Life beyond 80 - A look at Conventional WAG Recovery beyond 80% HCPV Injection in CO2 Tertiary Floods
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Abstract
During the past 38 years, CO2 flood technology for Enhanced Oil Recovery projects evolved from a partially understood process filled with uncertainties to a process based on proven technology and experience. Many questions involved with CO2 flooding have been thoroughly analyzed and answered. This knowledge is currently being used by a limited number of companies that actually know how to design, implement, and manage a CO2 flood for long term profit. Unfortunately, this knowledge has not been disseminated to operating companies interested in EOR flooding or to CO2 Sequestration Communities interested in storing CO2 in EOR projects.

The primary objective of this report is to target “Conventional WAG Techniques” which have been used in over 90% of all the Enhanced Oil Recovery projects implemented in the Permian Basin in Texas, Colorado, Oklahoma, and Wyoming. Over the years, oil companies have reported a wide range of values of Tertiary Oil Recovery, CO2 Utilization, and CO2 Retention, resulting in a wide range of variation and uncertainty. Many of the numbers reported to date are tied to a specific HCPV CO2 Injected based on some Economic Cut-off. This typically has been in the range of 30% to 80% HCPV Injected. The question becomes “What is life after 80% HCPV?” And “What effect does life after 80% HCPV have on Tertiary Oil Recovery, CO2 Utilization and CO2 Retention in different producing formations?” Results of this study show Tertiary Oil Recovery can be as high as 26% OOIP when slug sizes exceed 190% HCPV injected.

Carbon Sequestration Options: Five Recovery Methods for Enhanced Oil Recovery (EOR)
Most Enhanced Oil Recovery Projects use one of the following five operating methods: Conventional WAG Recovery, Gravity-stabilized Recovery, Double Displacement, Gas-cycling or Huff-and-Puff. The primary difference between methods depends on the reservoir geology and well pattern configuration. In Conventional CO2 floods, typical of West Texas, the formations are basically flat (Ramp Sequence), low perm, the fields are developed on pattern spacing (e.g. 5-spot patterns, 9-spot patterns, or Chickenwire patterns), and Conventional WAG Operating schemes are used to control mobility and CO2 flood response. In conventional WAG operations, the objective is to minimize the amount of CO2 purchased (CO2 stored in Sequestration projects), which is typically in the range of range of 30%-40% of the total HCPV CO2 injected. In un-conventional Gravity-Stabilized and Double Displacement case histories, Flue Gas, CO2, Lean Gas or N2 is usually injected in the top of the structure and oil is produced from the bottom. More CO2 can be sequestered than conventional WAG operations. As much as 80% of the total pore volume can be displaced with CO2. However, the reservoir must meet certain fluid-dynamic criteria and have structure to make the gravity-stabilized process work. In Gas-cycling projects, typical of projects operated by Denbury in Mississippi, CO2 is cycled through the formation. As much as 6 pore-volumes of CO2 are injected to recover 18% OOIP. In Huff-and-Puff operations, the CO2 is injected into and produced from the same well. The objective is to mobilize tertiary oil in the near vicinity of the well-bore, and then produce the CO2 and tertiary oil back. Then repeat the process (typically with 3 cycles). The process technically works. The economic success or failure depends on many factors. The amount of CO2 sequestered is minimal when compared to the other recovery methods.

Conventional WAG Recovery
Conventional WAG Operating Methods in the Permian Basin fall into one of four categories:
1. Continuous CO2 Injection
2. Constant WAG Injection
3. Tapered WAG Injection
4. Simultaneous CO2 Injection (Limited use)
What is WAG Management?

