Opportunities for CO2 EOR in Unconventional Reservoirs

Learning from the Permian;
Developing new knowledge
Opportunities for CO2 EOR in Shale Plays
Learning from the Permian;
Developing new knowledge
01 Learning from CO2 use in the Permian Basin
  • Rules of thumb: what are they based on?
  • Historic and current CO2 use in PB

02 Developing new knowledge for CO2 use in the Eagle Ford shale
  • Location
  • Current gas injection projects
  • Is there a potential for CO2?

03 CO2 potential in other shale plays?
Acknowledgements
material for this presentation came from:

• George Grinestaff, Shale IOR
• Mahendra K. Verma, USGS Report 2015-1071
• NETL (US DOE), “Carbon Dioxide Enhanced Oil Recovery”, 2010
• US EIA website
• TRRC website
• UH professors Michael Craig, Miguel Saldana
Methods to add energy to the reservoir or change the character of the contained oil (including by steam injection) became more generally known as EOR techniques.

Widespread application of CO2 injection has occurred in the Permian Basin and in New Mexico:

- Both areas have large, naturally-occurring sources of CO2 nearby, as well as large, mature waterflood operations.
Tertiary Production Phase
Enhanced Oil Recovery (EOR) using CO2 Injection

Although it is a gas, in contact with oil at high pressures (over 2,500psi), CO2 forms a miscible substance

Below the minimum miscibility pressure (MMP), CO2 and oil will no longer be miscible. As the oil density increases (as the light hydrocarbon fraction decreases), the minimum pressure needed to attain oil/CO2 miscibility increases. For this reason, oil field operators must consider the pressure of a depleted oil reservoir when evaluating its suitability for CO2 enhanced oil recovery. Low pressured reservoirs may need to be re-pressurized by injecting water.

01 Learning from CO2 use in the Permian Basin
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6
Flow Diagram of Petroleum Fluids

- **Wellhead**
- **Wellbore**
- **Gas**
- **Oil with Dissolved Gas**
- **Water**
- **Separator**
- **Separator gas**
- **Stock Tank**
  - **Stock-tank gas**
  - **Stock-tank oil**
  - **Water**

**INFORMATION BOX**
- PVT relationship modeled with an equation of state (EOS)
MMP from Slimtube testing

INFORMATION BOX
• PVT relationship modeled with an equation of state (EOS)
$p v T$ Surface for Water

$\rho = \text{density}$

$$\rho = \left[ \frac{\text{Mass}}{\text{Volume}} \right]$$

$\nu = \text{specific volume}$

$$\nu = \frac{1}{\rho}$$

$$\nu = \left[ \frac{\text{Volume}}{\text{Mass}} \right]$$

**INFORMATION BOX**

- PVT relationship modeled with an equation of state (EOS)
A substance that has a fixed chemical composition throughout is called a pure substance.

**Phase:** A distinct molecular arrangement that is homogenous throughout and separated from others by boundary surfaces.

**Solid**  
**Liquid**  
**Gas (Vapor)**

**INFORMATION BOX**
- PVT relationship modeled with an equation of state (EOS)
$p-T$ Phase Diagram for a Two-Component Substance

INFORMATION BOX
- PVT relationship modeled with an equation of state (EOS)
Phase Diagram for the Five Types of Reservoir Fluids

- Black Oil
- Volatile Oil
- Retrograde Gas
- Wet Gas
- Dry Gas

INFORMATION BOX

- The five types of Reservoir Fluids
Example Compositions of Reservoir Fluids (mol%)

