Studies of Foam for EOR and CO$_2$ storage: Liquid Injectivity$^3$, the Effect of Oil on Foam$^2$, and Generation In-situ in Heterogeneous Formations$^1$

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INTRODUCTION TO FOAM IN POROUS MEDIA

- Foams are a distribution of discontinuous gas bubbles in a continuous liquid phase.
- Gas mobility reduction, conformance improvement in displacement processes.
  - Enhanced oil recovery (EOR).
  - Shallow aquifer remediation - (D)NAPL removal.
  - CO₂ storage.

Subsurface applications:

1. Fried, A.N., 1961
2. Marsden, 1986
3. Kovscek and Radke, 1994
5. Hirasaki, G.J. et. al., SPE J., 1997
6. Alcorn, Z.P. et. al., 2018
7. Rognmo, A. et. al. 2018
Some considerations before extending conclusions from N₂-foam to CO₂-foam:

- CO₂-water systems have lower interfacial tension
- CO₂ foam can be easier to generate
- Lower pressure gradient required to sustain propagation
- Different rates of gas diffusion.
- CO₂ solubility in water is much higher than N₂.
- Different behaviour in the presence of oil.
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Liquid Injectivity in Surfactant-Alternating-Gas Foam Enhanced Oil Recovery

- Injectivity is a key economic factor of a foam EOR process
  - Gas injectivity in SAG process is good
  - Liquid injectivity is often very poor in a SAG process

What controls liquid injectivity? How to model it?

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EXPERIMENTAL DESIGN

Surfactant Solution

Quizix Pump

N\textsubscript{2}

dP\textsubscript{2}

6.9 cm

4.2 cm

CT Scan

Effluent Flask

Mass Flow Controller

P1

dP\textsubscript{2}

dP\textsubscript{t}
Pout

N\textsubscript{2}

Back-Pressure Regulator

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Field core is used for all experiments
Focus on middle section
*Free of entrance and capillary-end effects*
Liquid injection directly after steady-state foam
LIQUID INJECTION DIRECTLY AFTER STEADY-STATE FOAM

- Liquid injectivity directly following foam is poor
- Pressure gradient evolves over three stages
  - Liquid enters with relatively high mobility
  - Liquid penetrates foam in a finger
  - Displacement or dissolution of gas trapped within a finger into unsaturated injected liquid

Gong, J. et. al., EAGE IOR, 2019
How would gas-slug injection affect subsequent liquid injectivity?
The collapsed-foam region moves as a front from the inlet to the outlet as more gas is injected. Foam collapses or greatly weakens when a sufficient volume of gas is injected.
Foam collapses or greatly weakens after a prolonged period of gas injection, leaving less trapped gas. Subsequent liquid injection is much easier than following full-strength foam. Liquid sweeps the entire cross section without fingering.
LIQUID FOLLOWS PROLONGED PERIOD OF GAS INJECTION

- Translate to radial flow

If the gas slug in a SAG process is equivalent to the pore volume to a radius of 20 m from the well (far less than a pattern pore volume), at the end of injection of the gas slug ...

- In radial flow, radius out to 3 m represents half the pressure drop in a region of radius 100 m
LIQUID FOLLOWS A SMALLER GAS SLUG

End of gas injection

Gas-slug size: 250 PV

Foam collapses or greatly weakens to this position
LIQUID FOLLOWS A SMALLER GAS SLUG

At the end of gas injection, core is occupied by the collapsed-foam bank and the weakened-foam bank.

Gong, J. et al., EAGE IOR, 2019

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LIQUID FOLLOWS A SMALLER GAS SLUG

In the collapsed-foam region, liquid first flushes the entire cross section, then forms preferential paths.
LIQUID FOLLOWS A SMALLER GAS SLUG

In the weakened-foam region, liquid fingers through foam as in liquid injection directly following foam.
Bank-propagation model
BANKS IN A SAG PROCESS

Gas-injection period

Liquid-injection period

Gong, J. et. al., SPE J., 2019
Gas-injection period:

\[
\Delta p_t = \Delta p_F + \Delta p_{FCG}
\]

Key parameters:
Dimensionless propagation velocity
Total mobility of each bank
Liquid-injection period:

\[
\Delta p_t = \Delta p_{FCL} + \Delta p_{GD} + \Delta p_{LF} + \Delta p_F
\]

collapsed-foam bank

foam bank

gas-dissolution bank

liquid-fingering bank

Solve Darcy’s Law in each bank

Gong, J. et. al., SPE J., 2019
Linear-flow model gives reasonable fit to lab data. Especially Section 4.

