Design of safe injection pressure in a tight carbonate reservoir using THM coupling

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What's Next?
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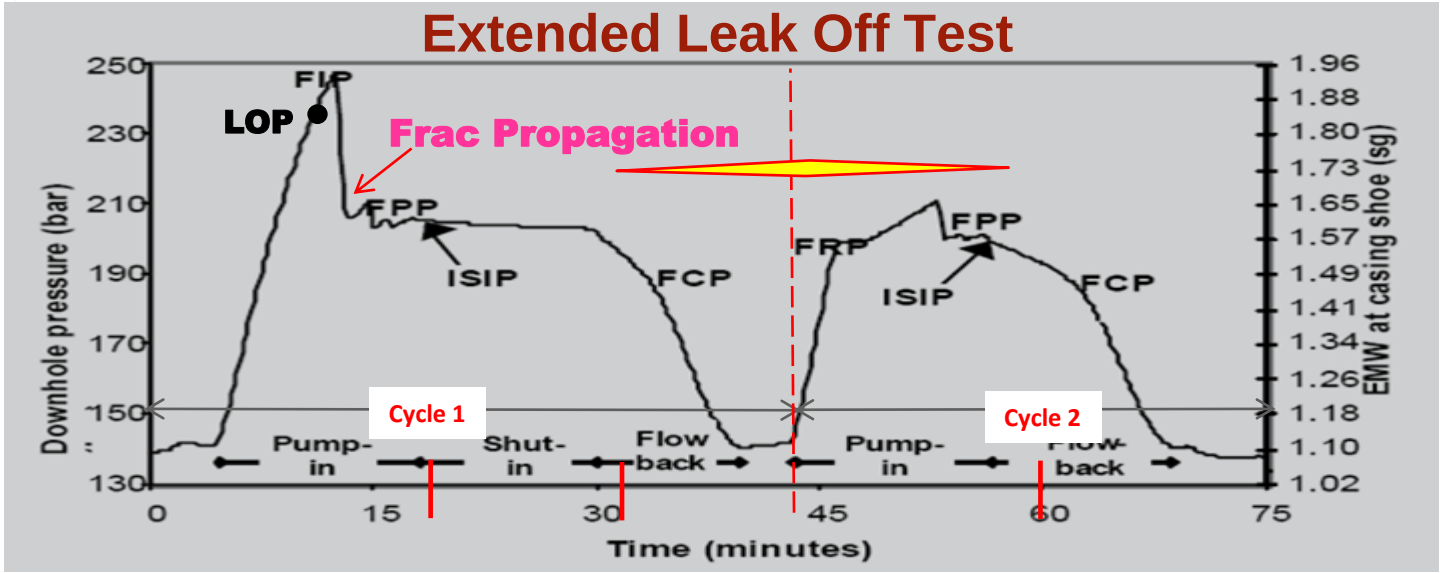
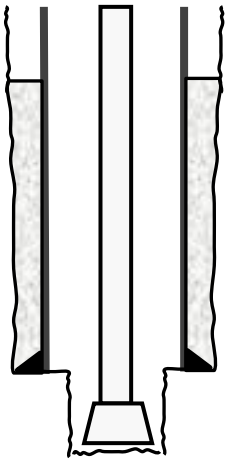
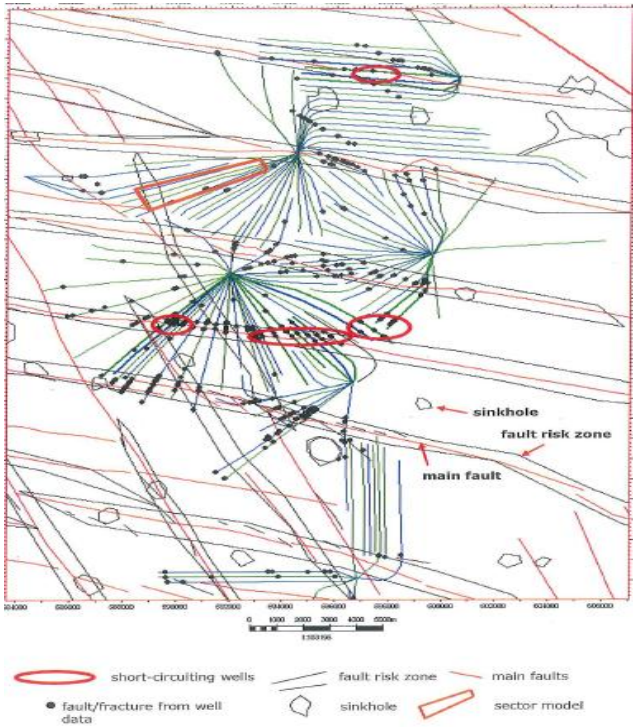
DATA from fracs done in wells are key for safe pressure design

- **LOP: Leak-Off Pressure**
- **FIP: fracture initiation pressure, called also breakdown pressure.**
- **FPP: fracture propagation pressure.**
- **ISIP: instantaneous shut-in pressure, recorded right after pumps shut in.**
- **FCP: fracture closure pressure, it is generally equal to the minimum in situ stress.**
- **FRP: fracture re-opening pressure.**

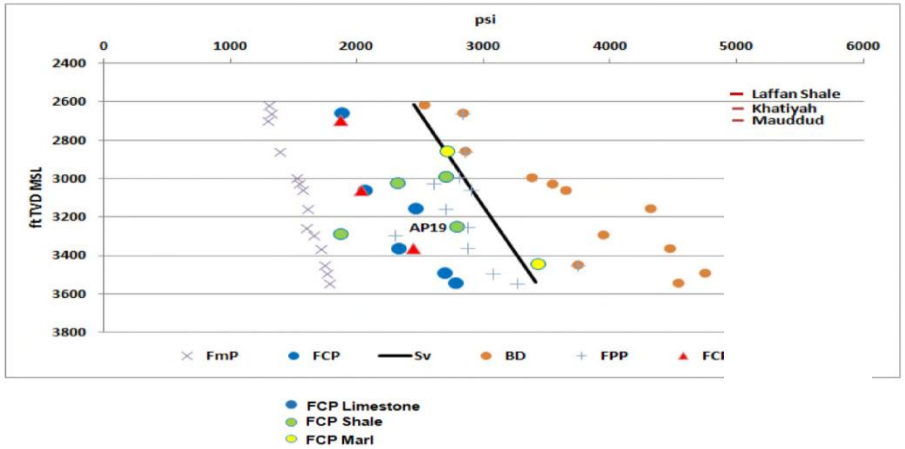




WELLS LAYOUT



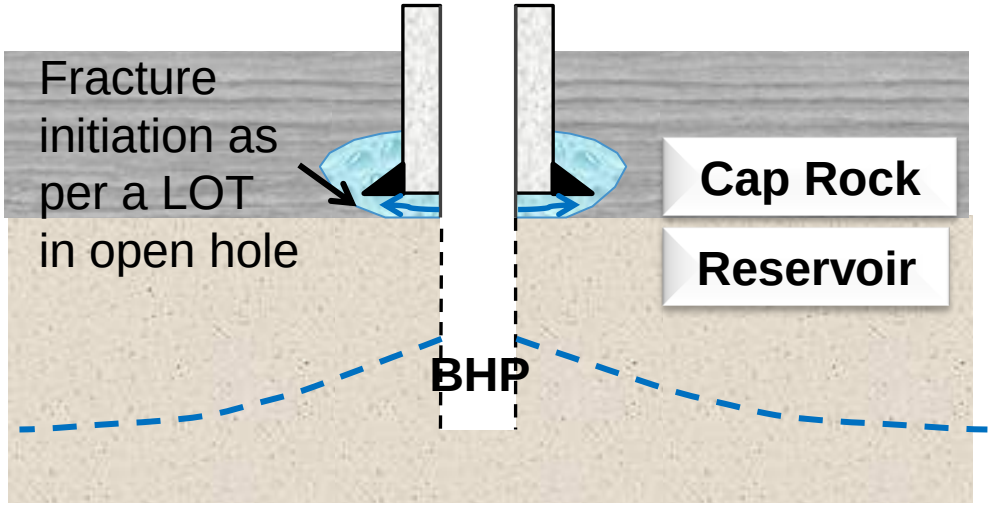
FRAC DATA



- Low perm : ~ 1-5 md
- The highest the DP between injectors and producers, the better the recovery and field economics

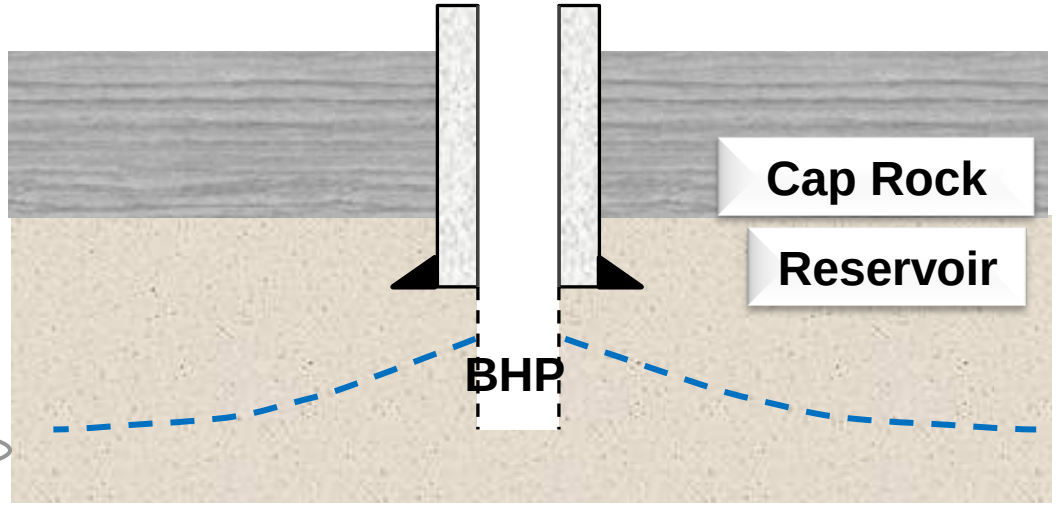
Standard design of maximum safe injection pressure

