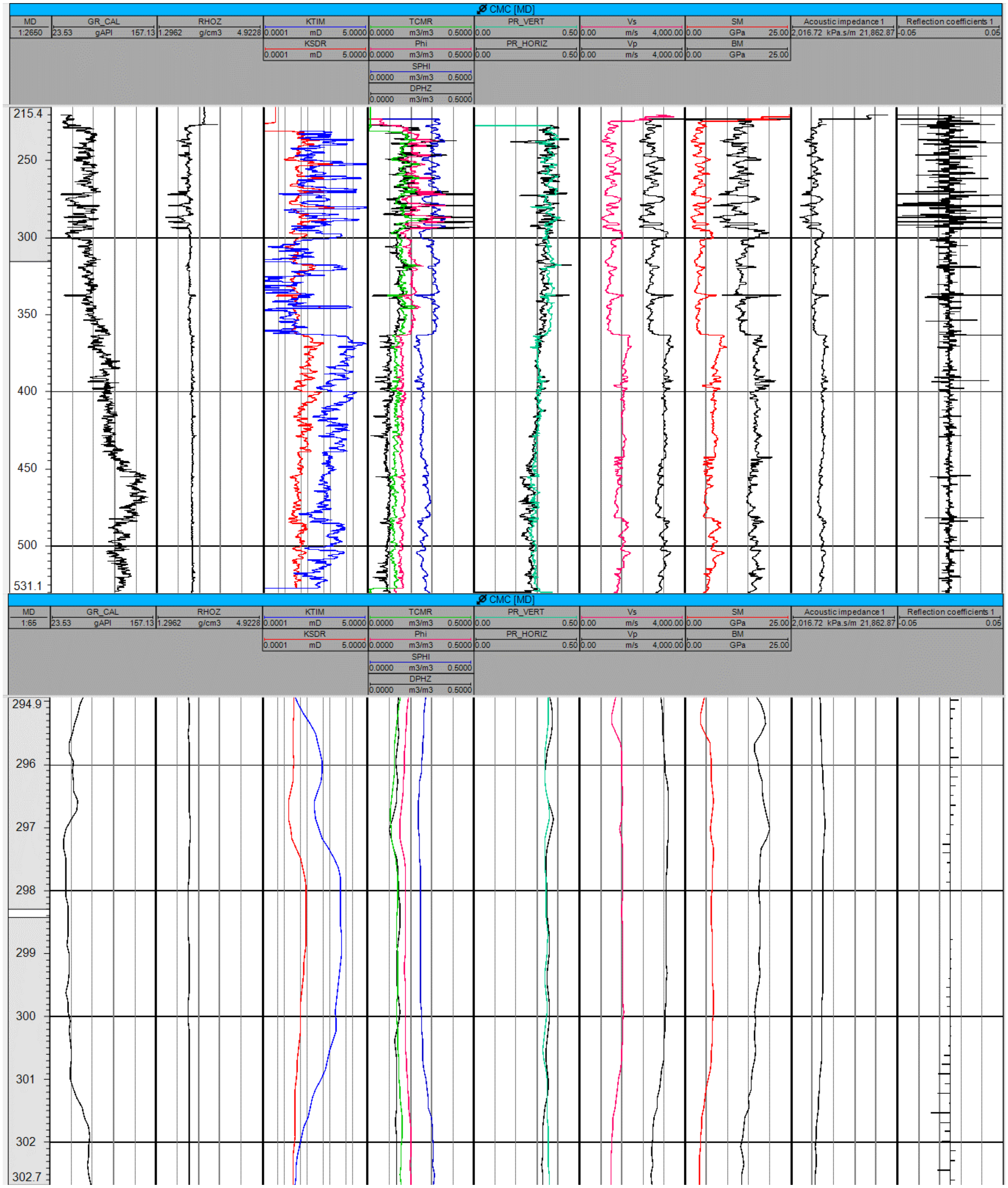

FIG.14. Base well log data for the injection well (top) and horizon (bottom) included: Track 1: Gama ray (gAPI) , Track 2: Density (g/cm3), Track 3: NMR permeability(KTIM and KSDR) , Track 4: Porosity (NMR porosity (TCMR) , Sonic porosity, Density porosity and red line shows average porosity) , Track 5 : Poisson's ratio (Vertical and Horizontal) , Track 6: P wave and S wave velocities, , Track 7: Dynamic Bulk and Shear modulus, Track 8: Acoustic Impedance, Track 9: Reflection coefficient.