In Sections 2 and 3, foam collapse takes a somewhat shorter time in experiment than in model.

WHY?

- Drying out and collapse of foam reflects interplay of pressure gradient, capillary effects, evaporation.
- Not all of these effects scale-up simply.
LINEAR-FLOW FIT FOR LIQUID INJECTIVITY

Liquid injection follows **135 TPV** gas

Liquid injection follows **245 TPV** gas

Linear-flow model gives reasonable fit to lab data

Gong, J. et. al., SPE J., 2019  J.Gong@tudelft.nl
Can conventional foam simulators represent our experimental findings?
PEACEMAN EQUATION VS. BANK-PROPAGATION MODEL

GAS INJECTIVITY

Dimensionless pressure drop [-]

Grid-block pore volumes gas injected [-]

Peaceman equation, Parameters fit to foam scan

Bank-propagation model
Peaceman equation, Parameters fit to foam scan

Bank-propagation model

Peaceman equation based simulation overestimates pressure peak by 70 times.
Peaceman equation based simulation overestimates pressure rise by 40 times at a later stage.

Peaceman equation, Parameters fit to foam scan

Bank-propagation model
In radial-flow calculations based on lab data, larger gas slugs increase injectivity of liquid slugs.

- Small effects of gas slug on subsequent liquid slug in Peaceman equation.
- The more gas is injected before liquid, the bigger error the simulation would give.
Example: 1 GPV liquid follows 10-GPV gas slug

1 Grid block = 100 x 100 m²

Conventional simulator
- Grid-block water saturation: ~0.45
- Grid-block mobility: 0.75 md/cP
- Dimensionless pressure rise: 300

Bank-propagation model
- Collapsed-foam region mobility: 150 md/cP
- Gas-dissolution region mobility: 66 md/cP
- Liquid-fingering region mobility: 0.85 md/cP
SUMMARY

- During gas injection following foam
  - Gas first weakens foam in the entire core.
  - Then a collapsed-foam region forms near the inlet and propagates slowly downstream.

- During subsequent liquid injection
  - Liquid sweeps the entire core cross section in the collapsed-foam region.
  - Liquid fingers through the weakened-foam region.
  - Gas dissolution is the key for forming the liquid finger and directing liquid to flow through the finger
SUMMARY

- Conventional simulation using Peaceman model
  - Underestimates injectivity.
  - Propagation of the collapsed-foam region.
  - Cannot represent the effect of previous gas injection on subsequent liquid injectivity

- A new set of experiments would need to be conducted and a new set of parameters fit to those results is necessary for each field application.

- With assumptions and approximations, this model is not predictive. It indicates trends in expected behavior. Be prepared for adjusting injection rate in field.
Simulators face two challenges:

- Grid resolution near well
- Mechanisms not represented in model
  - Evaporation of liquid during gas injection
  - Dissolution of trapped gas during liquid injection
  - Capillary-pressure gradients during drying near well
  - Fingering of liquid through trapped gas
SUMMARY

- CO$_2$ instead of N$_2$?
  - We expect similar overall behavior incl. bank-propagation
  - Liquid evaporation and foam collapse during gas injection could be different
  - CO$_2$ is more soluble
    - Faster gas dissolution into water
    - Faster propagation of the gas-dissolution front during liquid injection
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OUTLINE

- Foam for gas-mobility control
- Experiment investigation of foam flow regimes with oil
- Modeling of steady-state foam-oil flow
- CT study of foam corefloods with oil
- Summary
- Current challenges
- Foam-flow regimes in porous media
- High-quality regime at the upper left
- Low-quality regime at the lower right
- Crucial starting point for deeper exploration in geological formations

Pressure gradient as a function of $U_W$ and $U_g$, Osterloh and Jante (1992)
EXPERIMENTAL INVESTIGATION: FOAM-FLOW REGIMES WITH OIL

- Co-inject foam and oil to ensure steady state
- Fix $U_o/U_w$ ratio to quantify the effect of oil

Bentheimer core sample

Foam mobility-reduction factor with oil

- Two types of model oils used:
  - Hexadecane (C16), benign to foam stability
  - Mixture of C16 and oleic acid (OA), very harmful to foam

Water

Oil

Gas
- Two regimes still exist, oil affects both regimes, high-quality regime is more vulnerable to oil.
- Low-quality, tilted upward, not independent of $U_w$.

