Simulation and Experimental Investigations of CO$_2$ Injection in Both Conventional (Wellman Unit) and Unconventional Reservoirs

Department of Petroleum Engineering
Texas A&M University
Dr. David Schechter
19$^{th}$ Annual CO$_2$ Flooding Conference
Midland, TX
December 12$^{th}$, 2013
Observations

• CO₂ EOR recovers oil very effectively
• It’s limited by the availability of CO₂
• The laboratory and simulation research technology is aimed at improving the utilization of CO₂ (areal and vertical sweep efficiency) through mobility control
• Research into gravity stable floods (Wellman Unit)
• The research technology is improving prediction of processing rates (net utilization and gross utilization - Mscf CO₂/bbl EOR) with dimensionless curves for H₂O and CO₂
• The big prize is utilizing CO₂ in the ROZ & countless “boom” wells in unconventional liquid reservoirs (ULR)
Mobility Control with Viscosifier
Sweep Efficiency after 0.5 PV Injected

Pure CO₂

Fracture

Dodecamethylpentasiloxane Viscosified CO₂ Flood

Shuzong Cai, 2011
Chronological Stages of Depletion

Original Reservoir Conditions

Before Waterflooding (1979)

Waterflooding (Before CO₂ Flood), 1983

Waterflood and CO₂ Injection (1995)
Simulation Model

Full field, 3-D black oil simulation
“Imex” – CMG

Grid System

- Use of flexible grids: corner point, non-orthogonal geometry.
- 27 x 27 gridblocks I,J direction
- K, direction subdivided in 23 layers based on porosity correlations (geological description)
- Total 16,767 gridblocks
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

Swc, aprox 20% for \( \Phi = 8.5\% \)

Simulation Model
Input Data

Swc, aprox 20% for \( \Phi = 8.5\% \)
Use of isopach maps resulted from geological and petrophysical study in 1994

Geological and stratigraphic correlation (Core vs Log data)

Quantify major rock properties

Lateral and areal continuity

Isopach Maps

- 60 geological contoured maps from gross thickness, porosity and NTGR were digitized
- Interpolation between contour allows model to be populated

Gross Thickness

Porosity

Net to Gross Ratio

Simulation Model

Input Data
Simulation Model

3D – Structure Development
Measured BHP’s for History Matching

Individual Static Bottom Hole Pressure

![Graph showing individual static bottom hole pressures over time for different units.](image-url)
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
CO$_2$ Recovery Mechanism
Gravity Drainage

• 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

Ultimate Recovery, % OOIP

Pressure, psig

GOR = 150
GOR = 400
GOR = 600
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
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%
Schematic Diagram of the Core Holder and ROZ Procedure (Wellman Unit)

1. Brine @ 2000 psig
2. Oil @ 1650 psig
3. Brine @ 1650 psig
4. CO2 @ 1650 psig

Temperature = 150°F
Oil Recovery From the Wellman Unit Whole Core During CO$_2$-assisted Gravity Drainage at a Pressure of 1650 psig
$S_{or}$ From the Wellman Unit Whole Core During $CO_2$-assisted Gravity Drainage at Three Pressures Above and Below the MMP.
## CO₂ Recovery Factors in Whole Core Wellman Unit Gravity Drainage

<table>
<thead>
<tr>
<th>Experiment No.</th>
<th>1</th>
<th>2</th>
<th>3</th>
</tr>
</thead>
<tbody>
<tr>
<td>Core porosity</td>
<td>0.0676</td>
<td>0.066</td>
<td>0.066</td>
</tr>
<tr>
<td>Core permeability, md</td>
<td>15.4</td>
<td>12.7</td>
<td>12.7</td>
</tr>
<tr>
<td>Initial oil saturation</td>
<td>0.47</td>
<td>0.102</td>
<td>0.191</td>
</tr>
<tr>
<td>Oil type</td>
<td>Reservoir Oil</td>
<td>Separator Oil</td>
<td>Separator Oil</td>
</tr>
<tr>
<td>Temperature, °F</td>
<td>150</td>
<td>150</td>
<td>150</td>
</tr>
<tr>
<td>Pressure, psig</td>
<td>1,650</td>
<td>1,543</td>
<td>1,320</td>
</tr>
<tr>
<td>CO₂ injection rate, cc/hr</td>
<td>20</td>
<td>10</td>
<td>2</td>
</tr>
<tr>
<td>Oil recovery after 1.2 PV CO₂ inj.</td>
<td>0.76</td>
<td>0.51</td>
<td>0.115</td>
</tr>
<tr>
<td>Oil recovery after 2 PV CO₂ inj.</td>
<td>0.78</td>
<td>0.57</td>
<td>0.148</td>
</tr>
<tr>
<td>Residual oil saturation</td>
<td>0.09</td>
<td>0.03</td>
<td>0.10</td>
</tr>
</tbody>
</table>
Conclusions

- The MMP of W.U. oil is 1600 +/- 50 psig over a range of GOR’s 150 to 600 scf/bbl;