- BHP < FRP_cap rock – Safety Factor if the fractures in the cap rock are initially closed
- BHP < FCP_cap rock – Safety Factor if fractures in the cap rock are originally open
- This design is based on the assumptions that
  - The weakest point in the cap rock is the well itself
  - The cap rock at well is directly exposed or connected to the injection pressure in the well



Aggressive design of maximum safe injection pressure

- BHP < Sv – Safety Factor
- This design assumes that
  - The cap rock is not directly connected to the injection pressure because it is perfectly cemented and isolated
  - The only ways to have leaks through reservoirs seals are
    1. Naturally open fractures (to be checked)
    2. Fractures reopening due to tension stresses induced by arching (to be checked)
    3. Fracture induced in the reservoir followed by propagation in the cap rock (to be checked)



In the considered field, gains in productivity improve by up to 30% if this design is accepted

Evidence of sealing natural fractures in cap rock

- No mud losses outside reservoirs while drilling
- Laboratory tests on shale material shows sensitivity to injected water with fractures healing
- Gas caps were preserved during geological time
- Despite injection at much higher pressures than initial :
  - No 4D seismic anomalies
  - Mass balance in reservoir models is consistent with confined injection
  - Pressure measurements on infill wells are consistent with expectations

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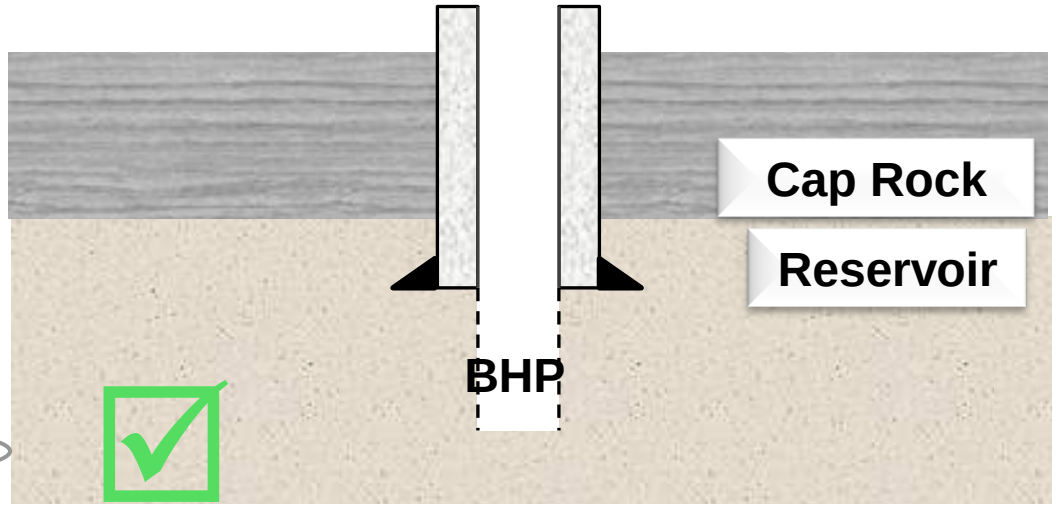

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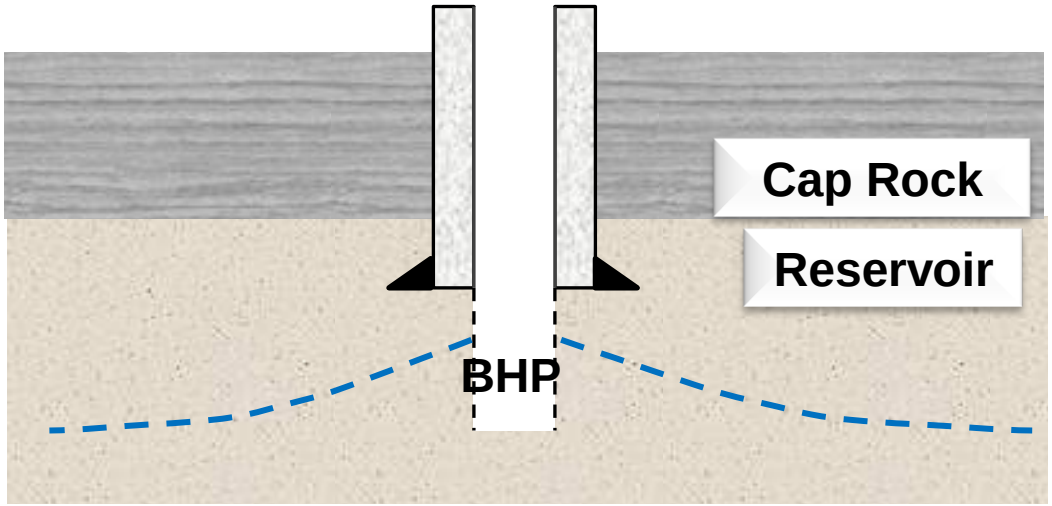
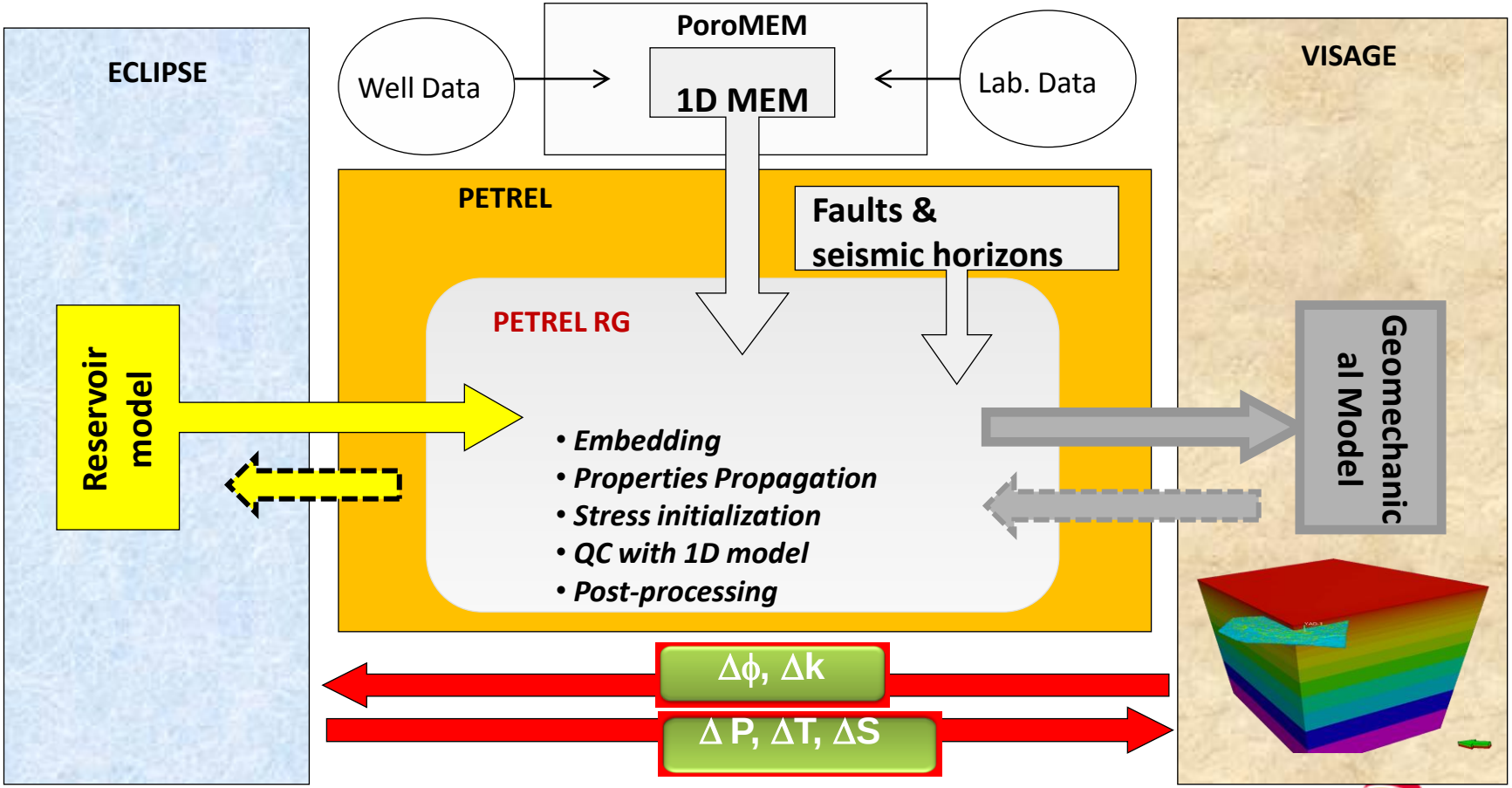
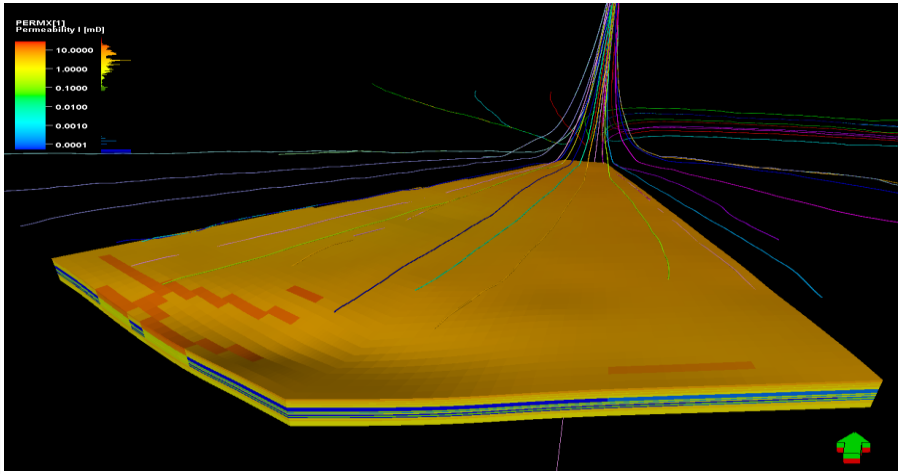
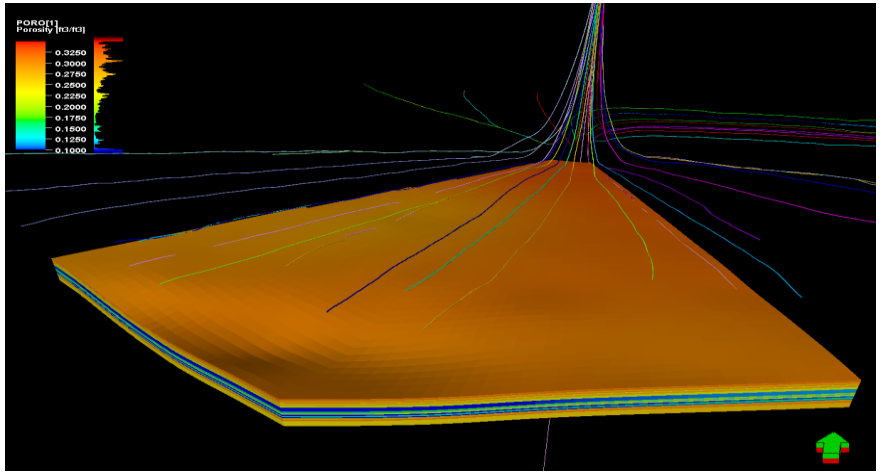
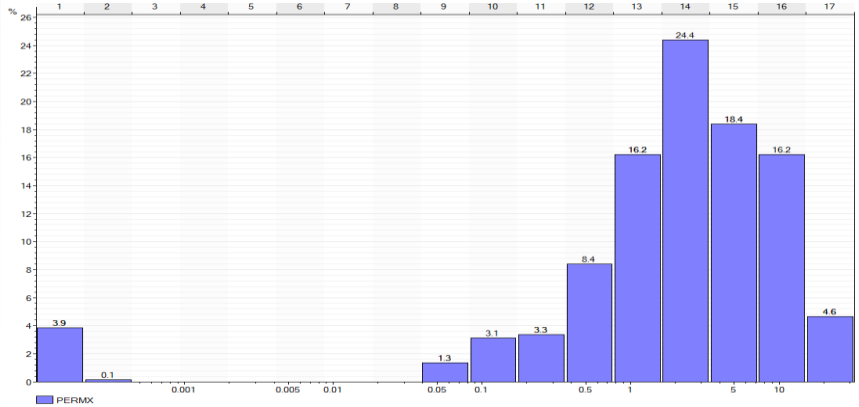


