# A Holistic Approach to Addressing Halite Precipitation and Remediation Strategies in $CO_2$ Injection Wells


**Professor Eric Mackay**
*Energi Simulation Chair in CCUS & Reactive Flow Simulation*
*Heriot-Watt University*

**Mr Oluwatosin Ogundipe**
*Heriot-Watt University*

**Professor Myles Jordan**
*SLB*



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# Overview

- Halite risk during $CO_2$ storage
- Predicting halite deposition
- Effects of imbibition and gravity
- Injection rate and intermittency effects
- Washwater treatments
- Conclusions
- Acknowledgements

# Halite Risk during $CO_2$ Storage

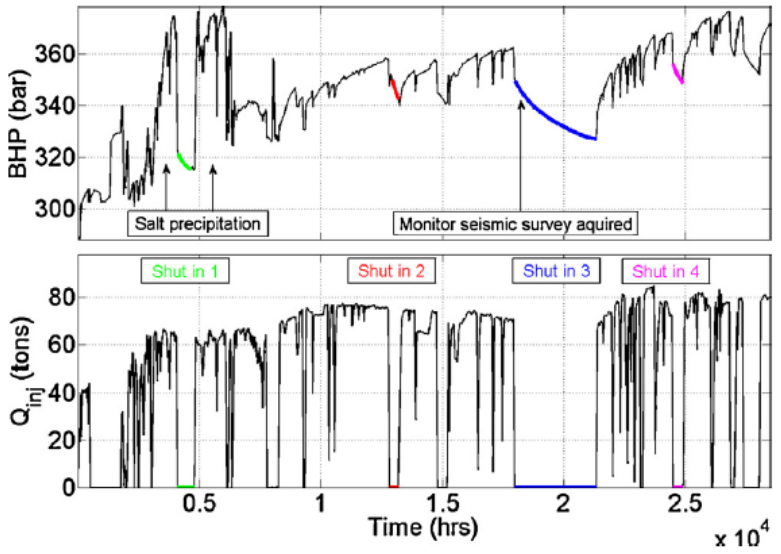
- Halite precipitation observed in Aquistore $CO_2$ injection well during shut in
- 340,000 mg/L formation brine
- Brine re-enters well during shut in:
  - Imbibition
  - Gravity
- Evaporation of brine causes increase in salinity to saturation
- Other minerals also precipitating?
- Could these cause more damage?

| Solution | | Precipitates | | | |
|---|---|---|---|---|---|
| | g/L | | mmoles/L | g/L | cc/L |
| $Na^+$ | 87.7 | Halite | 3815.0 | 222.95 | 102.7 |
| $K^+$ | 4.96 | Sylvite | 124.0 | 9.24 | 4.6 |
| $Ca^{2+}$ | 32.5 | $CaCl_2 \cdot 2H_2O$ | 809.3 | 118.98 | 64.3 |
| $Mg^+$ | 1.70 | $MgCl_2 \cdot 6H_2O$ | 70.0 | 14.23 | 9.1 |
| $Cl^-$ | 203.0 | Anhydrite | 1.6 | 0.22 | 0.1 |
| $SO_4^{2-}$ | 0.15 | Calcite | 0.4 | 0.04 | <0.1 |
| $HCO_3^-$ | 0.05 | Total | | | 180.9 |
| $Br^-$ | 0.71 | | | | |

# Halite Risk during $CO_2$ Storage

- Downhole video tool shows effect of brine ingress into well and evaporation
- More deposits lower down in well
- Can this also occur in formation?

- Loss of injectivity also observed in Snøhvit, which was partially recovered by MEG/ washwater treatments



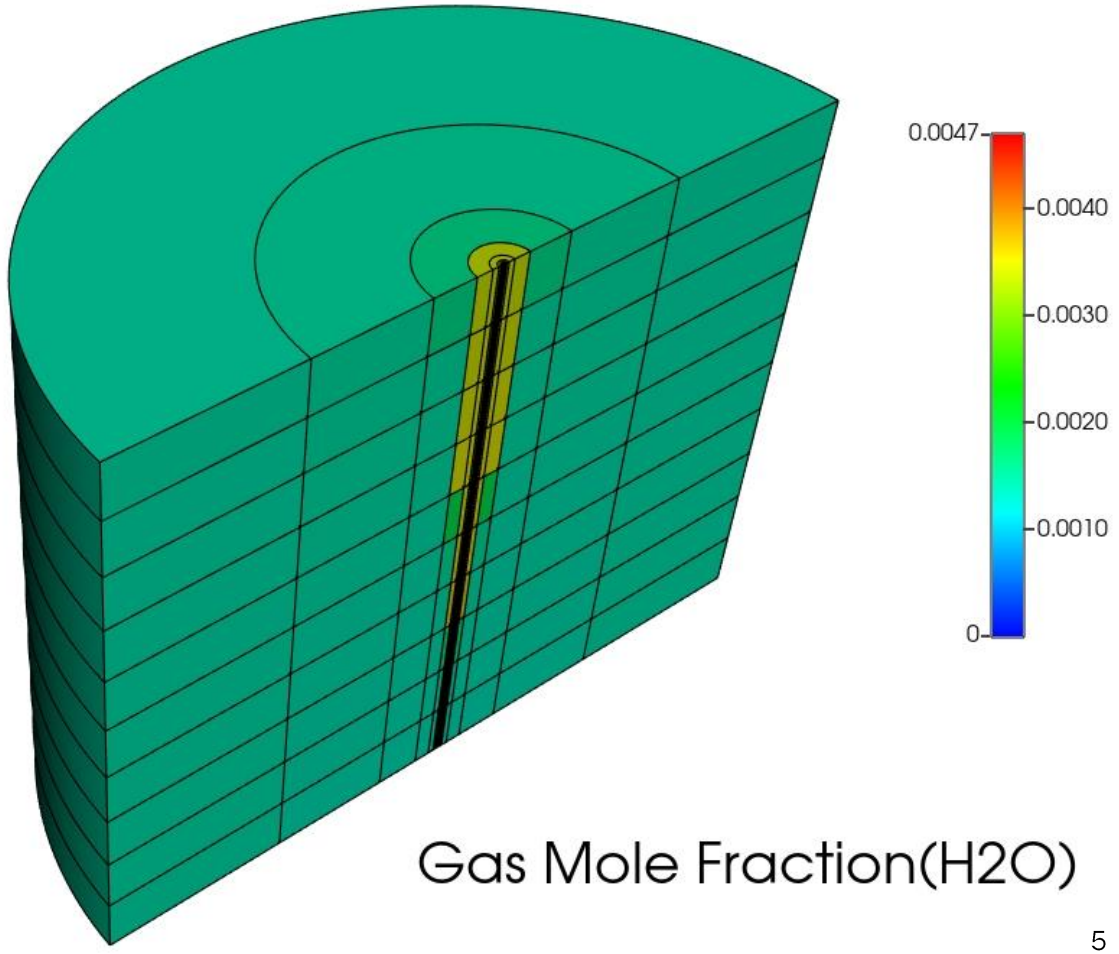

Grude *et al.* (2014)



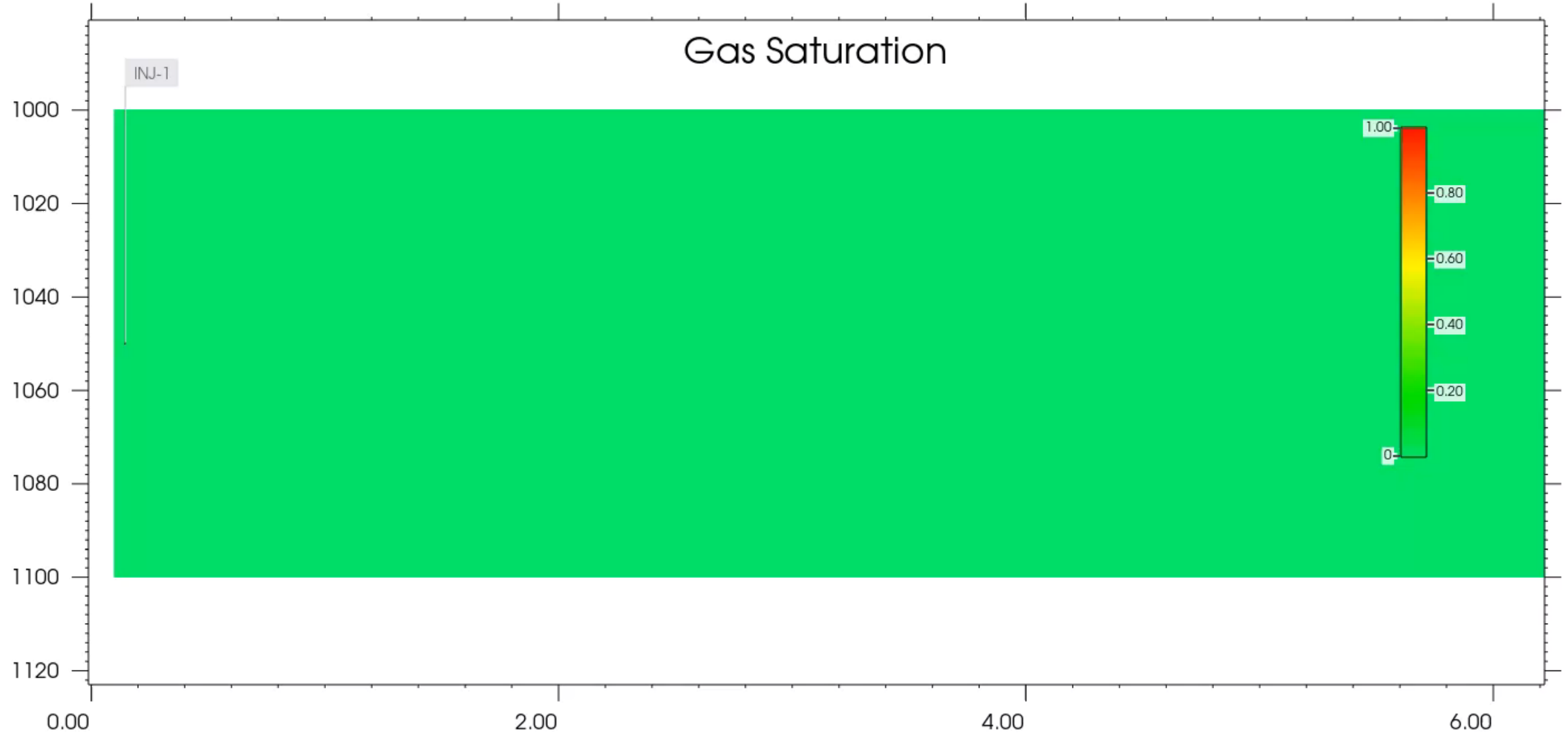
Talman *et al.* (2021)

