Overview or CO$_2$ Injection – Performance Metrics and the Wellman Unit Case History

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Texas A&M University
Important Metrics

Utilization = Mcf CO$_2$ per 1 Bbl EOR

Recovery Factor vs. HCPV Injected
Denver Unit Production/Injection History

Two Billion Barrels Oil Initially In-Place
Largest CO2 Project in the World

Primary | Secondary | Tertiary

Water Injection

Oil

CO2 Injection

Water Production

EOR

BBL/D, MCF/D

Jan-38 Jan-43 Jan-48 Jan-53 Jan-58 Jan-63 Jan-68 Jan-73 Jan-78 Jan-83 Jan-88 Jan-93 Jan-99

CO2 EOR Primer NETL
Rule of Thumb? – Good Waterflood ➔ Good EOR Response

CO2-10C_Spot: Primary Oil Forecast

CO2-10C_Spot: Dim Analysis Plots

Primary decline

Waterflood decline

Gas injection decline
## Metrics of Several Floods

<table>
<thead>
<tr>
<th>Field Scale Projects</th>
<th>feet</th>
<th>F</th>
<th>%</th>
<th>md</th>
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<th>API</th>
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<td>30</td>
<td>12.9</td>
<td>8.9</td>
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</tbody>
</table>

**Field Projects ==>** 11.7 | 6.3 | Average

**Pilot Projects ==>** 12.6 | 6.4 | Average
An auditor’s view, Mike Stell, Ryder Scott, Permian Basin Study Group, April 4, 2011
- Reserve booking guidelines, Mike Stell, Ryder Scott, CO2 Conference, Midland December 8, 2005
- What is important in the reservoir, Richard Baker, Appega Conference, April 22, 2004
Case History Wellman Unit

Wellman Unit Phase 1
Laboratory Evaluation of Injection in the Transition Zone
• Introduction
• Laboratory Evaluation
• Field Performance
To examine the performance of recovery at or near the MMP with CO$_2$ in:

- standard slim tube
- vertically-oriented, bead-packed large diameter tubes
- vertically-oriented reservoir cores at reservoir conditions

To examine possibility that residual oil exists below the original water-oil contact that could be mobilized by continuation of CO$_2$ injection
Wellman Unit Oil Characteristics

- separator oil taken at 61 °F and 126 psig
- average molecular weight: 147 g/mol
- GOR: 150 scf/bbl
- density: 0.8329 g/cm³ @ 100 °F and 1000 psig
- viscosity: 2.956 cp
Recovery vs. Pressure for Different GOR’s in Slim Tube

MMP=1600~1625 psig

GOR=150
GOR=400
GOR=600

Ultimate Recovery, \% OOIP vs. Pressure, psig
Recovery Curves for Each Large Diameter Tube Test

- Run A: 1700 psig / gravity stable
- Run B: 1550 psig / gravity stable
- Run C: 1400 psig / gravity stable
- Run D: 1700 psig / gravity stable
- Run E: 1400 psig / gravity unstable
- Run F: 1400 psig / horizontal

% OOIP of CO₂ Injected
% OOIP Produced Oil

- Run A: 1700 psig / gravity stable
- Run B: 1550 psig / gravity stable
- Run C: 1400 psig / gravity stable
- Run D: 1700 psig / gravity stable
- Run E: 1400 psig / gravity unstable
- Run F: 1400 psig / horizontal
Cores From Wellman 5-10

• 30’ whole core from 9400’ to 9430’
• 26 samples for standard core analysis
• 3’ section for gravity stable CO₂ tests
• helium porosities: 2.4% ~ 12.6%
• average porosity: 5.8% for 26 samples
• average water saturation: 42%
A Schematic Diagram of the Core Holder and Procedure

Temperature = 150 °F

(1) Brine @ 2000 psig

(2) Oil @ 1650 psig

(3) Brine @ 1650 psig

(4) CO2 @ 1650 psig

Vugular Carbonate Core

3500 psig Confining
Fluid Production vs. CO$_2$ Throughput During CO$_2$-Assisted Gravity Drainage at a Pressure of 1650 psig

After 9 days shut-in at 1640 psig and 150 F.

