3D Time-lapse Seismic Modeling for CO_2 Sequestration

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Outline

- Background/Introduction
- Methods
- Preliminary Results
- Future Work

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Goal

Flow simulation for time-lapse seismic modeling

To monitor:

- CO_2 movement and containment
- Long term CO_2 stability

To evaluate:

- Effectiveness of 4D seismic (CO_2 injection causes change of seismic response)

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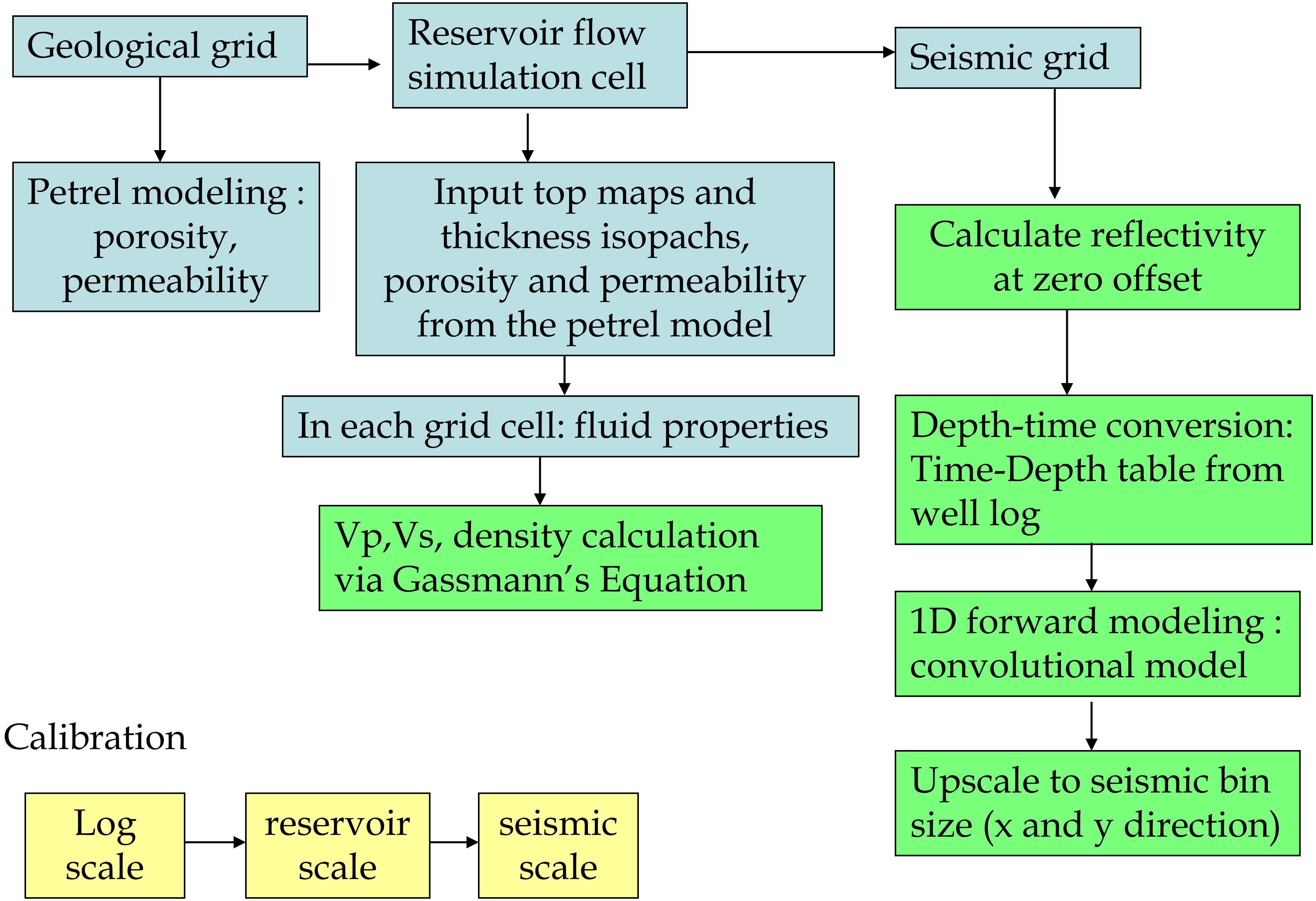
Flow Simulation

- Simulate liquid and gas flow in real world conditions

Geology (reservoir) → Flow simulation → Seismic modeling

- Generalized equation of state compositional simulator (GEM)- **by CMG (computation modeling group).** Used for:
  - CO_2 capture and storage (CCS)
  - CO_2 enhanced oil recovery