# Predicting Halite Deposition during $CO_2$ Storage

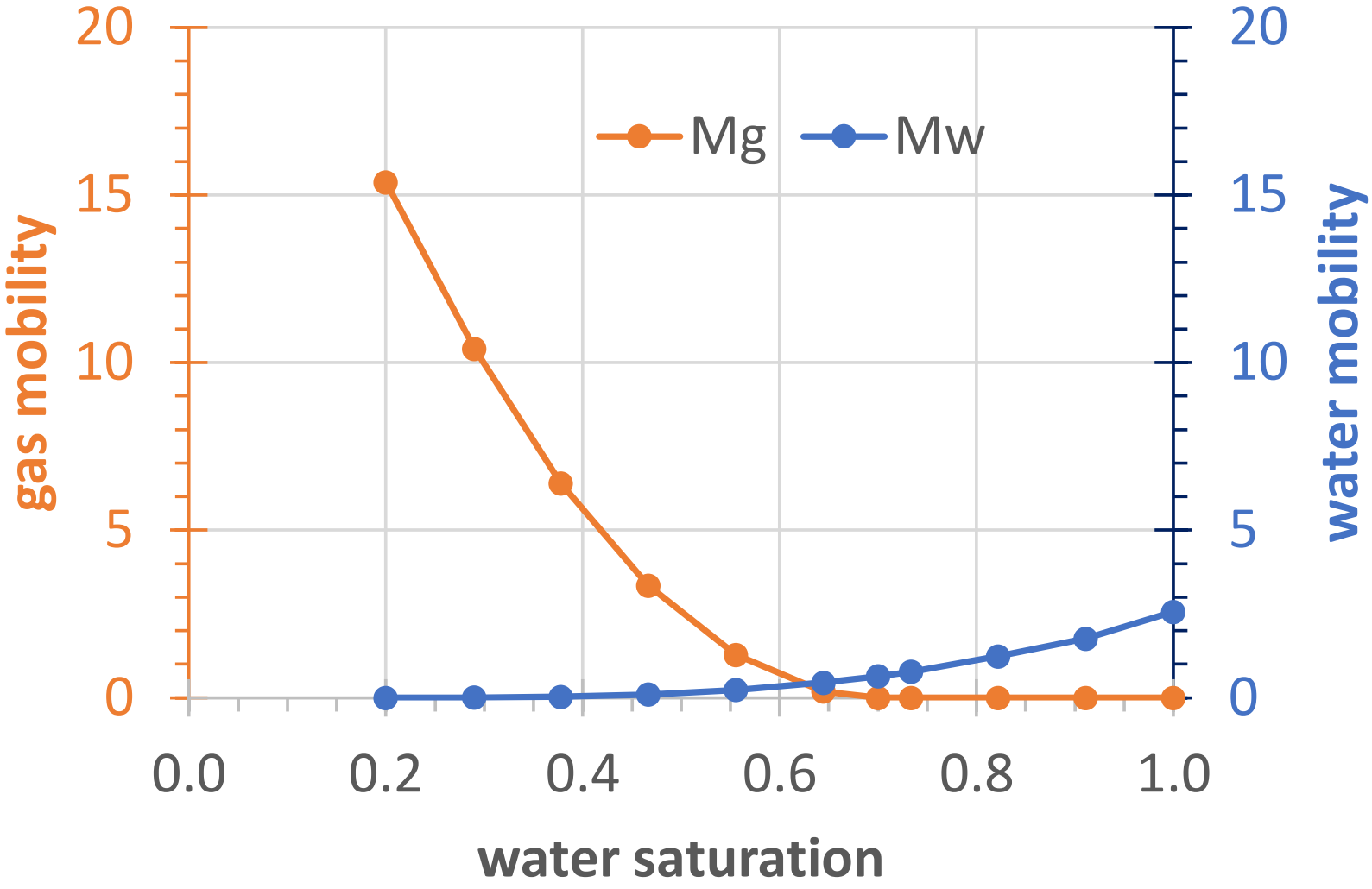
- Use 1D and 2D radial models of $CO_2$ injection into a saline aquifer
- Test impact of
  - Evaporation / no evaporation
  - Deposition / no deposition
  - Imbibition / no imbibition
  - Gravity (2D) / no gravity (1D)
- Calculate
  - Dry out zone
  - Porosity change
  - Injectivity change



# 1D No Vaporisation - Gas Saturation



# 1D No Vaporisation – Mobilities



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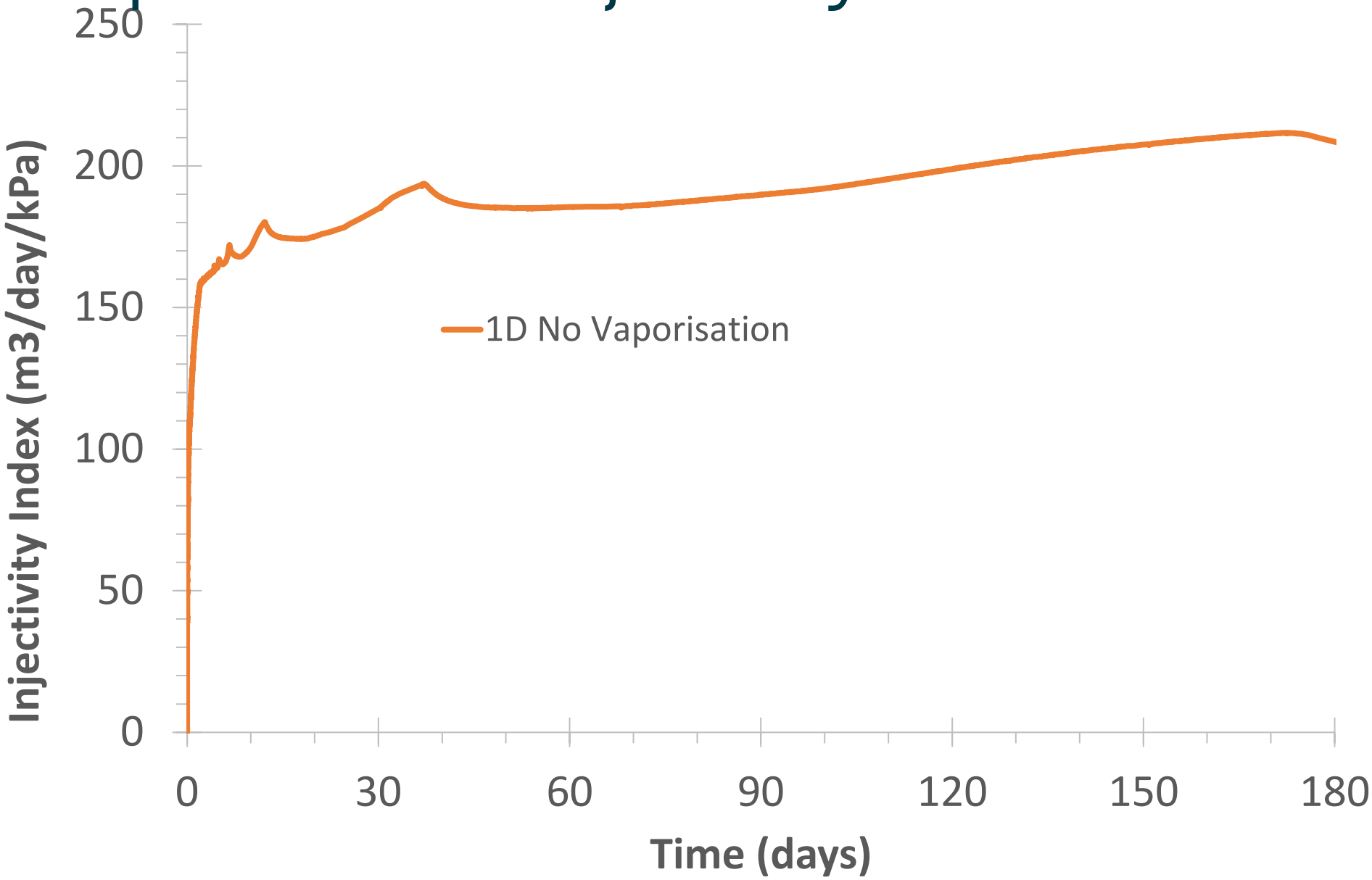
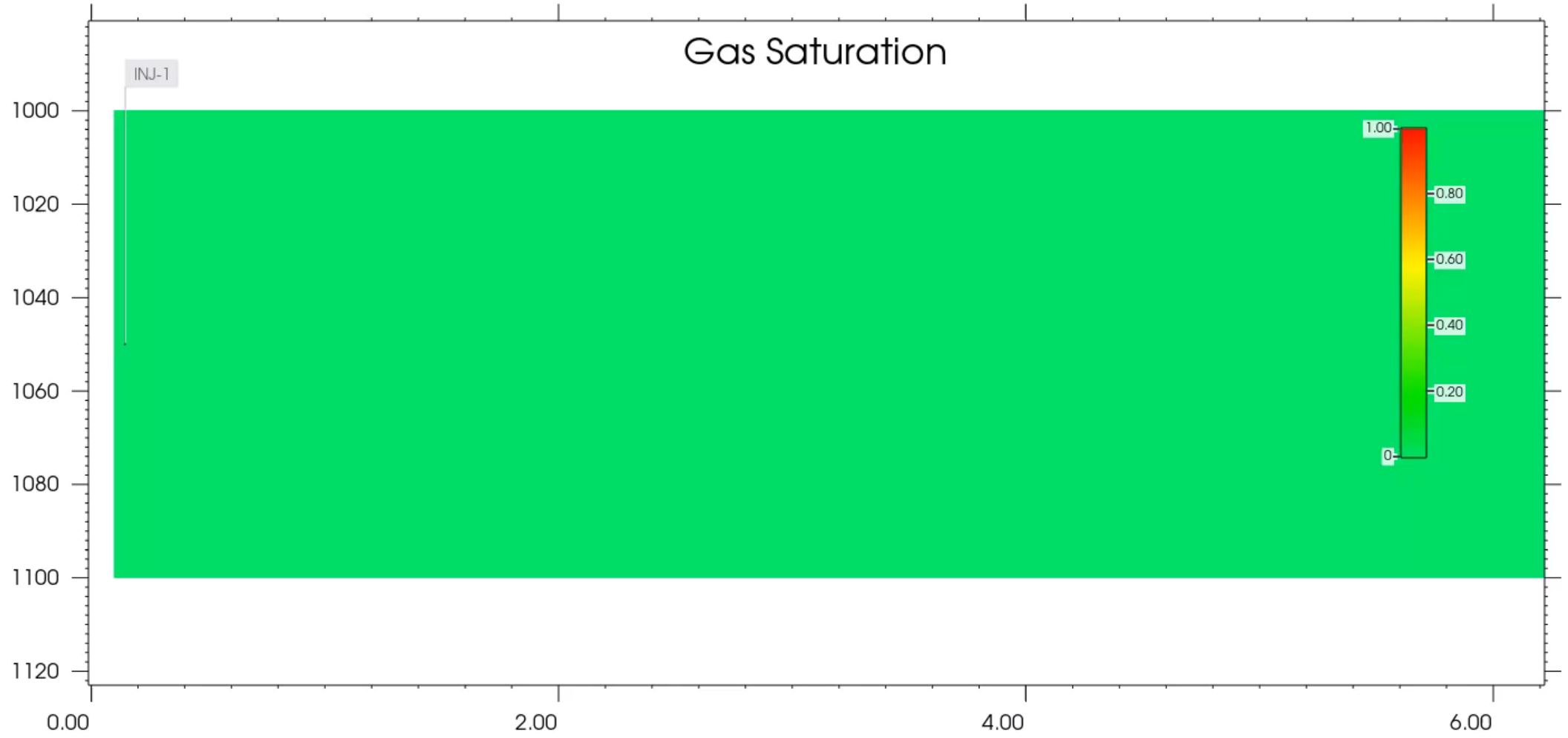


