Remediation of undesired CO_2 migration inside the reservoir

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on behalf of
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www.mirecol-co2.eu

Examples for remediation measures

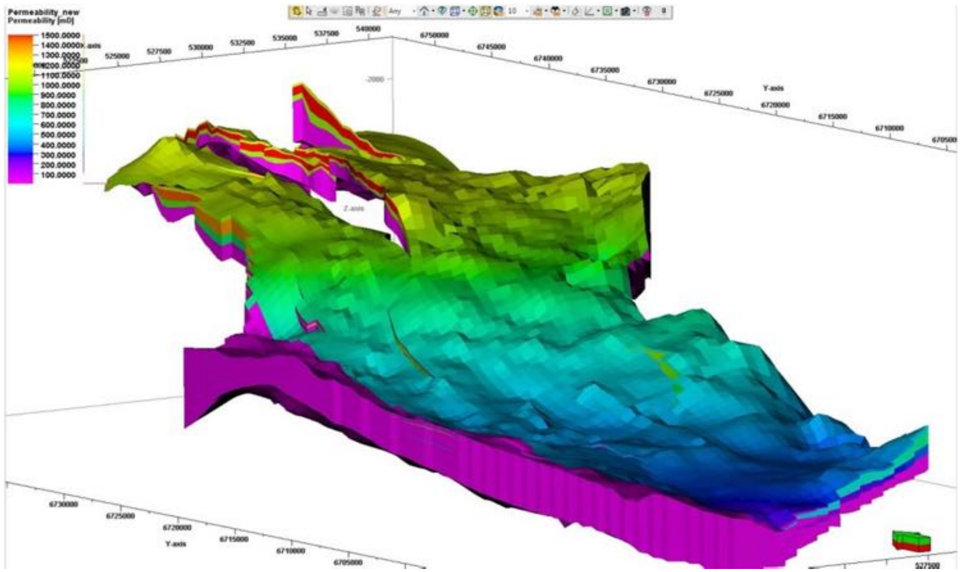
Assess the efficiency of different measures to manage or modify CO_2 flow patterns in the reservoir

- **Brine injection**:
  Investigate the effectiveness of water injection as a remediation measure for migration within the reservoir

- **Flow diversion**:
  Investigate the effectiveness of diversion of injected CO_2 to adjacent reservoir compartments for remediation of unintended CO_2 migration

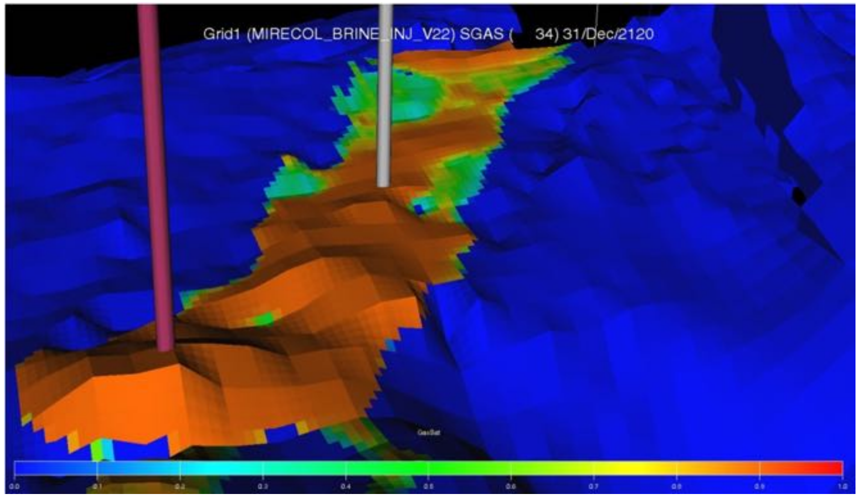
Selected model

- The **Johansen formation** has been investigated and the NW segment selected.
  - Johansen is a potential candidate for CO_2 Geological Storage.
  - The segment chosen is bounded by sealing faults to the west & north, pinch-out to the east, open and dropping deeper to the south.
  - 250km x 68km x 200-500m; depth 1600 – 2400m; 7 layers of alternating sandstone & shale; gridblocks 500m x 500m x 12m in sandstone.



injector

position of
remediation well WI



Simulations

- Fluids used: oil (water), gas (CO_2) & dissolved gas.
- A limit of 75% of lithostatic pressure was applied to both injectors.
- **Injection procedure**:

  a) Inject CO_2 only for 250 years to find when the plume reaches the fixed water injection (WI) well (i.e. at x years)

  b) Repeat (a) and stop CO_2 injection at year x-1 i.e. just before reaching the WI well; continue migration for a total of 510 years = unmitigated case

  c) Repeat (b) and inject water at 5000 sm^3/d in year x (for 1 year); continue migration to year 510 = mitigated case

Parameter & cases (scenarios) for simulation

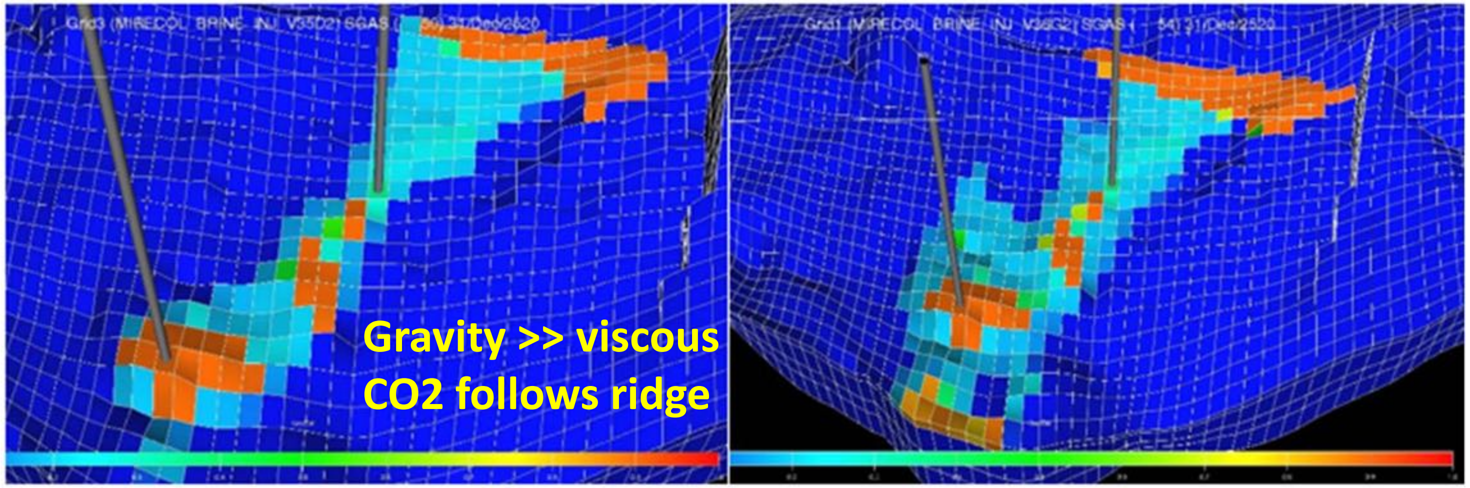
The most influential parameters for leakage were selected as follows:

