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"EOR Simulation Study in a Shale Oil Reservoir:

Supercritical CO_2 Injection Considering Molecular Diffusion, Capillary Pressure and Geomechanical Effects in Vaca Muerta"

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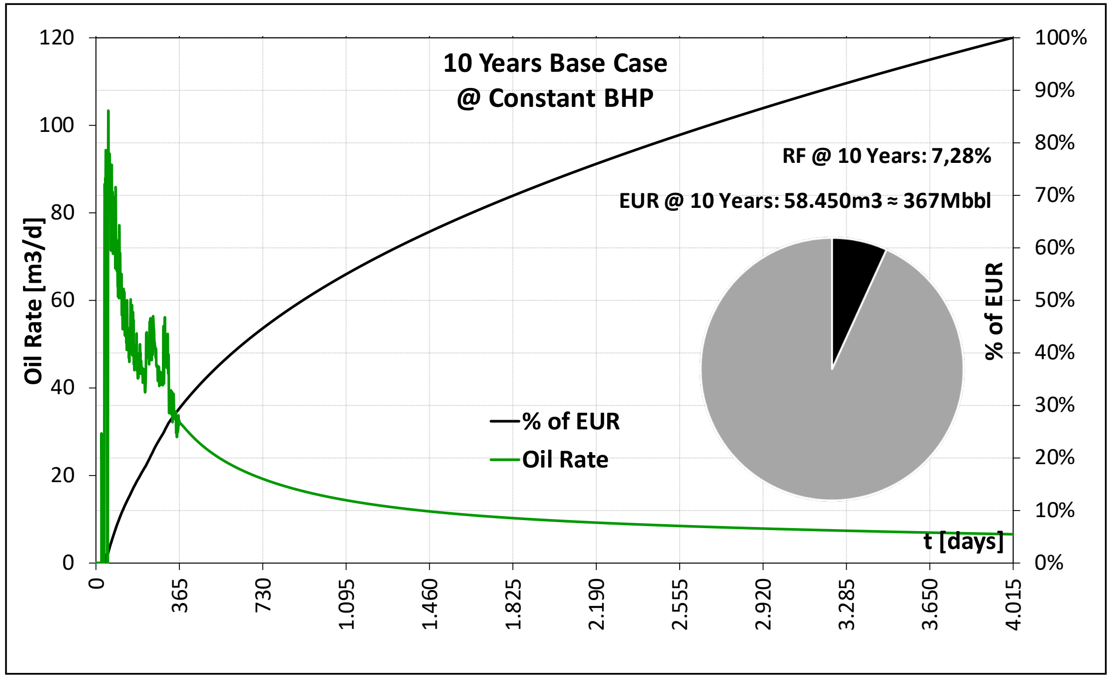
Introduction

Motivation and Objectives

- Shale oil reservoirs became very attractive in recent years due to the significant oil & gas in place expected in this regionally-extended plays.

- Development of unconventional fields involves innovative technologies and highly optimised drilling and completion techniques

- Still, recovery factor of shale oil wells is very low (< 10%)



Introduction

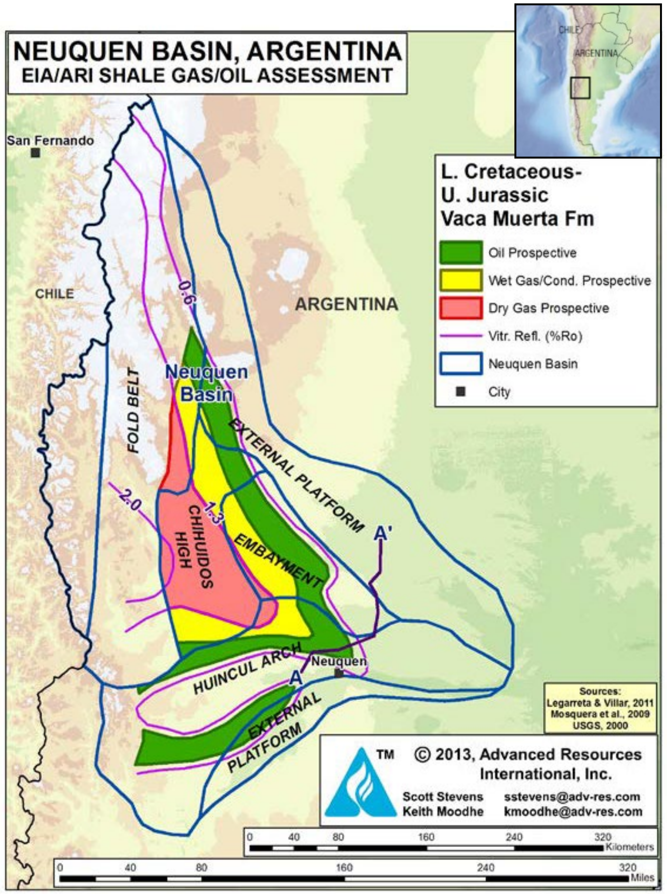
Motivation and Objectives

- By means of reservoir simulation, this study aims to evaluate the ***potential of CO_2 cyclic injection to increase RF in a shale oil well*** drilled in a resource play like the Vaca Muerta formation, addressing the following issues:

  - **What is the optimal cyclic injection scheme?**
  - **What is the impact of injected gas composition?**
  - **What is the impact of molecular diffusion mechanism?**

Introduction

Vaca Muerta Formation



- Black/dark grey rich marine shale located at the Neuquén Basin, extending over 30.000 Km2.
- Thickness from 20 m (margins) to 460 m (central area).
- TOC ranging between 1% - 8%, peaking 12% at the base.
- Matrix Ø between 4% - 13%, averaging 9%
- Wide range in matrix K, from hundreds of nD to tens of µD.
- Maturation window indicates dry gas, wet gas and condensate and oil prone areas
- GIIP ≥ 308 TCF of gas and STOOIP ≥ 16 billion bbl of oil.

Introduction

Gas-based EOR in Shale Oil Reservoirs

- Current gas-EOR expertise in unconventional shale/tight oil reservoirs mostly focused on US fields (Bakken, Eagle Ford), Canada & China

Laboratory studies using CO_2 in Bakken cores suggest that

- Molecular diffusion plays a significant role in hydrocarbon extraction from the matrix
- Either dominating oil transport [15] or complementing pressure driven advective "Darcy" flow [2].
- Additional effects observed include re-pressurization, viscosity and ITF reduction.

In **numerical simulation studies**

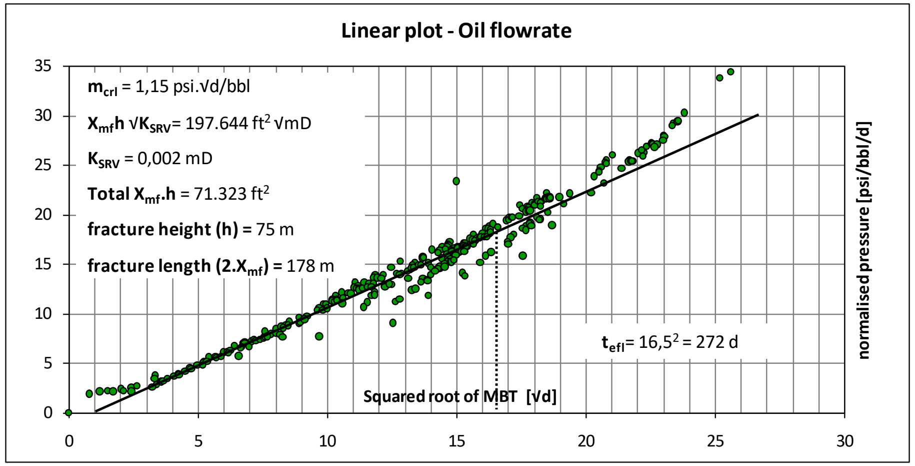
- Typical approach involves compositional models, with dual porosity [10] or dual permeability [1; 8; 9; 11] grids.
- The most common method found in literature is the Huff n' puff process.
- Other modelled techniques include gas flooding and WAG.