# 1D Vaporisation but no Damage - Gas Saturation



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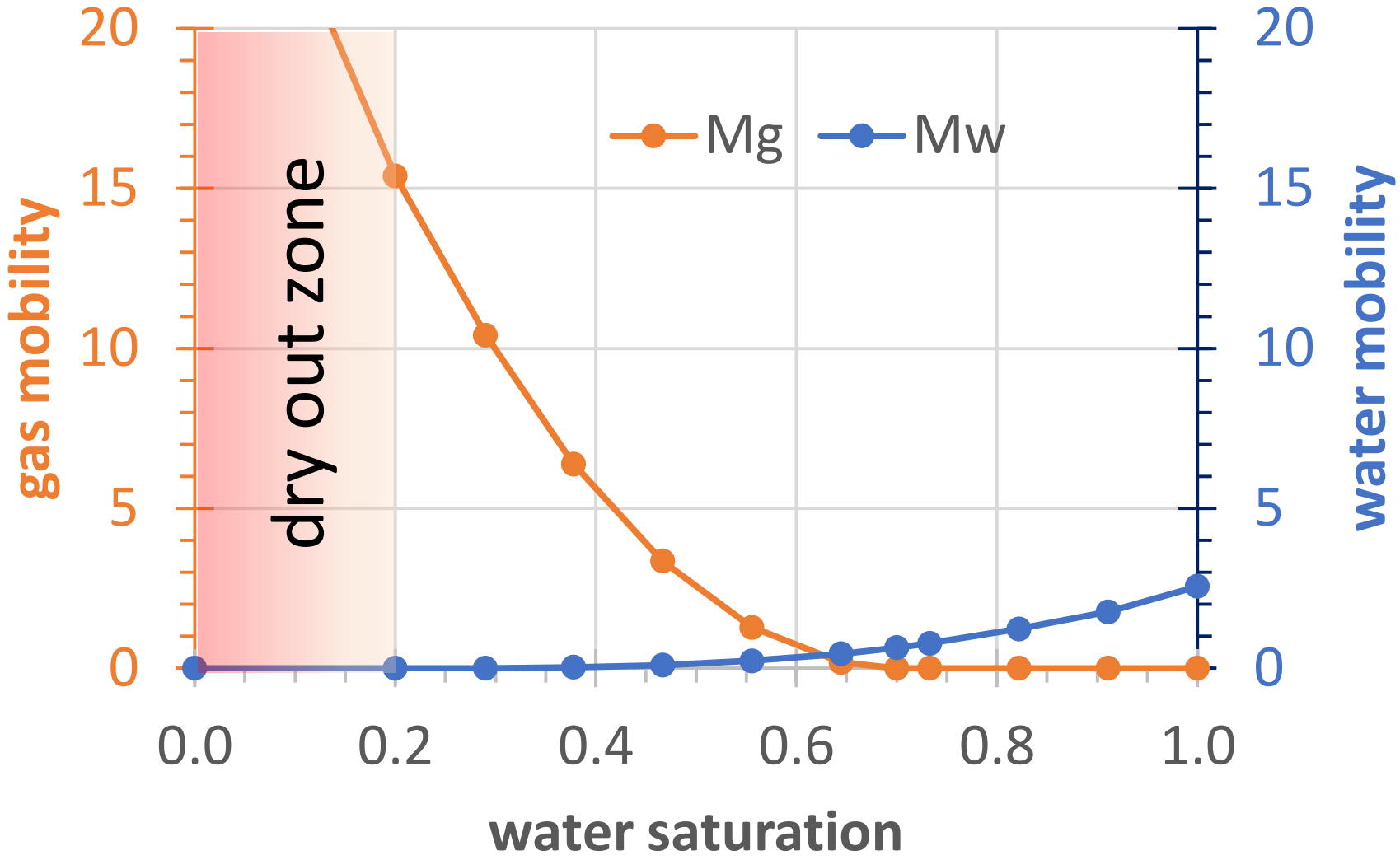