Geological grid
Reservoir flow simulation cell
Seismic grid
Petrel modeling : porosity, permeability
Input top maps and thickness isopachs, porosity and permeability from the petrel model
Calculate reflectivity at zero offset
In each grid cell: fluid properties
Depth-time conversion: Time-Depth table from well log
Vp,Vs, density calculation via Gassmann’s Equation
1D forward modeling : convolutional model
Calibration
Upscale to seismic bin size (x and y direction)
Log scale
reservoir scale
seismic scale

Background

- Study area: Dickman Field, Kansas
- Geology: carbonate build-ups, karst feature
- Two CO_2 capture and storage targets
    - Deep Saline Aquifer - primary
    - Shallower depleted oil reservoir - secondary

Dickman Field

Location: Ness County
Kansas State

Field Site

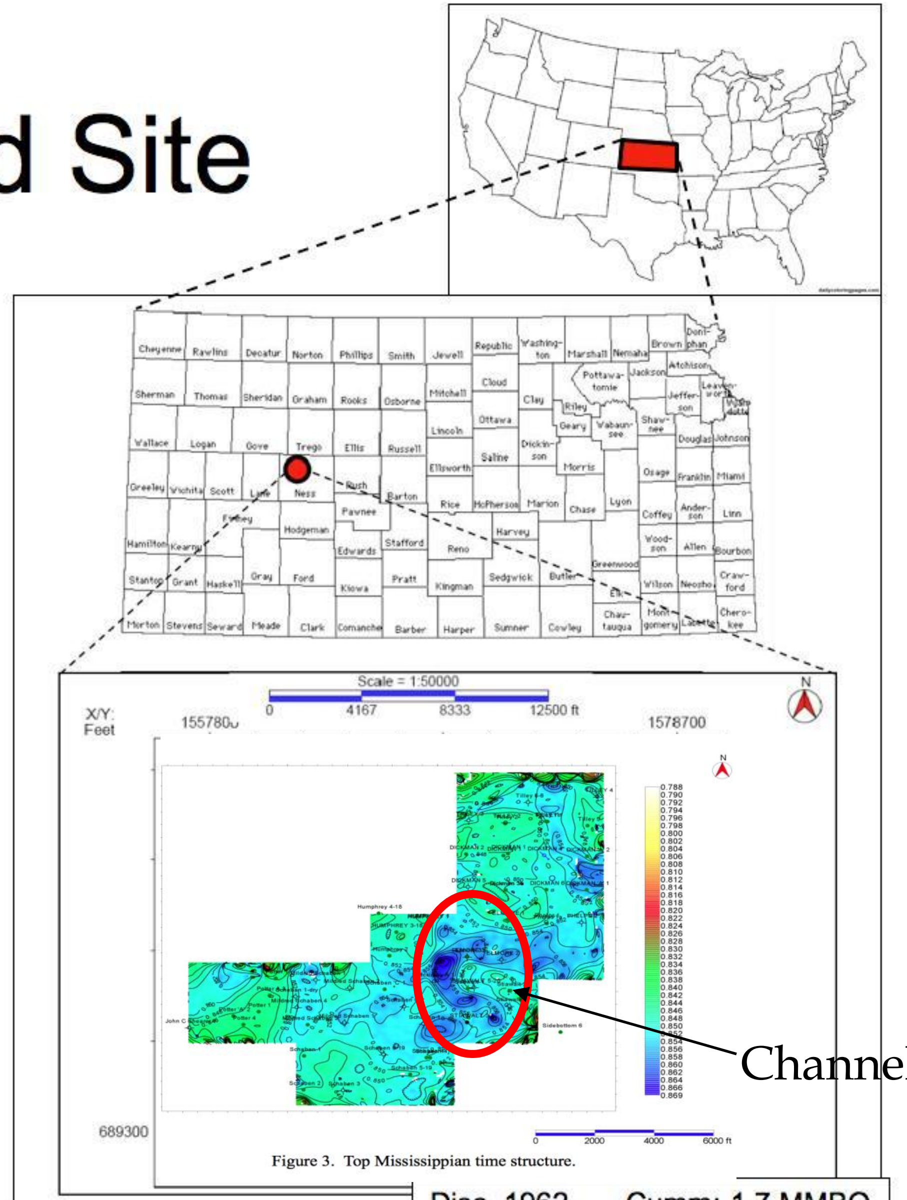


Figure 3. Top Mississippian time structure.