<table>
<thead>
<tr>
<th>Component</th>
<th>Black Oil</th>
<th>Volatile Oil</th>
<th>Retrograde Gas</th>
<th>Wet Gas</th>
<th>Dry Gas</th>
</tr>
</thead>
<tbody>
<tr>
<td>C1</td>
<td>56.9</td>
<td>66.7</td>
<td>72.7</td>
<td>88.7</td>
<td>96.37</td>
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<tr>
<td>C2</td>
<td>5.3</td>
<td>9.0</td>
<td>10.0</td>
<td>6.0</td>
<td>3.00</td>
</tr>
<tr>
<td>C3</td>
<td>3.8</td>
<td>6.0</td>
<td>6.0</td>
<td>3.0</td>
<td>0.40</td>
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<tr>
<td>i-C4</td>
<td>0.8</td>
<td>0.8</td>
<td>1.0</td>
<td>0.5</td>
<td>0.07</td>
</tr>
<tr>
<td>n-C4</td>
<td>1.2</td>
<td>2.5</td>
<td>1.5</td>
<td>0.8</td>
<td>0.10</td>
</tr>
<tr>
<td>i-C5</td>
<td>0.4</td>
<td>0.8</td>
<td>0.8</td>
<td>0.3</td>
<td>0.02</td>
</tr>
<tr>
<td>n-C5</td>
<td>0.4</td>
<td>1.2</td>
<td>1.0</td>
<td>0.3</td>
<td>0.02</td>
</tr>
<tr>
<td>C6</td>
<td>1.0</td>
<td>2.0</td>
<td>2.0</td>
<td>0.2</td>
<td>0.02</td>
</tr>
<tr>
<td>C7+</td>
<td>30.2</td>
<td>11.0</td>
<td>5.0</td>
<td>0.2</td>
<td>0.00</td>
</tr>
</tbody>
</table>

plus inorganics: N₂, CO₂, H₂S, H₂O

INFORMATION BOX
• The five types of Reservoir Fluids
Classification of Reservoir Fluids

• The behavior of the reservoir fluids during production is determined by
  – Composition of the reservoir fluids
  – Shape and location of the $p-T$ phase diagram
  – Reservoir conditions relative to the critical point on the $p-T$ phase diagram

• In naturally-occurring petroleum fluids, the critical point normally appears to the left of the top of the phase envelope.
  – Liquid and gas can co-exist at $p$ and $T$ higher than the critical point

INFORMATION BOX
• The five types of Reservoir Fluids
The Five Reservoir Fluids

1. _______
2. _______
3. _______
4. _______
5. _______

INFORMATION BOX
• The five types of Reservoir Fluids
Ternary Diagrams

Vertices: Pure components
Sides: Mixture of 2 components
Area: Possible combinations of the three components A, B, C

Point 2: Mixture of A and C
Point 3: Mixture of A, B, C
Length of 3-4: Composition of A
Length of 3-5: Composition of B
Length of 3-6: Composition of C

Line 2-1: Dilution line, adding B to the original mixture of A and C at Point 2
Point 7: 50% Point 2 + 50% B

INFORMATION BOX
- PVT relationship modeled with an equation of state (EOS)
Phase Diagram for a Three-Component Substance (C₁, nC₃, nC₅)

Equilibrium tie-lines are straight but not horizontal

Point 1: mixture of C₁, C₃, C₅

Point 2: Composition of equilibrium gas

Point 3: Composition of equilibrium liquid

|1-3|/|2-3|: quality of gas (lever rule)
|1-2|/|2-3|: quality of liquid (lever rule)

INFORMATION BOX
- PVT relationship modeled with an equation of state (EOS)
Phase Diagram for a Three-Component Substance ($C_1$, nC$_3$, nC$_5$)

INFORMATION BOX
- PVT relationship modeled with an equation of state (EOS)
Multi-Contact Miscibility

Schematic of the CO2 (carbon dioxide) miscible process showing the transition zone between the injection and production well. (Modified from Jarrell et al., 2002.)

INFORMATION BOX
• PVT relationship modeled with an equation of state (EOS)
When we inject CO2 into an oil reservoir, it becomes mutually soluble with the residual crude oil.