Using rock physics and Gassmann's equations with the available data, shows a one percent change in the bulk density and maximum a seven percent decrease in the acoustic impedance.

FWI MODEL

As mentioned in the previous parts, velocity and density in the reservoir will have changed after CO_2 injection and it will affect the seismic data. In this part, two models were made for the base data before and after injection. In order to perform the FWI of CO_2 injection, an acoustic approximation is used for time laps waveform analysis and solved according to seismic finite difference time domain (FDTD) modeling code based on acoustic velocity-stress staggered leapfrog scheme.

The FDTD is 2nd order in time and 4th order in space on central finite difference (CFD). The boundary conditions are set on all edges except surface based on Prefectly Matched Layers (PML) of the following references.

The first test is for a single shot data with 500 m geophones spread in each side of well. Position of the shot is located on the well. Figure 15 shows a layer cake model of P-wave velocity according to CMC well data, and Figures 16,17,18 are synthetic data for pressure, vertical and horizontal displacements for the base model.

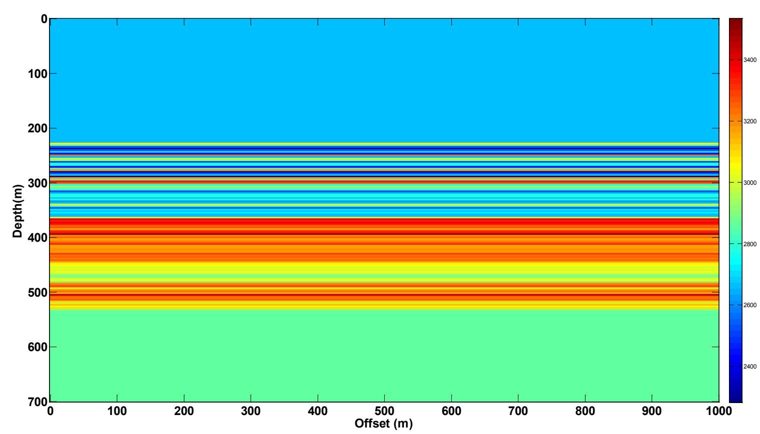

FIG.15. Initial velocity model for the project area made by CMC main well data

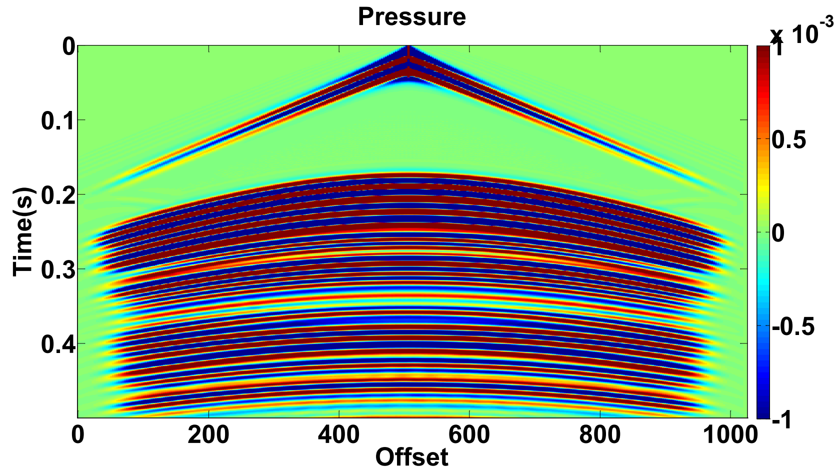

FIG.16. Synthetic shot (pressure) for initial model (before injection), (GI=3 m)