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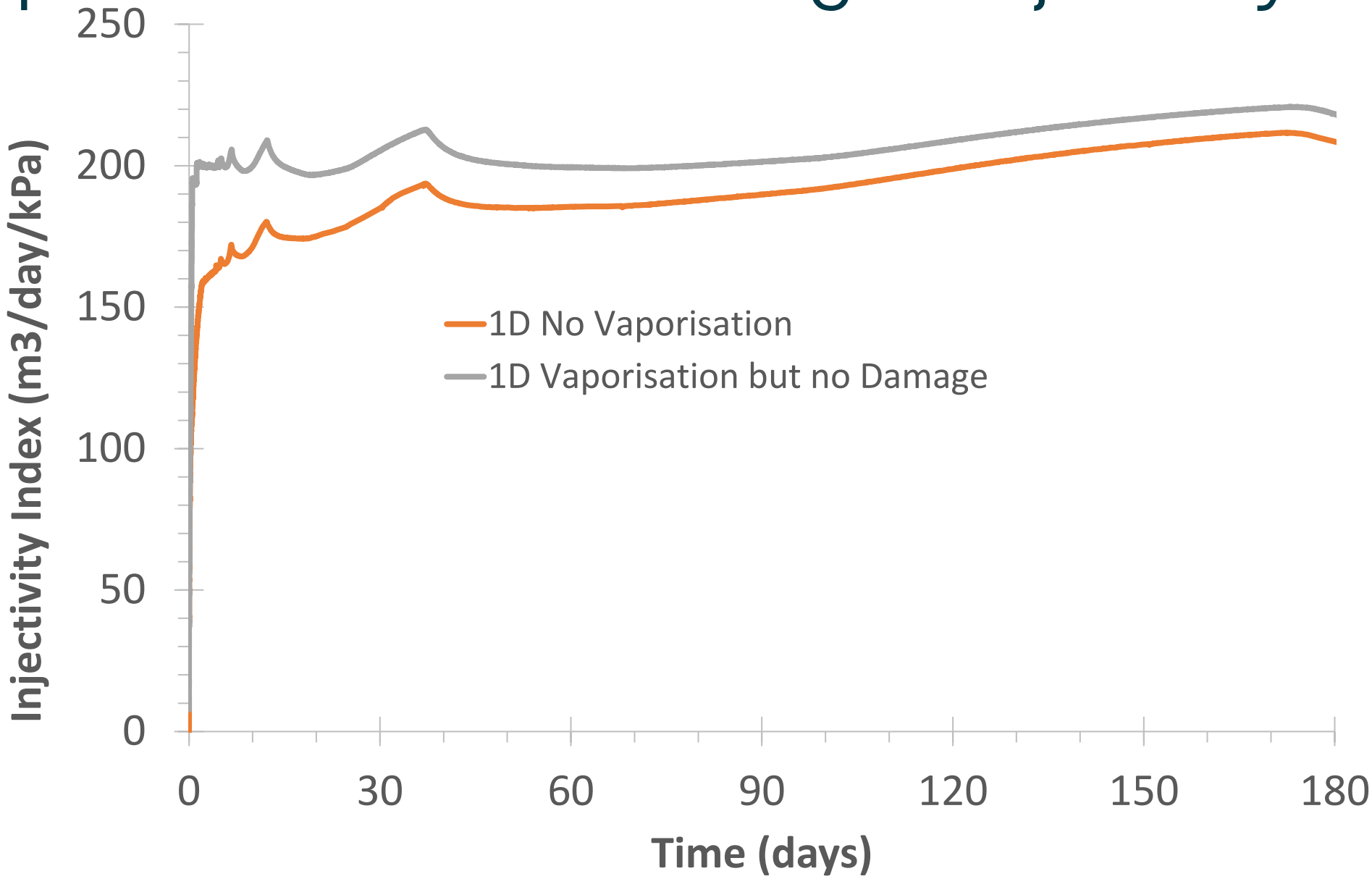
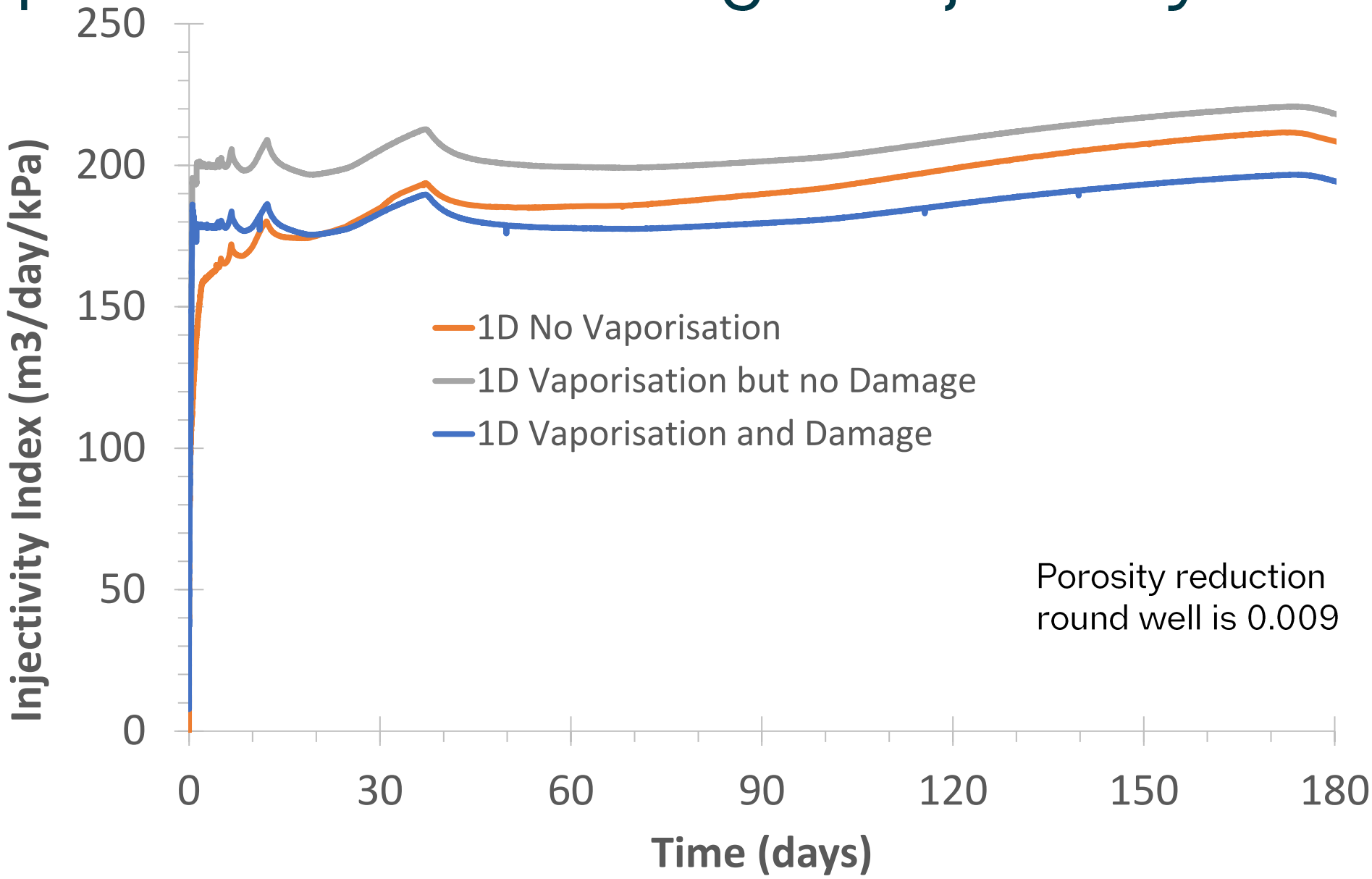
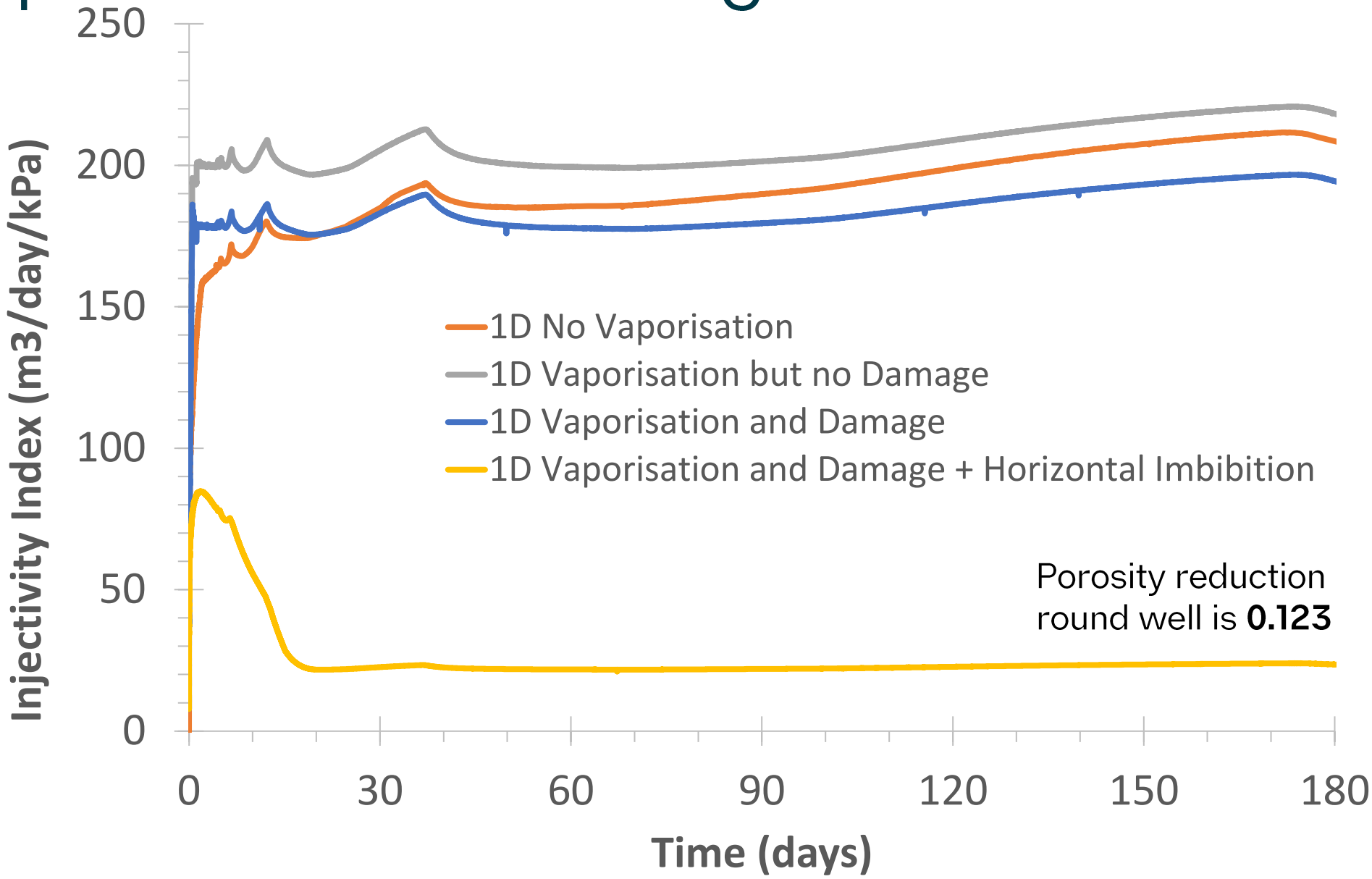


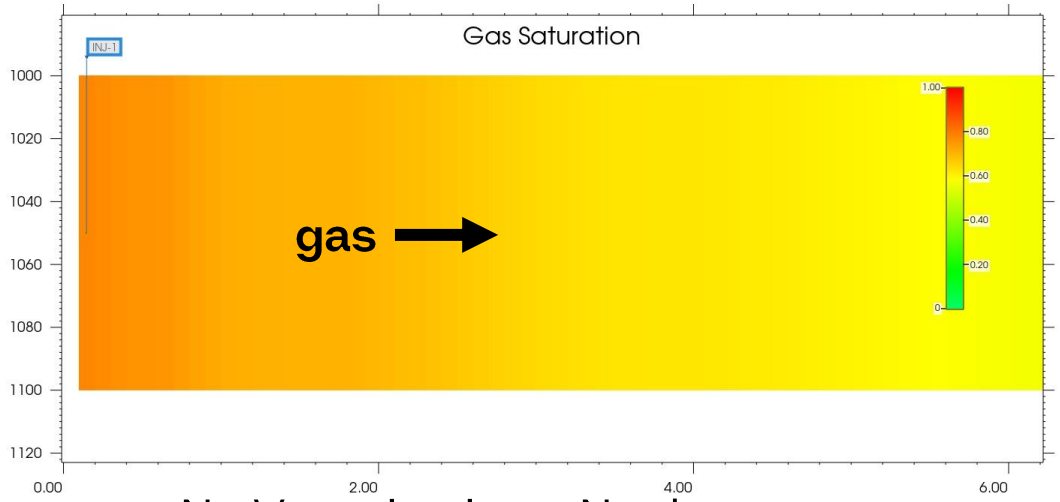
# 1D Vaporisation and Damage – Injectivity Index



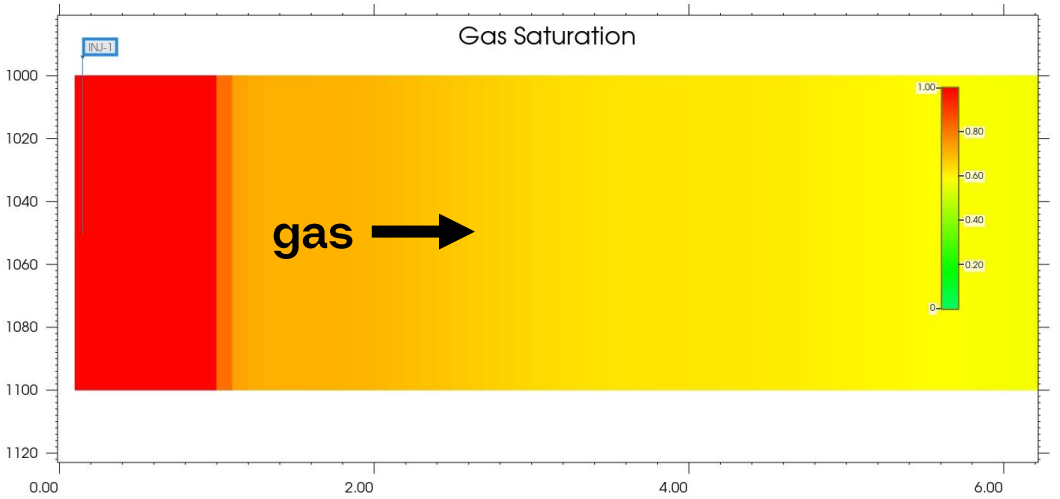
# 1D Vaporisation and Damage with Imbibition