Light hydrocarbons from the oil dissolve in the CO2 and CO2 dissolves in the oil. This occurs most readily when the CO2 density is high (when it is compressed) and when the oil contains a significant volume of “light” (i.e., lower carbon) hydrocarbons (typically a low-density crude oil).
Tertiary Production Phase
Enhanced Oil Recovery (EOR) using CO2 Injection

As the CO2 sweeps across the reservoir and mixes with the oil, it also causes it to swell. This allows more oil to flow to the producing well.

As CO2 dissolves in the oil it swells the oil and reduces its viscosity; affects that also help to improve the efficiency of the displacement process.

01 Learning from CO2 use in the Permian Basin
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- Historic and current CO2 use in PB
Often, CO2 floods involve the injection of volumes of CO2 alternated with volumes of water; water alternating gas or WAG floods.

This approach helps to mitigate the tendency for the lower viscosity CO2 to finger its way ahead of the displaced oil or to over-ride the oil. Once the injected CO2 breaks through to the producing well, any gas injected afterwards will follow that path, reducing the overall efficiency of the injected fluids to sweep the oil from the reservoir rock.
What is needed for a CO2 project?

**CO2 Source:** First, a pipeline to deliver CO2 to the field at a high pressure and density (>1200psi and 5 pounds per gallon) for the project— for comparison water density is 8.3 pounds per gallon).

**Simulation / pattern design:** This CO2 is directed to injection wells strategically placed within the pattern of wells to optimize the areal sweep of the reservoir. The pattern of injectors and producers can change over time and will typically be determined based on computer simulations that model different design scenarios.
Tertiary Production Phase
Enhanced Oil Recovery (EOR) using CO2 Injection

What is needed for a CO2 project?

**Monitoring system:** At the producing wells, fluids are piped to a centralized collection facility. A well manifold allows for individual wells to be tested to see how much oil, gas and water is being produced at each location and if the concentration of oil is increasing as the oil bank reaches the producing wells.
What is needed for a CO2 project?

**Surface separation facilities:** The produced fluids are separated and the gas stream, which may include amounts of CO2, must be further processed. Any produced CO2 is separated from the produced natural gas and re-compressed for re-injection along with additional volumes of newly-purchased CO2.

In some situations, separated produced water is treated and re-injected, often alternating with CO2 injection, to improve sweep efficiency (the WAG process mentioned earlier).
Tertiary Production Phase
Enhanced Oil Recovery (EOR) using CO2 Injection

• However, since CO2 is less dense than water or oil, it tends to rise to the top of the reservoir and bypass large quantities of oil on its path to the producer, or to finger through due to its lower viscosity.

• To combat this, the CO2 is often injected in slugs alternated with water, in a process known as water alternated with gas (WAG)

• This process tends to spread out the flood front, thereby increasing the sweep efficiency.

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Tertiary Production Phase
Enhanced Oil Recovery (EOR) using CO2 Injection

Other approaches that have been developed include:

– Surfactant Alternating Gas (SAG) – Foam generated in the reservoir can address the high-permeability streaks to improve sweep efficiency

– Low-viscosity foam with CO2 gas to keep the gas from migrating upward

• There are other drawbacks to using CO2:

– Corrosion

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01 Learning from CO2 use in the Permian Basin

- Rules of thumb: what are they based on?
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The Permian Basin covering West Texas and SE New Mexico has the lion’s share of the world’s CO2 EOR activity for two reasons:

1. reservoirs there are particularly amenable to CO2 flooding
2. large natural sources of high purity CO2 are relatively close

However, a growing number of CO2 EOR projects are being launched in other regions, based on the availability of low cost CO2
Screening Reservoirs for CO2 EOR: What kinds of reservoirs are most suitable?

In theory, any type of oil reservoir (carbonate or sandstone) could be suitable provided that:

1. the minimum miscibility pressure can be reached
2. there is a substantial volume of residual crude oil remaining
3. the ability of the CO2 to contact the crude oil is not hindered by geological complexity
Screening Reservoirs for CO2 EOR: What kinds of reservoirs are most suitable?