- 3D Seismic
  - 3.325 sq.mi.
- 142 wells
  - 54 in 3D area
  - 45 with digital logs
    - GR (43), Resistivity (25), Neutron (27), P-Sonic (6), Density (3), S-Sonic (1)
  - 7 with core
    - porosity and permeability
  - 3 full deep saline aquifer penetration

Disc. 1962 Cumm: 1.7 MMBO

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CO2 Properties

- Reservoir conditions at Dickman Field:

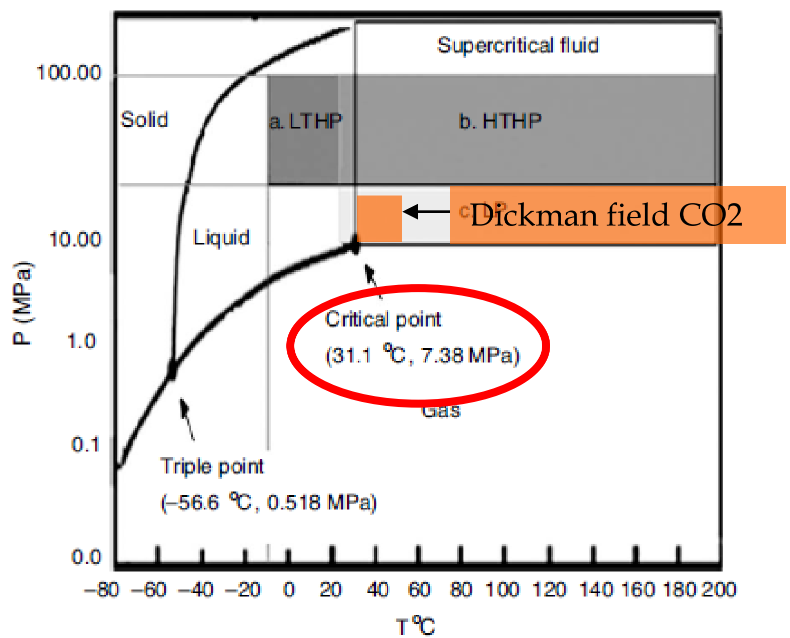
  Temperature: **31.7-48.8339° C**

  Pressure: **8.53~16.25mpa**

- CO_2: Supercritical fluid

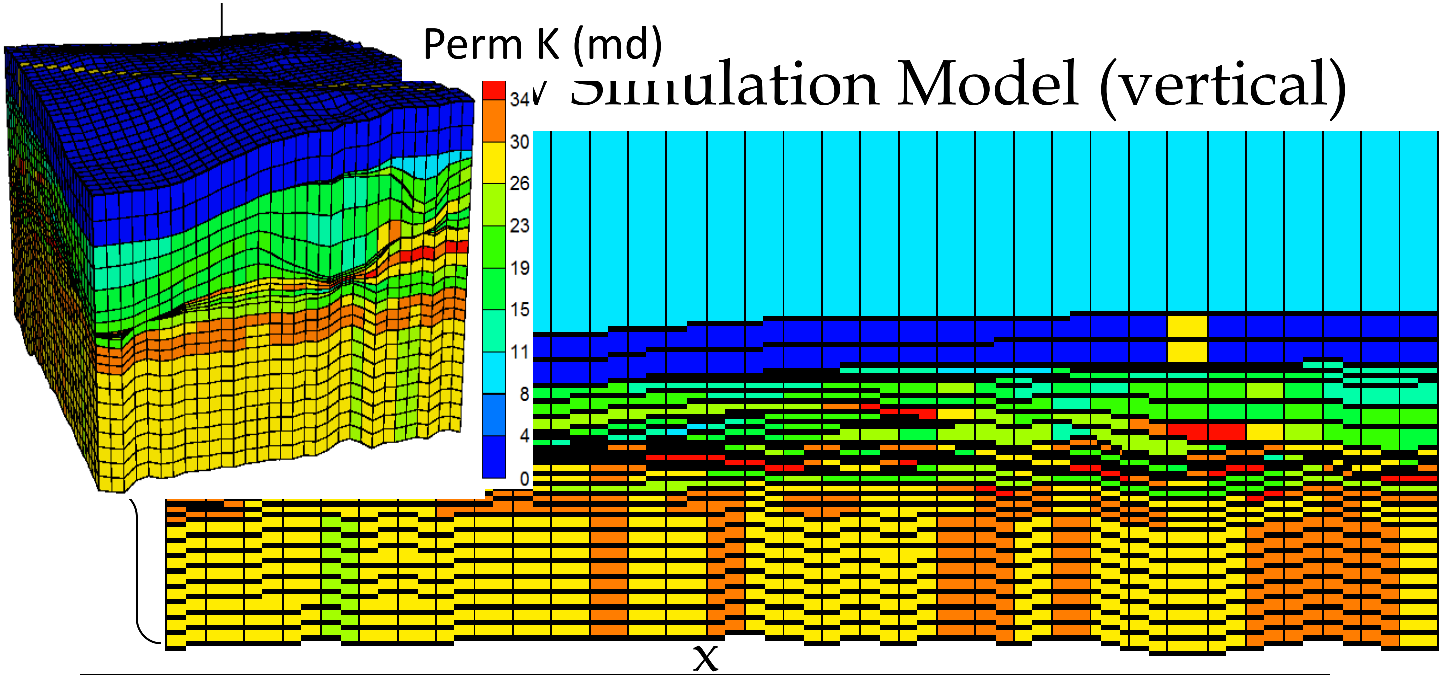
beyond dynamic critical point
: (T>31.1° C & P >7.38 MP,
Density: >0.469 g/cm3)