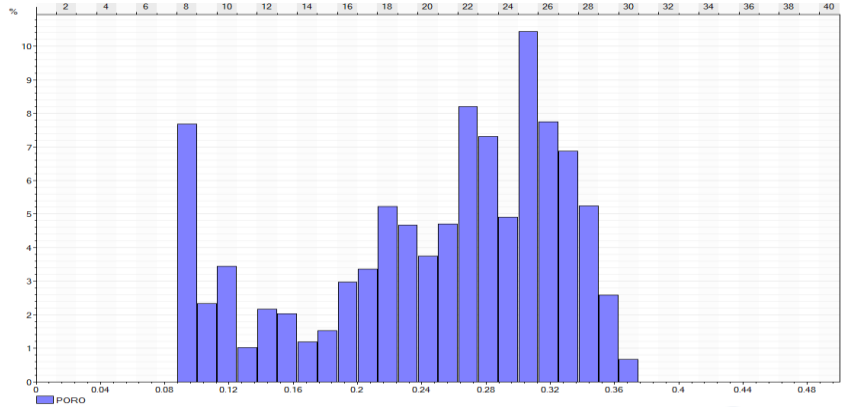
Coupled Reservoir-Geomechanics workflow



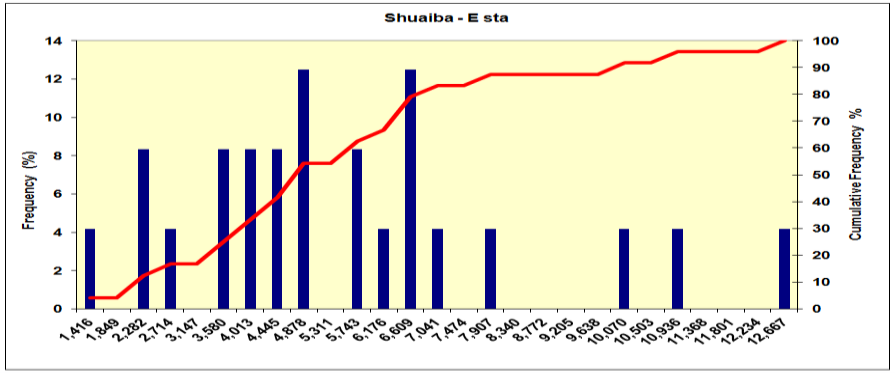

PERMX[1]
Permeability I [mD]
10.0000
1.0000
0.1000
0.0100
0.0010
0.0001


PORO[1]
Porosity [M3/M3]
0.3250
0.3000
0.2750
0.2500
0.2250
0.2000
0.1750
0.1500
0.1250
0.1000