After 3 days shut-in at 1740 psig and 150 F.
Changes in Fluid Saturations in the Wellman Unit Whole Core During CO$_2$-Assisted Gravity Drainage

After 3 days shut-in at 1740 psig and 156 F
After 9 days shut-in at 1640 psig and 150 F
Oil Recovery From the Wellman Unit Whole Core During CO$_2$-Assisted Gravity Drainage

- After 3 days shut-in at 1740 psig and 156 F
- After 9 days shut-in at 1640 psig and 150 F
Oil Recovery From the Wellman Unit Whole Core During CO$_2$-Assisted Gravity Drainage at a Pressure of 1650 psig

![Graph showing oil recovery vs. pressure]
$S_{or}$ From the Wellman Unit Whole Core During CO$_2$-assisted Gravity Drainage at Three Pressures Above and Below the MMP
Gravity Stable Outperforms Slim Tube!

The Impact of Gas-Assisted Gravity Drainage on Operating Pressure in a Miscible CO₂ Flood
Case History Wellman Unit

Wellman Unit Phase 2 Reservoir Performance of Injection in the Transition Zone
Terry county, TX, along the Horseshoe Atoll reef complex that developed in North Midland during Pennsylvanian and early Permian time.
INTRODUCTION

• History of the Wellman Unit CO$_2$ flood
• Two possibilities to optimize reservoir performance
  — Reducing CO$_2$ injection pressure to near the MMP
  — Mobilizing reserves in the water-oil transition zone below the original water-oil contact
Amount of CO$_2$ Sequestered in Gas Cap – 130 Bcf
2,100 acres = 3.3 mi² = 8.5 km²

### Overview
- Pinnacle Reef structure of 2,100 acres
- Wolfcamp / Cisco formation at a depth of approximately 9,200 - 10,000 ft
- Extensive exposure and erosion
- Vugular porosity is a large part of the storage and delivery system
- Evidence of widespread fracturing
- Fracture porosity is a small part of the storage but a large part of the delivery system
- Some sections of intercrystalline porosity
  - Intercrystalline porosity is a small part of the storage and delivery system
- Two main pinnacles with vertical relief of over 800 ft
- Limited active Permian / Pennsylvanian water drive

### Reservoir Properties

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<tr>
<th>Reservoir Property</th>
<th>Value</th>
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<tr>
<td>OOIP</td>
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<tr>
<td>Original Oil-Water Contact (“OWC”)</td>
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<td>Oil Column Thickness</td>
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<td>Average Porosity</td>
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<td>Initial Sw</td>
<td>20%</td>
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<tr>
<td>Residual So</td>
<td>35%</td>
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<tr>
<td>Average Permeability</td>
<td>135 mD</td>
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<td>Initial Reservoir Pressure</td>
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<td>Reservoir Temperature</td>
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<td>Initial Oil Gravity</td>
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<td>Oil Viscosity</td>
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Wellman Unit: Early Production History

Great primary and secondary performance but initial CO₂ flood implementation had limited success

### Primary Recovery (1950 to 1979)
- Peak production 8,288 bbl/d in 1974
- Initial reservoir pressure 4,105 psi but dropped below the 1,250 psi bubble point by 1976
- Field under allowable in early 1970s
- Discovery well IP’d over 2,100 bce/d
- Recovery ~34% of OOIP

### Secondary (1979 to 1983)
- Make-up water injection initiated in 1979 with four wells below the OWC
- Peak production of 10,082 bbl/d in 1982
- Waterflood activities were cut short by implementation of CO₂ activities
- Incremental recovery 10% of OOIP (10% total RF)

### Early CO₂ Flood (1983 to 2003)
- Union Texas began CO₂ injection in 1983
- Initial CO₂ flood performance was modest and hampered by low commodity prices and poor flood maintenance
- Flood was eventually discontinued in 2003 due to poor economics
Wellman Unit: Successful Re-initiation of the CO₂ Flood

Oil production has gradually risen above 2,000 bbl/d since the re-initiation of the flood

Commentary

- CO₂ flood under Trinity management (2006-present)
  - Re-started CO₂ injection, discontinued in-zone water injection, and instituted workovers to optimize perforations
  - In 2009 installed 20 MMcf/d recycle compression facility
- July 2012 – Trinity acquired property from Sandridge
  - Accelerated workover program and began staged increase in recycle compression
  - 2011 - 2013 CO₂ purchase constant at ~30 MMcf/d
  - 2013 – present reduced CO₂ purchases and began sharing supplies with George Allen project