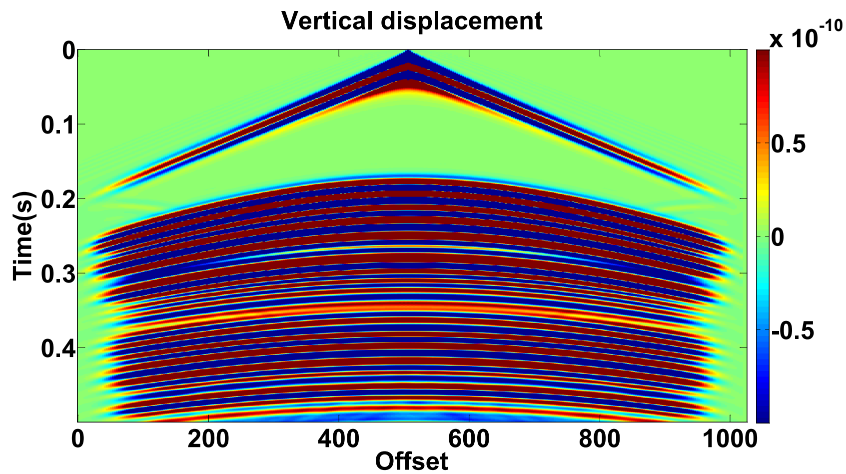

FIG.17. Synthetic shot (vertical displacement) for initial model (before injection)

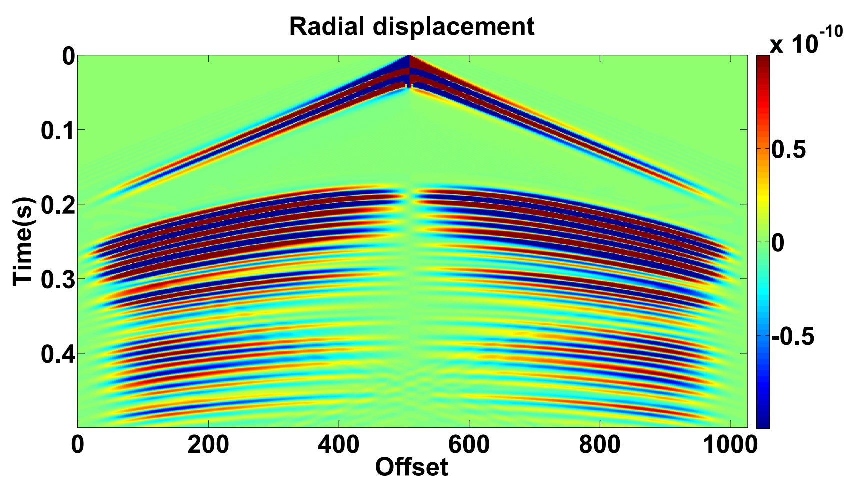

FIG.18. Synthetic shot (radial component displacement) for initial model (before injection)