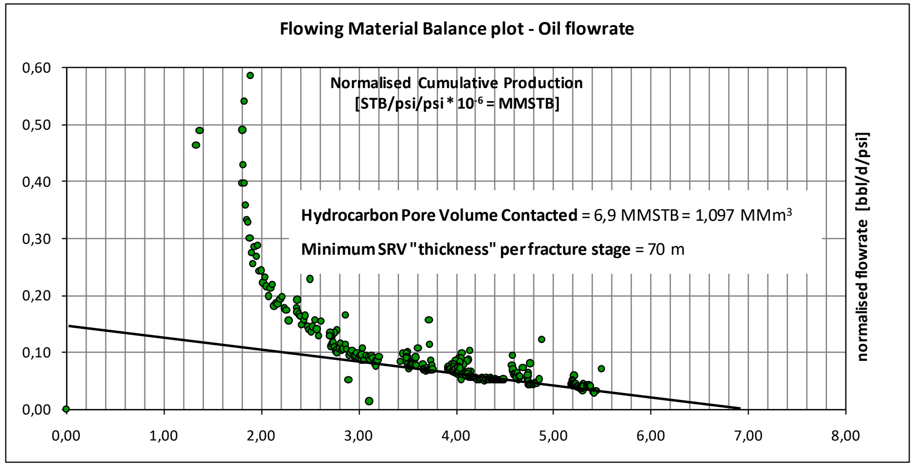
Pilot projects

- Limited information. Huff n' puff in the US and flooding reported in China, US and Canada [7; 12; 14].
- Results are not conclusive
- Most successful pilot reported by EOG at Eagle Ford → 30-70% increase in reserves has been declared
- No details provided but independent analysis from public data suggests a Huff n' puff using gas from the reservoir enriched with heavier components [7].

Methods and Procedures

Preliminary Analysis & Well Characterization

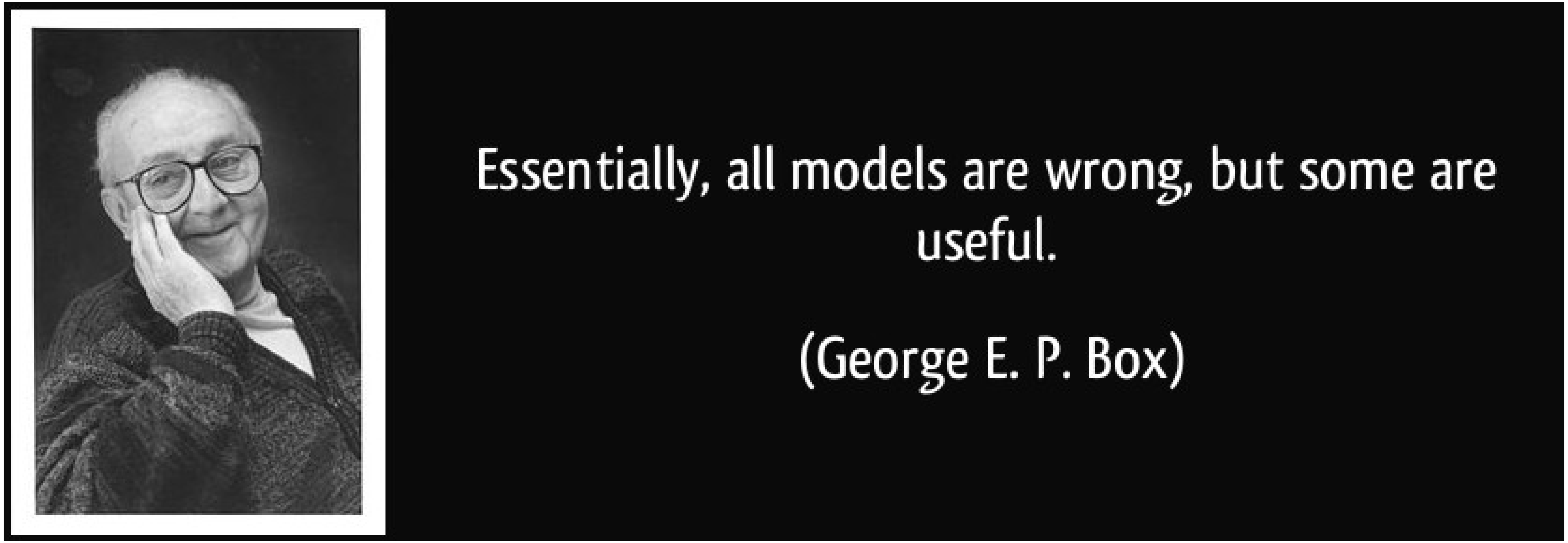




- Production data analysis applying RTA and FMB used to characterize the well [6; 16]:
  - Flow regimes identification in log-log normalized flowrate vs. material balance time
  - Linear plot used to estimate K_{SRV} and X_{mf}
  - Flowing material balance to estimate the SRV
- Ø and Sw for shale matrix estimated from vertical well logs using a simplified petrophysical workflow for Vaca Muerta [3].
- Core data used to validate log-derived calculations and generate a poroperm relationship for K_{matrix} .
- Homogeneous distribution assumed for K and Ø.

Methods and Procedures

Grid Definition and Fluid Model



Methods and Procedures

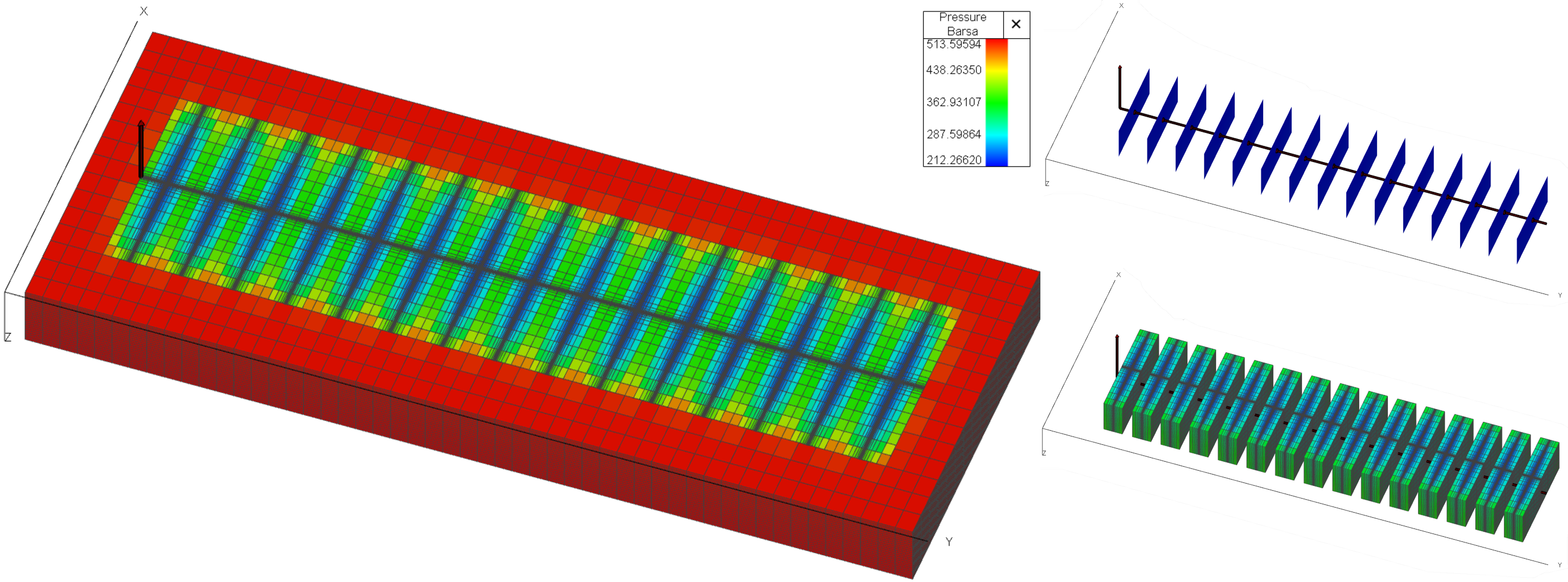
Grid Definition and Fluid Model

Model parameters	
Dimensions (x,y,z)	400m x 1.700m x 75m
Total amount of cells	237.375
Average porosity	6,6 %
Average matrix K	0,00019 mD
K_{SRV}	0,002 mD
Average Sw	0,35
HF conductivity	85 mD-ft
HF height	75 m
HF length	178 m
Amount of HF	15
Preservoir	500 Bar @ 3.010 m
Treservoir	134° C @ 3.190 m
Landing depth	3.190 m
Length of horizontal section	1.500 m