1) **CO_2 injection rate**
   ideally CO_2 leakage rate, but will be very difficult to estimate in reality, so injection rate is the nearest approximation
2) **Permeability**
   main reservoir factor controlling fluid flow
3) **Reservoir depth**
   affects densities and the amount of gaseous CO_2

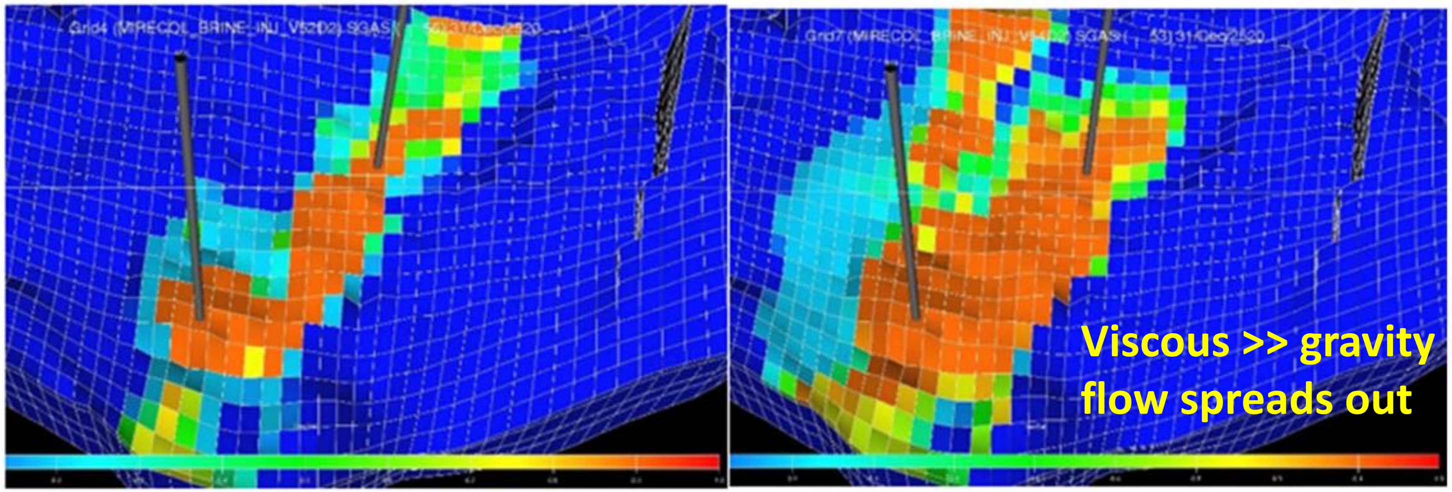
= 21 cases

CO2 Inj rate (t/yr)	K (mD)	Depth (m)	Case
5.0E+05	200	1800	v52
		2200	v49
	500	1700	v46
		2400	v43
	1000	1050	v40
		1650	v37
	1125	2200	v35
1.0E+06	200	1800	v53
		2200	v50
	500	1700	v47
		2400	v44
	1000	1050	v41
		1650	v38
	1125	2200	v34
3.0E+06	200	1800	v54
		2200	v51
	500	1700	v48
		2400	v45
	1000	1050	v42
		1650	v39
	1125	2200	v36

Migration pattern

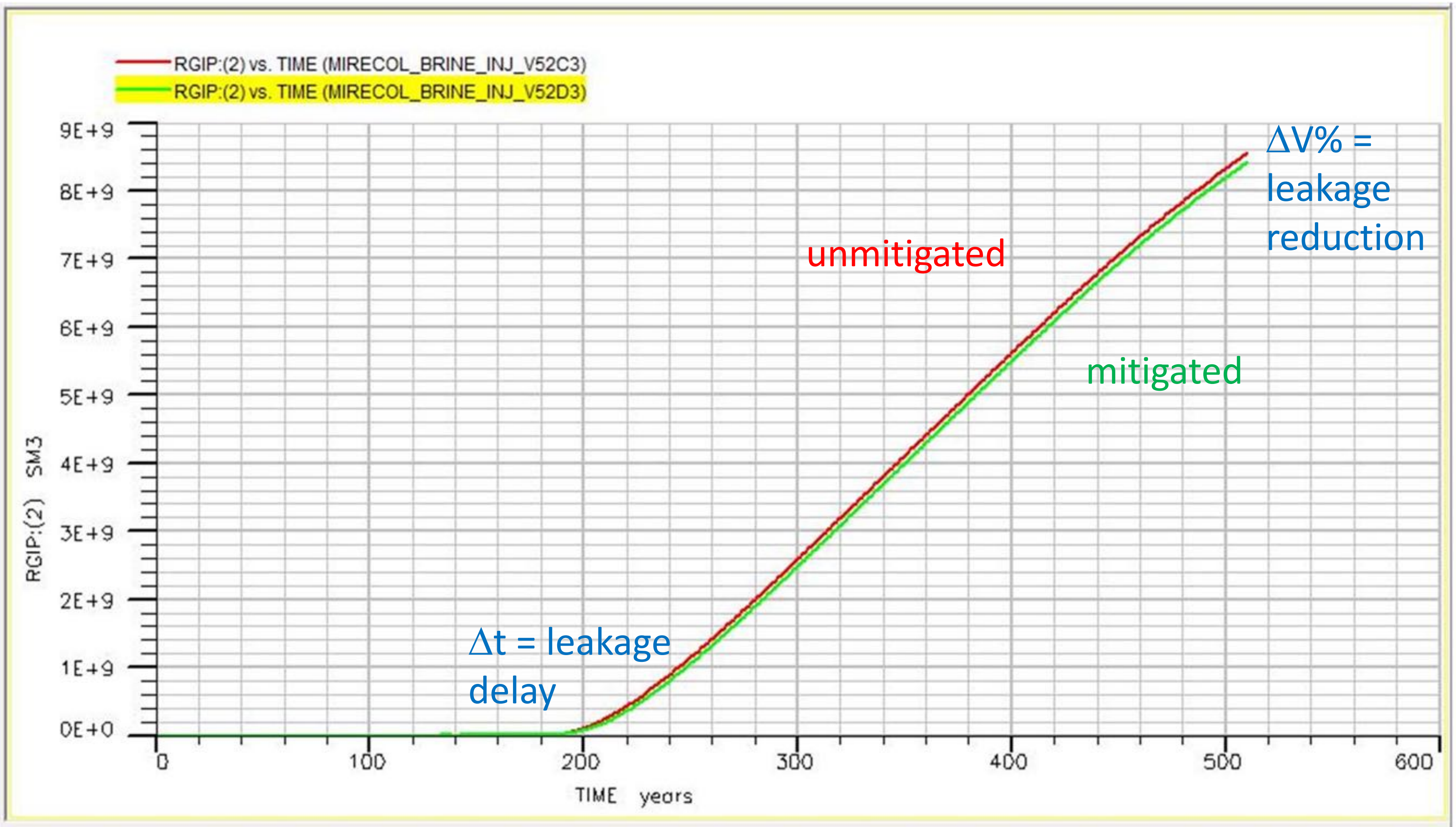


Final CO_2 saturations, 1125mD, 2200m deep, 0.5E6 t/y (left) & 3.0E6 t/y (right)