Most of the large reservoirs in the Permian Basin are carbonate formations—typically limestone or dolomite—that produce from depths of 3,000 to 7,000 feet, and have undergone extensive waterflooding.

Post-waterflood recovery could be 30 to 45 percent of the OOIP, with relatively high residual oil saturation. A successful CO2 EOR project could add another 5 to 15 percent of OOIP to the ultimate recovery.
# Tertiary Production Phase
## Enhanced Oil Recovery (EOR) using CO2 Injection

### Screening Reservoirs for CO2 EOR Suitability

<table>
<thead>
<tr>
<th>Parameter</th>
<th>Requirement</th>
</tr>
</thead>
<tbody>
<tr>
<td>Depth, ft</td>
<td>2,000 to 9,800 ft</td>
</tr>
<tr>
<td>Temperature, °F</td>
<td>&gt;250</td>
</tr>
<tr>
<td>Pressure, psia</td>
<td>above 1,200</td>
</tr>
<tr>
<td>Permeability, mD</td>
<td>above 1</td>
</tr>
<tr>
<td>Oil gravity, °API</td>
<td>above 27</td>
</tr>
<tr>
<td>Viscosity, cp</td>
<td>below 12</td>
</tr>
<tr>
<td>( S_{or} ), fraction of pore space</td>
<td>&gt;0.25</td>
</tr>
<tr>
<td>(after waterflood)</td>
<td></td>
</tr>
</tbody>
</table>

### 01 Learning from CO2 use in the Permian Basin
- Rules of thumb: what are they based on?
- Historic and current CO2 use in PB
Screening Reservoirs for CO2 EOR: What kinds of reservoirs are most suitable?

In theory, any type of oil reservoir (carbonate or sandstone) could be suitable provided that:

4. rock and fluid characteristics

5. past production behavior and response to waterflooding

6. detailed geological assessments

7. reservoir depth

Tertiary Production Phase
Enhanced Oil Recovery (EOR) using CO2 Injection

01 Learning from CO2 use in the Permian Basin
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Tertiary Production Phase
Enhanced Oil Recovery (EOR) using CO2 Injection

Screening Reservoirs for CO2 EOR:
What kinds of reservoirs are most suitable?

In theory, any type of oil reservoir (carbonate or sandstone) could be suitable provided that:

8. oil gravity
9. reservoir pressure
10. reservoir temperature
11. oil viscosity

01 Learning from CO2 use in the Permian Basin
- Rules of thumb: what are they based on?
- Historic and current CO2 use in PB
NOTES: CO2 Availability

Although the large Permian Basin reservoirs were readily recognized as ideal candidates for miscible flooding through CO2 injection, it was the ready availability of a low-cost source of CO2 that drove the Permian Basin’s EOR boom in the 1970s and 1980s.

The first commercial flood occurred in Scurry County, Texas, in 1972, in what was known as the SACROC Unit (SACROC stands for Scurry Area Canyon Reef Operators Committee). For this project, the operator (Chevron) recovered CO2 from natural gas processing plants in the southern part of the basin (that would have otherwise been vented) and transported the gas 220 miles for injection at SACROC.
NOTES: CO2 Availability

The technical success of this project, coupled with the high oil prices of the late 1970s and early 1980s, led to the construction of three major CO2 pipelines connecting the Permian Basin oil fields with natural underground CO2 sources (Sheep Mountain, McElmo Dome, and Bravo Dome.

Construction of the pipelines spurred an acceleration of CO2 injection activity in Permian Basin fields.
NOTES: CO2 Availability

Industry has spent more than $1 billion on 2,200 miles of CO2 transmission and distribution pipeline infrastructure in support of CO2 flooding in the Permian Basin.