- Single porosity model selected to balance calculation time with compositional and molecular diffusion requirements.
- 15 planar hydraulic fractures assumed orthogonal to the well.
- SRV surrounding the fractures with enhanced K derived from RTA analysis.
- Un-stimulated shale matrix surrounding the SRV, properties derived from petrophysical analysis.
- Logarithmically spaced LGR in XY plane to represent hydraulic fractures and SRV.
- Cartesian LGR applied on surrounding matrix cells.

Methods and Procedures

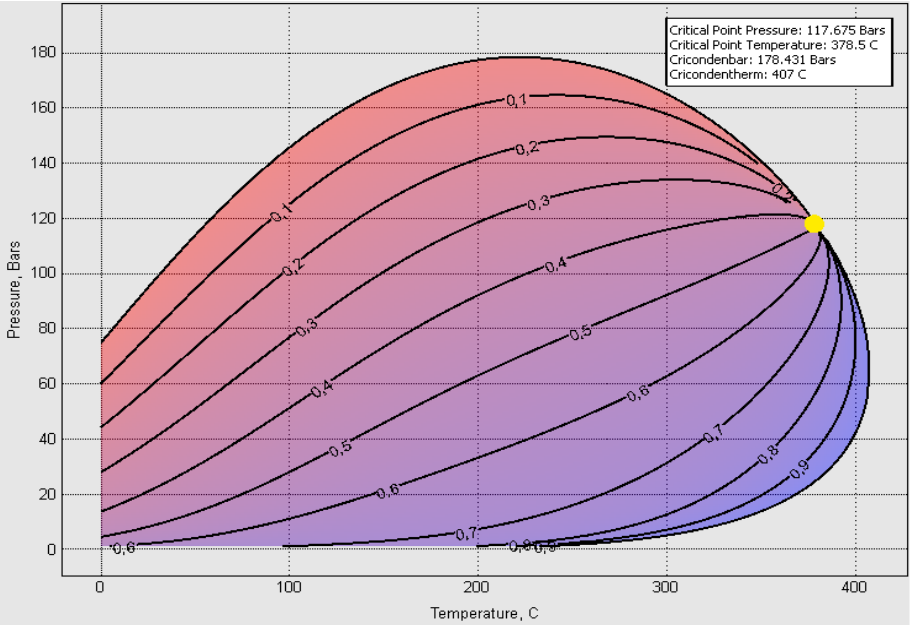
Grid Definition and Fluid Model



Full well model, HF and SRV detail (clockwise)
Pressure distribution for the base case after 10 years of depletion

Methods and Procedures

Grid Definition and Fluid Model



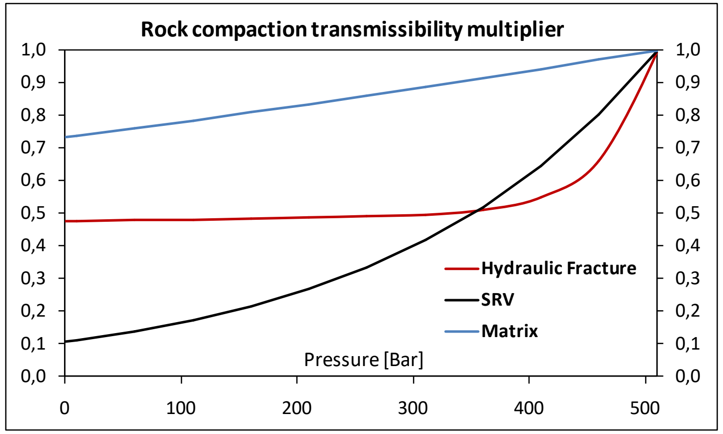
- Compositional model required to represent the multi-contact miscibility between CO_2 and oil and incorporate the molecular diffusion mechanism.
- 7 pseudo-components defined: CO2, N2, C1, C2, C3, C4-C6 and C7+.
- Peng-Robinson EOS tuned using curves from a representative black oil PVT (GOR, Bo, Bg, μ_{oil} & μ_{gas})
- Special miscibility tests (Swelling test, RBA, VIFT) not available.
- Pb: 161,5 Bars; Rs: 151,1 sm3/sm3; Bob: 1,603 rn3/sm3.
- Minimum Miscibility Pressure from Emera & Sarma correlation(5): 288,9 Bars (4191 psi).

Methods and Procedures

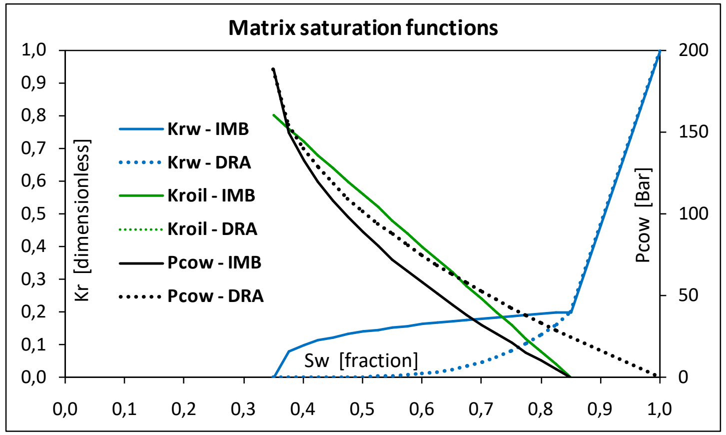
Additional Effects Considered

$$D_{ik} = \frac{1 - y_{ik}}{\sum_{j \neq 1} y_{ik} D_{ij}^{-1}}$$

- **Molecular diffusion:**
  - Assumed to play a major role in CO_2–oil physics in shales.
  - Modeled using Fick's law, driven by an intra-phase gradient in component concentration where coefficients obtained from Sigmund's correlation [17].



- **Geomechanical effects:**
  - Reduction of K and Ø with reservoir pressure, observed in VM and other overpressured shales [16].
  - Modelled by exponential functions for transmissibility and pore volume multipliers.