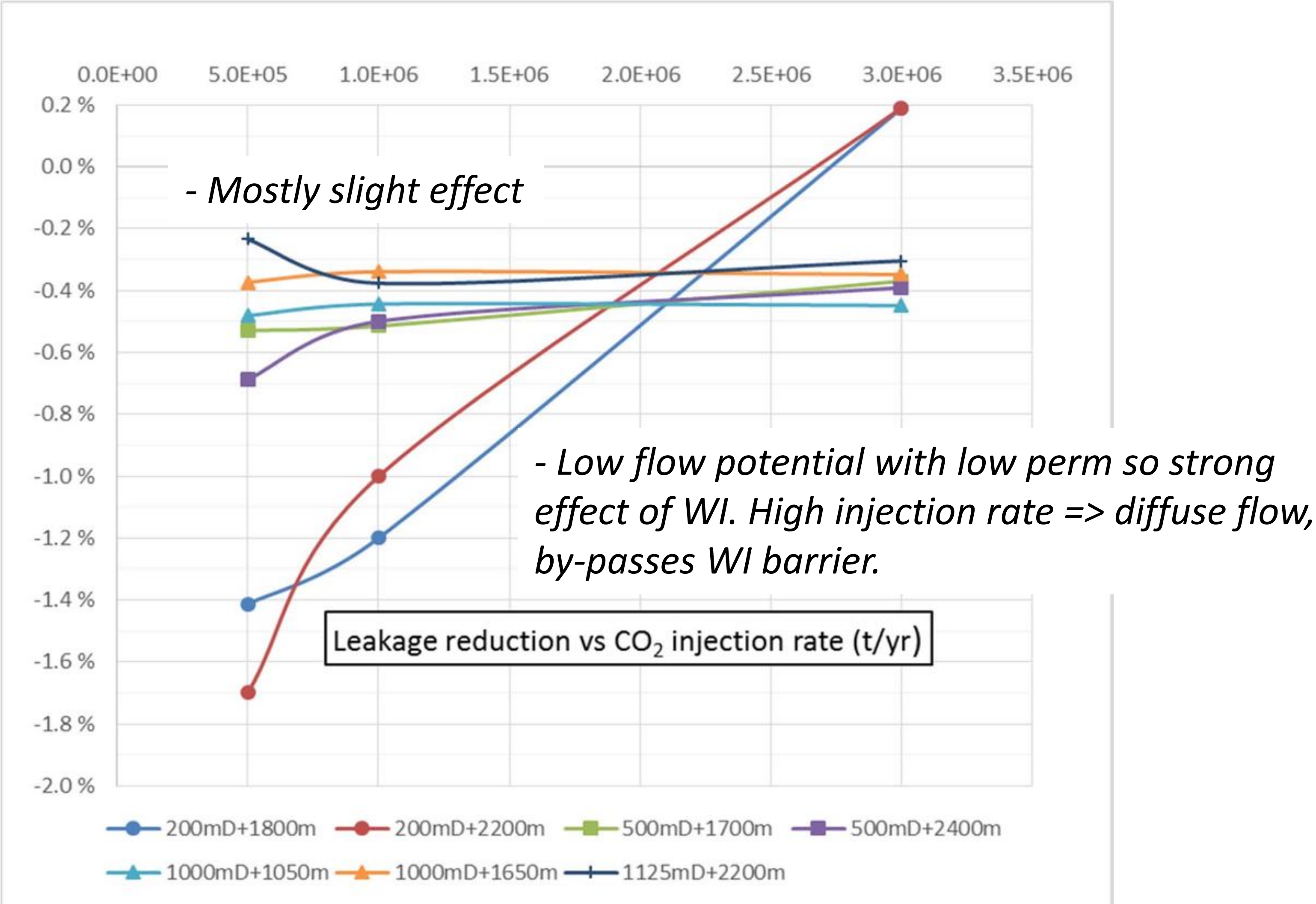


Final CO2 saturations, 200mD, 1800m deep, 0.5E6 t/y (left) & 3.0E6 t/y (right)

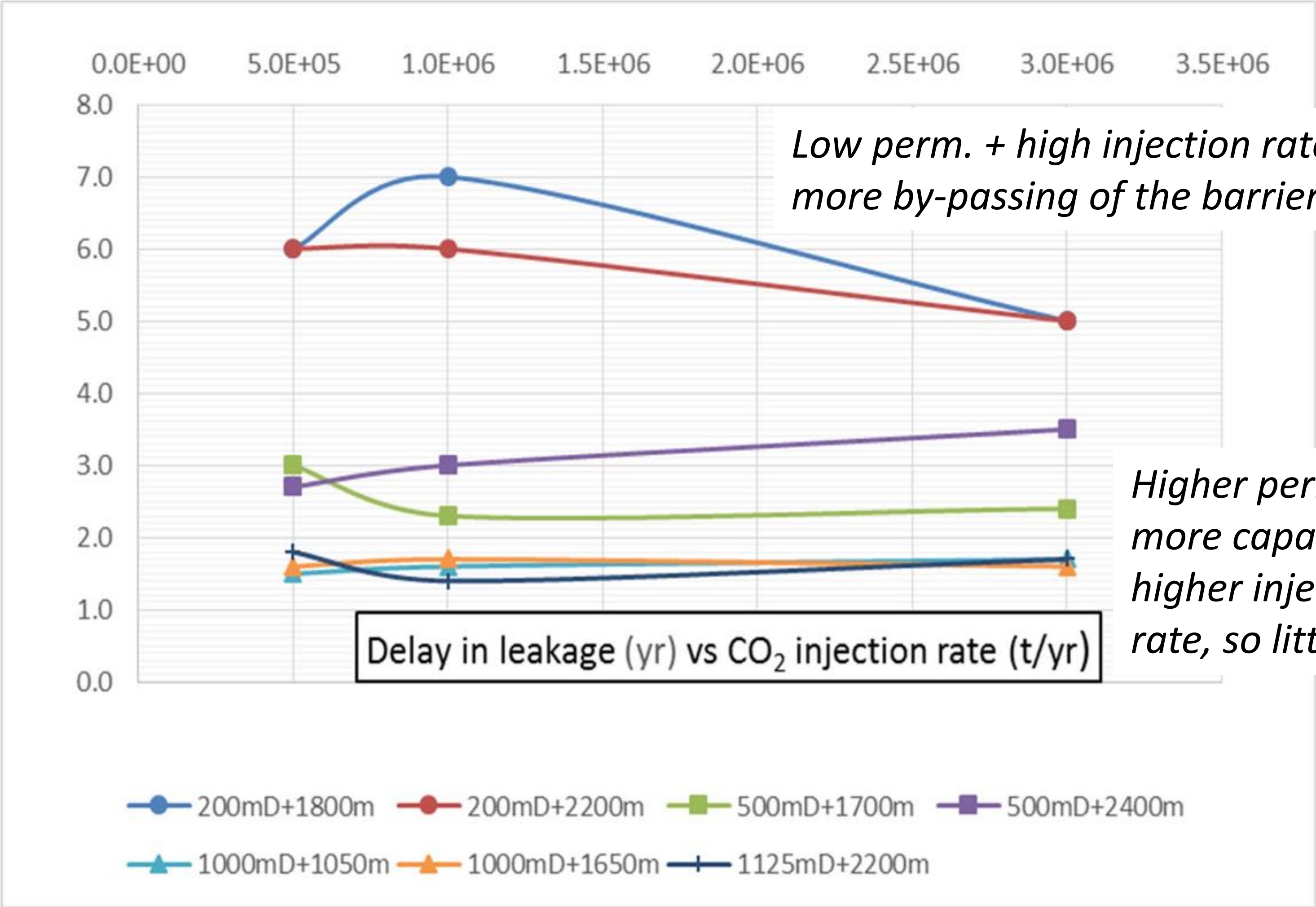
Complete leakage profiles over the entire simulation period for the 0.5E5 t/yr CO_2 injection, 200 mD permeability and 1800 m reservoir depth case, with and without water injection.