Typically, it costs $0.25-0.75 per thousand cubic feet to transport CO2 to West Texas fields from the sources to the north. With a substantial CO2 pipeline and distribution infrastructure in place, Permian Basin operators have spread the costs among several large fields, and the infrastructure in these “anchor” fields in turn has helped reduce the cost of delivered CO2 to smaller fields in the basin.

01 Learning from CO2 use in the Permian Basin
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Anthropogenic CO2 Sources

For years, ExxonMobil has sold CO2 from its La Barge, Wyoming gas processing facility to area oil producers for use in CO2 EOR projects. The company currently captures 4 million metric tons of CO2 annually for this purpose.
Why sequester CO2?

• 1 metric ton of CO2 equals 545 cubic meters (19.25 Mcf) at standard conditions of 14.7 psi and 70 °F

• The average American car emits about seven metric tons of CO2 per year
Tertiary Production Phase
Enhanced Oil Recovery (EOR) using CO2 Injection

• Prerequisites for a successful CO2 flood are reservoirs at depths in excess of at least 2,500ft (so that the high injection pressures are contained), and oil gravities of at least 22API

• Most CO2-EOR projects are conducted in a reservoir that is being or has been waterflooded

• Well-designed CO2 projects can recover an additional 20% of the oil originally in place

• Primary production, plus waterflooding, followed by CO2 flooding may recover as much as 60% of the total oil in the reservoir

• The recent capture of CO2 from hydrocarbon-burning industrial sites and power plants provides another source; it can be piped from these sites to appropriate oil-recovery projects
The Eagle Ford Shale

The Eagle Ford Shale is a hydrocarbon–producing formation of significant importance. It is capable of producing both gas and more oil than other traditional shale plays. It contains a much higher carbonate shale percentage: upwards of 70% in south Texas. It becomes shallower and the shale content increases as it moves to the northwest.

The high percentage of carbonate makes it more brittle and “frac-able”. The Eagle Ford Shale play trends across Texas from the Mexican border up into East Texas, roughly 50 miles wide and 400 miles long with an average thickness of 250 feet. It is Cretaceous in age resting between the Austin Chalk and the Buda Lime at a depth of approximately 4,000 to 12,000 feet. It is the source rock for the Austin Chalk and the giant East Texas Field according to the RRC.

CARBONATE ROCK

Sedimentary rock formed primarily from calcium carbonate (CaCO3) deposited in a marine environment; most commonly limestone. Many of the carbon dioxide floods found in the Permian Basin of West Texas are in oil reservoirs in carbonate formations deposited during the Permian Period.

02 Developing new knowledge for CO2 use in the Eagle Ford shale

• Location
• Current gas injection projects
• Is there a potential for CO2?
02 Developing new knowledge for CO2 use in the Eagle Ford shale

- Location
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Shale Cyclic Gas Injection: Process

- Inject hydrocarbon gas at high pressure
  - Swell, vaporize, and mobilize: Single Phase Flow above critical condition
  - Primarily cyclic injection > Servicing the SRV (Wells & fracture network)
  - Matrix penetration > 1 foot / year (project life 15+ years)

- Process is compositional: Known Technology
  - Process: PVT Phase behavior > void of displacement
  - Oil Wells > Gas condensate Wells
  - Inject Low Btu > Produce High Btu
  - Application to Unconventional NEW > Must think outside the BOX

02 Developing new knowledge for CO2 use in the Eagle Ford shale
  - Location
  - Current gas injection projects
  - Is there a potential for CO2?
Which Gas > higher recovery?

02 Developing new knowledge for CO2 use in the Eagle Ford shale

- Location
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- Is there a potential for CO2?