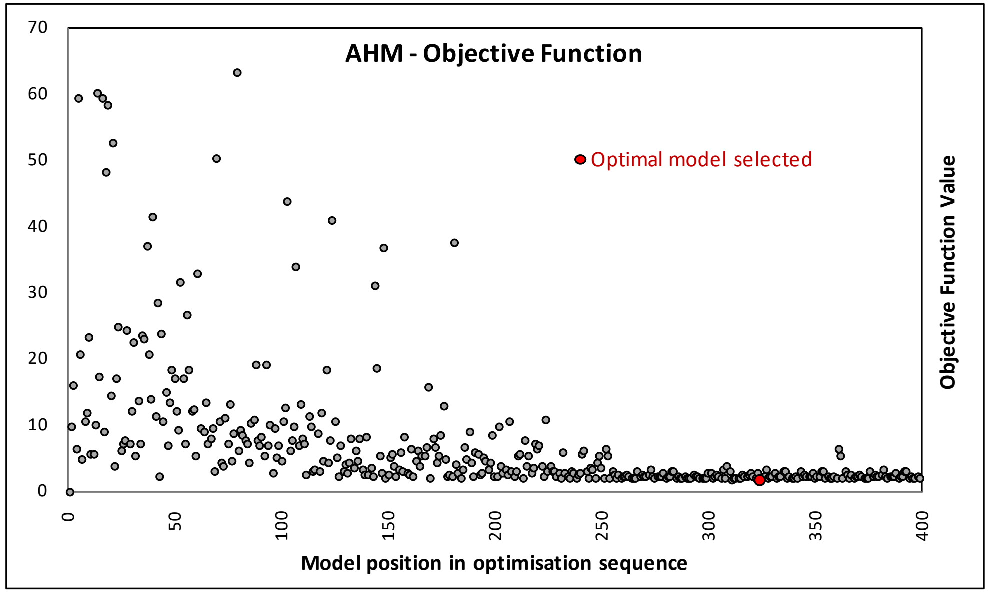


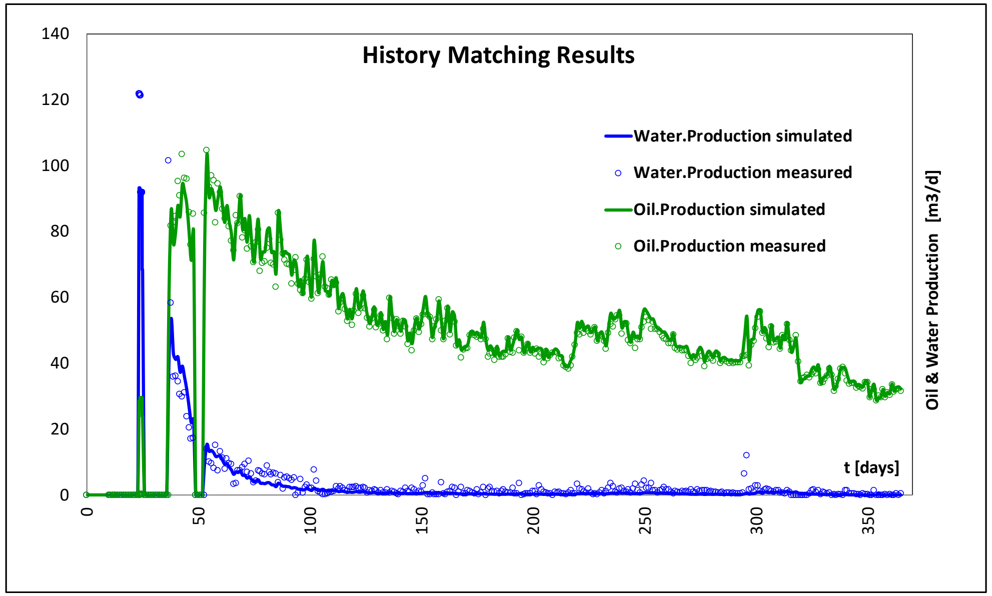
- **Capillary pressures:**
  - Strong capillary pressures in small matrix pores is assumed to control water retention during post-fracturing flowback in VM shale [18].
  - Capillary pressure curves modelled using Bentsen and Anli model.

Methods and Procedures

Assisted History Matching

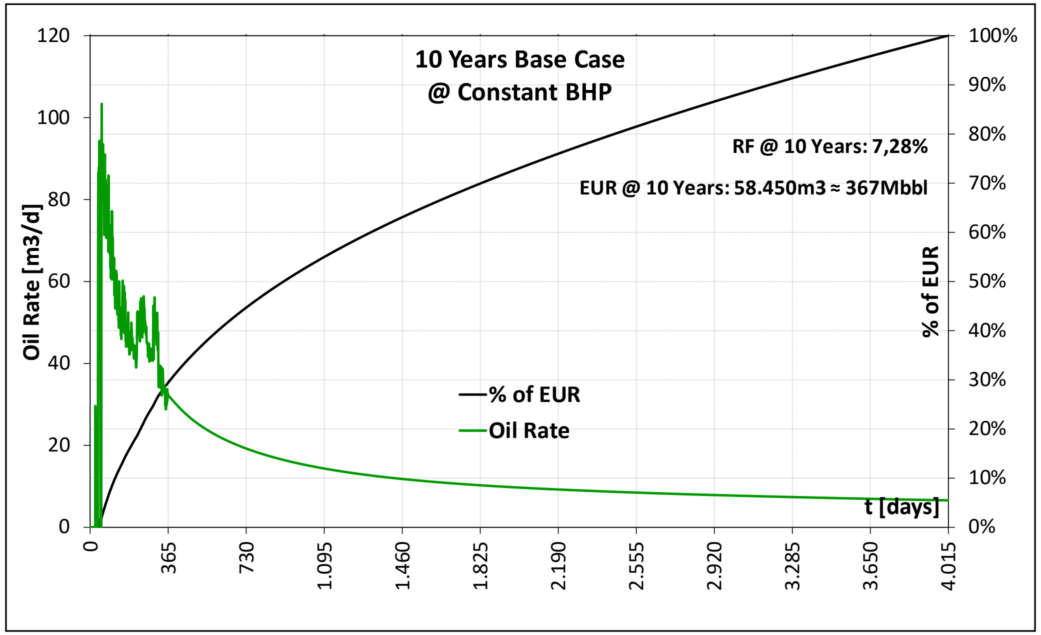
- Historical data included the fracturing stage, after-fracture close-in, flowback, after-flowback close-in and 1-year production period.
- Matching variables: *hydraulic fracture K*, *capillary pressure curves* and *pressure-dependent multipliers curves for K and pore volume*.
- An evolutionary algorithm was used for objective function optimisation, considering oil flowrate, water flowrate, total water injected and BHP.





Huff n' Puff Optimisation
Primary Production

- CO_2 flooding discarded due to uncertainty regarding reservoir heterogeneity
- Base case at constant BHP leads to 7,28% RF and 58.450 m3 EUR @ 10 years.
- "Step-by-step" optimisation to maximise Incremental NPV objective function.
- Injection BHP set at 680 Bars (above MMP and below Pfracture).
- Optimisation variables: **cycle duration**, **injection rate**, number of **injection days**, number of **soaking days** (production days per cycle indirectly optimised).



Huff n' Puff Optimisation

Cycle Duration

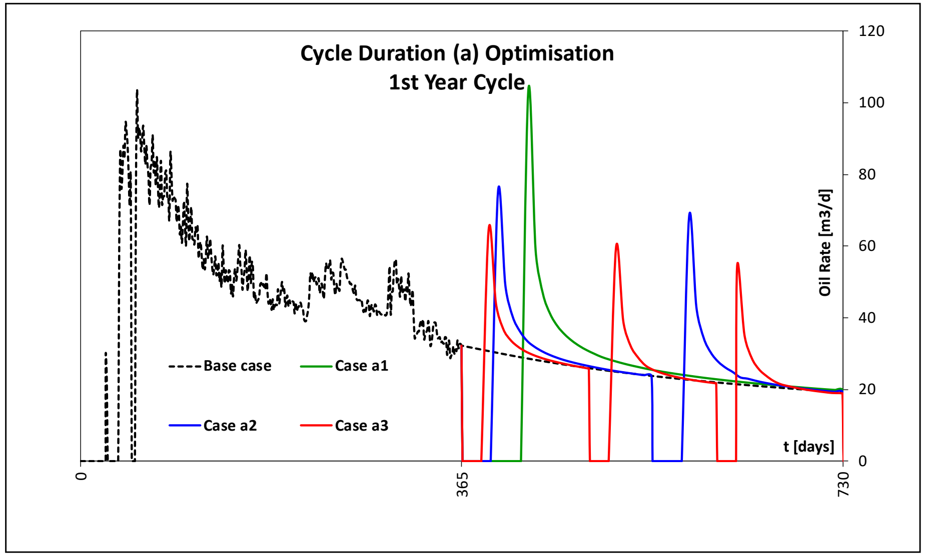
- Three scenarios defined for the investigation of the optimal Huff n' Puff cycle:
    - Scenario (a1) a single 365 days-cycles per year
    - Scenario (a2) 2 cycles of 183 and 182 days per year
    - Scenario (a3) 3 cycles of 122, 122 and 121 days are completed per year