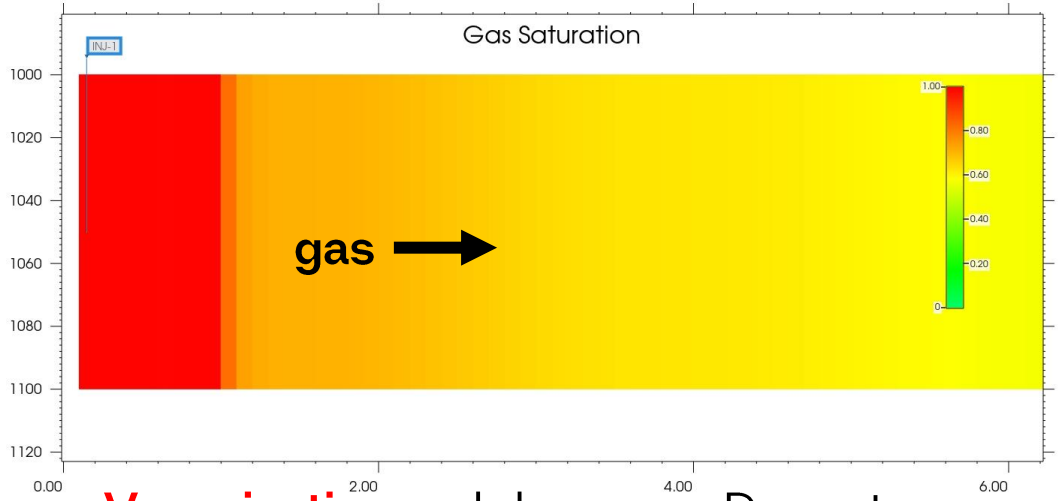
# Size of Dry Out Zone



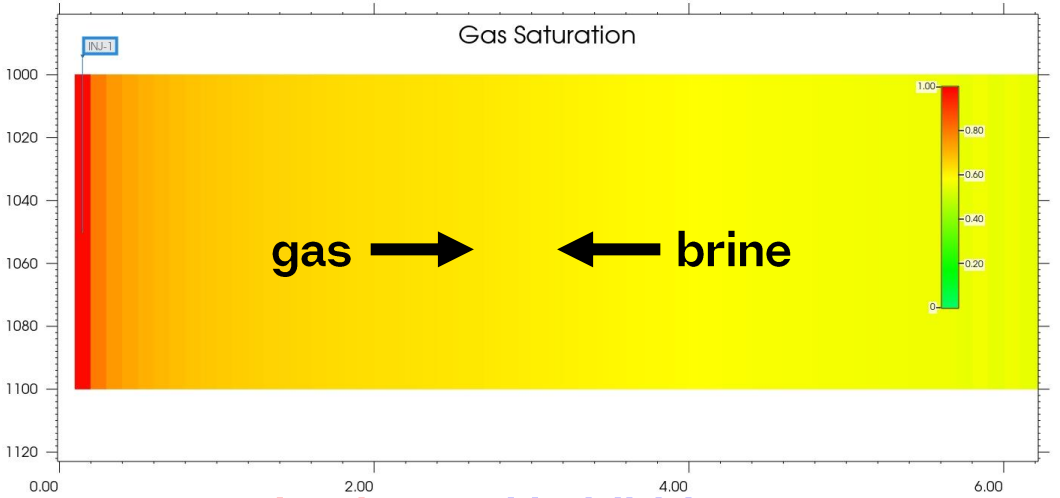

No Vaporisation – No dry out zone




**Vaporisation** – Dry out zone

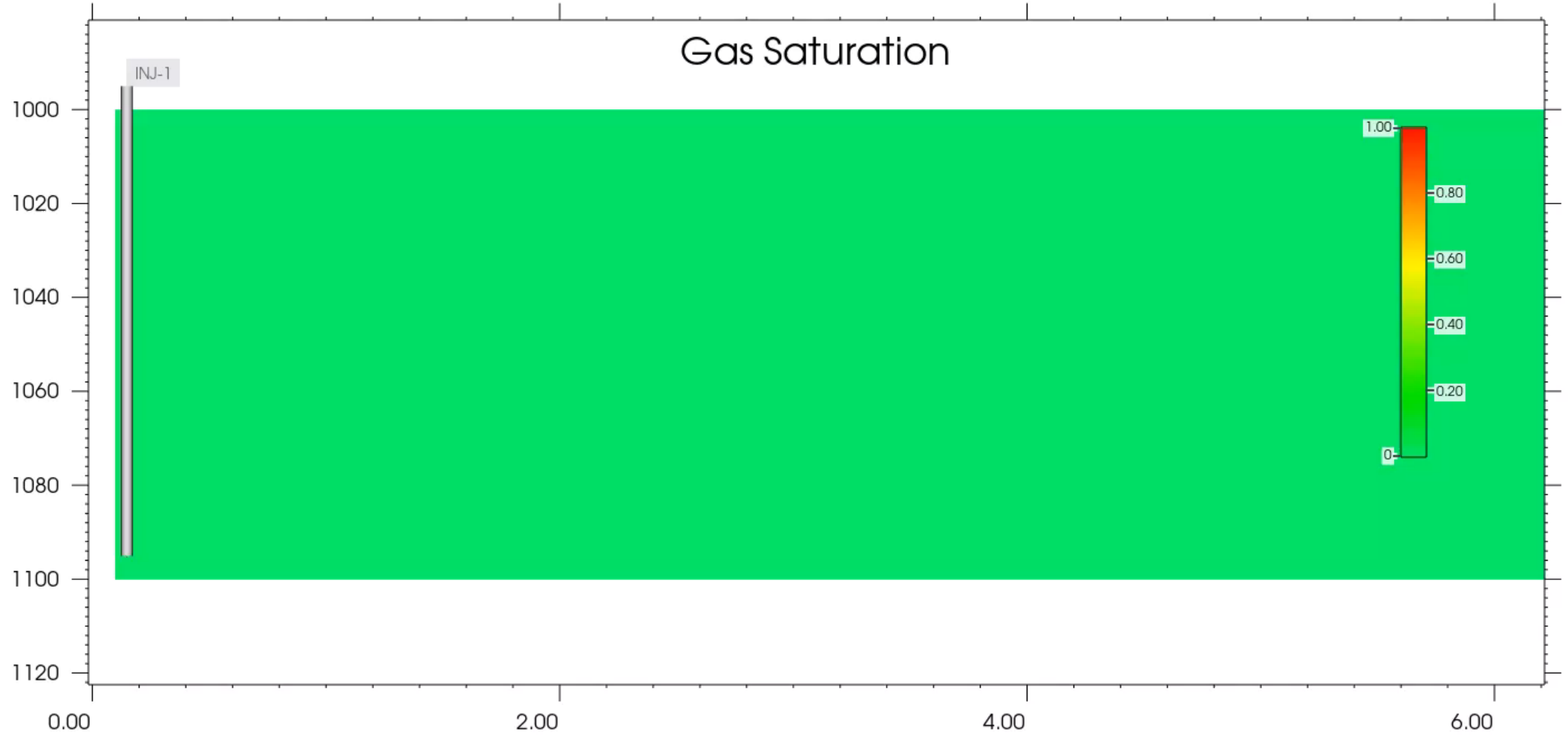



**Vaporisation** and damage – Dry out zone similar



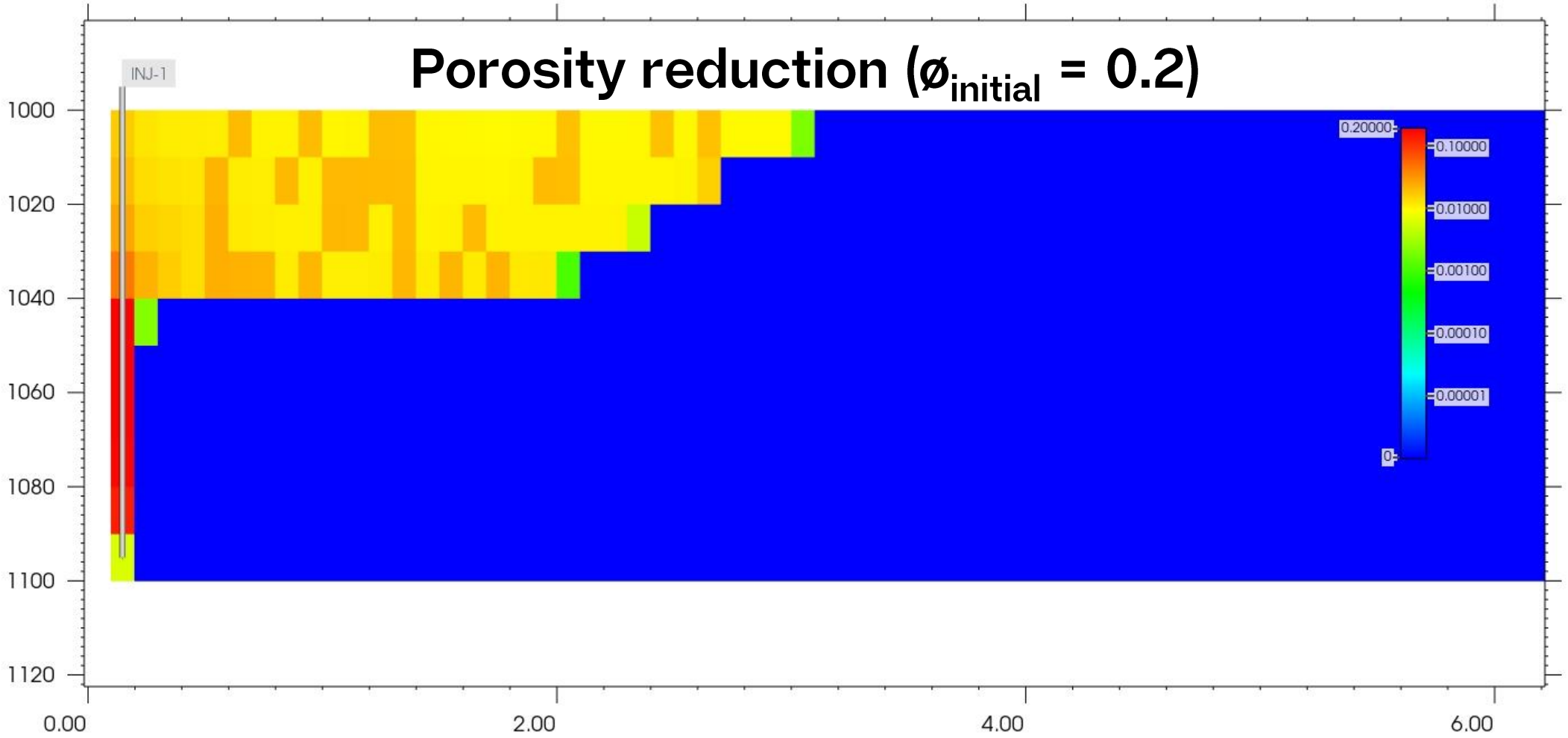

**Vaporisation and imbibition** – Dry out zone smaller

# 2D Vaporisation and Damage with Imbibition




Ogundipe *et al.* (2023)