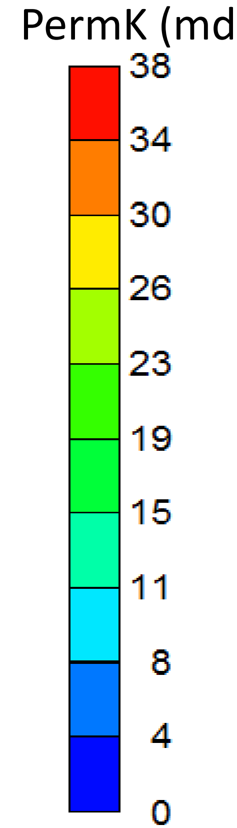
Gas phase
Liquid phase



(Han et al., 2010)

Simulation Model (vertical)





Flow simulation grid

NX=33 dx=500ft; NY=31 dy=500ft; NZ=32, dz: variable

Sim Layer No.	VerticalPerm	Porosity(%)	Formation Name
1-6	10 md	18.2	Shallow Reservoir layers
7-8	0.01 md	20.0	Two Seal Layers
9-10	0.7 Horizontal Perm	10.3	Ford Scott Limestone
11-13	0.5 Horizontal Perm	19.1	Cherokee
14-15	0.5 Horizontal Perm	16.5	Lower Cherokee
16	0.7 Horizontal Perm	14.8	Mississippian Unconformity
17-20	0.7 Horizontal Perm	20.0	Mississippian Porous Carbonate
25-32	0.7 Horizontal Perm	22.45	Mississippian Osage and Gillmor City

CO_2 monitoring

Scenario: CO_2 is injected for 50 yrs, then the injection well is shut in and flow modeling continues for 150 yrs

Input:

- Fluid simulation results for 150 yrs: (2002'-2155')
  grid cells: 33(x)*31(y)*32(z)
  dx=500ft, dy=500ft, dz: variable
  fluid properties data (porosity, CO2 saturation, etc.)

Output:

- Seismic simulation for 150yrs
  - implemented by MATLAB: binary file
  - Seismic Unix: headers correctly added and sorted and interpolated into the field seismic data bin size(82.5ft x 82.5ft)

- Comparison of seismic response due to CO_2 injection (between year 2002' and 2155')

CO_2 Saturation for Sim Layers 1-16 (Yr 2002′ and 2155′)