**Rich Gas**

<table>
<thead>
<tr>
<th>Frac</th>
<th>Meth</th>
<th>Prod</th>
<th>Rich</th>
</tr>
</thead>
<tbody>
<tr>
<td>C1</td>
<td>100</td>
<td>76</td>
<td>7</td>
</tr>
<tr>
<td>C2</td>
<td>0</td>
<td>15</td>
<td>74</td>
</tr>
<tr>
<td>C3</td>
<td>0</td>
<td>5</td>
<td>13</td>
</tr>
<tr>
<td>C4,5</td>
<td>0</td>
<td>2</td>
<td>3</td>
</tr>
</tbody>
</table>
02 Developing new knowledge for CO2 use in the Eagle Ford shale

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## Eagle Ford IOR Target: Fluid/GOR

<table>
<thead>
<tr>
<th>Region</th>
<th>GOR Range (scf/STB)</th>
<th>SG (°API)</th>
<th>Fluid Type</th>
<th>Proven Status</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>0–100</td>
<td>10.0–30.0</td>
<td>oil</td>
<td>Not Proven</td>
</tr>
<tr>
<td>2</td>
<td>100–500</td>
<td>30.0–41.4</td>
<td>oil</td>
<td>Not Proven</td>
</tr>
<tr>
<td>3</td>
<td>500–1,000</td>
<td>41.4–45.8</td>
<td>oil</td>
<td>Pilot</td>
</tr>
<tr>
<td>4</td>
<td>1,000–1,500</td>
<td>45.8–48.2</td>
<td>oil</td>
<td>Proven</td>
</tr>
<tr>
<td>5</td>
<td>1,500–2,000</td>
<td>48.2–49.8</td>
<td>oil</td>
<td>Pilot</td>
</tr>
<tr>
<td>6</td>
<td>2,000–3,000</td>
<td>49.8–52.0</td>
<td>volatile oil</td>
<td>Pilot</td>
</tr>
<tr>
<td>7</td>
<td>3,000–4,000</td>
<td>52.0–53.5</td>
<td>rich condensate</td>
<td>Not Proven</td>
</tr>
<tr>
<td>8</td>
<td>4,000–5,000</td>
<td>53.5–54.6</td>
<td>rich condensate</td>
<td>Pilot</td>
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<tr>
<td>9</td>
<td>5,000–8,000</td>
<td>54.6–56.7</td>
<td>condensate</td>
<td>Not Proven</td>
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<tr>
<td>10</td>
<td>8,000–15,000</td>
<td>56.7–59.4</td>
<td>condensate</td>
<td>Not Proven</td>
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<tr>
<td>11</td>
<td>15,000–50,000</td>
<td>59.4–63.6</td>
<td>condensate</td>
<td></td>
</tr>
<tr>
<td>12</td>
<td>&gt;50,000</td>
<td>&gt;63.6</td>
<td>dry gas</td>
<td></td>
</tr>
</tbody>
</table>

---

02 Developing new knowledge for CO2 use in the Eagle Ford shale

- Location
- Current gas injection projects
- Is there a potential for CO2?
Unconventional Gas Injection Pilot Options

• Segregated Huff-n-Puff Pilot of Well or Wells (no close neighbors)
  – See EOG Eagle Ford Martindale Pilot as example

• Cycle Pad of Wells with commercial project in mind
  – See EOG Eagle Ford Henkhaus as example

• Parent to child completion IOR (2 for 1: IOR and Pilot)
  – See EOG Steen Scruggs as example
  – Gas injection in Parent before completion of New Child Wells
  – Reduce completion risk from depleted reservoirs
  – Pilot gas injection, solve Parent/Child, produce back highly stimulated Wells
Eagle Ford Shale Field Results Study
Analytics to Simulation
Available to Purchase
see: www.shaleior.com

Shale IOR LLC

02 Developing new knowledge for CO2 use in the Eagle Ford shale
- Location
- Current gas injection projects
- Is there a potential for CO2?
Executive Summary: Eagle Ford CGEOR

- 6+ years of IOR history across 30 pads injecting produced gas
- Cyclic gas injection started by EOG with 1 Well in late 2012 then progressed to 4 Wells at a time with different cycles to pilot and understand reservoir and operational process
- EOG Projects progressed to 7 – 10 Wells injecting at one time
- Current projects use 4+ compressors, 20-30 Wells, and 40-50 MMscfd
- Recent pilots or projects by Marathon, ConocoPhillips, EP Energy, Murphy, and PetroEdge