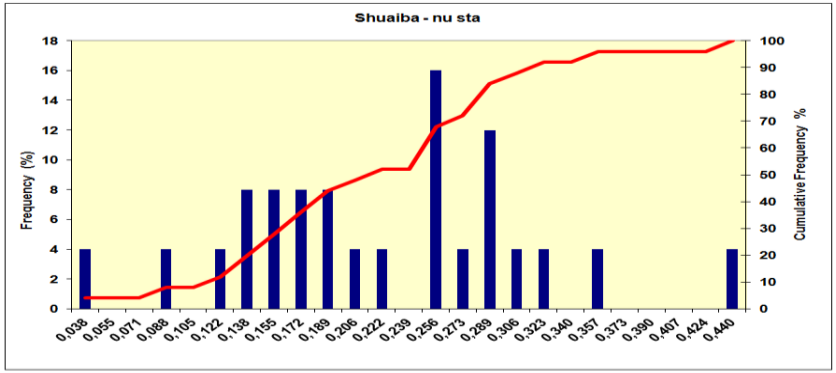

%
3.9
0.1
1.3
3.1
3.3
8.4
16.2
24.4
18.4
16.2
4.6
PERMX


%
PORO

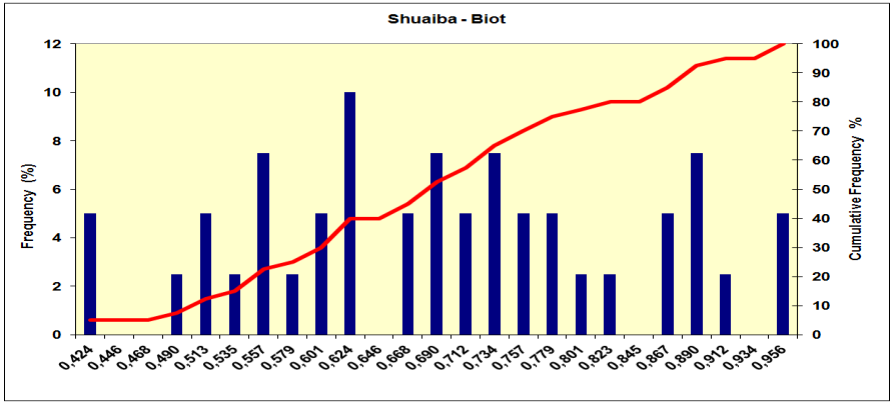
Poro-elastic properties



P10 = 2,3 Gpa P50 = 4,9 Gpa P90 = 10,1 Gpa

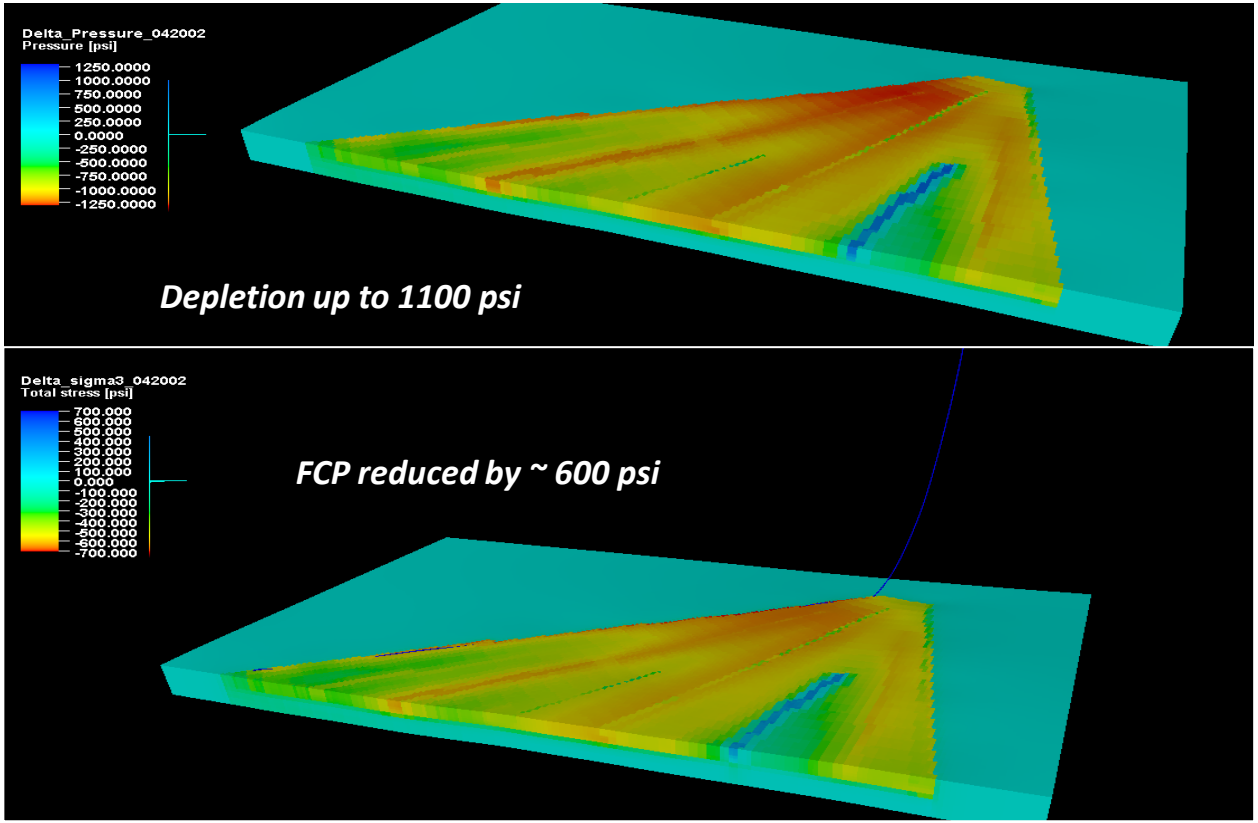


P10 = 0,12 P50 = 0,22 P90 = 0,32

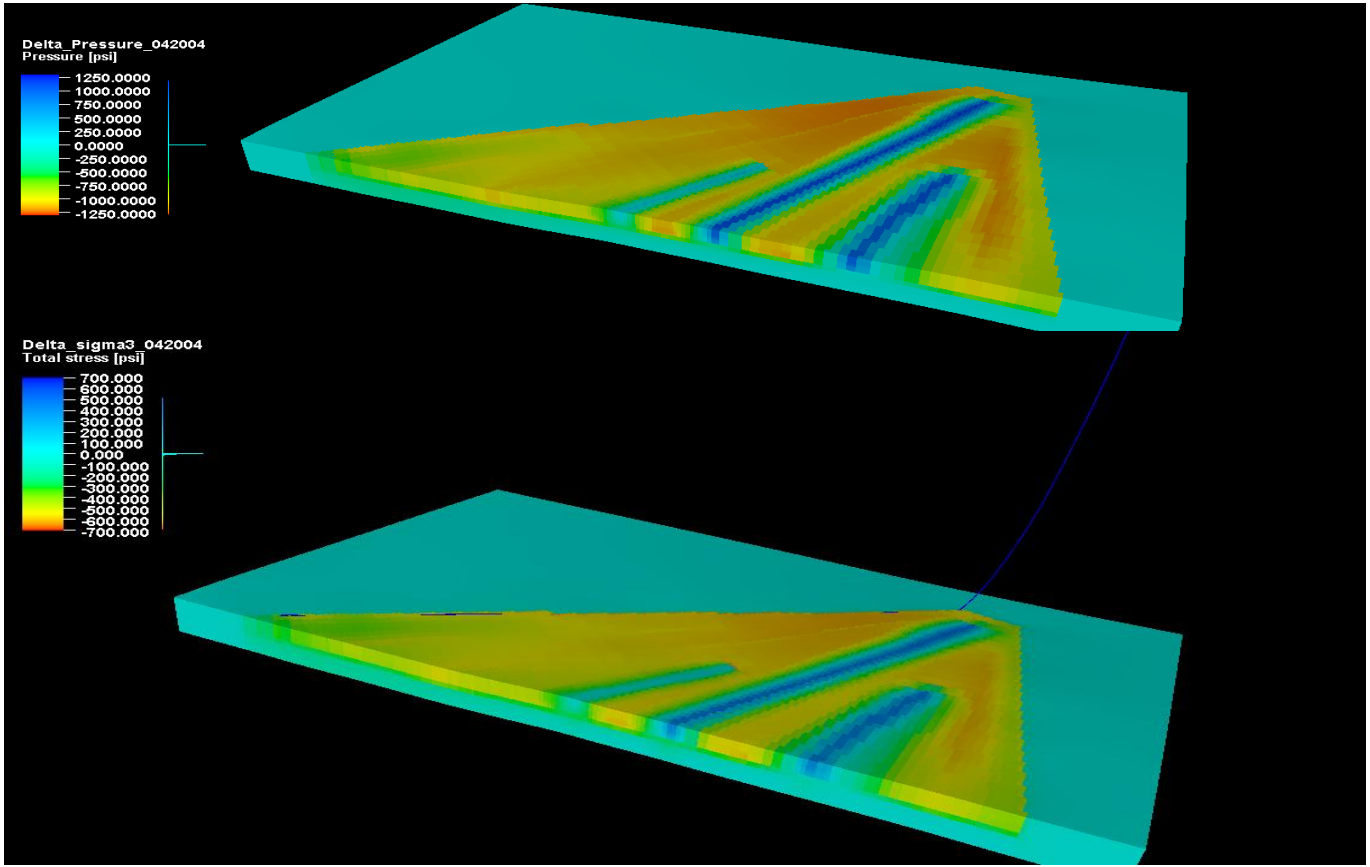


P10 = 0,51 P50 = 0,69 P90 = 0,89

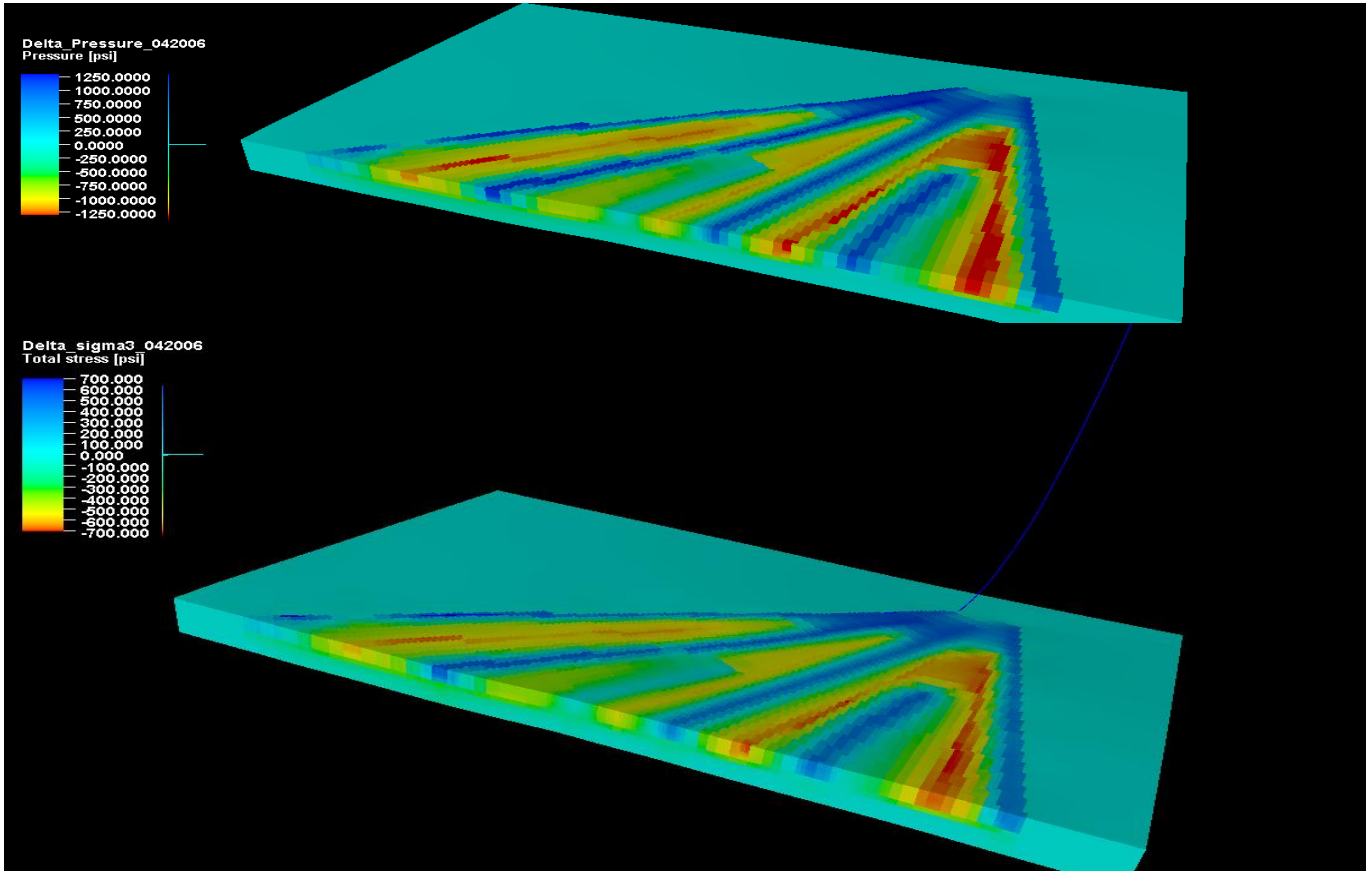
Sector model – ΔP and Δsig3 – April 2002