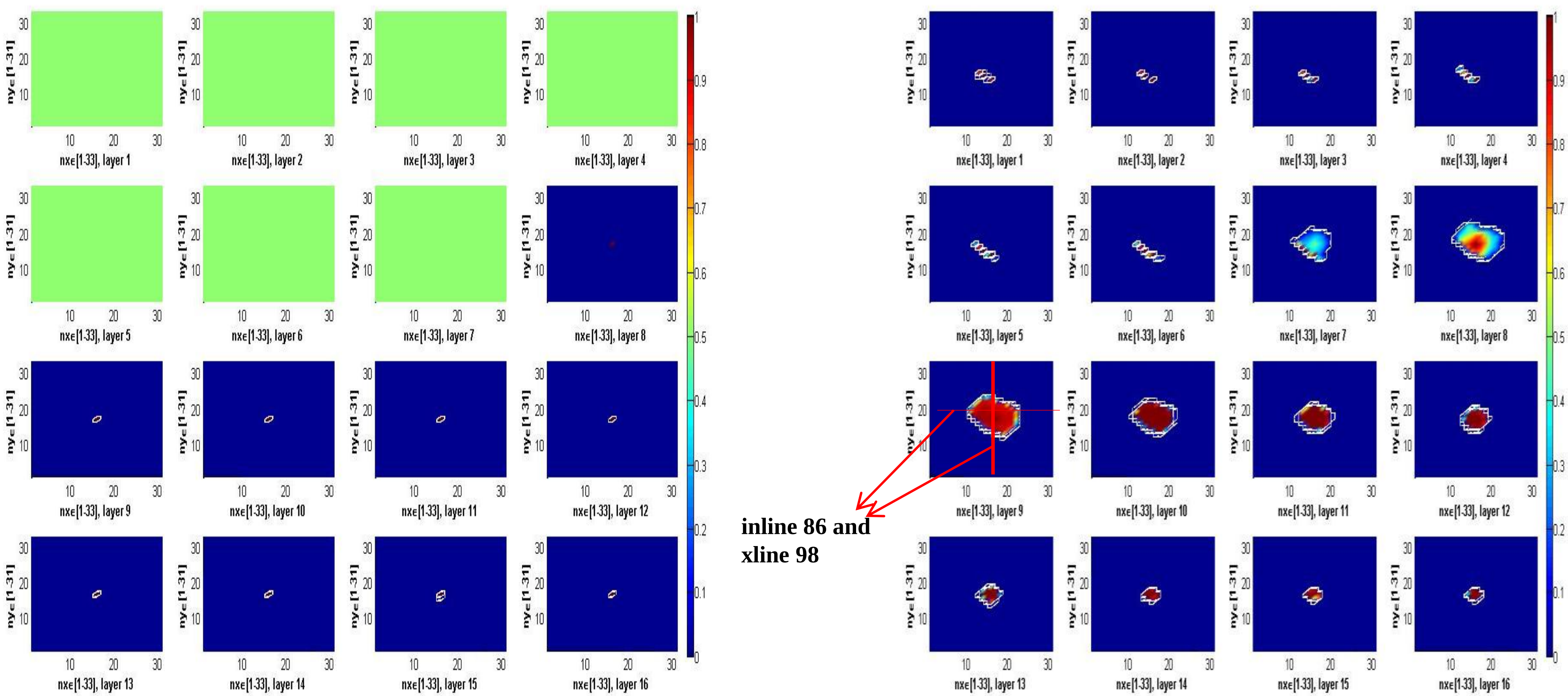


Figure 1. CO_2 saturation for simulation layers from 1 through 16 for years 2002 (L) and 2155 (R). Two seismic lines (inline 86 and crossline 98) in sim layer 9 have been pulled out for comparison.