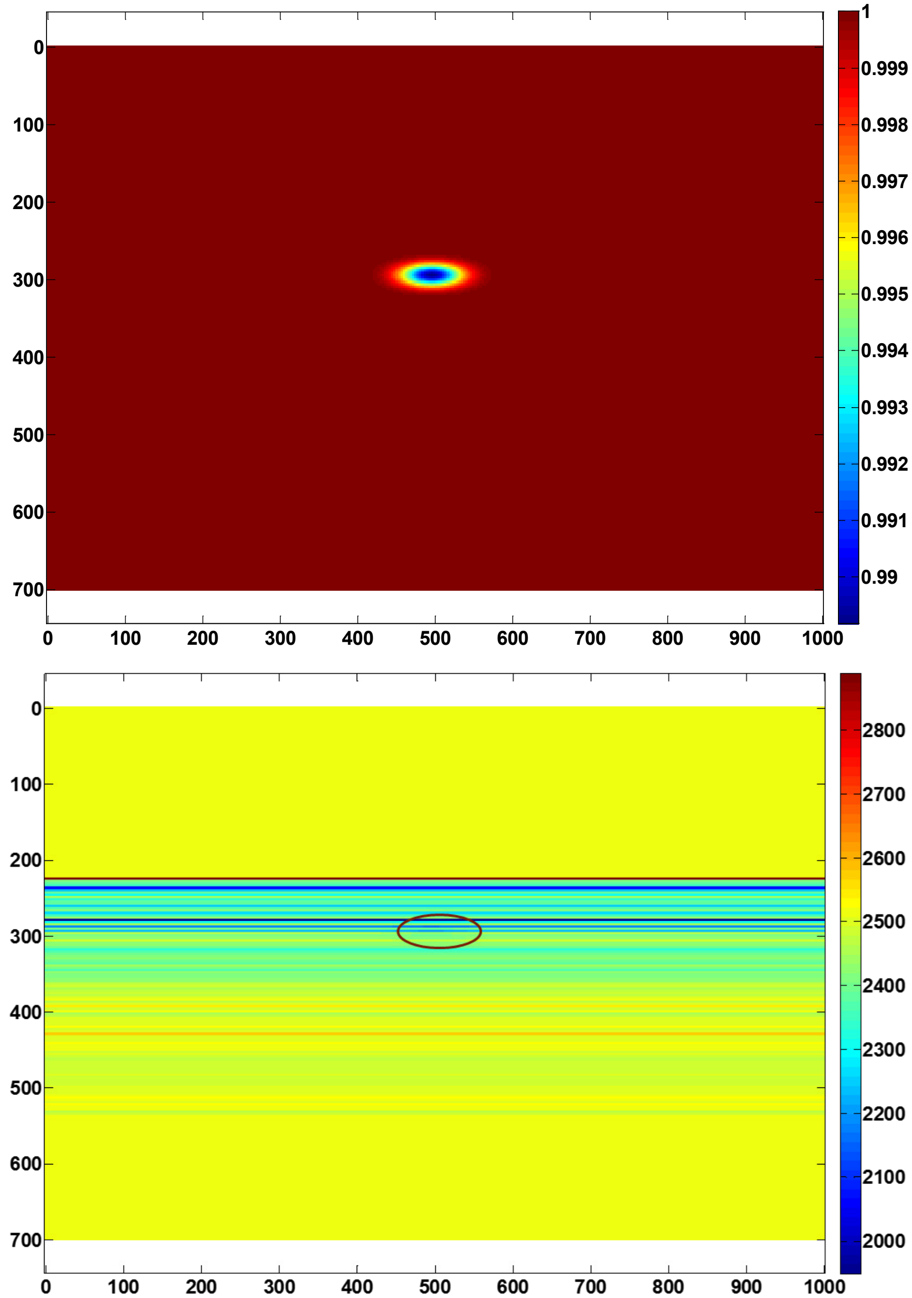

FIG.19. Density change after the injection procedure, the top image demonstrated one percent change in density by the injection and the bottom image is the layer cake model of density.