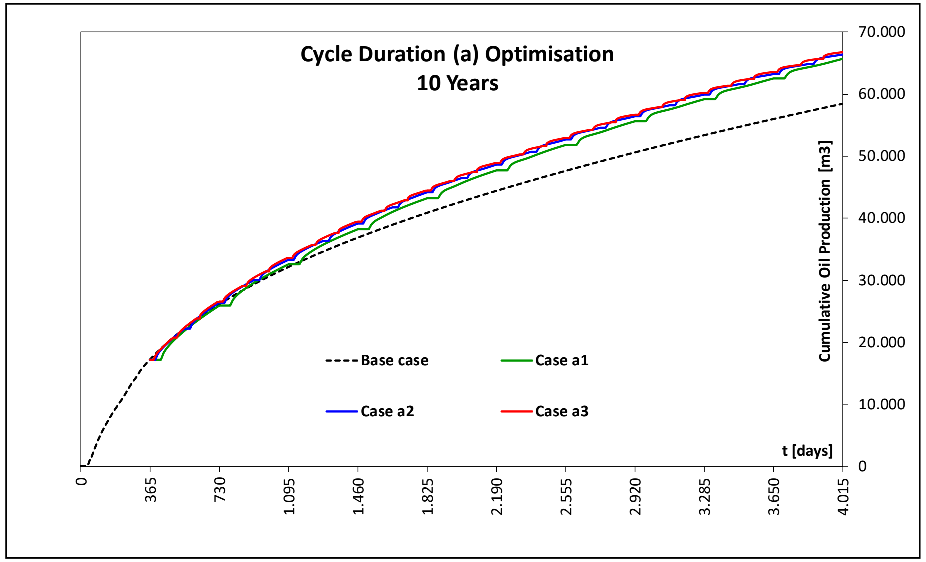
- Injection, soaking and production days per year are evenly distributed.

- Injection rate and therefore total injected gas is equal for all cases.

- Both incremental RF and ΔNPV increases as the cycle duration decreases.

→ Optimal configuration is 3 cycles per year leading to 14,2% in RF and ΔNPV of 0,63MM$





Huff n' Puff Optimisation

Injection Days & Injection Rate

- Injection rate and number of injection days control the total amount of CO_2 injected.

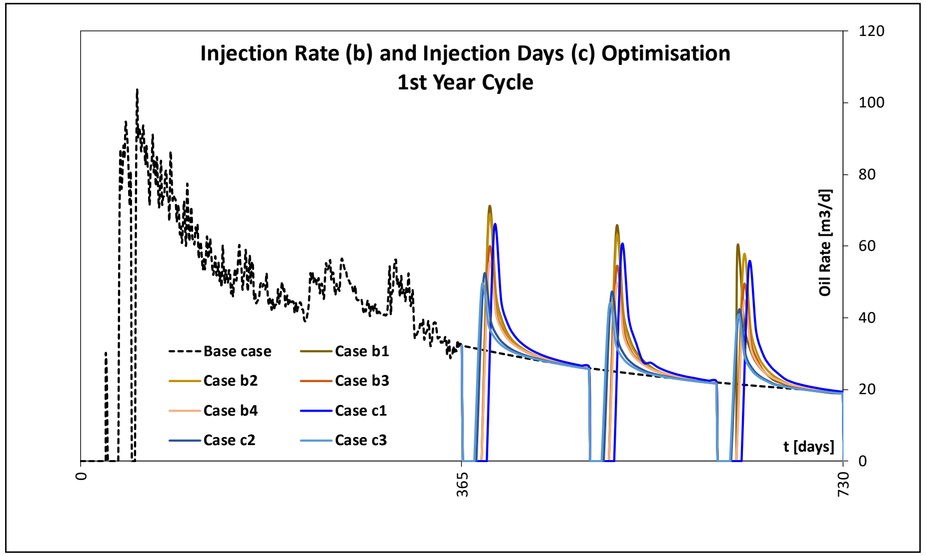
→ Both variables have been optimised for a 3-cycle per year scheme.

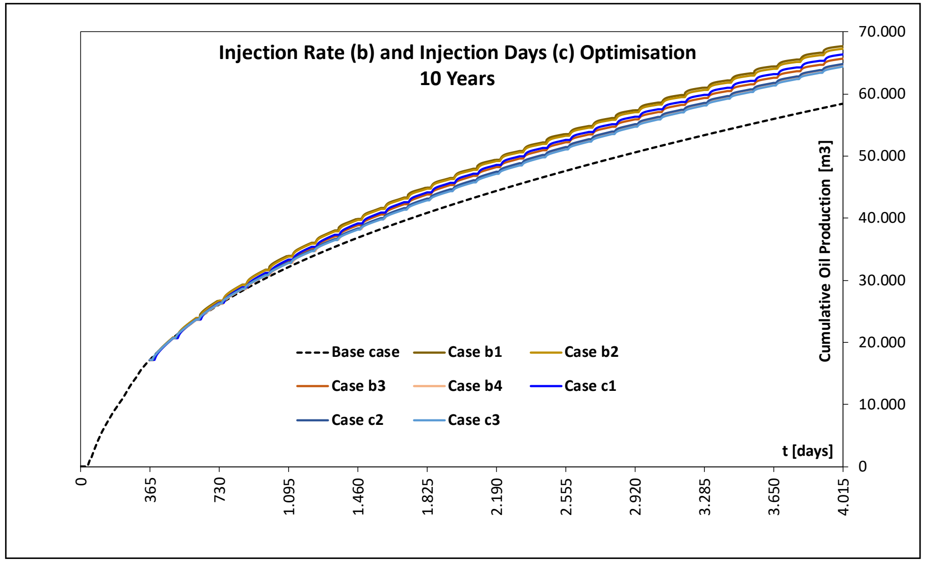
- 30% increase in injection rate ↑RF to 15,8% but process efficiency & ΔNPV decreases.

→ Optimal injection rate is 105 Mm3/d leading to 12,4% ↑RF, CO_2 use ratio: 40,6 Mscf/bbl and ΔNPV: 0,73MM$.

- Injection days increase from 50 to 65 yields a 13,6% increase in RF, but ΔNPV is 0,67MM$.

→ Optimal total injection time is 35 days per year with a RF increase of 10,9% & ΔNPV of 0,76MM$.





Huff n’ Puff Optimisation
Soaking Days

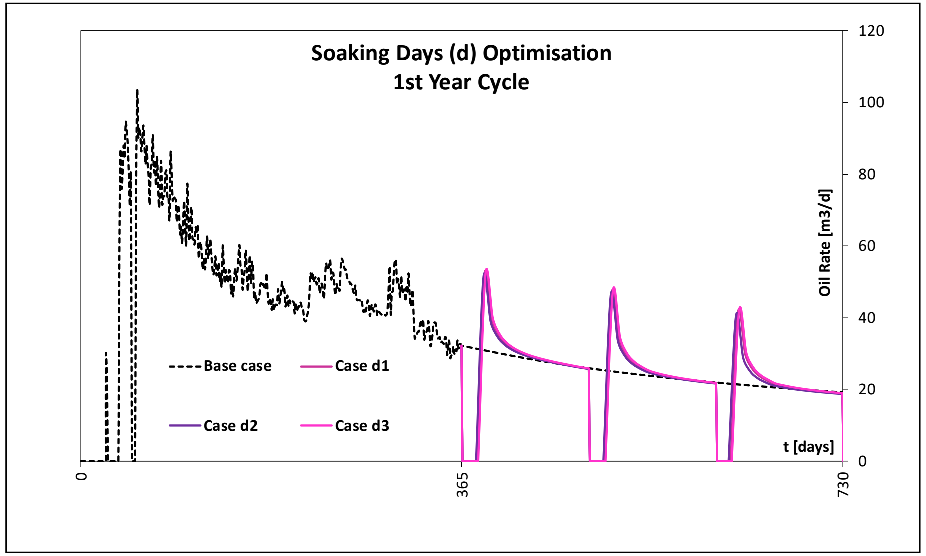
- Soaking days reduction from 7 to 5 is detrimental in all aspects: incremental oil falls from 6.391 m3 to 6.346 m3 while ΔNPV is reduced to 0,75MM$.