# 2D Porosity Change

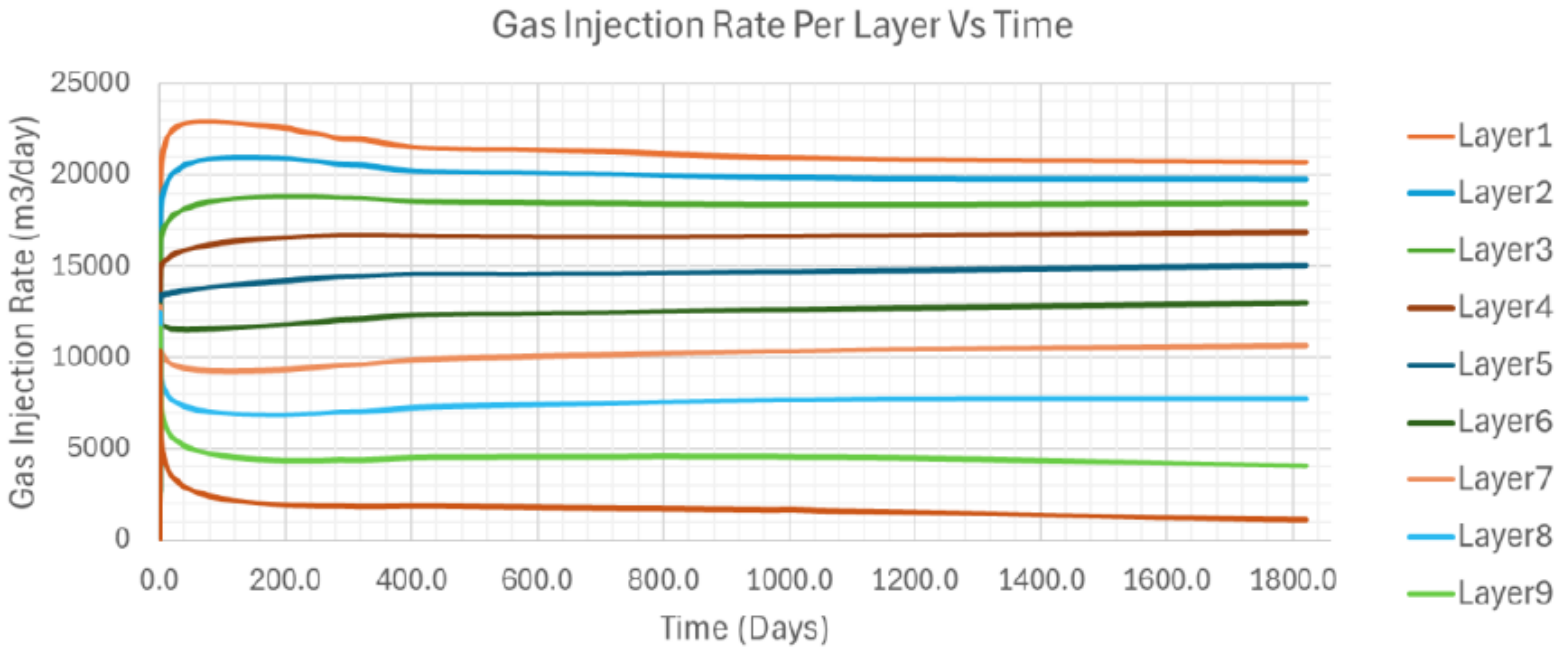


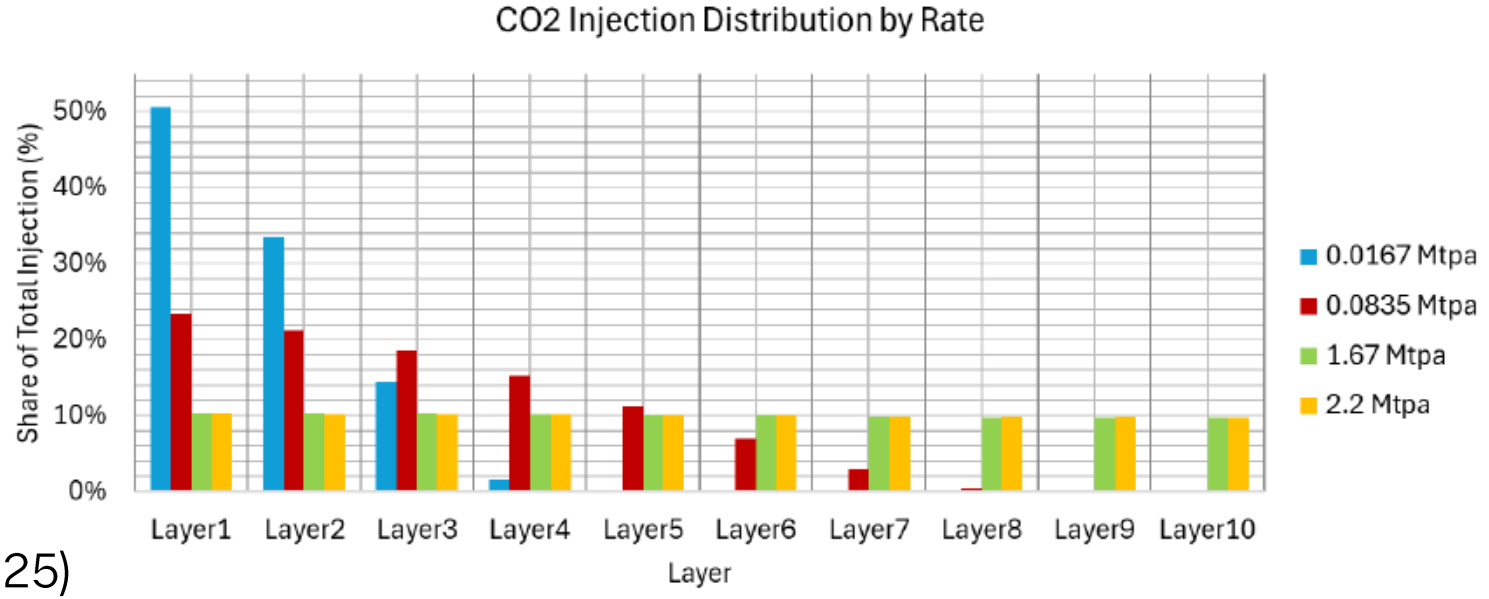
# Effect of Gravity

- Density difference between $CO_2$ and water
- Higher mobility of $CO_2$ than water
- Effect of imbibition

..... all promote gas injection at top of well, and brine recharge and halite deposition towards bottom of well

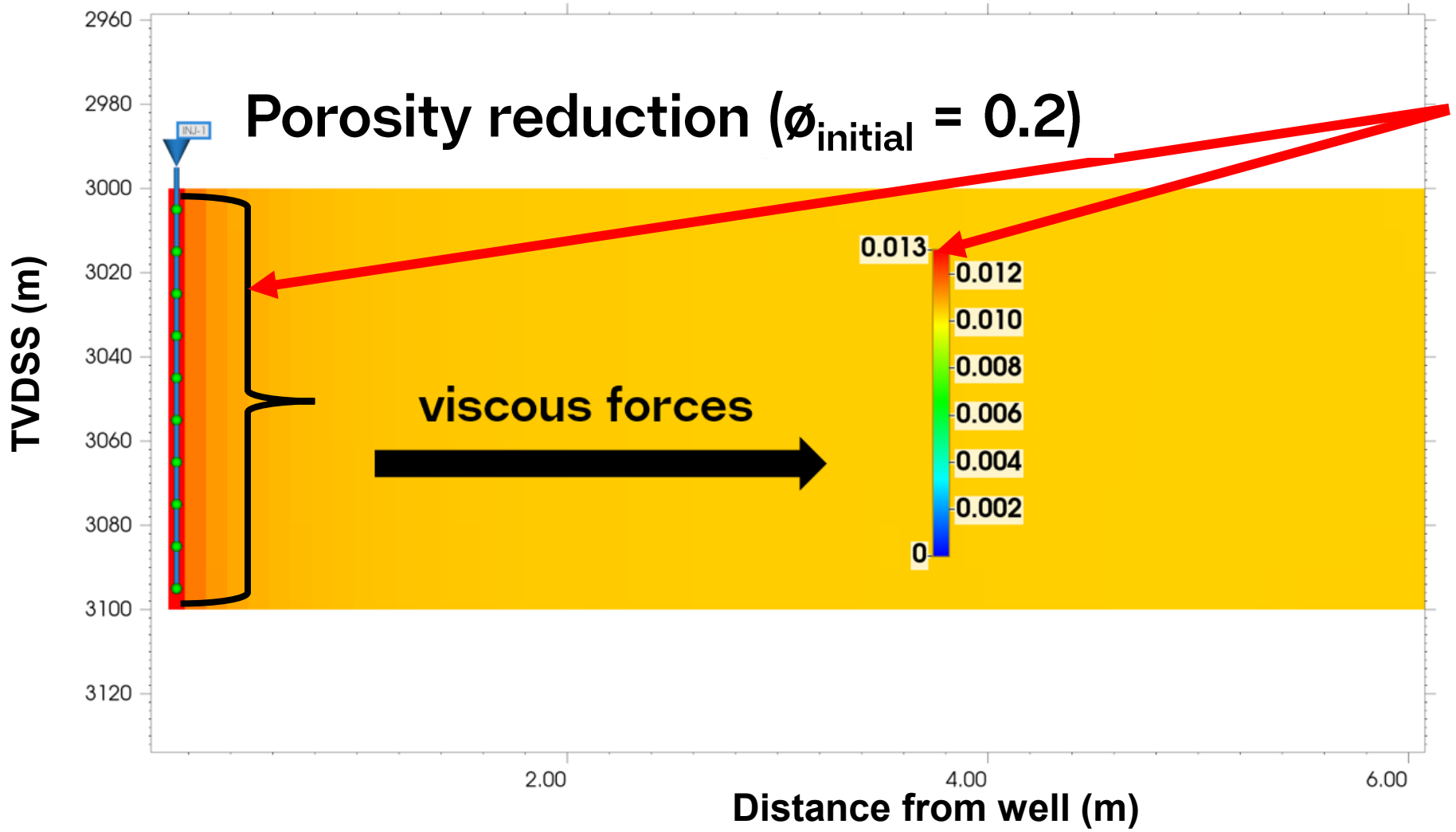
**Qinj = 0.167 Mtpa over 100m interval**