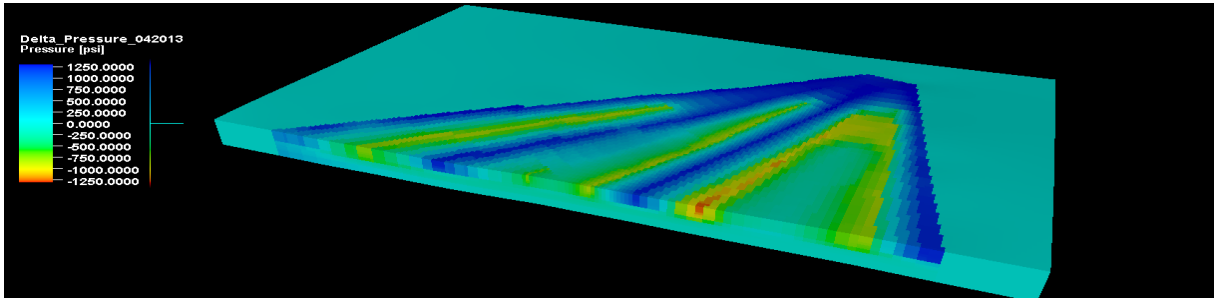
ΔP and Δsig3 – April 2004

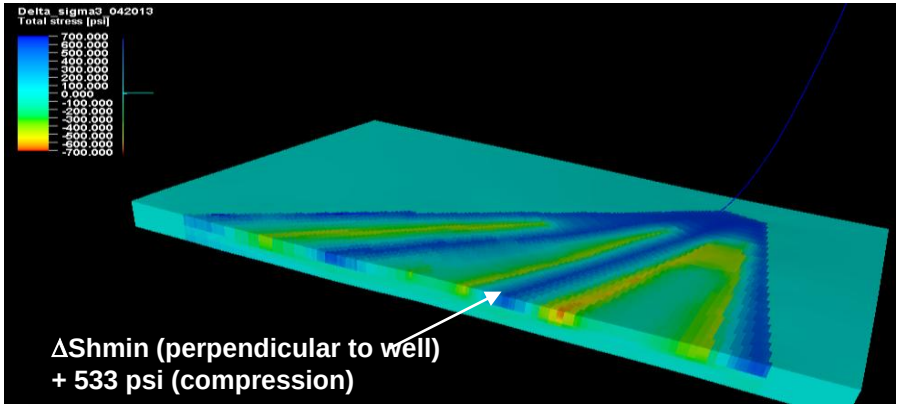


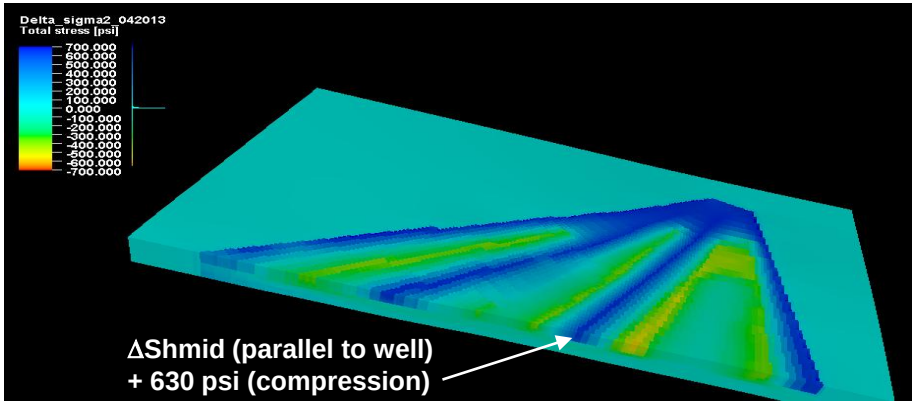
ΔP and Δsig3 – April 2006



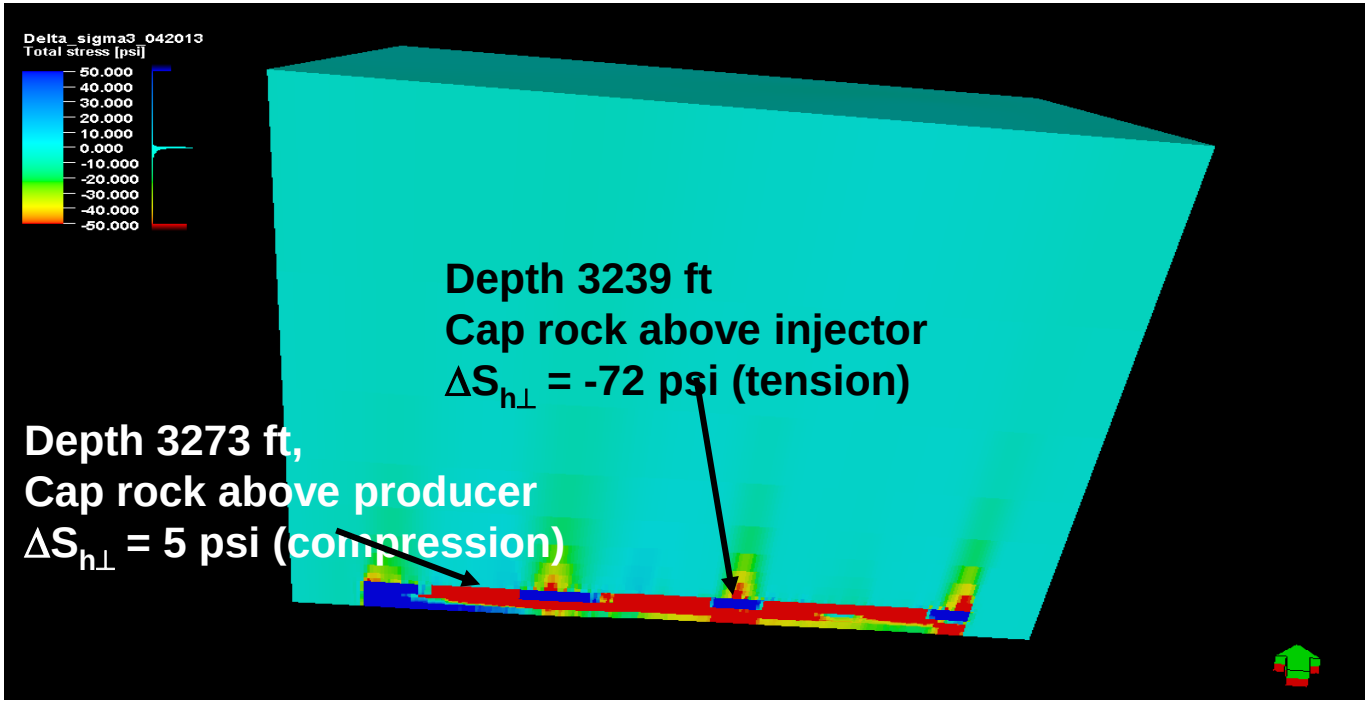
ΔP and Δsig3 – April 2013







Stress changes in the overburden