Seismic Data Inline 86 (Yr 2002′ and 2155′) and Difference

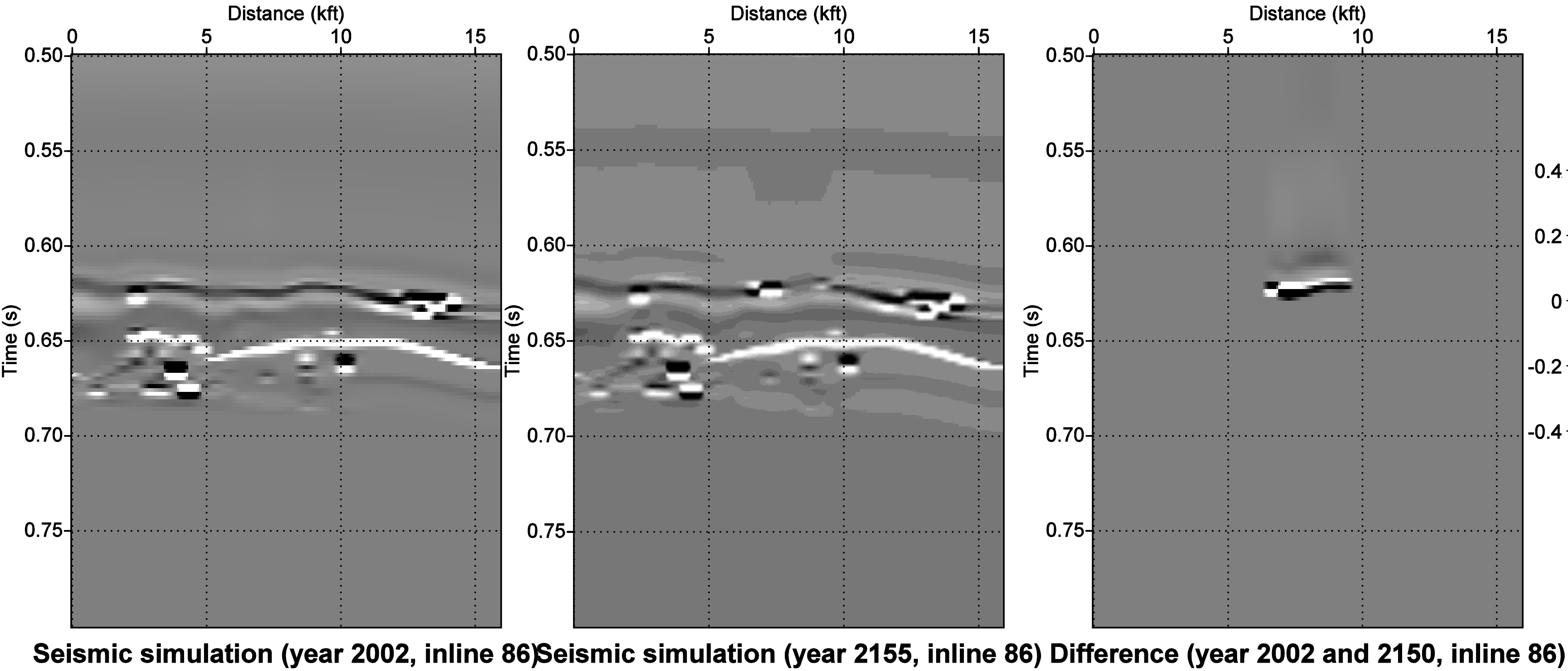


Figure 3a. Seismic data (inline86) at the different simulation time (2002′ and 2150′) and the difference. Displayed from 500ms to 800ms. It caused 4% impedance change.

Seismic Data Xline 98 (Yr 2002′ and 2155′) and Difference

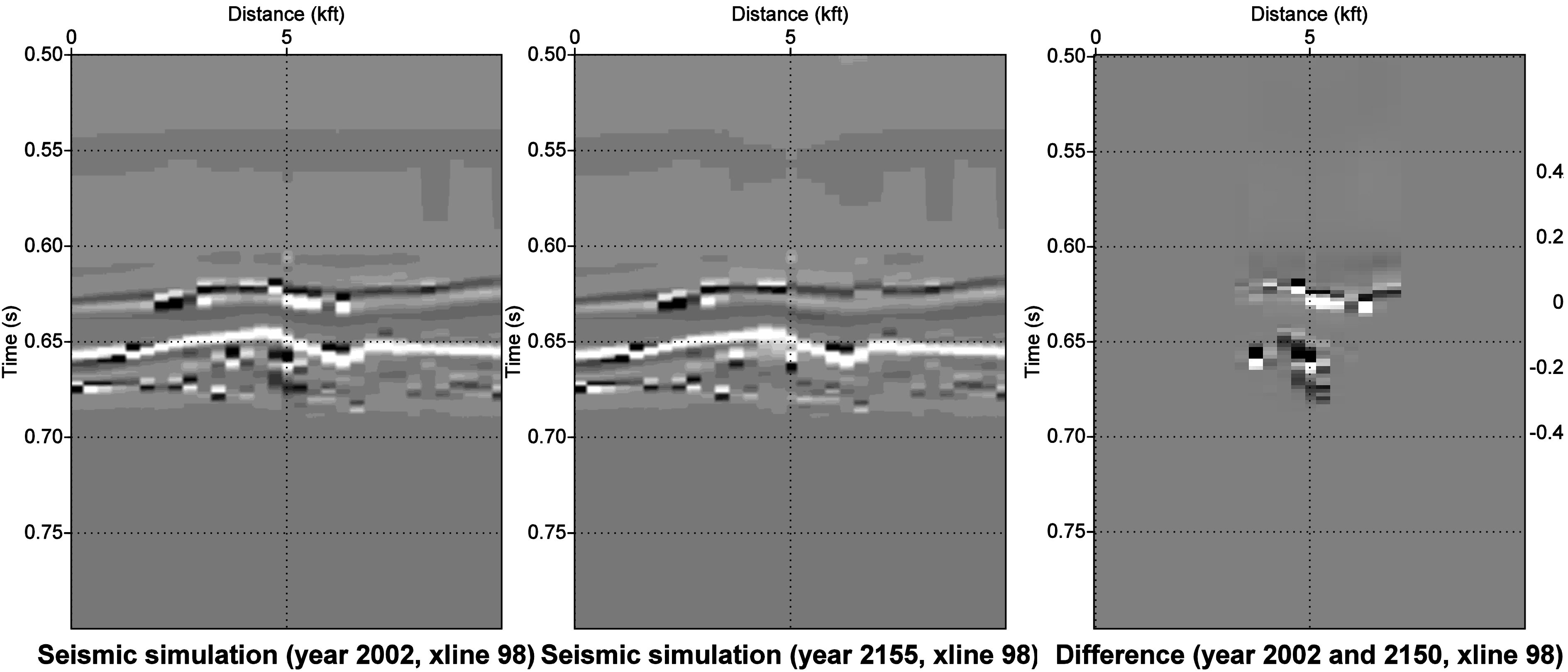


Figure 3b. Seismic data (crossline 98) at the different simulation time (2002′ and 2155′) and the difference. Displayed from 500ms to 800ms.