Graph:
- 2005: Resumed CO₂ purchase
-停止了CO₂吹扫/销售和水的再注入回到Wolfcamp
- 2009-2013: 20 MMcf/d recycle compression
- 2013-2017: Staged increase of recycle compression to 70 MMcf/d
- Increased production to 2,000+ bbl/d
- Trinity acquired property from Sandridge in June 2012

Legend:
- Green (Oil, bbl/d)
- Blue (Water, bbl/d)
- Orange (CO₂ Purchases, Mcf/d)
- Gray (Gas Injection, Mcf/d)
Primary Depletion (1950 – 1979)

1) 1950-53 oil rate peaked 6 MSTBD

2) 1954 allowable restrictions oil rate reduced to 3, then 1.7 MSTBD

3) 1966 oil rate peaked 8 MSTBD

4) 1976-79 produced below $P_b$ until reached minimum 1,050 psig

Cum. Oil: 41.8 MMSTB
RF: 34.6%
5) 1976-79 GOR did not increase secondary gas cap formed. 
H₂O cut: from 10 to 25%

Cum. Oil: 41.8 MMSTB  
RF: 34.6%
Historical Reservoir Performance

Waterflooding (1979 – 1983)

1979 - four flank H₂O injectors
re-pressurize (MMP), re-dissolve
part of the gas, displace oil upward

Cum. Oil: 23.9 MMSTB
Sec. RF: 19.5%
Waterflooding (1979 – 1983)

- Pressure increased from 1,050 to 1,600 psig prior CO₂ (1983)
- Water cut from 25 to 40%
- GOR aprox. constant
- Water cut controlled by plug downs
- Oil rate increased to 9 MSTBD
Historical Reservoir Performance


• 1983-89 - Three crestal Injectors to displace oil downward and reduce Sor

Cum. Oil: 6.3 MMSTB
Ter. RF: 5.4%

- 1984-89, CO₂ Inj. From 5 to 15 MMCFD.
- 1985, break water cut from 40 to 85%. (ESP’s, leaks, corrosion)
- GOR peaked to 3000 SCF/STB (mostly CO₂)
- Pressure from 1600 to 2,300 peaked at 2,500 psig in 1994.

Cum. Oil: 6.3 MMSTB
Ter. RF: 5.4%
Wellman Unit Annual CO₂ Utilization
Wellman Unit Individual Static Bottom Hole Pressure

[Graph showing bottom hole pressure over time for different units, with markers for each unit and years from A-49 to J-94.]
Chronological Stages of Depletion

Original Reservoir Conditions

Before Waterflooding (1979)

Waterflooding (Before CO₂ Flood), 1983

Waterflood and CO₂ Injection (1995)
INITIAL WATER DISTRIBUTION PROFILE SHOWING WOC, TRANSITION ZONE AND IRREDUCIBLE WATER SATURATION (20%) IN THE OIL ZONE
Simulation Model

3D – Structure Development
Simulation Model
Input Data

Gross Thickness

Porosity

Net to Gross Ratio
**Permeability**

- Use previous estimations from correlations between open logs and core measurements
  
  \[ K = 10^{(0.167 \times \text{Core porosity} - 0.537)} \]

- Relationship may not be representative due to fractures and vugular porosity

**Water Saturation**

\[ Swc, \text{ aprox } 20\% \text{ for } \Phi = 8.5\% \]
Simulation Model
Input Data

Fluid Properties

• Use PVT properties contained in previous lab and reservoir studies

  • Bubble point: 1248 – 1300 psig
  • Rs, 400-500 SCF/STB
  • Oil Gravity, 43 API
  • OFVF, 1.30 RB/STB
  • Oil Viscosity, 0.4 cp
  • Black oil fluid type

Relative Permeability

• Special core analysis for core well No. 7-6 included measurements on only two samples with a low non-representative permeability

• Use functions derived from Honarpour’s correlation (past studies)
Simulation Model
Input Data

Initial Oil-water and gas Relative Permeability
Simulation Model
Input Data

Capillary Pressure Data

- Only 4 samples, $K > 1$ md (Special core Analysis)
- Data normalized by Leverett’s J-function
- Shape suggests lack of capillary transition zone
- Good vertical communication capillary effect “no significant”
Results: Primary Depletion