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02 Developing new knowledge for CO2 use in the Eagle Ford shale

- Location
- Current gas injection projects
- Is there a potential for CO2?
### 2019 Shale IOR Summary Table: EOG Eagle Ford Cyclic Gas Injection

<table>
<thead>
<tr>
<th>IOR</th>
<th>Unit name</th>
<th>Date</th>
<th>Wells #</th>
<th>Spacing feet</th>
<th>Compressor Count</th>
<th>Well EUR</th>
<th>Well IOR</th>
<th>Inj Well count</th>
<th>Pad IOR bopd</th>
<th>Well IOR bopd</th>
<th>PI TOP</th>
</tr>
</thead>
<tbody>
<tr>
<td>Pad</td>
<td>Steen Scruggs</td>
<td>Nov‐12</td>
<td>1</td>
<td>1500+</td>
<td>2 &gt;0</td>
<td>160</td>
<td>146</td>
<td>1</td>
<td>250</td>
<td>250</td>
<td>10950</td>
</tr>
<tr>
<td></td>
<td>Martindale</td>
<td>Dec‐14</td>
<td>4</td>
<td>500</td>
<td>2 &gt;1 &gt;0</td>
<td>173</td>
<td>190</td>
<td>4</td>
<td>850</td>
<td>213</td>
<td>9864</td>
</tr>
<tr>
<td></td>
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**3 Pilots**  
**16 Commercial Installations**

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**02 Developing new knowledge for CO2 use in the Eagle Ford shale**

- Location
- Current gas injection projects
- Is there a potential for CO2?
Reservoir Simulation
History Match

Eagle Ford
La Salle Co, Texas

02 Developing new knowledge for CO2 use in the Eagle Ford shale
- Location
- Current gas injection projects
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02 Developing new knowledge for CO2 use in the Eagle Ford shale

- Location
- Current gas injection projects
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02 Developing new knowledge for CO2 use in the Eagle Ford shale

- Location
- Current gas injection projects
- Is there a potential for CO2?
Martindale Pilot: Simulation history match

• A significant amount of reservoir engineering has been completed to understand and guide the interpretation of IOR field history

• We believe that a compositional prediction is best practice

• Shale IOR/IRT has matched the Martindale Pilot in detail and found:
  – Gas injection rates, cycle Well count, cycle times, pressure, and fill up volumes from simulation have been guided by field history and results provide a good understanding of what is being done in the field

• We believe that there is room for IOR improvement based on our compositional understanding
  – Projects are yielding IOR Ratio = 1.75+ from decline analysis and history match predictions, however simulation results also show large uplift with optimal gas composition and cycle operations

Proprietary & Confidential

02  Developing new knowledge for CO2 use in the Eagle Ford shale

• Location
• Current gas injection projects
• Is there a potential for CO2?
Economics
Screening Tool: Input & Output Example

02 Developing new knowledge for CO2 use in the Eagle Ford shale

- Location
- Current gas injection projects
- Is there a potential for CO2?
### Eagle Ford Economics and Cash Flow: Produced Gas EOR Project

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#### Example Case
- 2 Comp & 10 Wells EUR=300mbo
- Field Matched Produced Gas
- NRI=75%

#### Screening Tool: Input & Output Example

- Developing new knowledge for CO2 use in the Eagle Ford shale
  - Location
  - Current gas injection projects
  - Is there a potential for CO2?
CO2 potential in other shale plays?

Do these other shale plays meet the criteria?

Bakken Shale & Three Forks System

Appalachian Basin (Marcellus, Utica)

Haynesville (East Texas)/Louisiana

STACK/SCOOP (Oswego, Meramec, Osage, Woodford)
CO2 potential in other shale plays?
Do these shale plays meet the criteria?