Future Work

- To perform a full wave forward modeling to obtain more realistic result
- A smoother and better-defined porosity distribution may help improve the seismic data quality

Acknowledgement

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    - Eric Swanson

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END

Extra slides

Geology Model

<u>Petrel modeling</u>:

- faults interpretation *constrained* by seismic volume attributes
- *up-scaled* log porosity based on lithozones
- relationship between:
  1) core porosity and log porosity
  2) core porosity and permeability
  3) seismic impedance and neutron porosity

permeability

Guiding propagation of permeability in property modeling

(Zeng,2009)

CO_2 Storage

- T=121F & P=2200 psi :

Density=0.7 ton/m^3

Brine solubility= 64 ton per acre-ft

- Porosity=0.2, Sw=20%, CO_2 trapped in 1 acre-ft :

1233(m^3 per acre-ft)*0.2*(1-0.2)*0.7 ton/m^3=140 tons

Dickman Field

Acreage = 240 acres

Net Pay Zone Thickness = 7 feet

Average depth = 4424 feet in MD

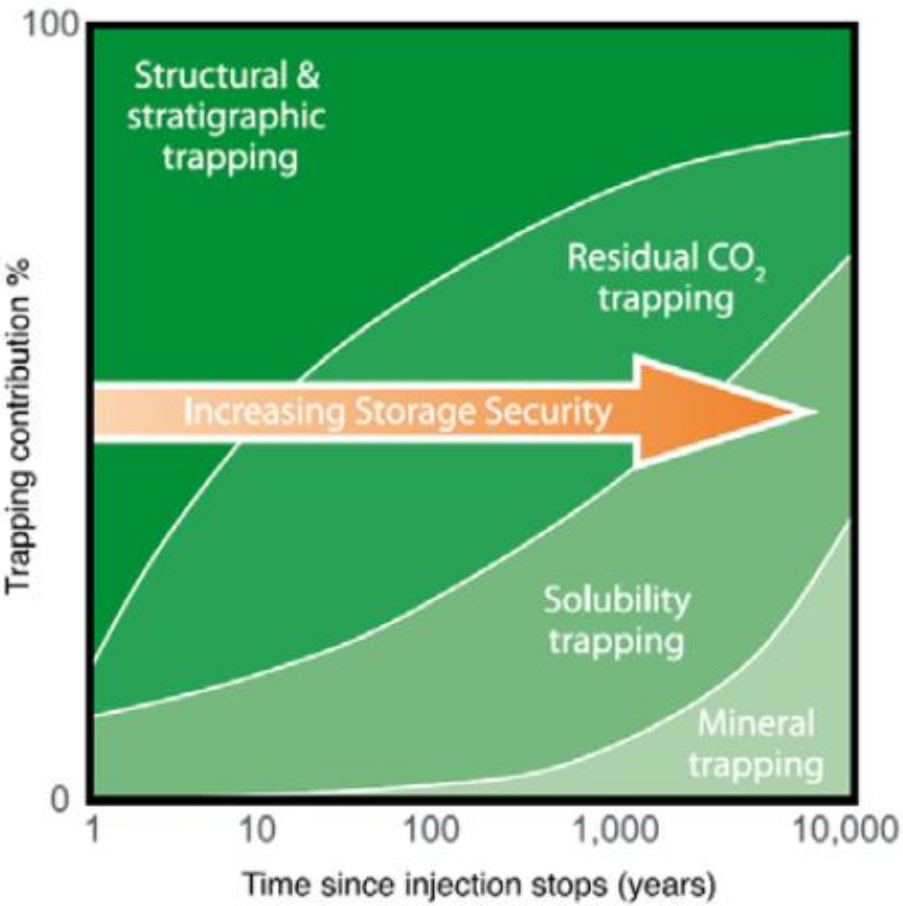
Oil API gravity = 37 API (0.84 g/cm3)

The reservoir average temperature = 113 $^\circ$ F

The reservoir average pressure = 2066 psi

TDS (Total Dissolved Solid) salinity = 45,000 ppm

CO_2 Safe Storage



- Trapping Mechanisms
  - Structural trapping
  - Solubility trapping(CO2 highly soluble in brine)
  - Residual gas trapping (immobile gas in porous media)
  - Mineral trapping (chemical changes)