- Reservoir performance, slim tube, large diameter tube and gravity stable core floods in W.U. whole core at reservoir conditions demonstrate excellent displacement efficiency with $S_{or}$ after $CO_2 < 10\%$ for a range of pressures;
Conclusions

• Gravity stable core flooding results from transition zone core taken from the W.U. demonstrates that oil not mobilized by water influx in the transition zone can be effectively mobilized with CO$_2$ over a range of injection pressures;
Conclusions

• 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 CO$_2$ purchases would be a positive benefit. The reduction in reservoir pressure is constrained by voidage replacement issues;
Conclusions

- CO$_2$ flooding in the W.U. has performed exceptionally well due to gravity stable displacement above MMP. This results in excellent sweep and displacement efficiency. Over 42 bcf of CO$_2$ has been injected and recovered 7.2 MMbbls of tertiary oil. The resulting utilization is 5.83 Mcf CO$_2$ injected per barrel of incremental oil as of the late 90’s.
Enhanced Oil Recovery in ULR

CO₂ Injection
Objective

To observe the effect of CO$_2$ into ULR core and the effect that it may have on oil productivity.
Motivation

CO₂ Oil Recovery

- Shale sidewall cores with negligible permeability
- Conventional CO₂ flooding was not possible
- Oil couldn’t be recovered

A totally different approach was required
Experimental Procedure

CO₂ Oil Recovery

Shale cores were soaked in CO₂

A high permeability media was provided to store CO₂ in contact with the shale cores

Core holder was placed horizontally

Schematic of cores packing

- Aluminum Core holder
- Confining Fluid
- Roll cover
- Sleeve
- Glass beads
- Shale core 2
- Shale core 1
- Sandstone top
Experimental Procedure

CO$_2$ injection through the core is not intended.
Experimental Procedure

6. Oil production was collected by intervals in CT number changes and maintained.

Displacement Equipment Schematic
Experimental Equipment

CO₂ Oil Recovery
New CT Scanner at Texas A&M PE Department
Results

Oil Recovery

- 0.4 cm$^3$ of oil were recovered

\[
\text{OOIP} = \text{Core Volume} \times \phi \times (1 - Sw) 
\]

- Different scenarios for recovery factor

<table>
<thead>
<tr>
<th>$S_{wi}$, %</th>
<th>Porosity ($\phi$), %</th>
</tr>
</thead>
<tbody>
<tr>
<td>0</td>
<td>36</td>
</tr>
<tr>
<td>30</td>
<td>51</td>
</tr>
<tr>
<td>6</td>
<td>18</td>
</tr>
<tr>
<td>25</td>
<td></td>
</tr>
</tbody>
</table>
Results

Core weight

- Mass of Core 1 increased by 0.07 g
- Mass of Core 2 increased by 0.06 g

<table>
<thead>
<tr>
<th></th>
<th>Sample 1</th>
<th>Sample 2</th>
</tr>
</thead>
<tbody>
<tr>
<td>Weight before experiment, g</td>
<td>50.48</td>
<td>45.39</td>
</tr>
<tr>
<td>Weight after experiment, g</td>
<td>50.55</td>
<td>45.45</td>
</tr>
<tr>
<td>Diameter, cm</td>
<td>2.53</td>
<td>2.53</td>
</tr>
<tr>
<td>Length, cm</td>
<td>3.97</td>
<td>3.48</td>
</tr>
<tr>
<td>Bulk volume, cm³</td>
<td>19.94</td>
<td>17.50</td>
</tr>
</tbody>
</table>

First Experiment
Test conditions: 3000 psi, 150 F
CT Number behavior

Average CT number for both cores

An increasing trend is observed

First Experiment
Test conditions: 3000 psi, 150 F
Results

CT Images
Shale sidewall core 1

Slice 20

Slice 30

First Experiment
Test conditions: 3000 psi, 150 F
Results

CT Images

Shale sidewall core 2

Slice 42
Slice 50

First Experiment
Test conditions: 3000 psi, 150 F

2.5 hr 4.3 hr 30.1 hr 50.7 hr 58.4 hr 72.5 hr 78.1 hr 95.1 hr 99.1 hr
Since CT number correlates to density

The experiment was repeated at 1600 psi, where a higher density difference exists.
Results

Oil Recovery

- 0.4 cm$^3$ of oil were recovered

OOIP = Core Volume $\times \phi \times (1 - Swi)$

- Different scenarios for recovery factor

<table>
<thead>
<tr>
<th>$S_{wi}$, %</th>
<th>Porosity ($\phi$), %</th>
</tr>
</thead>
<tbody>
<tr>
<td>0</td>
<td>39, 19</td>
</tr>
<tr>
<td>30</td>
<td>55, 28</td>
</tr>
</tbody>
</table>