Al Manai (2025)

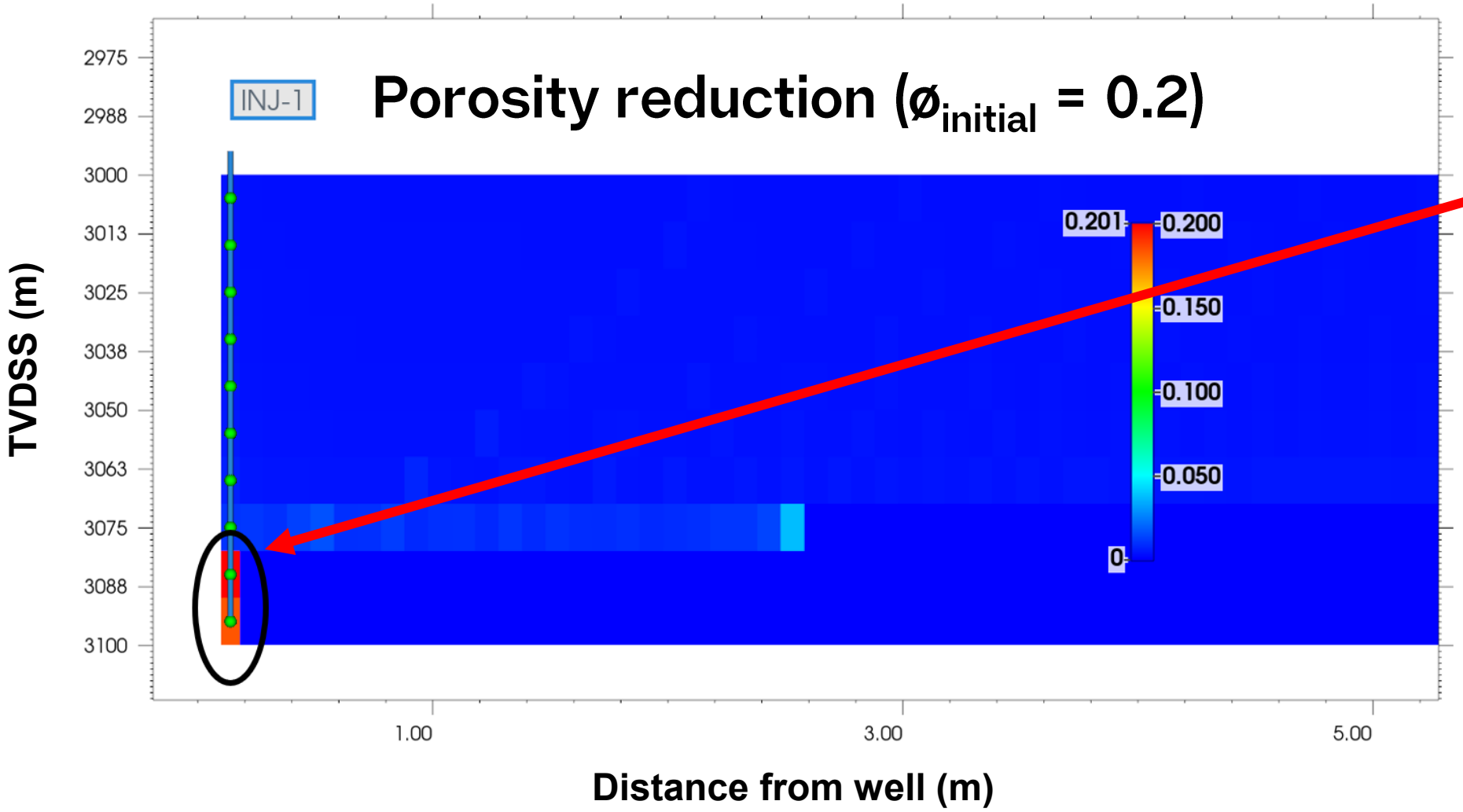
# 1 Mtpa Injection Rate – Negligible Porosity Loss




**Porosity after 36 months decreased from 0.2 to 0.187 uniformly along length of well.**

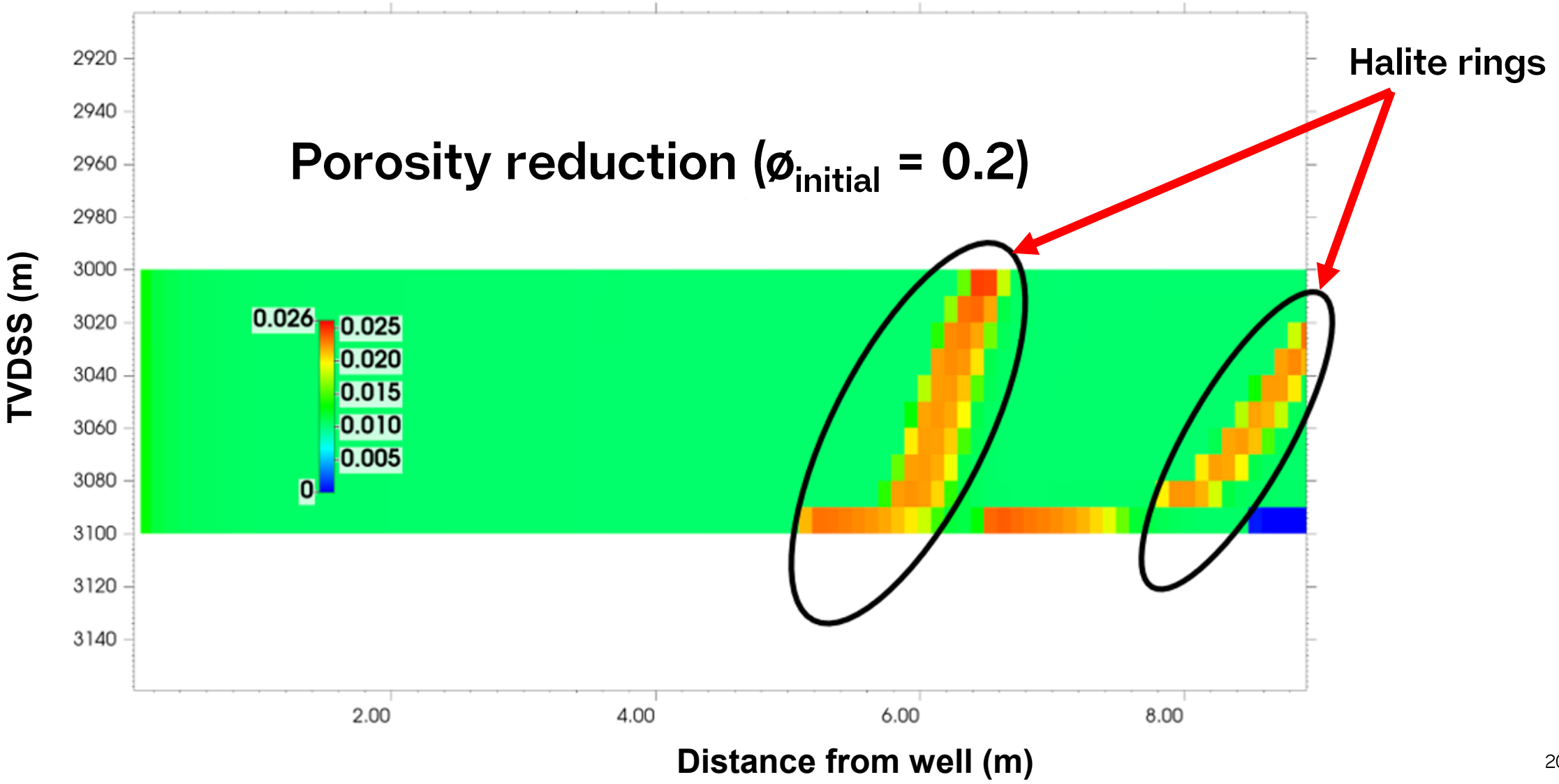
Ogundipe *et al.* (2024)