Diagnosis
Results: Waterflooding

WOC Movement

(a) 1950

(b) 1979

(c) 1983

208 ft

210 ft
Results: CO$_2$ Injection
Chronological Oil Saturation Distribution

a) Primary depletion

b) Waterflooding

c) CO$_2$ miscible flooding
   Oil saturation considered overestimated due to the excess of oil production
Plug-down operation isolates shallower high-GOR perforations and adds deeper perforations tracking the oil column

Plug-Down Process

- Objective
  - Optimize total oil production and maximize total oil recovery through flood surveillance and targeted perforations
  - Perforations in wells track the movement of the oil and ROZ column

- Plug-Down Operation
  - Candidate wells identified by increasing GOR, ability to plug down well or identify better quality reservoir at given perf depth in adjacent wells
  - Old perforations are squeezed and isolated in the plug-down procedure using packers and an isolation string
  - Two-packer system with tubing in-between straddles the perforation now in the CO₂ cap
  - New perforation intervals selected are generally 10 to 20 ft below any CO₂ indicated on the logs
  - New perforations target ~10 ft at a time

- Timing Considerations
  - Generally 18 to 24 months per well
  - 10 plug-downs expected per well annually
  - Intervals selected so that the next interval can be isolated (minimum 20 ft of separation)
  - Once OWC reaches initial original OWC of about -6,680 ft TVDSS more plug-downs will not be needed

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<th>Total Cost</th>
<th>Number of Plug-Downs</th>
<th>Average Cost</th>
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<td>2016</td>
<td>$2.34MM</td>
<td>9</td>
<td>$0.26MM per plug-down</td>
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<tr>
<td>2017</td>
<td>$1.64MM</td>
<td>4</td>
<td>$0.41MM per plug-down</td>
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<tr>
<td>2018+</td>
<td>$3.55MM</td>
<td>10</td>
<td>$0.35MM per plug-down</td>
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### Wellman Unit: Illustrative Plug-Down Process

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<tr>
<th>Step</th>
<th>Description</th>
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| 1    | - Active perforations at oil column depth  
      - High oil production  
      - Low GOR |
| 2    | - Oil column depth drops below perforations  
      - Lower oil production  
      - Increasing GOR |
| 3    | - New perforations selected 20+ ft below existing  
      - Squeeze old perforations  
      - If reservoir quality is low, adjacent well is selected |
| 4    | - Plug isolates upper perforations  
      - High oil production  
      - Low GOR |

[Diagram of the process steps]
Recycle Compressor

NGL Recovery Plant
Conclusions

• CO₂ flooding in the W.U. has performed exceptionally well due to gravity stable displacement above MMP.

• Reducing pressure from above the MMP to near the MMP does not reduce efficiency in laboratory. BHP in the W.U. could be reduced to near the MMP with no reduction in displacement efficiency.

• The reduction in CO₂ purchases would be a positive benefit. The reduction in reservoir pressure is constrained by voidage replacement issues.

• Excellent sweep and displacement efficiency is observed in the lab and the field with residual oil saturation in strong agreement with lab and gas cap.

• Over 130 Bcf of CO₂ has been injected and sequestered in the gas cap.

• Gravity drainage combined with excellent well diagnostics and monitoring results in outstanding recovery factor of 63%.
This is why I don't like 4000 psi anymore …

DuPont

TM

Viton®

3,000 hr at 450 °F

48 hr at 601 °F

Resistance to chemical degradation to oil, fuels, lubricants, and most mineral acids

Resistance to aliphatic, aromatic hydrocarbons that dissolve other rubbers

Resistance to atmospheric oxidation, sun, and weather. Fungus and mold

However…after 35 hr with CO₂ at 4000 psi and 165 °F

WARNING: GRAPHIC CONTENT

The following image and/or content may be disturbing to some viewers. Viewer discretion is strongly advised

__________________________________________________________

__________________________________________________________

ADVERTENCIA: IMAGENES FUERTES

La siguiente imagen y/o contenido podría resultar perturbador para algunas audiencias. Se aconseja discreción
Team Effort
Introduction