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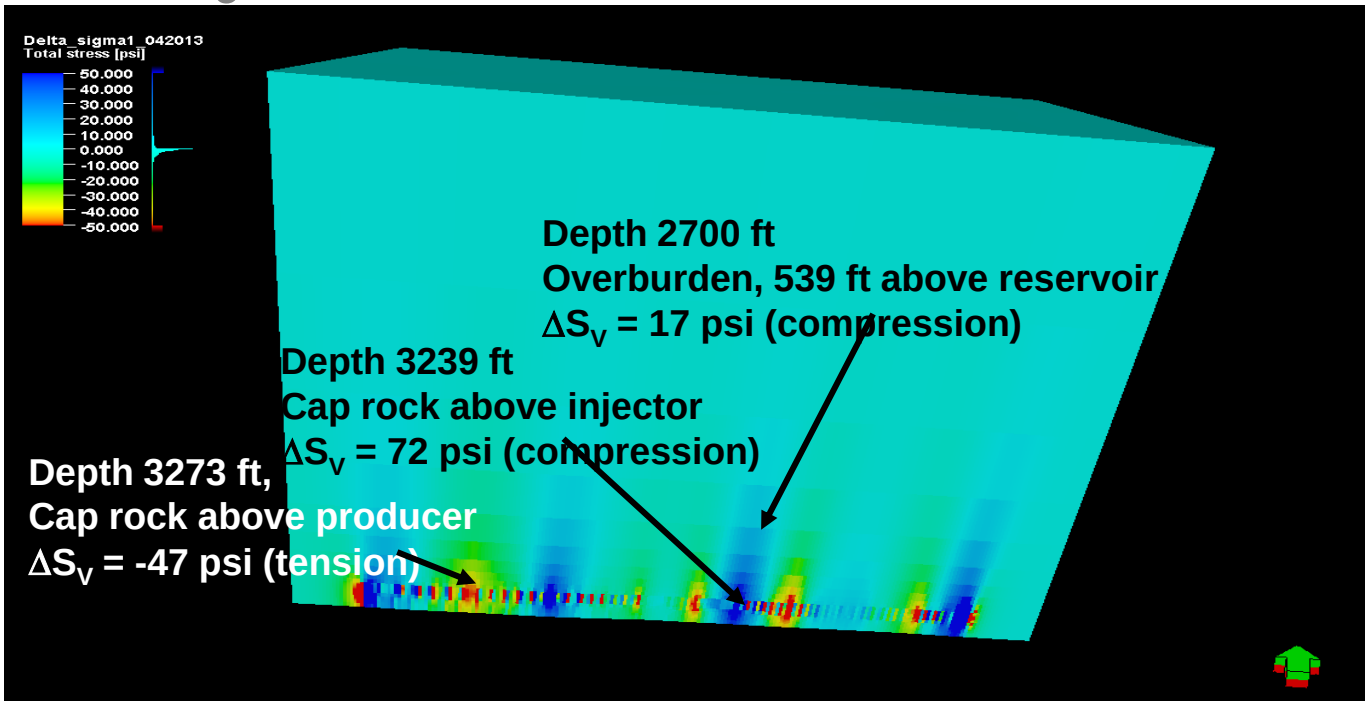

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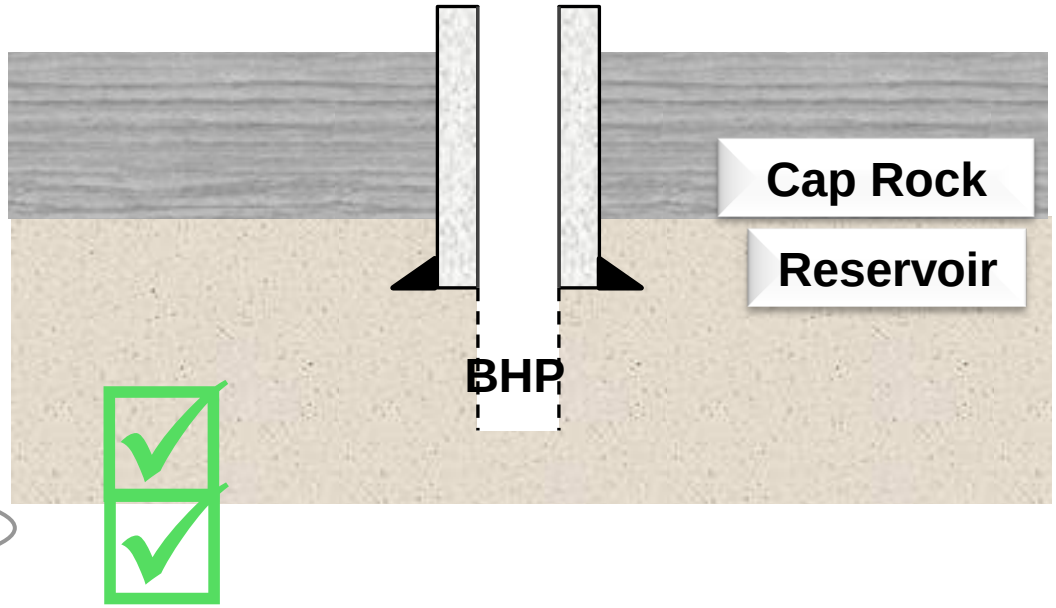

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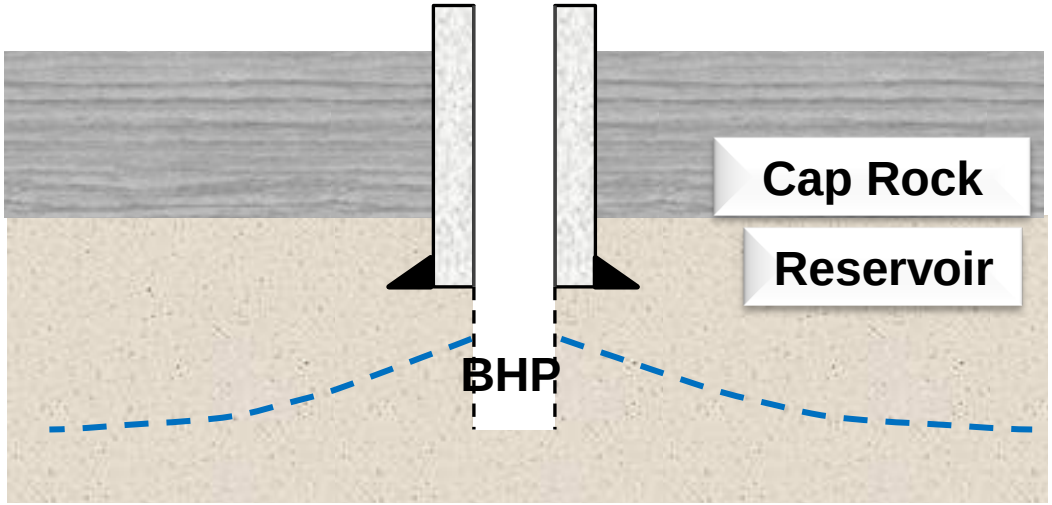
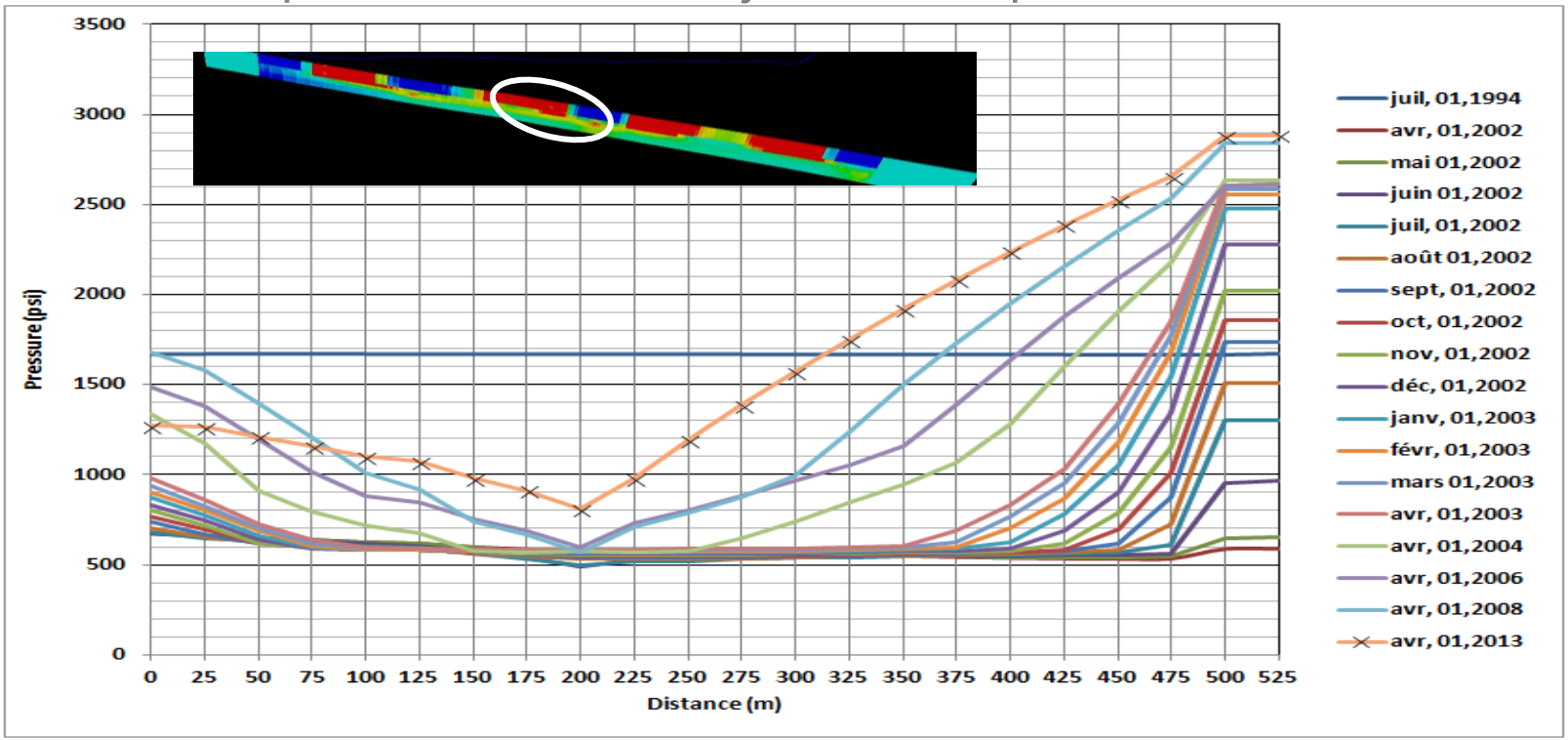
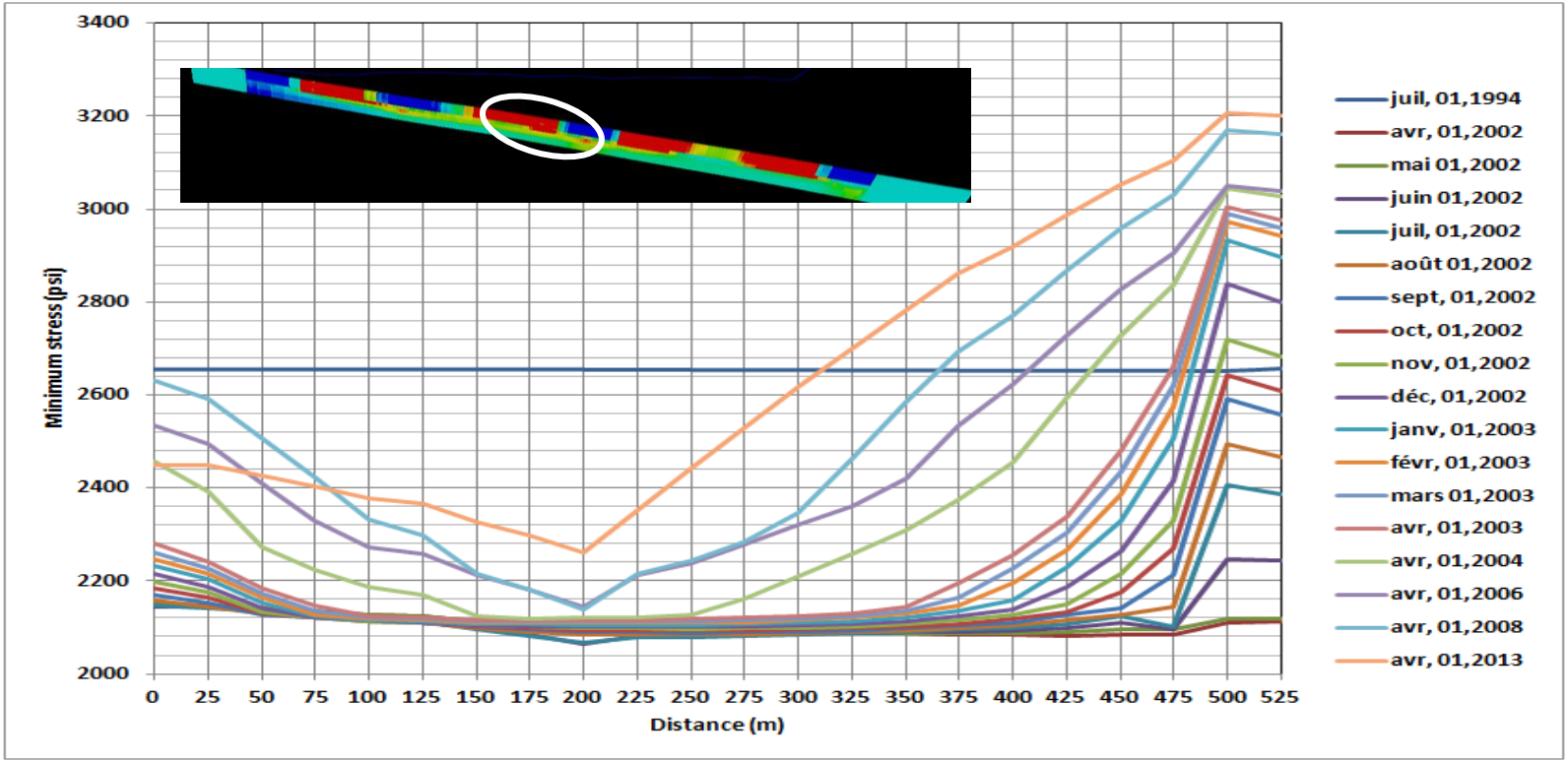