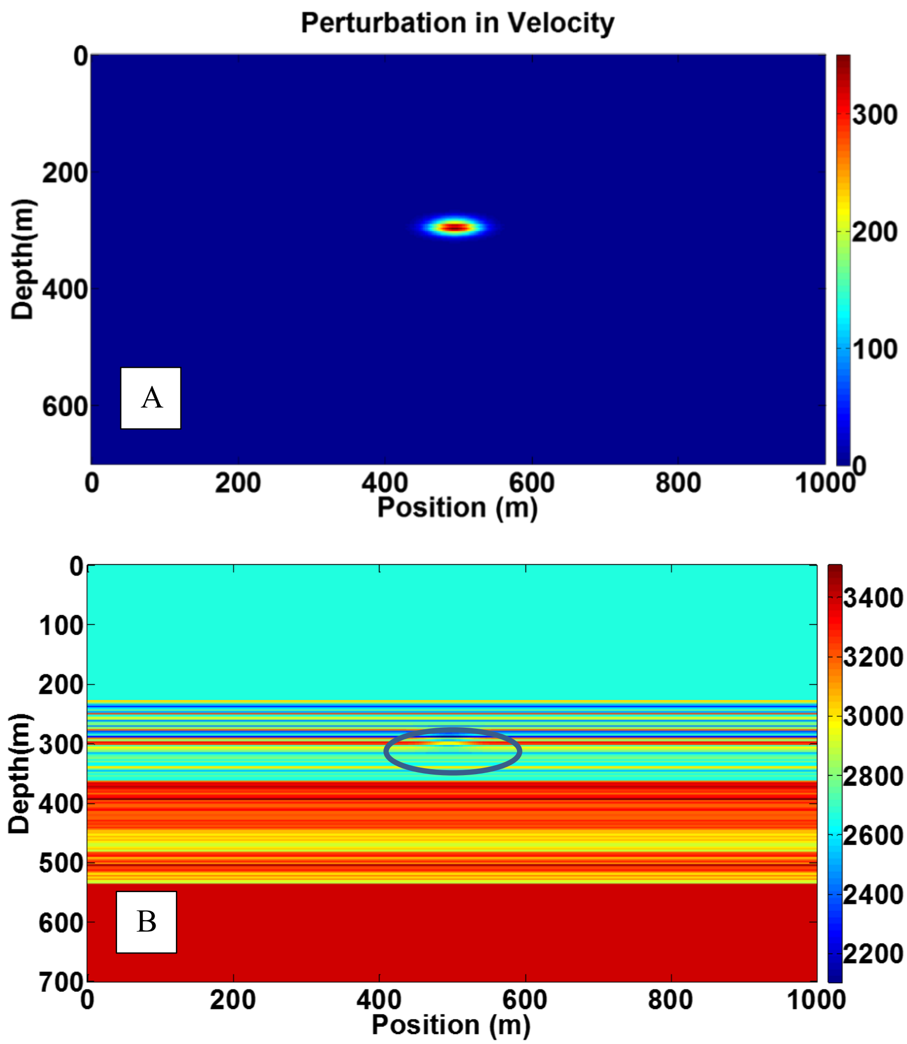

FIG.20. A and B. Velocity perturbation due to gas injection calculated by Gassmann's equation in the Basal Belly River sandstone

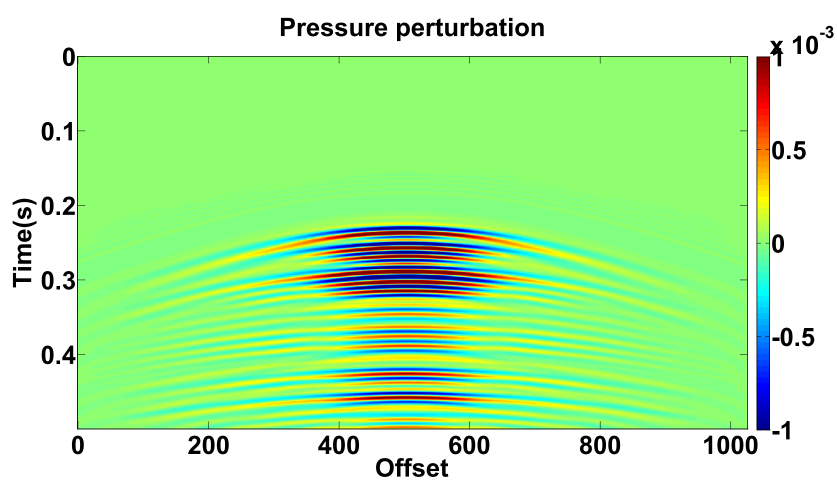

FIG. 21. Pressure differences in raw shot model (time lapse-base), model was built by 1 km geophones spread with RI=3m.