Leakage reduction vs CO_2 injection rate



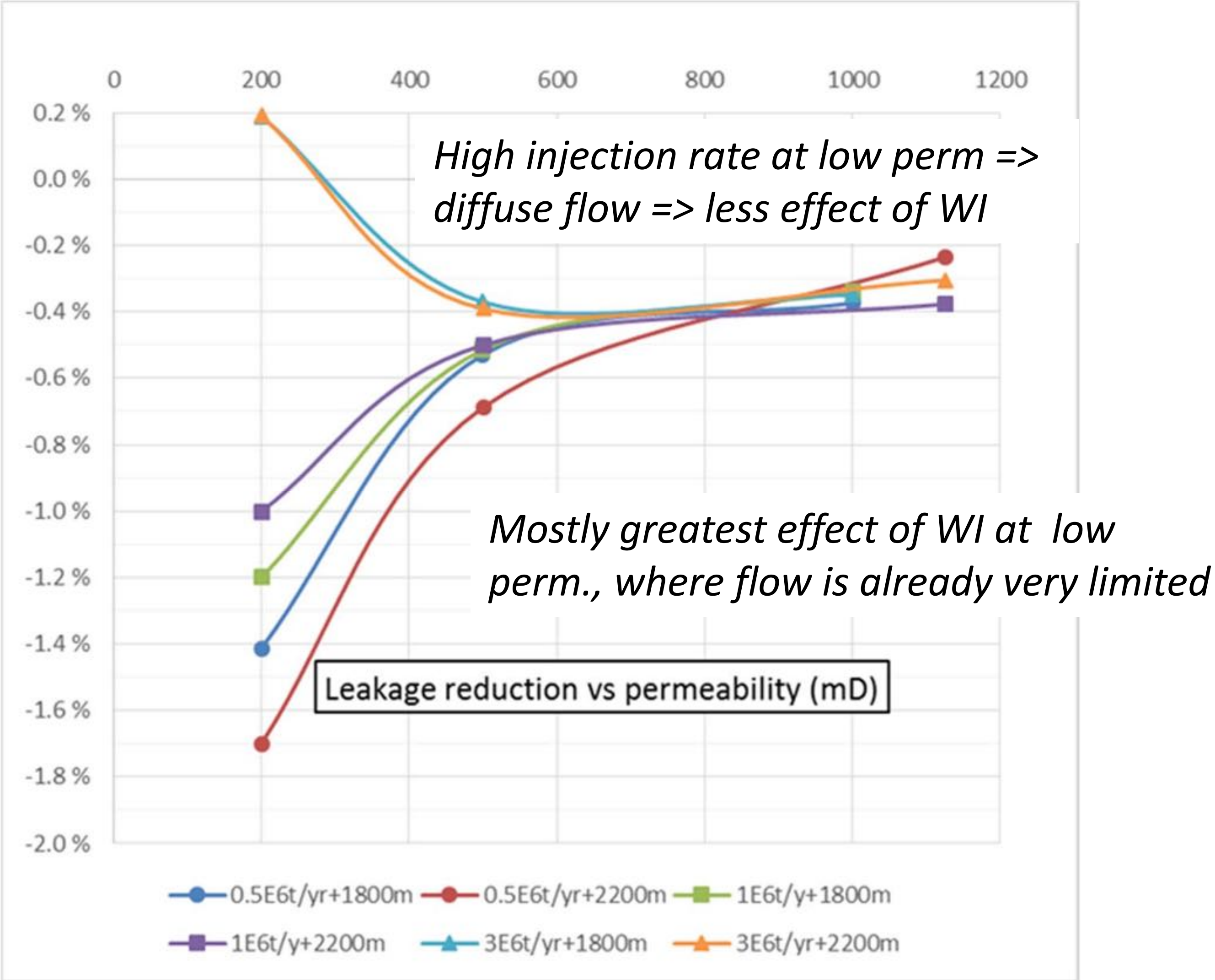
Delay in leakage vs CO_2 injection rate



Low perm. + high injection rate gives more by-passing of the barrier

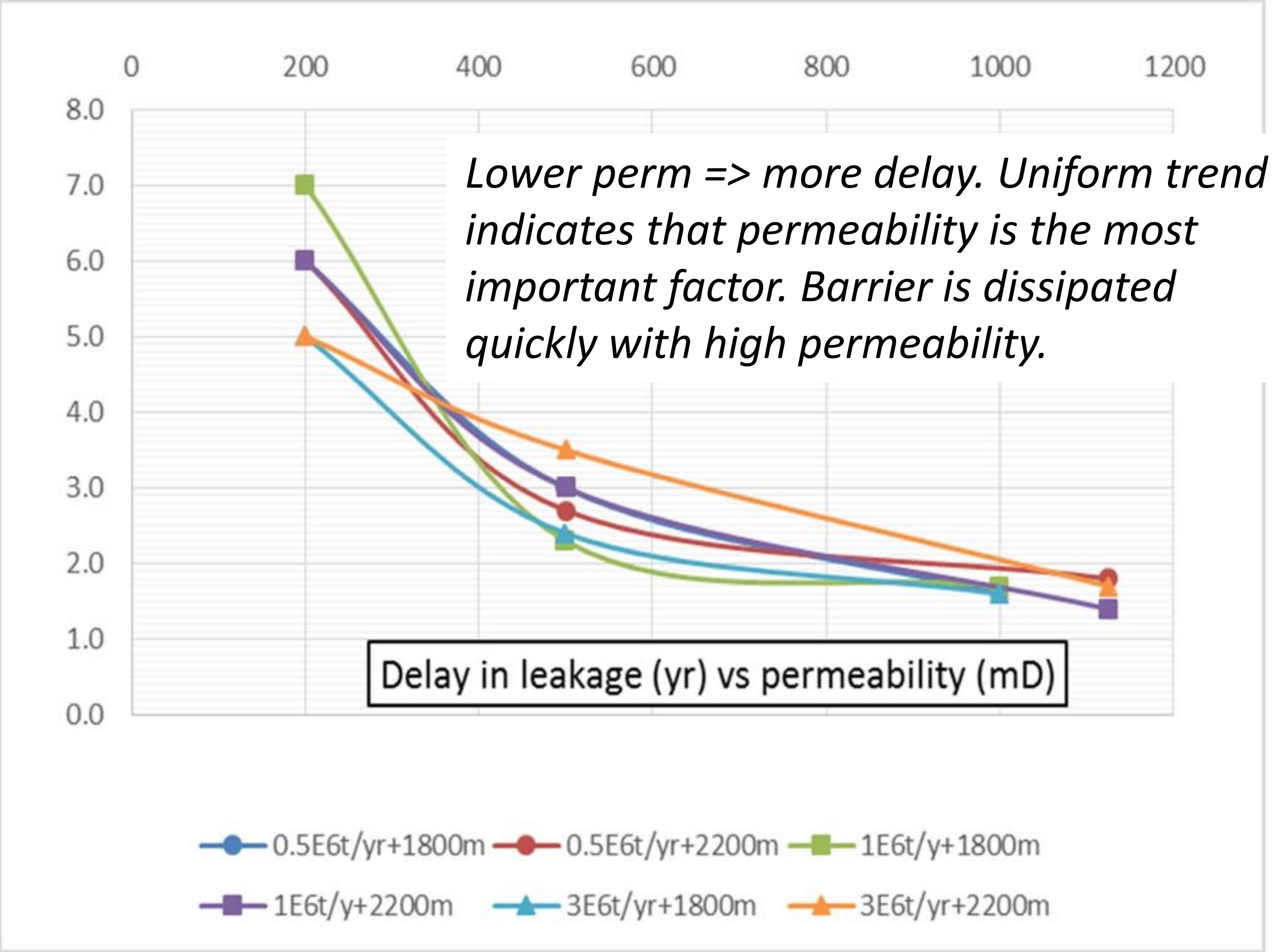
Higher perm. gives more capacity for higher injection rate, so little effect

Leakage reduction versus permeability



Brine injection

Delay in leakage vs permeability

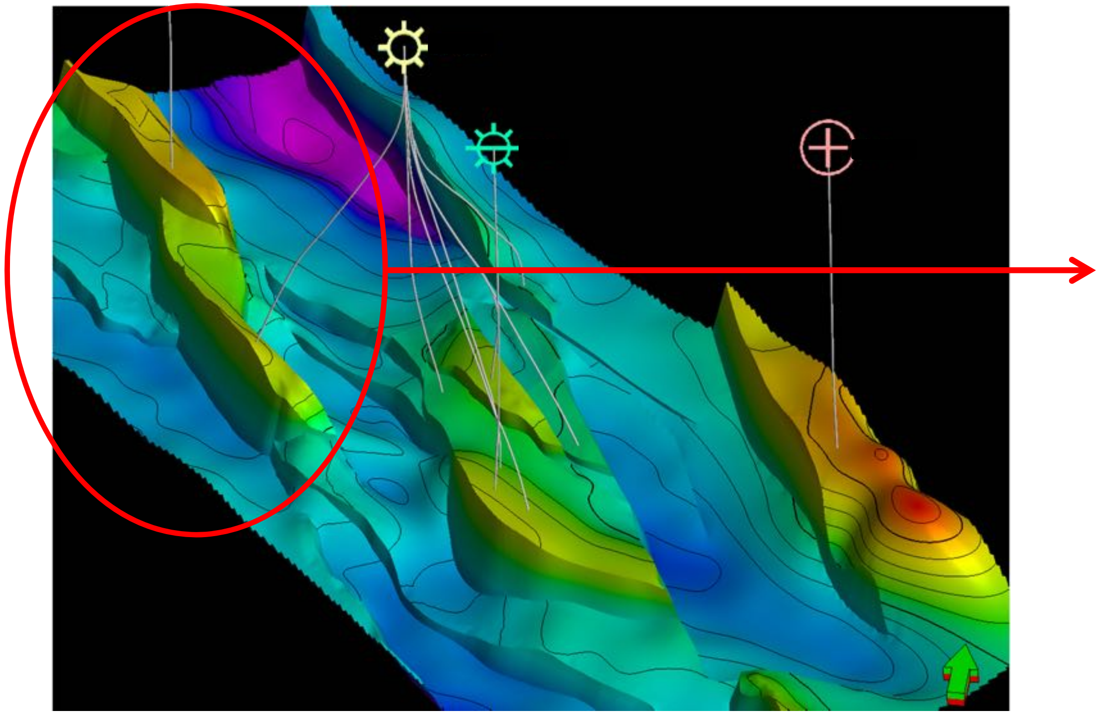


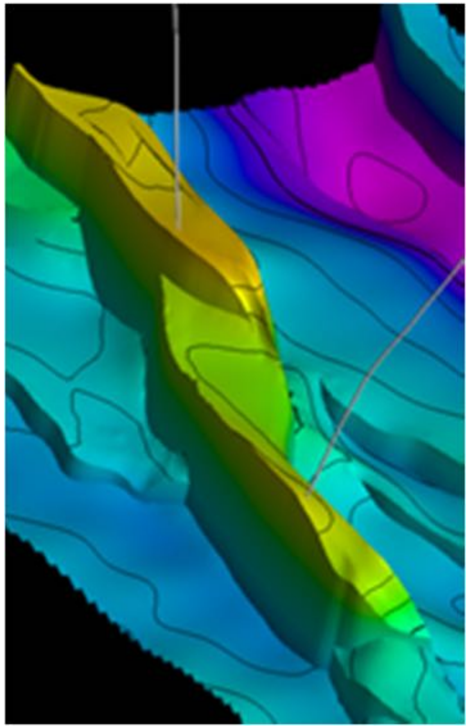
Conclusions

1) Water injection does not provide a long-lasting blockage to CO_2 migration (1.4 to 7 years from the beginning of water injection).
2) Permeability has dominating effect on the CO_2 migration pattern with CO_2 injection rate having a lesser effect.
3) Very low permeability results in large reductions in leakage (more effective mitigation), although this is mitigated by high CO_2 injection rates when viscous flow takes over.
4) No consistent trend in leakage reduction was observed due to variations in reservoir depth.
5) The delay in CO_2 migration (i.e. the longevity of mitigation) is generally unaffected by variations in CO_2 injection rate or reservoir depth. However decreasing permeability has a strong increasing effect on the duration of mitigation.
6) The spatial effect of mitigation by water injection showed almost no variation between the cases studied.