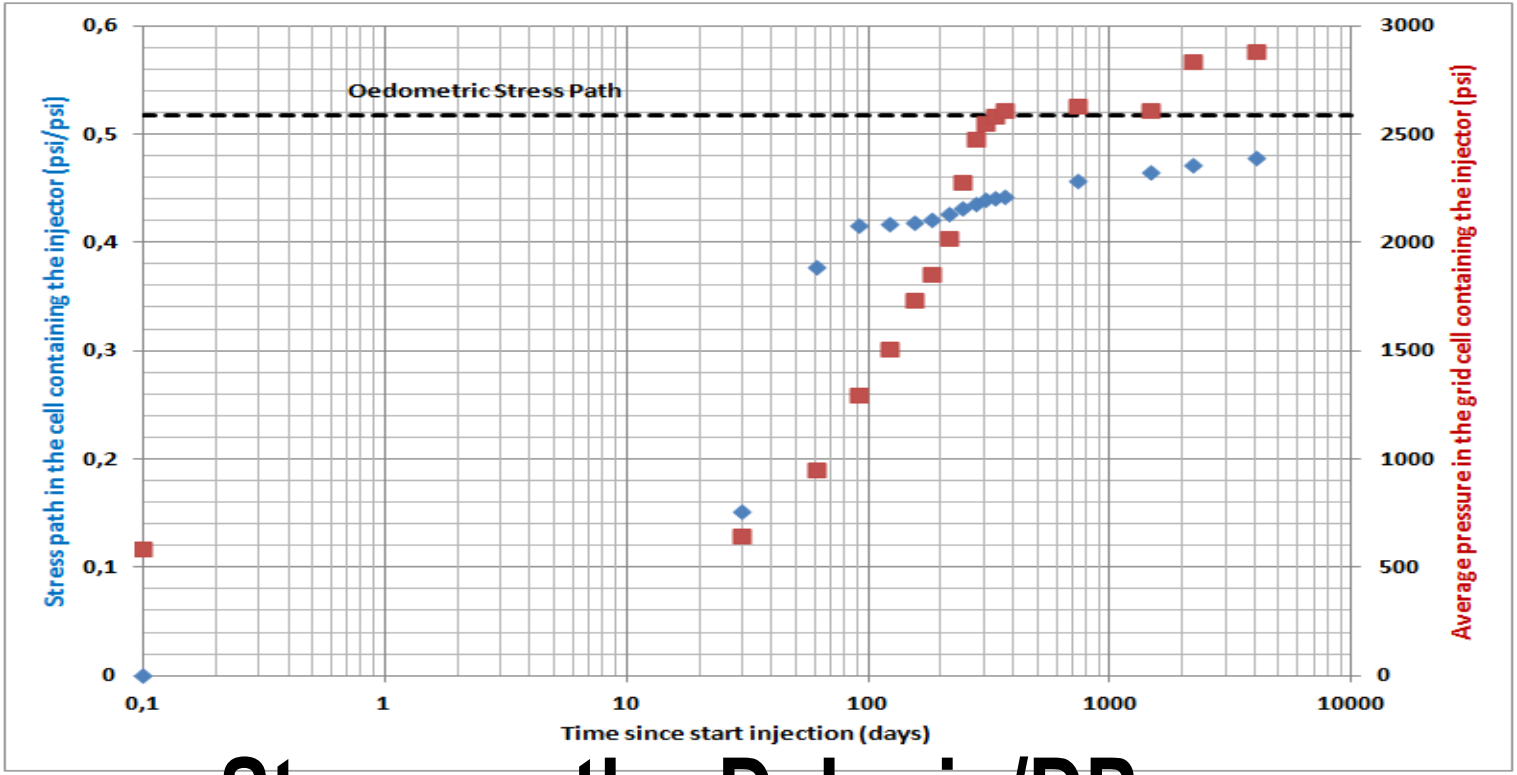
Profiles of pressure between injectors and producers