Core-flooding + CT scanning integrated equipment

Reservoir temperature
Reservoir pressure
Confining pressure
CT Scanning capability
Core-flooding + CT scanning integrated equipment
CO₂ Injection in shale physical simulation

CO₂ is injected
Soaking is allowed (0 – 22 hr)
CT Scanning is done periodically
CO₂ is displaced with fresh CO₂
The pressure is kept constant
Produced oil

1. – Original crude oil used for core re-saturation
2. – Effluents | Shale | 2500 + 3500 psi | 22 hr
3. – Effluents | Sandstone | 2500 psig | 3rd Cycle | 3500 psig | 22 hr
4. – Effluents | Sandstone | 2500 psig | 1st & 2nd cycles | 22 hr

Vaporizing gas drive
1. – Dead oil

2. – Effluents was flashed at room conditions

3. – The produced oil is clearly lighter than the injected oil

4. – The oil produced from the Berea is heavier than the oil produced from the organic rich shale
Compositional changes with time

Test run 2.4
2nd set – well 2
3100 psig | 21 hrs
RF = 26.15 %
Slice from the center

Slice from the edge

1 in (2.54 cm)

0.57 hr  25.25 hr  50.78 hr  73.63 hr  103.90 hr
The Impact of MMP on Recovery Factor During CO$_2$ – EOR in Unconventional Liquid Reservoirs

Imad A. Adel, Francisco D. Tovar, Fan Zhang, David S. Schechter, Texas A&M University
Results and Discussions
Minimum Miscibility Pressure

- The addition of iodobenzene does not cause a significant increase in the oil density either.
Results and Discussions

Effect of pressure on recovery factor

- Increasing pressure always leads to an increase in the recovery factor

SPE-191752-MS • The Impact of MMP on Recovery Factor During CO₂ – EOR in Unconventional Liquid Reservoirs • Imad Adel
Results and Discussions

Time-frame for recovery

- Most of the oil is recovered during the first cycle
- Similar results were observed in all the huff-and-puff experiments
- The oil recovery rate starts decreasing after the first cycle until it levels off as the maximum recovery is approached

Recovery factor per cycle during CO\textsubscript{2} huff-and-puff experiment on core plug EF3 at 3,500 psig and soak time of 10 hours

SPE-191752-MS • The Impact of MMP on Recovery Factor During CO\textsubscript{2} – EOR in Unconventional Liquid Reservoirs • Imad Adel
Results and Discussions
CT-Scanning

- CT-scans are performed regularly to track the changes in density as a function of time and space.
- The color on the left side changed from blue and green color to red, which means the density of that area decreased to a lower value.
  - Evidence that CO\textsubscript{2} penetrate into the core plug and oil extracted out from the matrix.

CT-scan images from the gas injection experiment of core EF3 at 3,500 psi
Results and Discussions
CT-Scanning

- The CT number of the doped oil is higher than the CT number of the CO₂ phase at all pressures:
  - This CT number decrease indicates that the oil was replaced by the CO₂ inside of the core
- The CT number of the doped oil is higher than the CT number of the CO₂ phase at all pressures

Average CT number for entire core plug during gas injection experiment at 3,500 psi
Results and Discussions
CT-Scanning

- The slices at both end of the core plug, have a more substantial CT number decreases during the experiment.
- The CT value of slices 1 and 37 is lower than slices at the middle of the core:
  - CO\textsubscript{2} contacts a larger area per slice at the edges of the cores, Hence a larger decrease in CT values.

Average CT number for each slice during gas injection experiment at 3,500 psi
Results and Discussions
CT-Scanning – Flow path

The pixels for delta CT number above 50 HU were marked as 1

We counted the number of times high CT number were shown for each pixel during the gas injection experiment

➢ The high flow path region can be generated and used to determine the parameters of the core-scale simulation model

High flow path region from the experiment at 3,500 psi for slices 4 and corresponding CT image before the experiment
Vaporizing gas drive

Slim tube MMP is developed after multiple contacts
Peripheral slow-kinetics vaporizing gas drive

Huff-and-puff

- Gas
- Liquid
- Mixture
- Critical point
- Critical tie line

Injection gas

Production

Poor transport slows down the development of miscibility

We disrupt the process with each production cycle

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URTEC 2903026 | Gas Injection for EOR in Organic Rich Shales. Part II
Peripheral slow-kinetics vaporizing gas drive

Legend

- Carbon dioxide
- Oil
- Miscible front
Peripheral slow-kinetics vaporizing gas drive

We are continuously disrupting the gas enrichment process

Continuous flooding

Gas
Liquid
Mixture
Critical point
Critical tie line
Peripheral slow-kinetics vaporizing gas drive

Increasing the pressure improves the ability of the gas to strip out oil components.