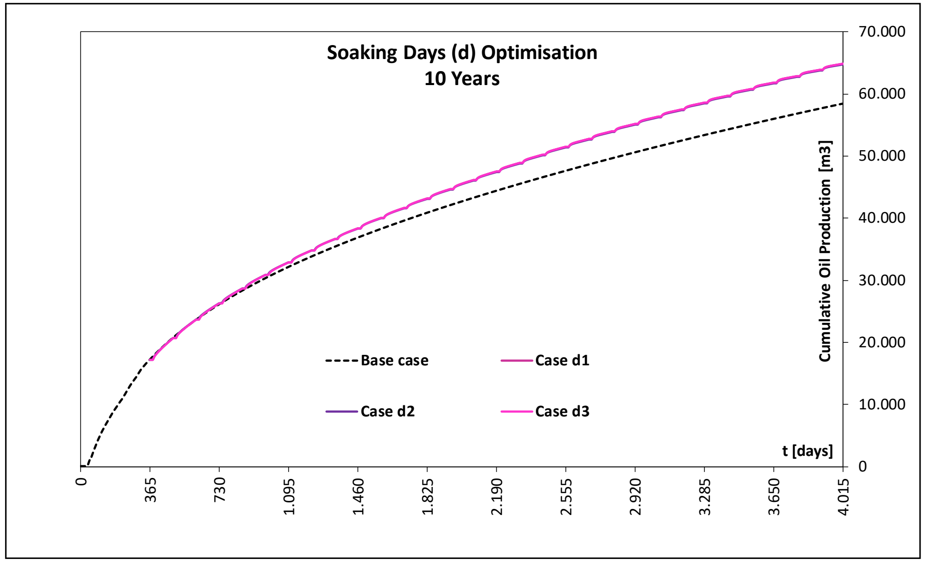
- Extending soaking to 12 days increases RF by 11,1% and ΔNPV also increases to 0,78MM$ even though total production time is reduced.

- In longer soaking periods the deferred production overcome benefits from CO_2 injection.

- Soaking time is assumed to allow deeper penetration of CO_2 into the SRV as molecular diffusion develops → CO_2 molecules are transported within the oil phase from a high concentration area (miscible zone) to a low concentration area (reservoir oil).

→ **Dynamics between oil & CO_2 are critical for the definition of optimal soaking time.**





Huff n' Puff Optimisation

Optimal Injection Cycle

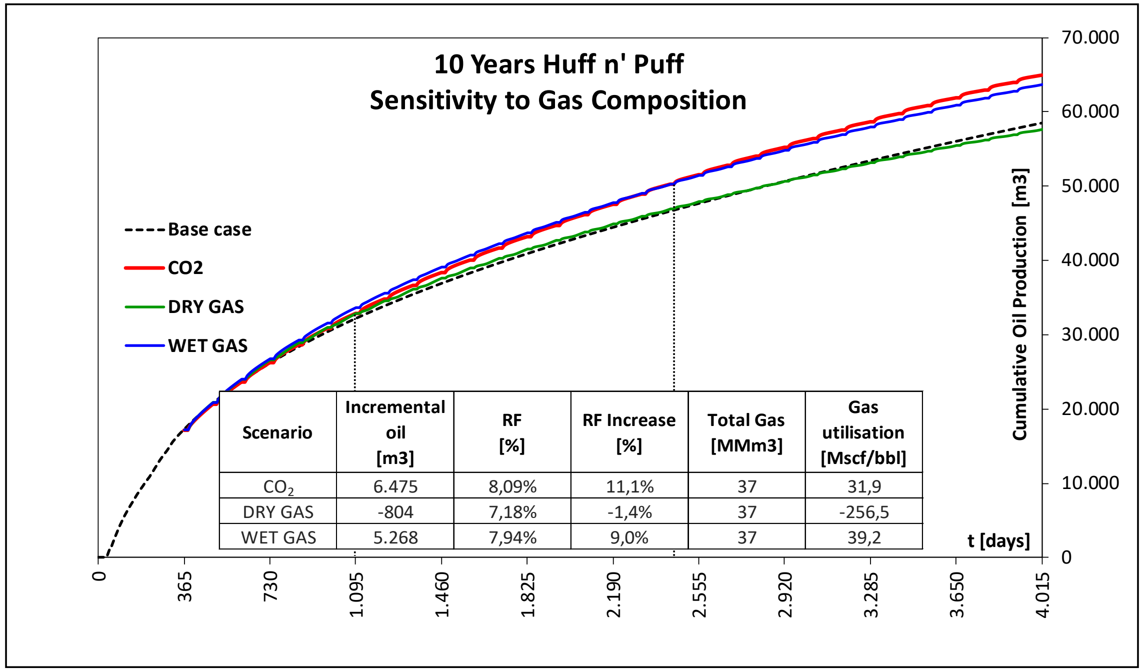
- 3 cycles per year with a total of 35 injection days and 12 soaking days per year evenly distributed.
- Injection flowrate of 105.000 m3/d and Injection pressure 680 Bars.

Optimisation Stage	Scenario	Case	Incremental oil [m3]	RF [%]	RF Increase [%]	Total Gas [MMm3]	Gas utilisation [Mscf/bbl]	ΔNPV [MM$]
-	-	Base case	0	7,28%	-	-	-	-
Cycle duration	1 cycle/y	Case a1	7.276	8,19%	12,4%	75	57,9	0,23
	2 cycles/y	Case a2	7.913	8,27%	13,5%	75	53,2	0,51
	3 cycles/y	**Case a3**	**8.314**	**8,32%**	**14,2%**	**75**	**50,6**	**0,63**
Injection rate	195 Mm3/d	Case b1	9.259	8,43%	15,8%	97	59,1	0,49
	172 Mm3/d	Case b2	8.854	8,38%	15,1%	86	54,7	0,57
	105 Mm3/d	**Case b3**	**7.260**	**8,19%**	**12,4%**	**52**	**40,6**	**0,73**
	75 Mm3/d	Case b4	6.316	8,07%	10,8%	37	33,3	0,72
Injection days	65 days/y	Case c1	7.939	8,27%	13,6%	68	48,3	0,62
	35 days/y	**Case c2**	**6.391**	**8,08%**	**10,9%**	**37**	**32,3**	**0,76**
	30 days/y	Case c3	5.970	8,03%	10,2%	31	29,6	0,74
Soaking days	9 days/y	Case d1	6.432	8,08%	11,0%	37	32,1	0,77
	5 days/y	Case d2	6.346	8,07%	10,9%	37	32,5	0,75
	12 days/y	**Case d3**	**6.475**	**8,09%**	**11,1%**	**37**	**31,9**	**0,78**
	15 days/y	Case d4	6.497	8,09%	11,1%	37	31,8	0,77

Sensitivity Analysis

Injected Gas Composition

- Injected gas is replaced by DRY GAS (100%C1) and WET GAS (70%C1-15%C2-15%C3).
- WET GAS outperforms CO_2 during the first 68 months (17 cycles) but after 10 years RF is 2,1% lower.
- DRY GAS outperforms CO_2 during the first 2 years (6 cycles) but after 10 years RF is < than base case RF.