Profiles of Minimum stress between injectors and producers

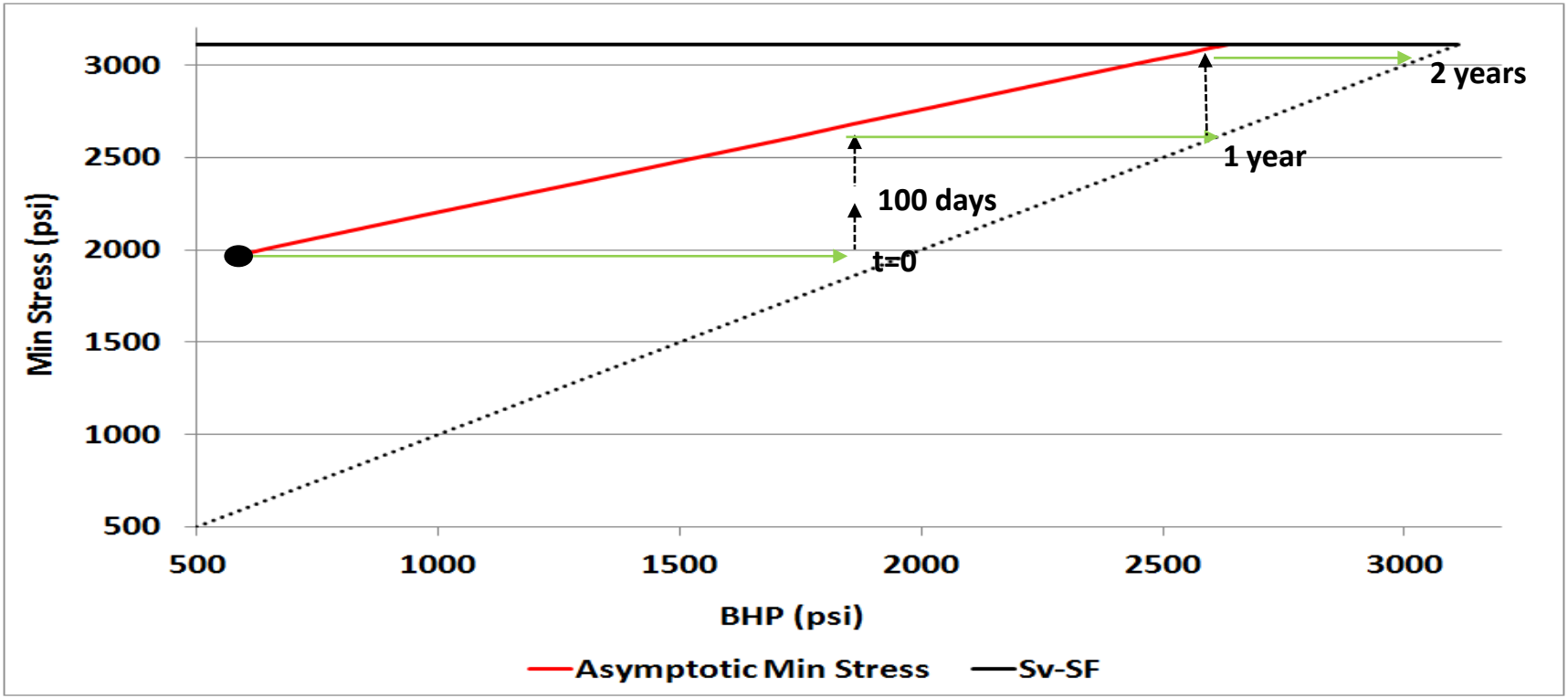


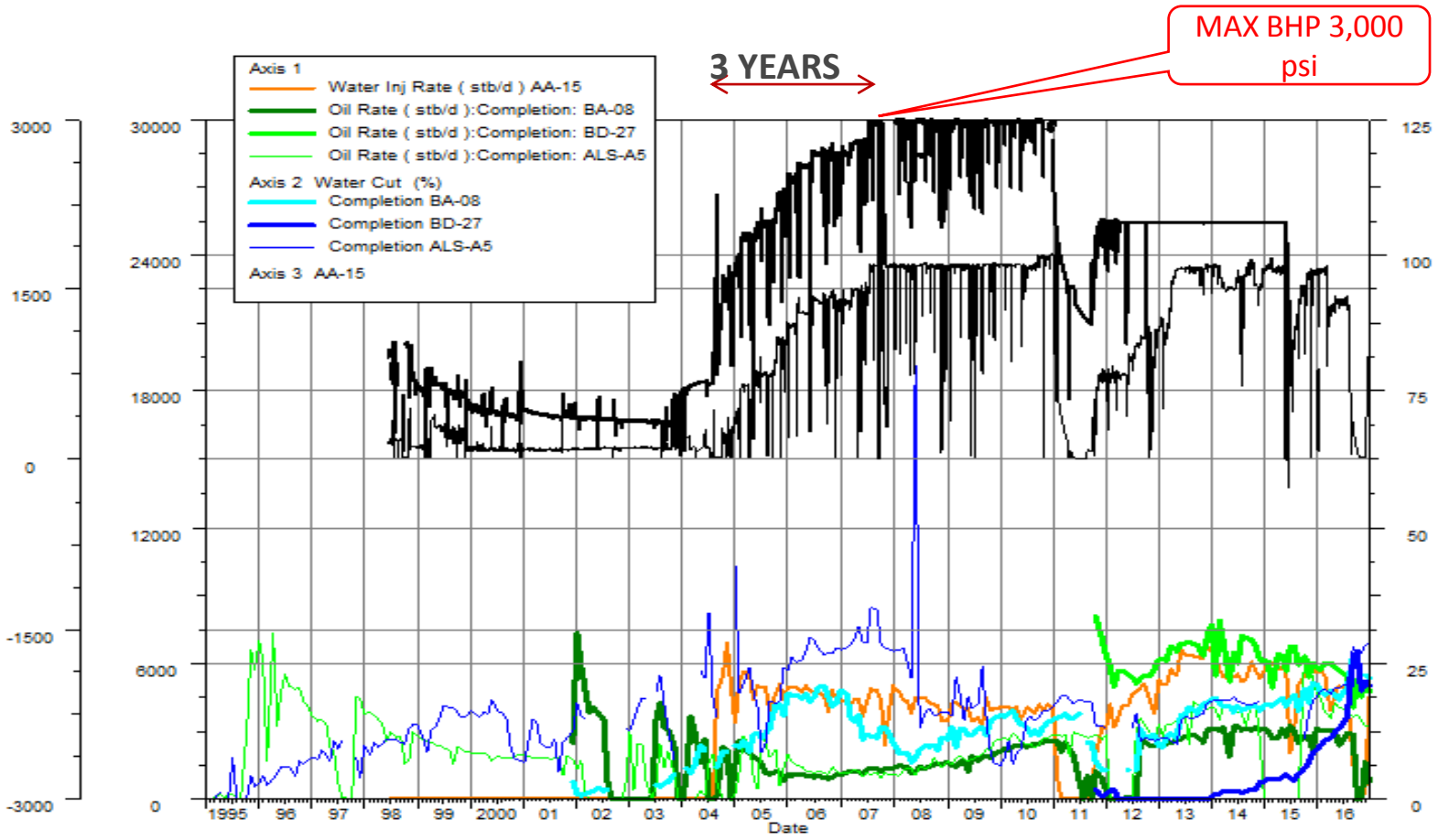
Stress path (ΔShmin/ΔP) in the grid cell containing the injector



Stress path : Dshmin/DP

Min stress versus pore pressure during pressure ramp up




MAX BHP 3,000 psi
3 YEARS
Axis 1
Water Inj Rate (stb/d) AA-15
Oil Rate (stb/d):Completion: BA-08
Oil Rate (stb/d):Completion: BD-27
Oil Rate (stb/d):Completion: ALS-A5
Axis 2 Water Cut (%)
Completion BA-08
Completion BD-27
Completion ALS-A5
Axis 3 AA-15
3000
1500
0
-1500
-3000
30000
24000
18000
12000
6000
0
125
100
75
50
25
0
1995 96 97 98 99 2000 01 02 03 04 05 06 07 08 09 10 11 12 13 14 15 16
Date

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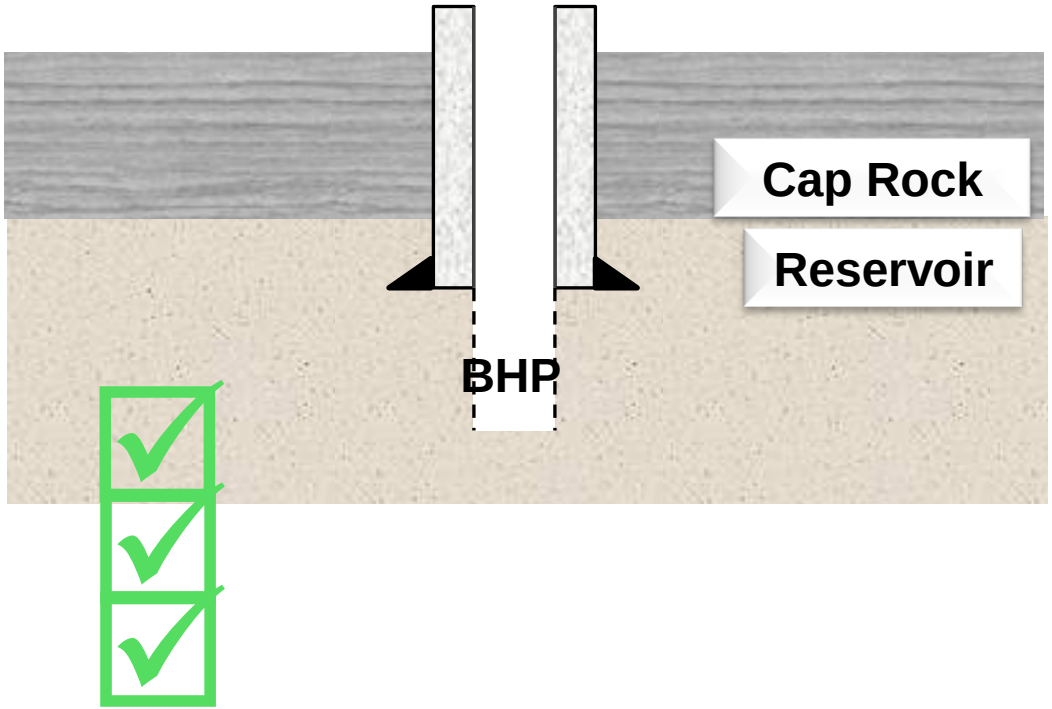

Conclusions

- Maximizing the injection pressure in tight carbonate fields is key for optimized and economic development.
- For both safety and reservoir management purposes injection must be done below fracturing regime
- Coupled geomechanics-reservoir models is necessary to capture the evolution of fracturing pressure with pressure and temperature
- High pressure injection was successfully implemented necessitating ramp up and monitoring procedures in close connection with the understanding of the geomechanical response of reservoir and cap rock to pressure and temperature changes

Thank you