URTEC 2903026 | Gas Injection for EOR in Organic Rich Shales. Part II
Minimum Miscibility Pressure (MMP) for Eagle Ford Oil

• The MMP was measured using the slim tube technique using an 80-ft coil.
• The MMP was determined to be 2,132 psi.
Results of Gas Injection Experiments

- The recovery factors increases as the pressure increases.
- The maximum RF is 49% of OOIP at 3,500 psi.
- RF is less than 5% when pressure below MMP.

SPE-191502-MS • Enhanced Oil Recovery in Unconventional Liquid Reservoir Using a Combination of CO2 Huff-n-Puff and Surfactant-Assisted Spontaneous Imbibition • Fan Zhang
Results of SASI Related Experiments

- Surfactants lead to wettability alteration and IFT reduction.
- Up to an extra 12% of oil recovered through spontaneous imbibition experiments
Observation during SASI

- At the beginning of SASI, foam was collected at the top cylinder.
- CO$_2$ existed inside the core plugs after gas injection experiments.
- Even though 49% of OOIP produced from gas injection experiment, additional oil can be recovered from SASI.
Recovery Factor of Hybrid EOR Experiments

- Up to 49% of OOIP was produced from CO$_2$ huff-n-puff experiments.
- The maximum recovery factor of hybrid EOR experiments is 58% of OOIP.

SPE-191502-MS • Enhanced Oil Recovery in Unconventional Liquid Reservoir Using a Combination of CO2 Huff-n-Puff and Surfactant-Assisted Spontaneous Imbibition • Fan Zhang
• Three months of re-saturation and aging process.
• Recovering up to 58% of the OOIP in only 12 days.

SPE-191502-MS • Enhanced Oil Recovery in Unconventional Liquid Reservoir Using a Combination of CO2 Huff-n-Puff and Surfactant-Assisted Spontaneous Imbibition • Fan Zhang
CT-Scan Images from Gas Injection and Imbibition Experiments

- Gas injection experiments: more oil recovered from low CT number region (larger pores).
- SASI: most of oil produced from high CT number region (smaller pores).
Color Change of Produced Oil

- Lighter and intermediate components of the oil are recovered during the CO$_2$ huff-n-puff experiments.
- Heavier components are recovered during the SASI.

SPE-191502-MS • Enhanced Oil Recovery in Unconventional Liquid Reservoir Using a Combination of CO2 Huff-n-Puff and Surfactant-Assisted Spontaneous Imbibition • Fan Zhang
Color Change of Oil during Spontaneous Imbibition Experiments

- The color of the produced oil changed from lighter to darker.
- Lighter components of oil are recovered within the first 24 h.
- A large fraction of the oil produced from the SASI is coming from the smaller pores.
Low IFT Imbibition and Drainage

Dr. David S. Schechter

Texas A&M University
Low IFT Imbibition and Drainage:

Gravity Dominates at Low IFT
Imbibition: Mechanisms and Recovery

Imbibition Mechanisms

CGR > 5
\[ t_c - H^2 \]

5 > CGR > 0.2

CGR < 0.2
\[ t_g - H \]

Imbibition Recovery

\[ R\% \]
Capillary Imbibition Cell

- Core Sample
- Annular Space (0.08 cm)
- Oil Produced
- Wetting Phase Inlet

- Indiana Limestone: 15 md
- Berea Sandstone: 100 md
- Berea Sandstone: 500 md
- Brown Sandstone: 700 md
Imbibition Rate Theory

\[ t_d = t \sqrt{\frac{k \sigma \cos \theta}{\phi \mu_w L^2}} \]
Correlation of IFT and $\Delta \rho$

\[
\sigma = \sigma \times \left[ \frac{\Delta \rho}{\Delta \rho^*} \right]^{\frac{\gamma}{\beta}} \\
\frac{\gamma}{\beta} \approx 3.8
\]
Capillary and Gravity Imbibition
Phase Diagram for Brine/IC8/IPA System
Phase Behavior Data