# 0.05 Mtpa Injection Rate – Damage at Well Bottom

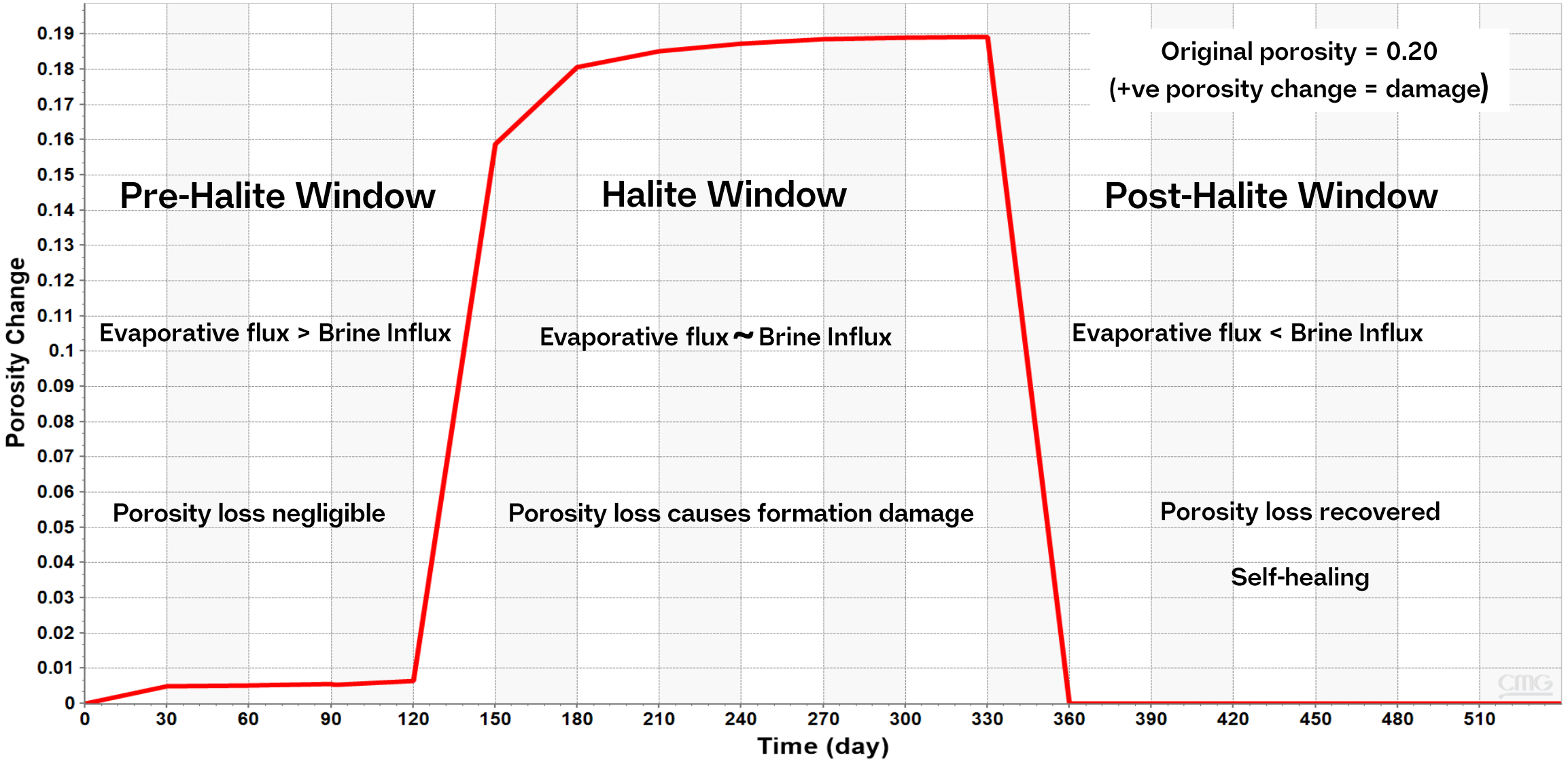



**Porosity change is localized, with complete occlusion at bottom of well**

# Intermittent Injection Rate – Minor Loss in Rings



# Washwater Treatments – Halite Window



# Washwater Challenges

- Water-only wash treatments may lead to
  - corrosion risk ($CO_2$ plus water = carbonic acid)
  - hydrate risk
- Recommendation to include in wash water treatments:
  - thermodynamic hydrate inhibitor such as Mono Ethylene Glycol (MEG) plus water as a “water wash” mixture, or
  - kinetic hydrate inhibitor (KHI) and/or
  - corrosion inhibitors

# Conclusions

- **Evaporation** only occurs into **dry $CO_2$** stream
  - evaporation of water alone **increases** injectivity
- Salt deposits occur when
  - dissolved salts are present in formation brine
  - brine can flow into dry out zone due to capillary and gravity effects
- **Greatest damage** to $CO_2$ injectivity occurs when
  - **brine salinity is higher** (but can occur at any salinity)
  - **brine flux** into dry out zone is **close** to **but less than evaporative flux**
- **Damage minimised when injection rates are high**
  - better to have intermittent high rate than continous low rate injection
- **Wash water treatments** beneficial in early periods
  - but need to **manage corrosion** and **hydrate risks** using addtives

# Acknowledgments


- Sponsors **of FAST JIP** at Heriot-Watt University

Baker Hughes CHEMISERVIS CLARIANT Chevron

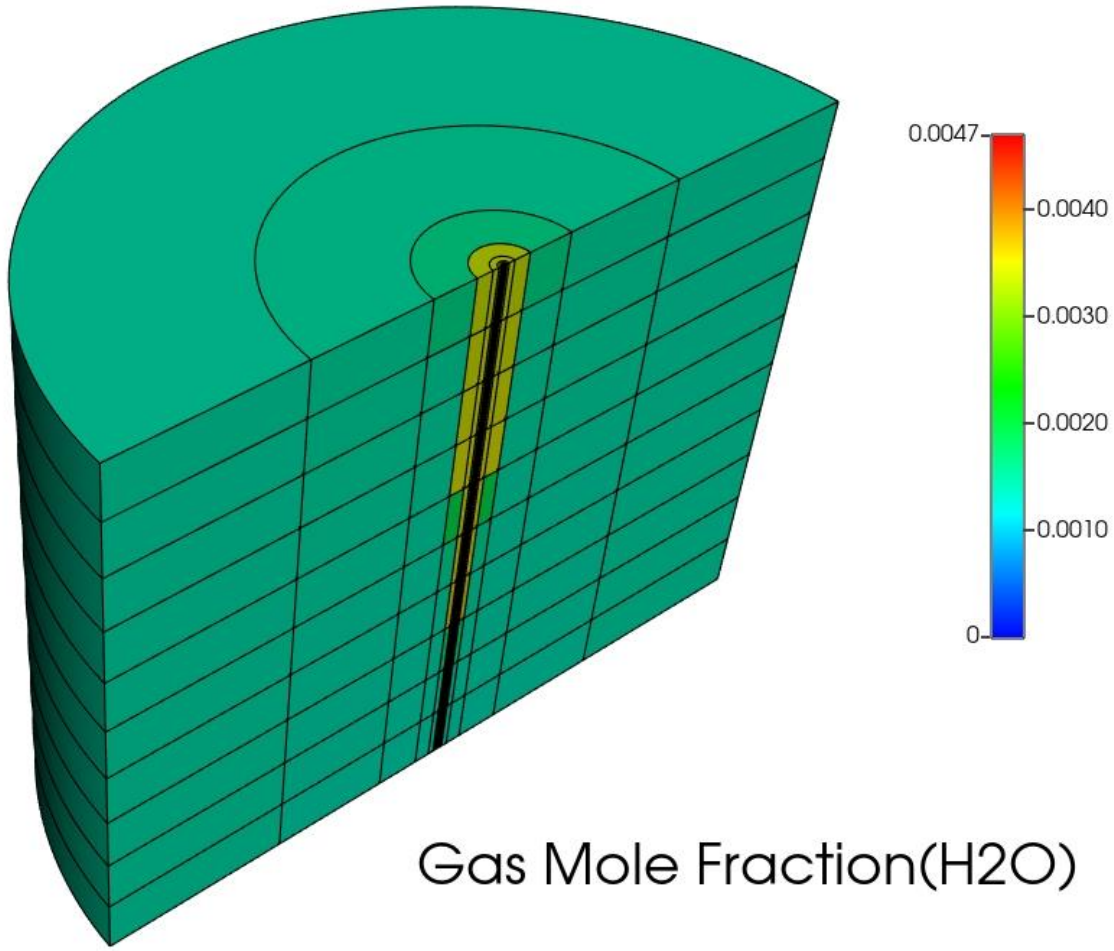
equinor HALLIBURTON Harbour Energy BR PETROBRAS

REPSOL Shell slb TotalEnergies vedanta transforming for good Y-TEC

- **CMG Ltd** for use of **GEM** reactive transport reservoir simulator CMG
- **Energi Simulation** for funding the chair in *CCUS and Reactive Flow Simulation* at Heriot-Watt University energi SIMULATION
- **PTDF** for funding scholarship held by Oluwatosin Ogundipe "a foundation for the future" PTDF

# Model Setup

| PROPERTY | VALUE |
|---|---|
| Geometry | 1D Radial (110 x 1 x 1 cells) |
| Dimensions | 2 km x 180° x 100 m |
| Radial cells | 100 x 0.1 m, then increasing exponentially to outer cell of 1 km |
| Porosity | 0.2 |
| Outer cell pore volume multiplier | $1x10^{5}$ (constant pressure boundary) |
| Rock compressibility | $1x10^{-6}$ 1/kPa at 10,000 kPa |
| Permeability | 100 mD |
| Depth | 1 km |
| Initial pressure at 1 km | 10,000 kPa |
| (Isothermal) temperature | 50 °C |
| Water compressibility | $4.5x10^{-7}$ 1/kPa at 10,000 kPa |
| Water viscosity | 0.39 cP |
| Initial water saturation | 1 |
| Aqueous components | $Na^{+}$, $Cl^{-}$, CO2 (Henry's Law) |
| Activity model | Pitzer |
| Formation brine composition | 5.6 M NaCl |
| Gas phase components | $CO_2$, $CH_4$, $H_2O$ |
| Equation of State | Peng Robinson |
| Injected gas | pure $CO_2$ |
| Well type | Vertical (100 m) |
| Injection rate | 76,200 $sm^3$/day (=0.1 MT/yr) |
| Injection period | 6 months |
| Permeability reduction model | Kozeny-Carman (exponent 2.0) |



# What is Effect of Imbibition?

- Brine continously re-invades dry out zone due to capillary presure
- As brine evaporates
  - Halite deposits
  - More brine is imbibed
  - Deposition greatest where rate of evaporation and rate of imbibition are matched
- What about gravity?