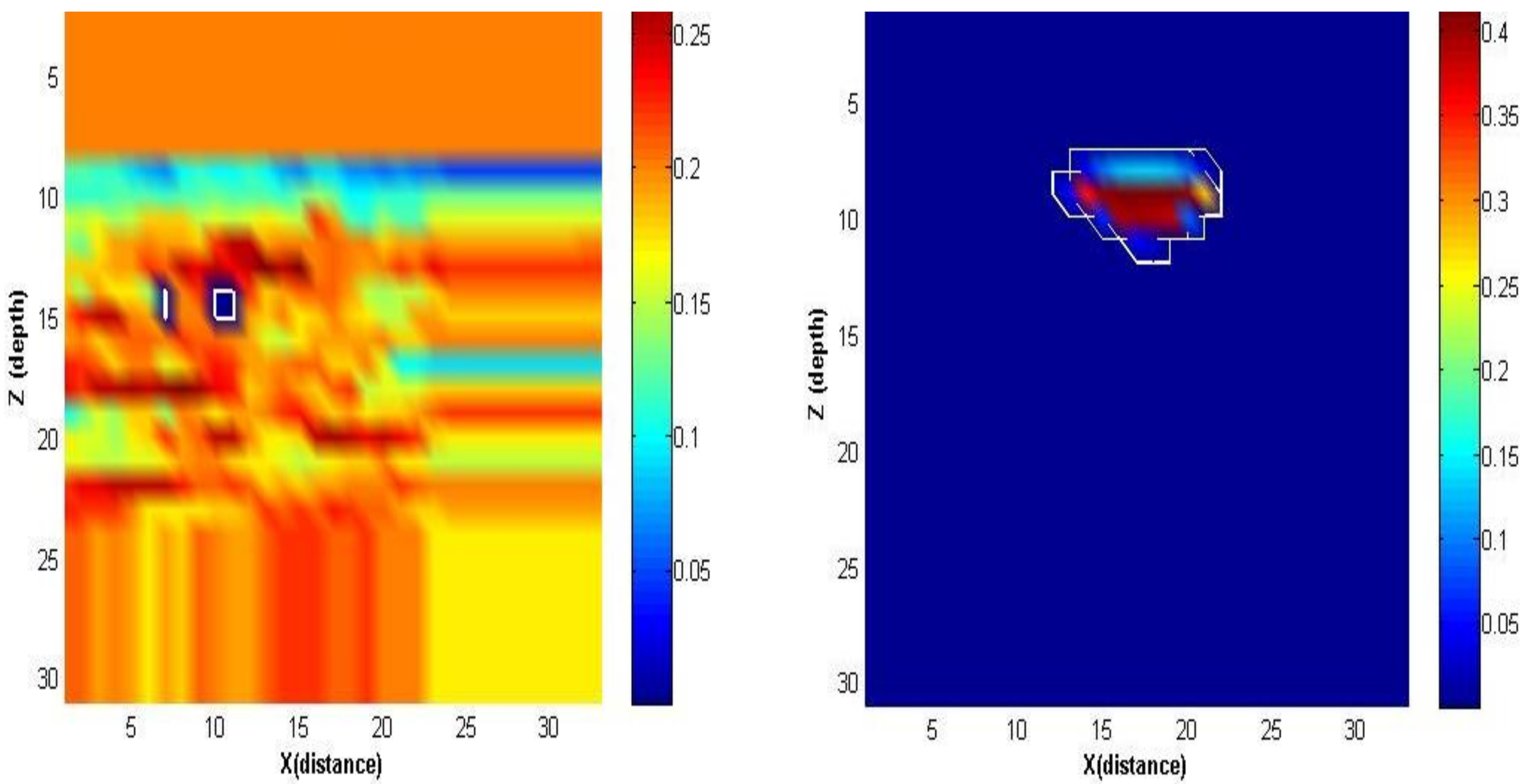
(Geng, 2009)

Flow Simulation Model

Acquifer model (from top to base)

1. Fort Scott Limestone → CO_2 storage target
2. Cherokee Group
3. Lower Cherokee Sandstone
4. Mississippian Carbonate → CO_2 storage target
5. Lower Mississippian Carbonate

a) **Porosity distribution, inline86** b) **CO2 saturation, inline86**



1 mile

Figure 2. Vertical sections related to inline 86 for year 2155.

(a) Porosity distribution. (b) CO2 saturation

Discussion

After CO_2 being injected for 150yrs,

at the location where has the highest change for CO_2 saturation:

S_{CO_2} change: 0%~42%

Impedance change: 4%

Reflection coefficient change: 41% (non-linear)