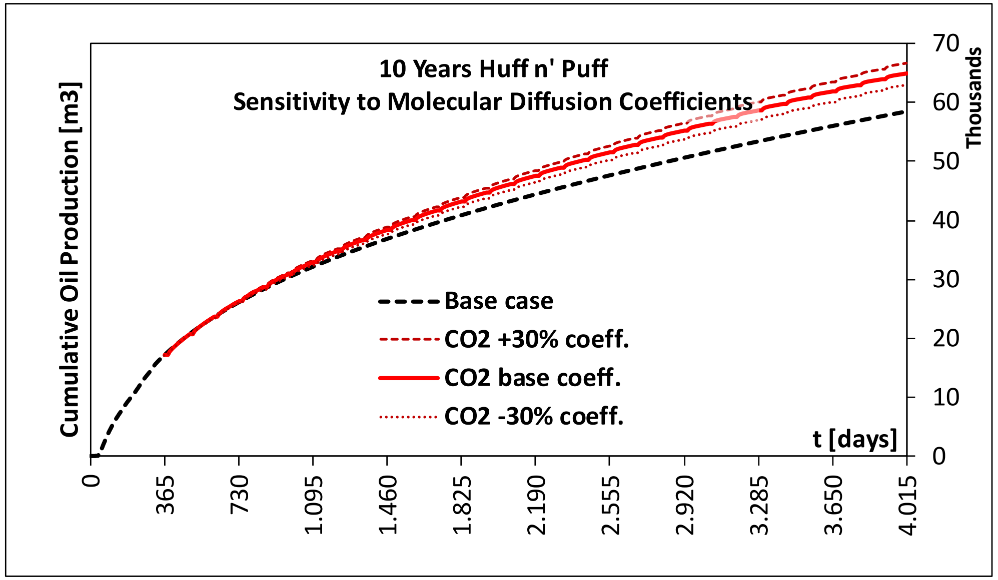


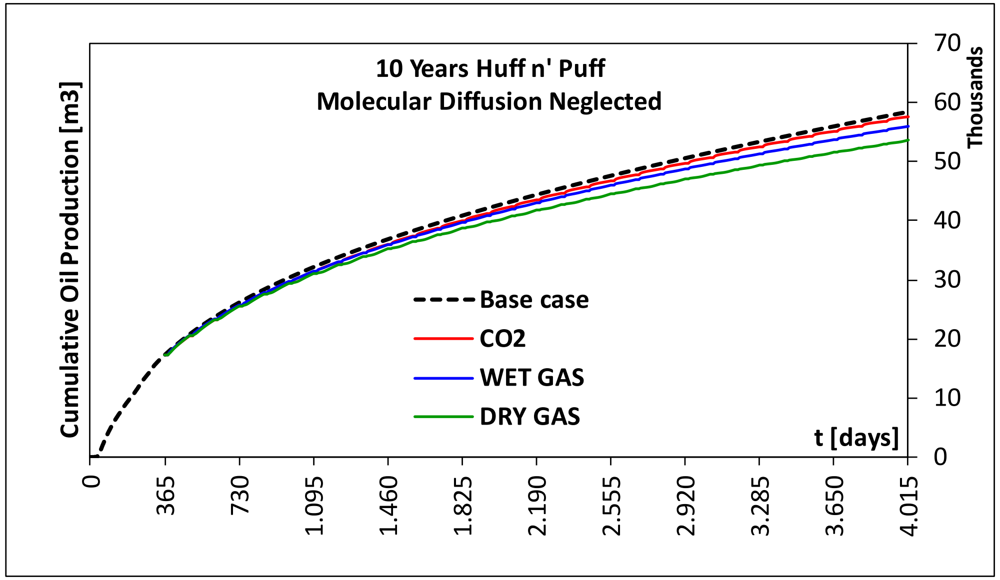
Scenario	Incremental oil [m3]	RF [%]	RF Increase [%]	Total Gas [MMm3]	Gas utilisation [Mscf/bbl]
CO_2	6.475	8,09%	11,1%	37	31,9
DRY GAS	-804	7,18%	-1,4%	37	-256,5
WET GAS	5.268	7,94%	9,0%	37	39,2

Sensitivity Analysis

Molecular Diffusion Coefficients

- If all coefficients are increased by 30% there is a 26% increase in RF and 48% increase in ΔNPV to 1,15MM$ respect to the base case.
- If coefficients are reduced by 30% the RF is 29% lower and ΔNPV is 0,36MM$, i.e. 53% lower than the base coefficients case.
- If molecular diffusion is neglected → cyclic gas injection is detrimental and for all gas injection cases RF is below the base case.



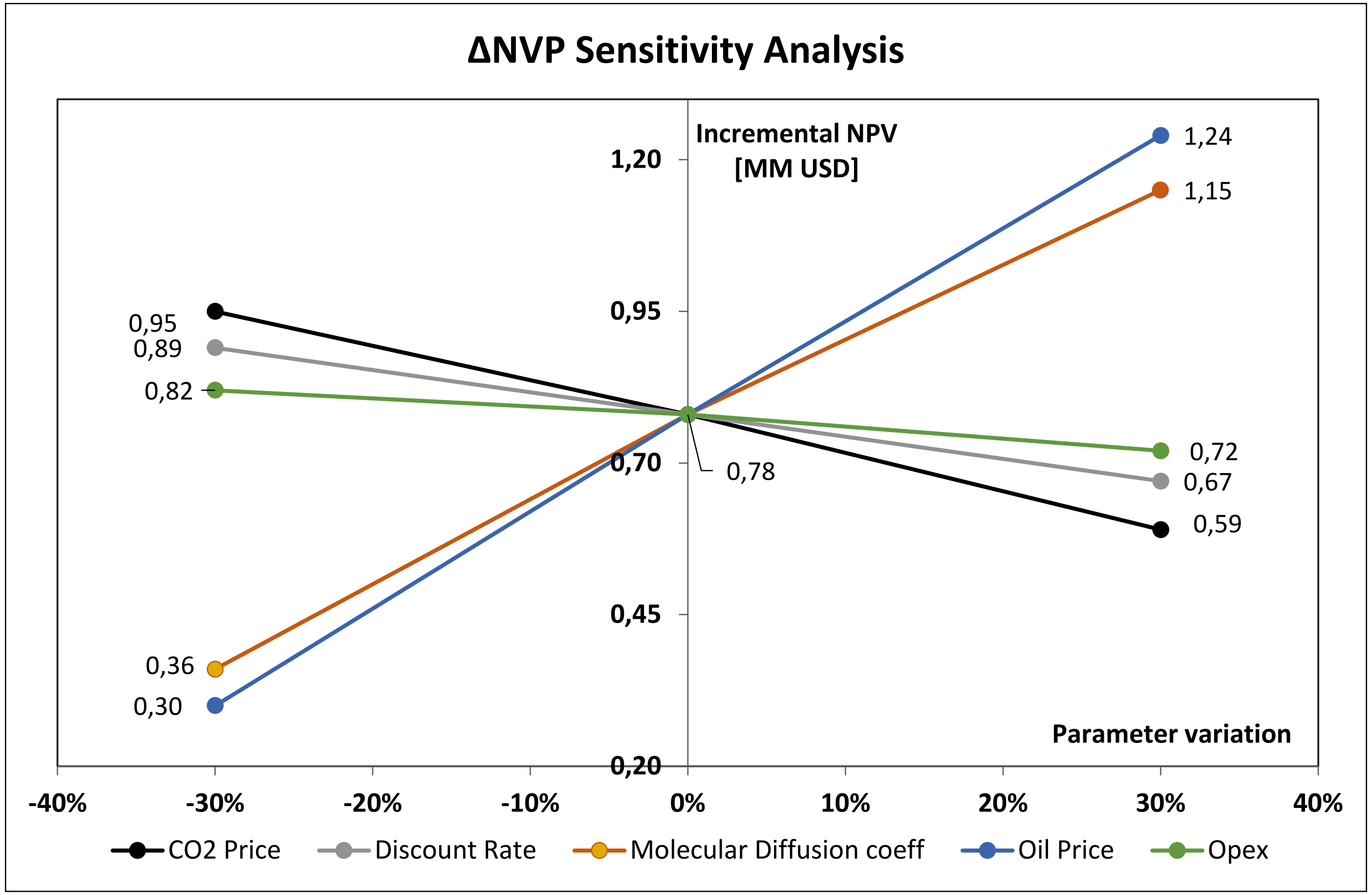


Sensitivity Analysis

Economic Model Sensitivity

- Oil Price: 70 USD/bbl.
- Discount Rate: 10%
- Opex: 7.5 USD/bbl.
- CO_2 Price: 22,8 USD/tonne
- Tax: 12%