Inspiration

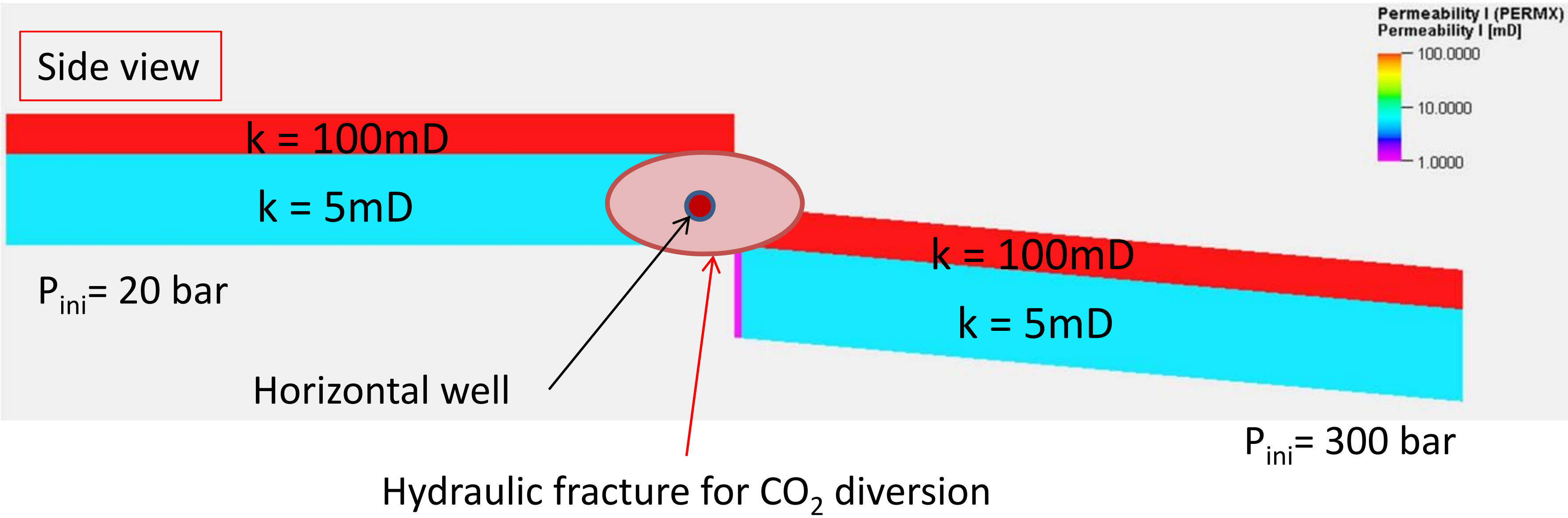
- Compartments in the subsurface creating many small gas fields
- (Sub-seismic) faults in aquifers creating barriers
- Diversion of CO_2 to nearby reservoir compartments may remediate unintended CO_2 migration



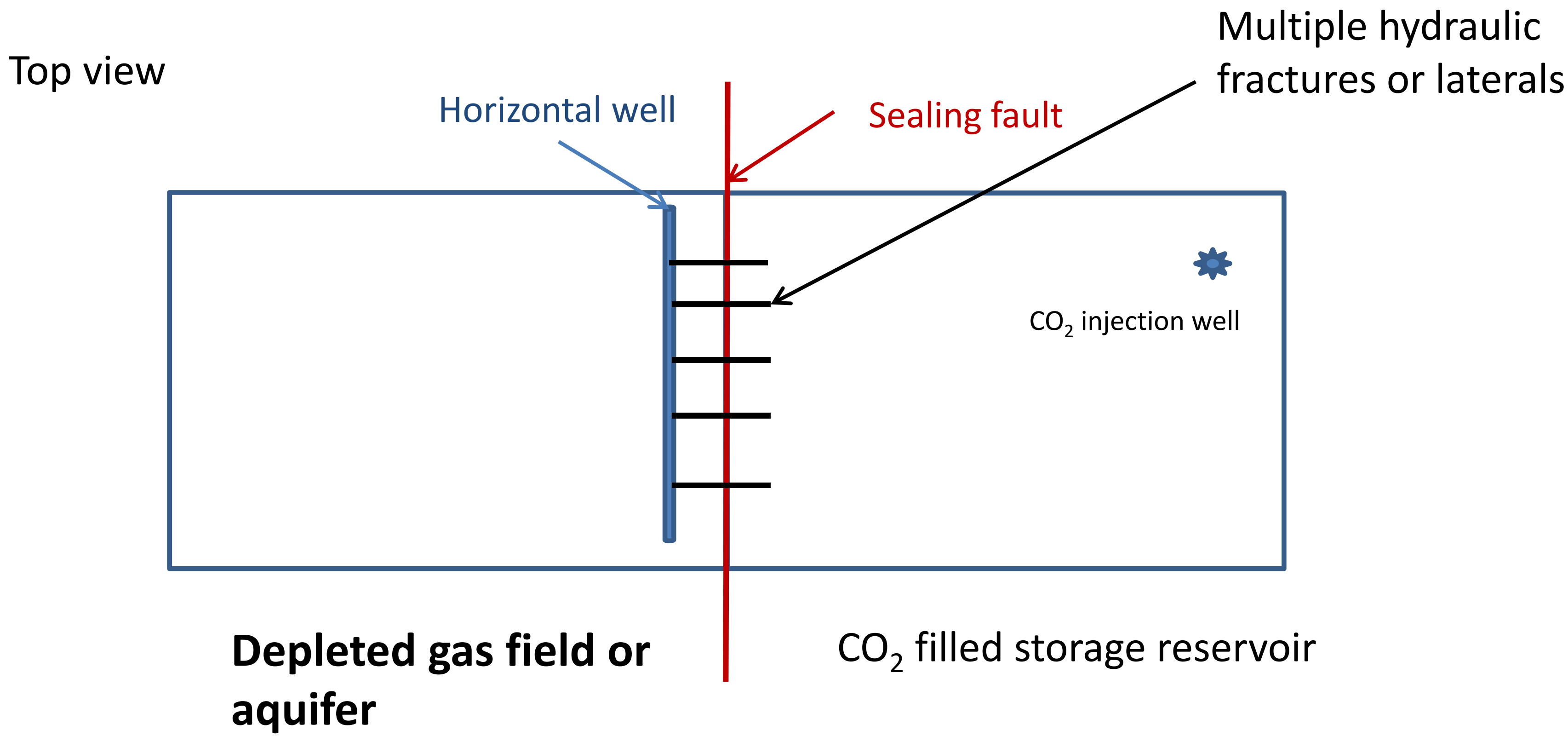


Synthetic study: base case setup

- Dip of storage reservoir: 5°
- Fault juxtaposition: 30%
- Storage compartment located downdip
- Parameters varied: juxtaposition, dip, permeability receiving compartment, fracture permeability, P_{ini}, ΔP