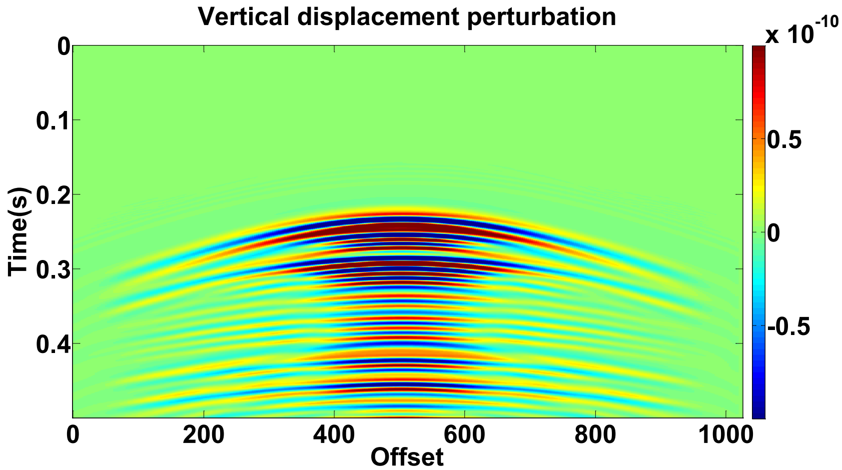

FIG. 22. Vertical displacement difference between baseline and monitor shots

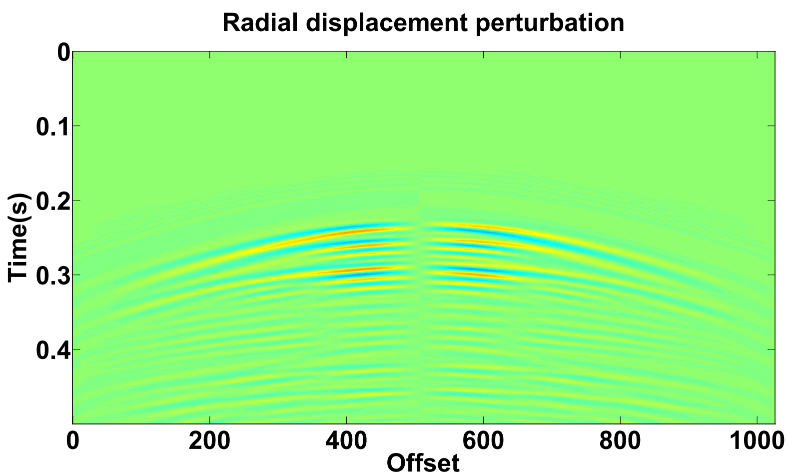

FIG.23. Radial displacement difference between baseline and monitor shots.

For a complementary seismic time lapse research, we focused on a full 2D seismic model with a full data processing with RTM (Reverse Time Migration). The RTM algorithm assumes two-way wave equation but associated imaging condition is one-way wave equation (i.e., convolution of downgoing and upgoing waves). Result of difference between the monitor and baseline data generating synthetic models after processing has been demonstrated in Figure 24. In this model, the receiver spread is 1 km long with 200 shots and GI=SI=3m.

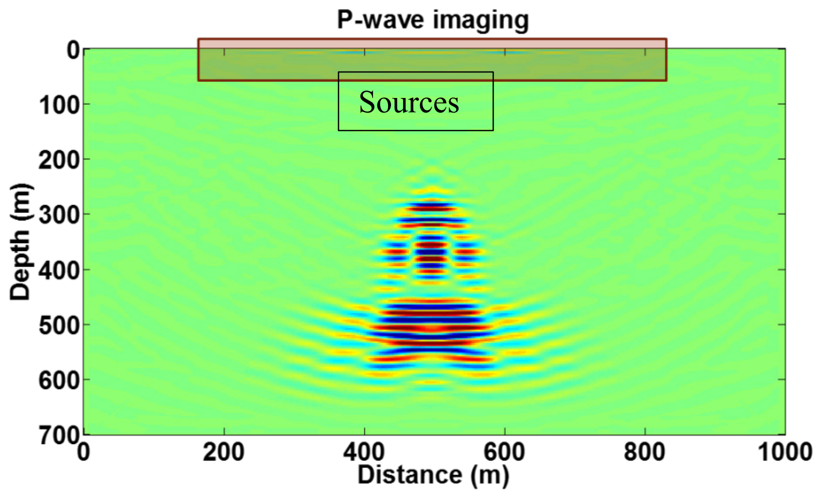

FIG .24. Migrated difference of a 2D line acquisition on the reservoir, the image is differentiated in 2nd order to remove the low frequency artefact of Reverse Time Migration.

CONCLUSIONS

For this project we made at least five different geomodels with the different data sets and sizes. The main geomodel made by CMC injection well data and (1*1 km) it tested for the simulation. The fluid simulation result demonstrated a CO_2 plume as ellipsoid with 120 m radius and 12 m thickness. For the simulation two strategy were used that result of constant mass injection was target of rock physics study and seismic modeling. The saturation of CO_2 reached to maximum 70 percent and, the bulk modulus and P-wave velocity were estimated by Gassmann's equation and also acoustic impedance demonstrates a decrease up to 7% in the centre of the reservoir.

In the seismic modeling part, a single shot across the well with 1 km receivers spread and group interval of 3 m and a 2D line were modeled. In the baseline shot it is possible to recognize a remarkable change for the time lapse model. A difference of 2D model (base model-monitor model) was migrated and it reveled a realistic seismic change was observed. The study area has very simple layer-cake geology, dip angle of layers is less than two degrees, the surface is flat with no static problem and injection zone is in very shallow depth. So the next step will be a field injection and time lapse seismic acquisition, that it can be compared with the synthetic model. We expect that inversion and study of real seismic time lapse data also can improve the geomodel and simulation result and one step forward in the seismic 4D reservoir studies.

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