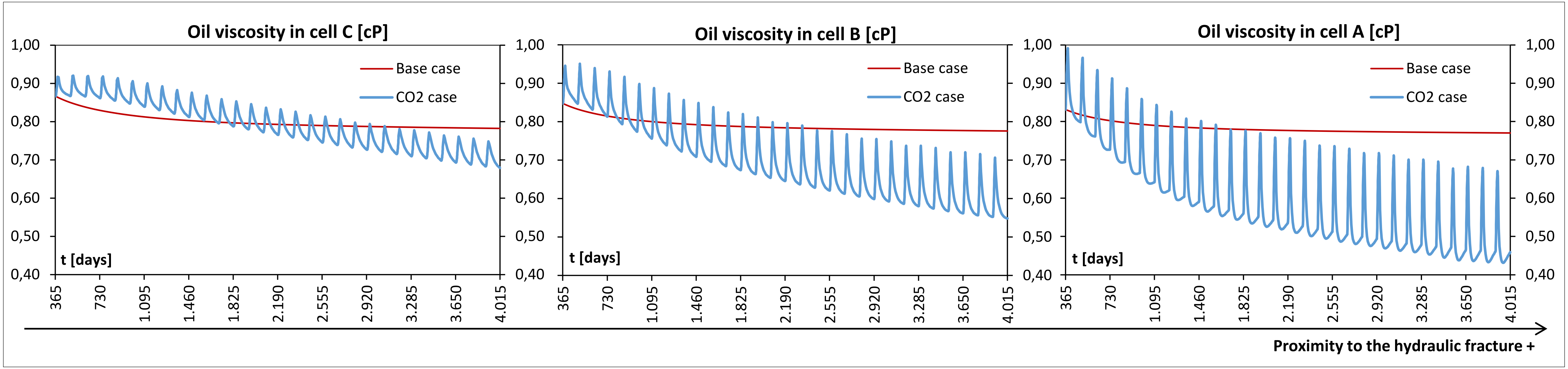
- Oil Price: 50%
- Discount Rate: 15%
- Opex: 6.5%
- CO_2 Price: 17%
- Molecular Diffusion coeff.: 50%



CO_2 Effects In Oil Production

Oil Viscosity Reduction

- CO_2 injection above MMP will create a miscible area where oil and CO_2 form a single liquid phase.
- CO_2 concentration gradient between miscible area and oil triggers molecular diffusion → CO_2 is transported into the SRV modifying composition.
- As oil composition becomes richer in CO_2 → sustained **reduction in μ_{oil}** → increase in $M_{oil}=K.K_{roil}/\mu_{oil}$



Oil viscosity vs. time for cells A, B and C, being A the closest to the miscible zone.

CO_2 Effects In Oil Production

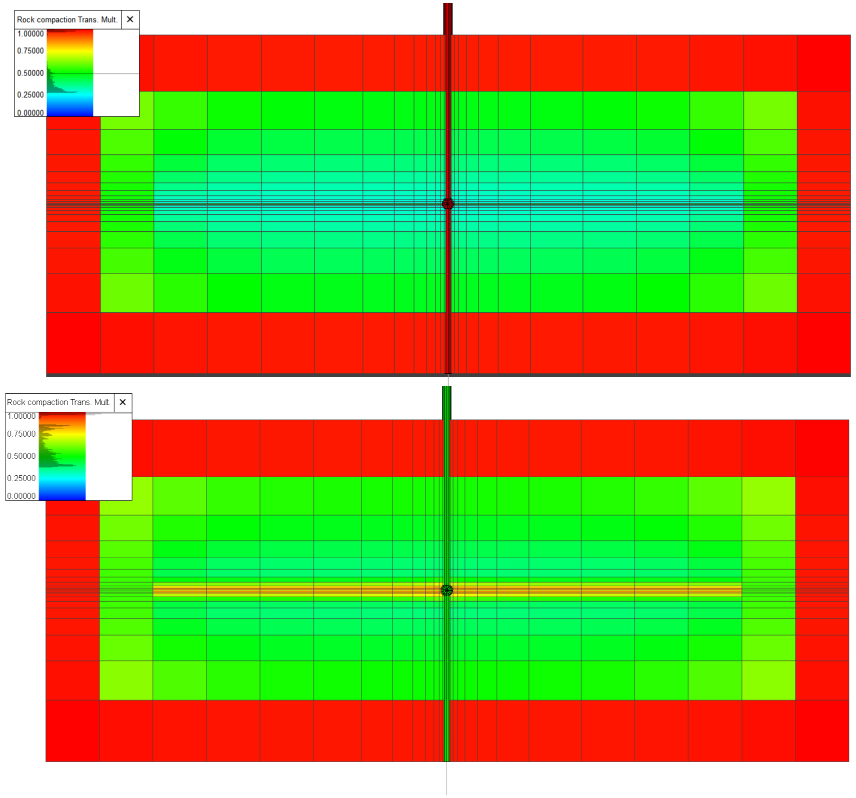
Oil Swelling & Reservoir Re-pressurization

- Increase in CO_2 molar fraction increases the volume occupied by oil, known as **oil swelling**:
- Oil droplets trapped in small matrix pores may result expulsed.

→ Additional oil can flow towards the fractures and being produced

- An additional consequence of gas injection is the **re-pressurization** of the SRV and the HFs:
- Rock compaction in shales as pressure decreases will negatively affect K_{SRV} and K_{HF} .
- Pressure increase will temporary "expand" matrix pores/small fractures in the SRV and HFs.

→ Increase in $M_{oil}=K.K_{roil}/\mu_{oil}$ due to increase in K, modelled by transmissibility multipliers



Transmissibility multipliers top view for the base case (above) and CO2 huff n' puff case (below), for the same time step.

Conclusions

- **CO_2 cyclic injection** may potentially **increase oil recovery in VM horizontal wells**: **up to 15,8% ↑ in RF** technically possible after 10 years.
- **Shorter huff n' puff schemes with 3 cycles per year** provide higher recovery factor and production acceleration.
- **Increasing amount of total injected CO_2 increases oil recovery** until maximum where ΔNPV starts to decrease.
- **An increase in soaking days** at expense of production days **may increase RF and ΔNPV**, as more time is given to the CO_2 to penetrate SRV.
- Cyclic injection of **"wet gas" produces comparable long term results** but **pure C1** with the same injection scheme **results detrimental**.
- A 30% change in molecular diffusion rates will have high impact in RF (~30%) & ΔNPV (~50%) + neglecting molecular diffusion produces negative results → **molecular diffusion consideration and accurate estimation of diffusion rates is critical**.

Suggestions for Future Studies

- Select a **candidate well where natural fractures are** expected to be **active** allowing deeper CO_2 penetration, and include NF in the model.

- **Investigate** the effect of **miscible gas injection in a depleted scenario**, i.e. where a significant saturation of free gas is expected in the SRV.

- It is highly recommended to carry out **Swelling, Slim Tube, RBA or VIFT lab tests to calibrate EOS** and provide more accurate values for the MMP. Laboratory tests providing **empirical data for diffusion rates for CO_2 & VM oil** in shale samples is also recommended.

- A **stochastic optimization approach** using ranges & an optimization algorithm is recommended to determine optimal operational parameters.

- A single porosity model was used to balance accuracy and computational capacity. The approach proposed by Kurtoglu [(10)], where **dual-porosity** is used **to model natural fractures/SRV and discrete hydraulic fractures** are included, is **recommended** if possible.

- Account for uncertainty providing a **range of possible outcomes** in an ensemble-type modelling approach rather than a single model forecast

Acknowledgements

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A to k

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PREGUNTAS?

GRACIAS!