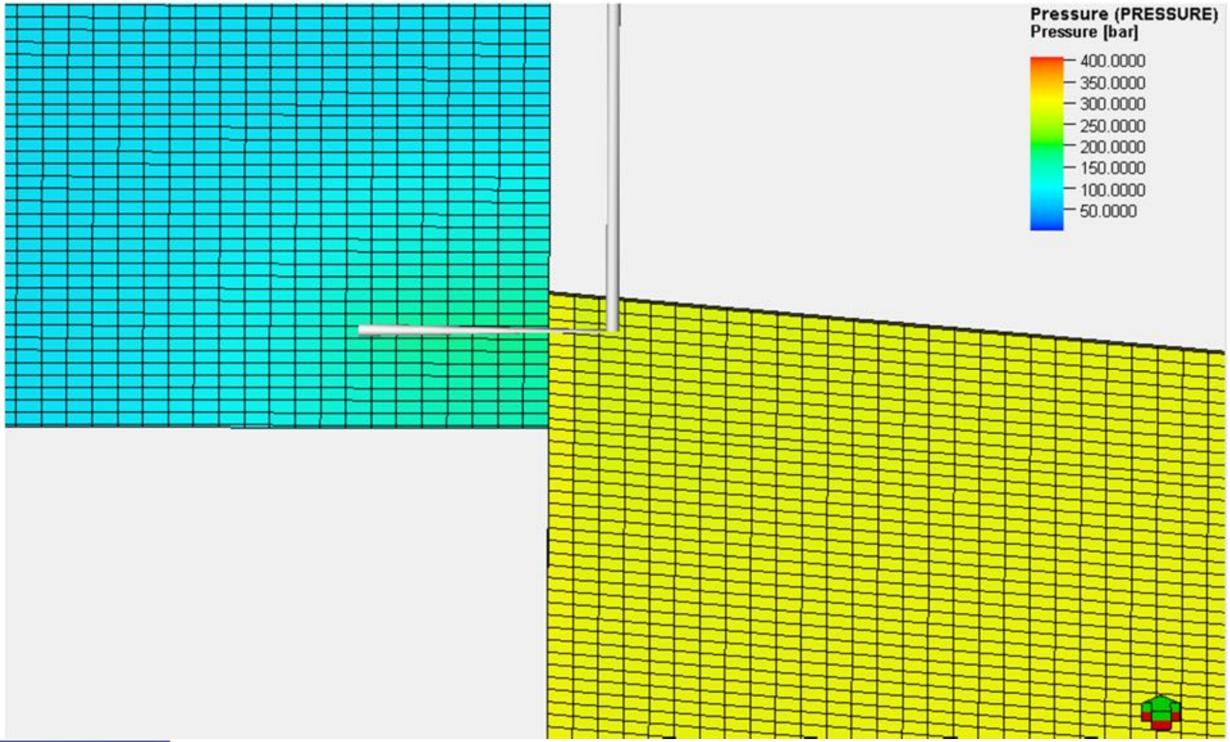
Schematic


Top view
Horizontal well
Sealing fault
Multiple hydraulic fractures or laterals
CO_2 injection well
Depleted gas field or aquifer
CO_2 filled storage reservoir

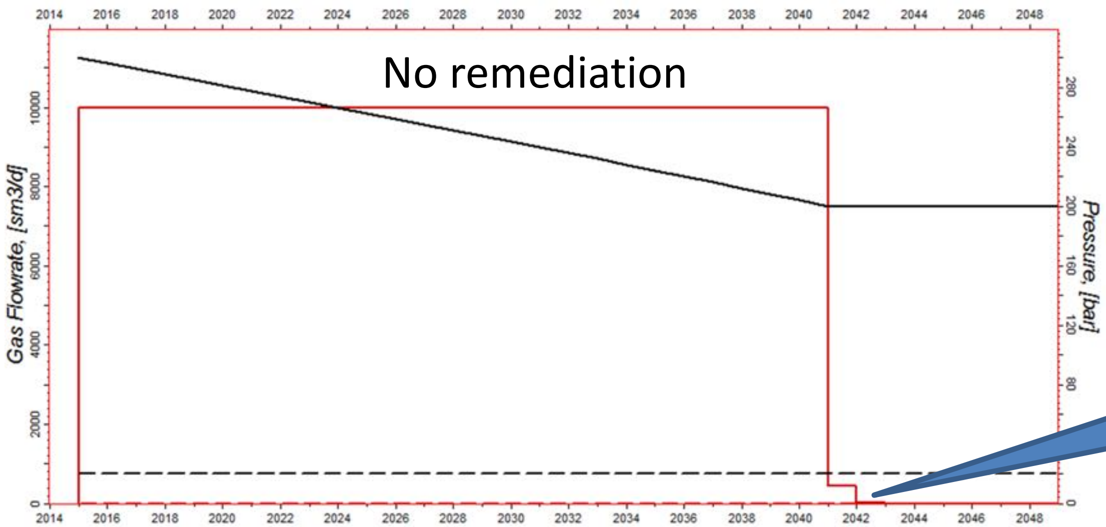
Radial jet drilling instead of hydraulic fracturing