**Reference without oil**

$U_o/U_w=0.25$ with $C_{16}$

- $\nabla P$, 3 times lower
- $\nabla P$, 2 times lower

Tang, J. et. al., SPE J., 2019
- Oil type plays as significant a role as oil saturation
- Gas-mobility reduction is 40x lower in the high-quality regime and 7x lower in the low-quality regime

**Reference without oil**

**U_o/U_w = 0.25 with 20% OA**

Steady-state foam flow without oil  Steady state foam flow with 20% OA in oil

Tang, J. et. al., SPE J., 2019  J.Tang-4@tudelft.nl
MODELLING OF STEADY-STATE FOAM + OIL FLOW

- Implicit-texture modelling: "wet-foam" algorithm and "dry-out" algorithm
- Contour shift reflects the effect of oil on each regime.
- Each algorithm represents the effect of oil only on one regime or the other.

\[
k_{rg}^f = k_{rg}^o \times FM(S_w, S_o)
\]

With wet-foam algorithm

With dry-out algorithm

\[
(U_o/U_w) = 0.25
\]
Foam properties were estimated from steady-state data.

Good match to experimental data, except for the upward-tilting $\nabla P$ contours in the low-quality regime.
One must combine wet-foam and dry-out algorithms to represent the effect of oil on both regimes.

Data on foam flow with 20% OA

Model fit to data

Tang, J. et. al., SPE J., 2019
CT STUDY OF DYNAMIC FOAM COREFLOODS WITH OIL

- Pre-generated foam vs. in-situ-generated foam with C16.
- Two injection methods show similarities in foam dynamics.
- Foam develops quickly, followed by refinement in texture.

Mobility reduction factor (MRF)
Simjoo and Zitha (2013)

Sectional pressure drop
Tang (2019)

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- Pre-generated foam vs. in-situ-generated foam with C16 + 20% OA.
- Foam behavior is very different.
- In-situ foam generation is very difficult even at $S_{or} \sim 0.1$.
- Pre-generated foam shows two stages of propagation.

![Graph of sectional pressure drop for in-situ-generated foam and pre-generated foam](image)
Foam-flow regimes in porous media with oil
- The two regimes for foam without oil apply to foam with oil.
- Oil affects both regimes, but has a stronger impact on the high-quality regime.

Modeling of foam flow with oil
- Each of the two algorithms for foam represents the effect of oil only on one regime or the other.
- The currently applied foam model, though simplified, gives a good match to data.
SUMMARY

- Dynamics of foam with oil
  - Pre-generated foam behaves very differently than in-situ generated foam, depending on oil type.
  - Currently applied foam models needs further investigation for reliable prediction of foam EOR.
Need an effective approach for estimation of oil-related foam-simulation-model parameters.

Implicit-texture modeling of foam EOR uses steady-state data to predict dynamic behavior. The reliability needs to be verified.

With $N_2$ foam, oil affects foam through its interaction with aqueous phase. With $CO_2$ foam, oil interacts with both aqueous and gas phases, especially when miscibility is involved.
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Foam Generation by Snap-off in Flow Across a Sharp Permeability Transition
WHAT DOMINATES IN THE RESERVOIR?

- In the near-well region,
  - SAG flood, gas draining liquid → leave-behind, snap-off
  - High $\nabla P$ → lamella division

- What happens away from the wells?
  - Low $\nabla P$, low velocity, surfactant and gas slugs might’ve mixed.
  - Can we still expect foam?
WHY ARE WE INTERESTED IN THIS?

- Snap-off doesn’t only happen during drainage.
- There are several documented ways in which snap-off can occur.¹
- A particular mechanism of snap-off could help generate foam and improve sweep efficiency away from wells.

¹Rossen, W.R., 2003
Snap-off can cause foam generation independent of pressure gradient in flow across a sharp increase in permeability (Falls, A.H. et al. 1988, Hirasaki. et al. 1997).

Previous experiments were all under drainage and questions still remain.

"Internal" capillary end-effect

Rossen, W.R., 1999

Tanzil, D. et al. 2002
Sharp heterogeneities do exist in subsurface formations\textsuperscript{1,2,3} (e.g. laminations, cross-strata, layer boundaries).

Design an experiment with no foam generation by other mechanisms.

Do we observe foam generation? Validate (or contradict) theoretical predictions.