<table>
<thead>
<tr>
<th>Tie Line</th>
<th>$\Delta \rho$ (g/cc)</th>
<th>IFT (mN/m)</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>0.33</td>
<td>38.1</td>
</tr>
<tr>
<td>2</td>
<td>0.21</td>
<td>1.07</td>
</tr>
<tr>
<td>3</td>
<td>0.11</td>
<td>0.10</td>
</tr>
</tbody>
</table>
Imbibition in 15 md Limestone
Imbibition in 100 md Berea
Imbibition in 500 md Berea

Graph showing the relationship between Frac. OOIP recovered and time (days) for different IFT values.
Imbibition in 700 md Brown Sandstone

- IFT = 38.1 mN/m
- IFT = 1.07 mN/m
- IFT = 0.10 mN/m

Fraction of Original Oil in Place (OOIP) Recovered vs. Time (Days)
Bond Number

\[ N_B = \sqrt{\frac{K \sigma \cos \theta}{\phi \Delta \rho gh}} \]
Remaining Saturation vs. CGR for Imbibition
Remaining Oil Saturations at Different IFTs
Critical Scaling Theory

\[ \Delta \rho = \Delta \rho^* \left[ 1 - \frac{T_r}{T_c} \right]^\beta \quad \text{where } \beta = 0.325 \]
\[ \sigma = \sigma^* \left[ 1 - \frac{T_r}{T_c} \right]^\gamma \quad \text{where } \gamma = 1.26 \]
Test of Critical Scaling
Critical Scaling

Slope = 3.88
Drainage:
Mechanisms and Recovery

Drainage Mechanisms

Drainage Recovery

CGR > 1
CGR < 1
CGR << 1

R%
Gravity Drainage Cell

Nonwetting Phase Inlet

Annular Space (0.08 cm)

Core Sample

Indiana Limestone 15 md
Berea Sandstone 100 md
Berea Sandstone 500 md
Brown Sandstone 700 md

Wetting Phase Produced
Remaining Saturation vs. CGR for Drainage

[Schematic diagram showing remaining wetting phase saturation vs. $N_{B}^{-1}$ with data points from various studies labeled: Schechter (1994), Pavone et al. (1989), Stensen et al. (1990), Suffridge and Renner (1991), Saidi (1987), and Jacquin et al. (1987).]
Height vs. Permeability

Height vs. permeability for \( N_B^{-1} = 1 \) for the \( \text{CO}_2/\text{C}_{10} \) System

IFT = 0.848 mN/m
IFT = 0.529 mN/m
IFT = 0.245 mN/m
IFT = 0.101 mN/m
IFT = 0.029 mN/m
IFT = 0.013 mN/m
Non-equilibrium Drainage
Non-equilibrium Drainage:

![Graph showing nonequilibrium drainage: vaporizing case]

IPA "Vaporization"
Imbibition and Drainage in 500 md Berea

- Drainage 0.1 mN/m
- Imbibition 0.1 mN/m
- Drainage 1.0 mN/m
- Drainage 38 mN/m

Frac. Pore Volume Recovered

Time (Days)

$N_B^1 = 0.040$

$N_B^3 = 0.227$

$N_B^1 = 5.13$
Spontaneous Imbibition and Drainage
Imbibition at high value of $N_B^{-1}$ ($N_B^{-1} > 5$) is dominated by capillary forces, and the rate of imbibition is limited by the counter-current flow of the wetting and nonwetting phase.

At low values of $N_B^{-1}$ ($N_B^{-1} \ll 1$), imbibition is dominated by vertical flow driven by gravity forces.
For intermediate values of $N_B^{-1}$, the combined effects of gravity segregation and capillary-driver imbibition can lead to faster recovery of the nonwetting phase than is observed for either gravity-dominated or capillary-dominated flow.

Gravity drainage of wetting phase from fully saturated vertical cores occurs for $N_B^{-1} < 1$. 
Gas injection processes can be used to recover oil from fractured reservoirs by gravity drainage at low $N_B^{-1}$. 

Conclusions
Recovery factors under nitrogen injection

0%