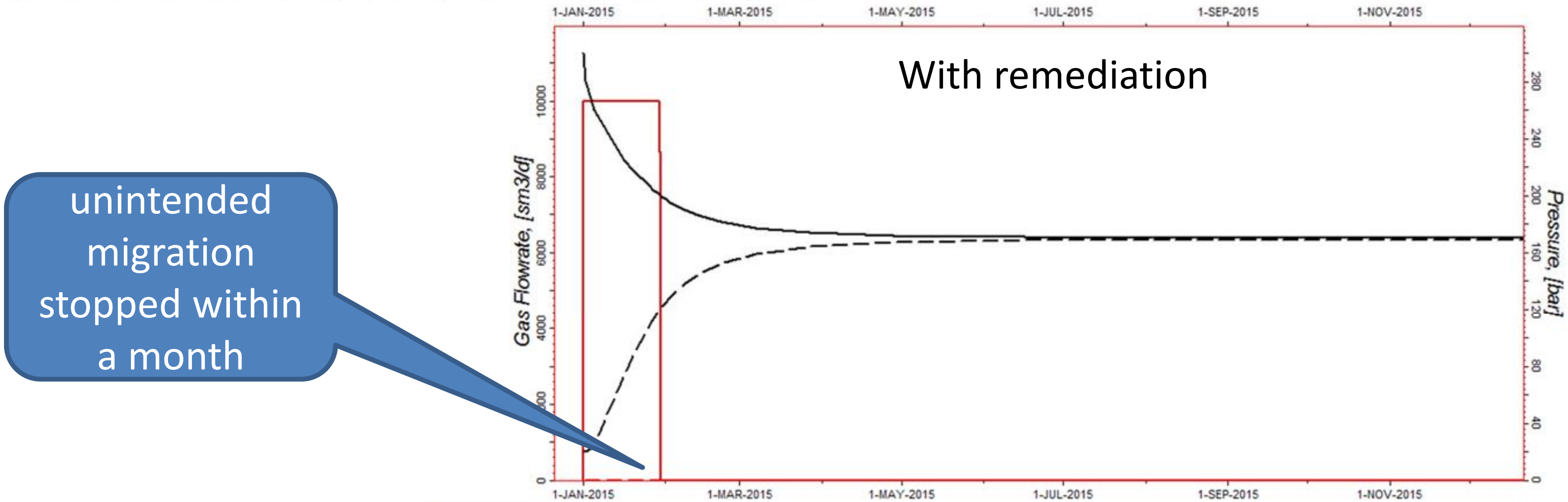
www.petrojet.ca

One 2-inch lateral of 100m long: unintended migration stopped after 130 d.



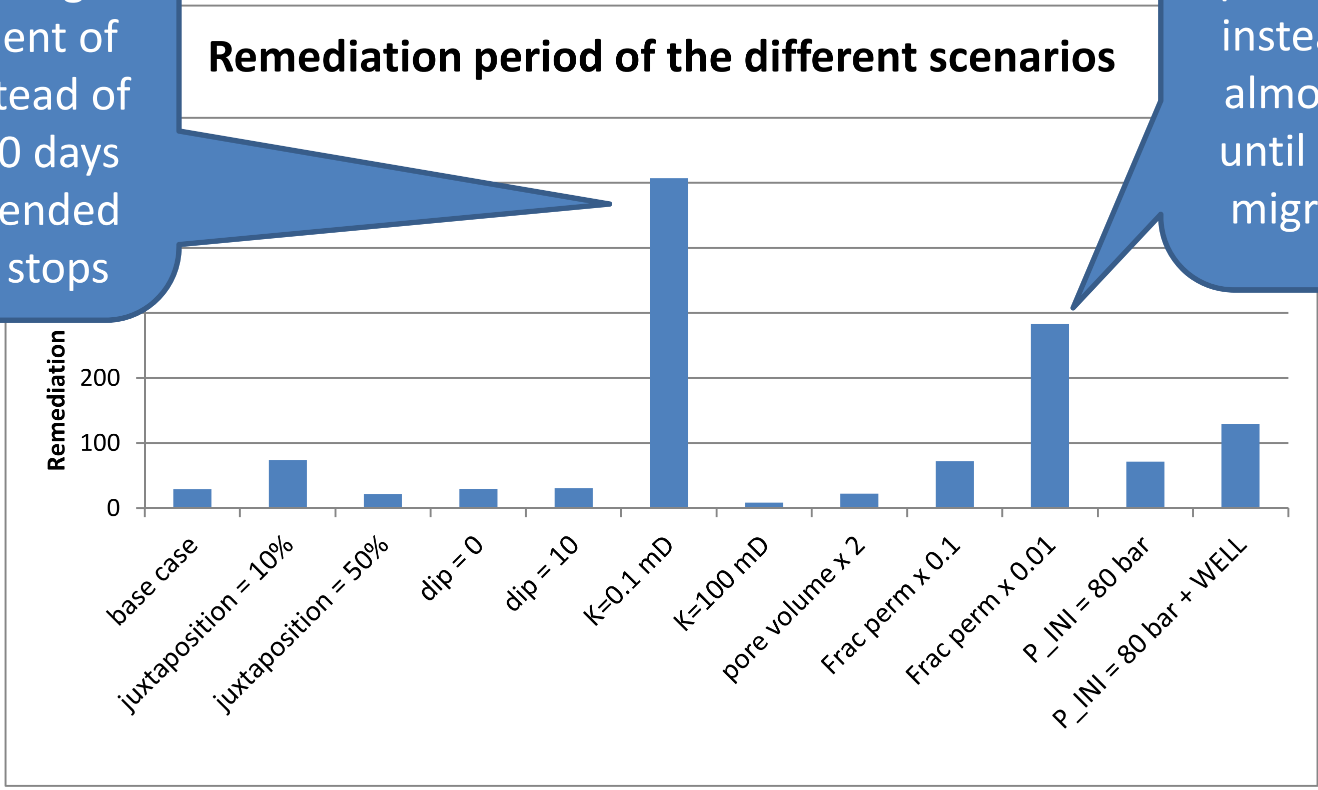
Results


No remediation
Gas Flowrate, [sm3/d]
Pressure, [bar]
Pressure storage compartment
Pressure receiving compartment
Gas migration rate
unintended migration stops after 27 years


With remediation
Gas Flowrate, [sm3/d]
Pressure, [bar]
unintended migration stopped within a month

Results

permeability in the receiving compartment of 0.1 mD instead of 5 mD: >500 days until unintended migration stops



Fracture permeability 4D instead of 400D: almost 300 days until unintended migration stops

Key parameters

Key parameters	bin 1	bin 2	bin 3	bin 4
Adjacent compartments	yes	no		
Depleted gas field or aquifer?	DGF	Aquifer		
Pressure difference between compartments (bar)	0	0-100	100-200	200-300
Fracture or lateral	fracture	lateral		
Transmissibility of fracture	0-50	50-500	500-5000	
Permeability of receiving comparment (mD)	0-1	1-50	>50	
Juxtaposition (%)	1-10	10-25	>25	

Key parameters are effecting the results (e.g response time) of technique the most

Example:- Adjacent compartments? → NO→ technique not applicable
- permeability receiving compartment
  → low → long response time
  → high → short response time

Output

INPUT	Scenarios			
Key parameters	**1**	**2**	**3**	**4**
Adjacent compartments	no	yes	yes	yes
Depleted gas field or aquifer?		DPG	DPG	DPG
Pressure difference between compartments (bar)		0	280	280
Fracture or lateral			fracture	fracture
Transmissibility of fracture			1000	100
Permeability of receiving compartment (mD)			5	5
Juxtaposition (%)			5	5
OUTPUT (as best as you can estimate) for the operator				
likelihood of success [%]	0	0	56%	40-60%?
spatial extent of remediation (km)			similar to reservoir size	similar to reservoir size
economic cost of remediation (€) OR list of materials required			well, hydraulic fracture, monitoring	well, hydraulic fracture, monitoring
response time of remediation (months)			0.97	2.31
longevity of remediation (months)			infinity	infinity

Likelihood of success defined as:
Example scenario 3: P(total)=P(HF)*P(HFI)*P(RT)*P(L)=0.80*0.70*1*1=56%

P(HF)=Success ratio hydraulic fractures
P(HFI)=Success ratio hydraulic fracture trough interface or fault
P(RT)= normalized response time
P(L)= normalized longevity