Investigate the effect of:
- permeability contrast ($k^H/k^L$) – Shah et. al., SPE J., 2018
- fractional flow ($f_g$) – Shah et. al., SPE J., 2019
- velocity ($u_t$) – Shah et. al., SPE J., 2019

Does the foam mobilize and propagate at field-like velocities? \textsuperscript{1}Reineck and Singh, 1980 \textsuperscript{2}Collinson and Thompson, 1989 \textsuperscript{3}Hartkamp-Bakker, 1993
EXPERIMENTAL METHODOLOGY

Procedure:

1. CO₂ flush
2. Saturate with brine (1 wt.% NaCl)
3. Inject N₂ + brine (at desired f_g)
4. Inject N₂ + surfactant solution (0.5 wt.% CMC, 1 wt.% NaCl)
So what do we observe?

Here's an experiment assisted with CT-scanning, \( u_t = 0.67 \text{ ft/d} \), \( f_g = 60\% \), \( k^H / k^L \approx 4:1 \), core placed horizontally.

RESULTS

In-situ saturation measurements

Shah, S.Y. et. al., SPE J., 2019
In-situ saturation measurements
RESULTS

In-situ saturation measurements
RESULTS

In-situ saturation measurements
RESULTS

In-situ saturation measurements
RESULTS

In-situ saturation measurements
RESULTS

In-situ saturation measurements
Magnitude of pressure gradient is similar but that of fluctuations increases as velocity decreases.

Shah, S.Y. et. al., SPE J., 2019
RESULTS

Effect of velocity

Observed weaker foam in outlet tubing at lower velocity.
No clear effect of $f_g$ observed. At $f_g<60\%$, foam was generated in the low-perm zone itself.

\[ \mu_{\text{app}} = \frac{k^H \nabla P}{u_l + u_g} \]

\[ u_t = 0.67 \text{ ft/d}, \quad k^H/k^L \approx 4:1 \]

Shah, S.Y. et. al., SPE J., 2019
Foam strength appears to increase with increase in permeability contrast.

\[ \mu_{\text{app}} = \frac{k^H \nabla P}{u_l + u_g} \]

Shah, S.Y. et. al., SPE J., 2018
At a given permeability contrast, we observe foam generation in drier flows than predicted by theory.

Effect of $f_g$ unclear.
Analytical saturation response to a sharp change in permeability (Yortsos and Chang, 1990)
CAN WE VALIDATE THEORETICAL RESPONSES?

- Analytical saturation response to a sharp change in permeability (Yortsos and Chang, 1990)

- Falls, A.H. et al. (1988) estimated $P_{C}^{sn} \approx 1/2 P_{C}^{e}$
We obtained $P_c$ curves for sintered glass porous media from Berg et al. (2014).

These curves were extended to the petrophysical and fluid properties of our system.

**CAN WE VALIDATE THEORETICAL RESPONSES?**
Phase saturations extracted from CT results (sensitive to CT error and slice width).
CAN WE VALIDATE THEORETICAL RESPONSES?

- $P_c < P_c^{sn} \approx \frac{1}{2} P_c^e$ at the boundary of the low-permeability zone.

- Foam generation is observed as soon as surfactant reaches the boundary.

Shah, S.Y. et. al., SPE J., 2019
SUMMARY

- Demonstrated foam generation across a sharp increase in permeability.
- Demonstrated propagation at field-like velocities (< 1ft/d).
- Reduced $\lambda_g$ high-permeability zone (benefits sweep efficiency away from wells).
- Foam generation triggered as soon as surfactant reaches the boundary.
SUMMARY

- Foam strength higher with greater permeability contrast.

- Foam generation takes longer across greater permeability contrast.

- No clear effect of $f_g$ in range of conditions studied.

- Some theoretical responses verified and some inconsistencies observed.
This process is intermittent (also reported by Falls et al., 1988).

Intermittency greater with greater $k^H/k^L$, higher $f_g$ and lower $u_t$. 

SUMMARY

- Foam generation
- $S_g \uparrow$, drier flow
- Local $P_c$ momentarily exceeds $P_{c}^{sn}$
- New liquid invades the boundary or local imbibition re-saturates the region
- $S_w \uparrow$ at the boundary
- $P_c < P_{c}^{sn}$
WHAT DOES IT MEAN FOR THE FIELD?

- Implications for the field:
  - Foam generation deep in the reservoir
  - Propagation even at field-like superficial velocities
  - Foam generates in the high-permeability layers, blocks flow and reduces:
    - $\lambda_v$
    - Extent of gravity segregation
  - Reduced cross-flow
  - Improved reservoir scale sweep efficiency
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