This test was prematurely terminated because of a water leak

Second Experiment
Test conditions : 1600 psi, 150 F
Results

Core weight

- Mass of Core 1 increased by 0.95 g
- Mass of Core 2 increased by 0.86 g

<table>
<thead>
<tr>
<th></th>
<th>Sample 1</th>
<th>Sample 2</th>
</tr>
</thead>
<tbody>
<tr>
<td>Weight before exp.</td>
<td>40.09</td>
<td>36.04</td>
</tr>
<tr>
<td>Weight after exp.</td>
<td>41.04</td>
<td>36.90</td>
</tr>
<tr>
<td>Diameter</td>
<td>2.53</td>
<td>2.52</td>
</tr>
<tr>
<td>Length</td>
<td>3.62</td>
<td>3.29</td>
</tr>
<tr>
<td>Bulk volume, cm³</td>
<td>18.20</td>
<td>16.42</td>
</tr>
</tbody>
</table>

Second Experiment
Test conditions: 1600 psi, 150 F
Results

CT Number behavior
Average CT number for sidewall core 1

Second Experiment
Test conditions: 1600 psi, 150 F

A decreasing trend is observed
Results

CO₂ Oil Recovery

CT Images
Shale sidewall core 1

Second Experiment
Test conditions: 1600 psi, 150 F

Slice 20
Slice 30

5.1 hr
25.4 hr
34.9 hr
43.8 hr
55.4 hr
67.5 hr
Results with CT Number

CO$_2$ Oil Recovery

Average CT number for sidewall core 2

Different trends are observed

Second Experiment
Test conditions: 1600 psi, 150 F
Results

CT Images
Shale sidewall core 1

Slice 45
Slice 50

5.1 hr  25.4 hr  34.9 hr  43.8 hr  55.4 hr  67.5 hr

CO₂ Oil Recovery

Second Experiment
Test conditions: 1600 psi, 150 F
What is next?

3\textsuperscript{rd} Experiment

- Production Vs. time data
- Produced oil composition

Numerical Model

- Sensitivity analysis to understand influence of parameters
Oil production was accomplished by soaking shale cores with CO₂ at 3000 psi and 1600 psi. Recovery in both cases is estimated to be from 18 to 55 % of OOIP. The permeability of the cores does not allow for conventional CO₂ flooding.

CT imaging was done during the course of the experiment revealing changes inside the sidewall cores.

Changing the pressure of the test influenced the behavior of CT number, this could be related to the different densities of CO₂ at the two experimental conditions.

More work is required to better understand the mechanisms causing oil production during these tests.
New Equipment - Chevron Imaging Lab and Chaparral CO₂ EOR Lab

CO₂ Oil Recovery
CO₂ and Enhanced Oil Recovery in Unconventional Liquid Reservoirs

Department of Petroleum Engineering
Texas A&M University
Dr. David Schechter

Please Join Our Newly Established JIP
Dimensionless Curves
Improving Prediction of CO₂ Injection in Conventional Reservoirs
Methodology
Evaluation of Water-Flood Recovery

- Cumulative dimensionless WF calculated for each pattern

\[
\text{DimRecovery(\%)} = \frac{\text{Oil (after WF start)} - \text{Primary Oil Fcst}}{\text{OOIP}}
\]

Primary Production DCA Sample: Pattern J-1 (8.5%/yr)

Primary Production DCA Sample: Pattern J-7 (9%/yr)

Anino Adokpuye 2013
Methodology

Dimensionless Recovery Curves – WF & CO₂ Comparisons

While a pattern is under the initial pure CO₂ slug (prior to WAG), DTI = DCI
Results & Observations

Strong WF & CO₂ Correlations

Initial overlay (perfect correlation) of WF & CO₂ recovery - diverge at ≈10% dim injection.
Short-lived waterflood (only 36% DWI-WF) - although, enough to trend for comparison.
Results & Observations

Strong WF & CO₂ Correlations

WF & CO₂ recovery curves remain parallel through 200% dimensionless injection!
Curves tend to diverge at ≈20% DEOR
Conclusions

• Results from dimensionless analysis of well-established vintage water and CO₂ injection patterns show the usefulness of dimensionless water-flood curves as a basis for prediction of performance under CO₂ injection
Surfactant Studies in ULR

CO₂ Injection in Conventional and Unconventional Liquid Reservoirs

Department of Petroleum Engineering
Texas A&M University
Dr. David Schechter
Barnett Shale

The penetration of anionic surfactant in this particular siliceous shale core is shown in this sequence of fluid in seven cross-sectional views of the core before flooding, 0 hours, 30 minutes, 1 hour, 2 hours, 4 hours and 20 hours after flooding.

This slice is one of the 18 slices used to create the horizontal view in the previous slice.
Changing Contact Angles

Frac Water w/o surfactant: 110°

Frac Water with surfactant: 35°
Barnett Shale

- Anionic surfactant
  - Superior penetration magnitude
  - Better matrix penetration – spontaneous imbibition
  - Best oil recovery
  - Low ‘contact angle’ with oil-saturated shale surface
Barnett Shale

Grey - clay
Blue - carbonate
Yellow - silica
Contact Angle & IFT Measuring Capabilities

- Static and dynamic contact angles
- Surface and interfacial tension
- Surface free energy of solids and their components
- Temperature control unit to maintain reservoir temperature

Dataphysics OCA 15 Pro
Experiment Design - Contact Angle

Shale sample

Captive bubble method

Capillary Needle