All Conventional WAG Injection Projects have one thing in common. CO₂ is injected into the reservoir and the produced recycle CO₂ must be re-injected back into the reservoir to maximize oil recovery. This was first demonstrated by Caudle and Dyes in 1958 when water was added to CO₂ to decrease solvent mobility. As CO₂ technology was transferred from the lab to the field, most all of the Major Oil Companies in the 1970’s and early 1980’s adopted the use of Constant Water-Alternating-Gas (WAG) Injection based on the theory that alternate gas water injection is necessary to maintain mobility control and maximize oil recovery. During the late 1980’s, Tapered WAG Operations were adopted to improve the overall recovery process. WAG Injection can be best demonstrated as shown in Figure 1a and 1b.

Reservoir Modelling

Through the 1980’s and 1990’s, Amoco, Shell, Arco, Mobil, and Texaco committed significant manpower to evaluate the feasibility of full field scale CO₂ flooding in the Permian Basin. Before the initiation of field scale floods, many pilots were drilled and much reservoir simulation was conducted to understand the CO₂ flooding process. Today, there are over 82 active CO₂ projects in the United States producing over 237,000 BOPD and CO₂ flooding is expanding to many parts of the world. Reservoir simulation has been an integral part of reservoir management in understanding the CO₂ flood tertiary recovery process. Reservoir Modelling was used in the development of Tapered WAG. Simulation today is used in the initial design of slug sizes and gas-water ratios (GWR), and allows Reservoir Engineers to explore different operating scenarios that best match field performance.

The development of Reservoir Simulators over the years has permitted a greater reliability in simulating the miscible process over a wide range of injection gas-water ratios. Confidently estimating the response of the reservoir to CO₂ injection generally involves history matching Primary and Secondary performance. The model developed for this study has properties that are typical of West Texas San Andres Dolomite reservoirs. These models incorporate the latest state-of-the-art understanding of the physics and mathematics pertaining to reservoir characteristics, recovery mechanisms, and operating conditions. In 1986, the model used to develop tapered WAG was simulated with Amoco’s GCOMP simulator in Blackoil mode with a miscible option (3 hydrocarbon component model). This model implies the solvent mixes with the reservoir oil in all proportions with no phase separation. Today, Compositional Simulation is being used to simulate the miscible process.

Model Development

For this analysis, it was important to determine if the predictions generated by the simulator reasonably agreed with actual field performance. The model used in this study incorporates historical production and injection waterflood performance from the Slaughter Estate Unit in Slaughter field and scaled to a single five-spot pattern. In addition, lessons learned from full-field CO₂ flooding experience provided additional insight of both reservoir heterogeneity and understanding of the complex CO₂ flood process. The Model represents an inverted 5-spot (10X10X6 Grid) Well Configuration with Injector in the middle and one-quarter Producers located on the corners. The model contains six layers with phi-h and k-h varying areally. The model contains both a Primary Recovery Period as well as a Secondary Recovery Period of water injection. Reservoir Parameters are shown on the next page in Table 1.
Table 1 – Model Grid Properties (General)

<table>
<thead>
<tr>
<th>Average Model Properties</th>
<th>Average Pattern Properties</th>
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<tr>
<td>Model Type</td>
<td>Pattern Type</td>
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<tr>
<td>Average Pattern (5-spot)</td>
<td>Primary and Secondary</td>
</tr>
<tr>
<td>Model - Primary and</td>
<td>Model - Primary and</td>
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</table>
| Production and Injection | Injection History for the 25-acre model are shown on Figures 2a, 2b, 3a, and 3b. For the 25 acre model, Primary Oil Rate peaked around 125 BOPD and Secondary Oil Rate peaked around 215 BOPD.

Model – Primary and Secondary Recovery

Historical Oil Production Rate

- Conventional WAG Model
- Waterflood Base Prediction
- Historical Oil Production Rate

[Figure 2a. – Historical Production Performance]

Historical Water Injection and Production

- Conventional WAG Model
- Waterflood Base Prediction
- Historical Water Injection and Production

[Figure 2b. – Historical Injection Performance]

Historical GOR and Water-Cut

- Conventional WAG Model
- Waterflood Base Prediction
- Historical GOR and Water-Cut

[Figure 3a. – Historical GOR, Water-Cut]

Historical Oil Recovery (Primary and Secondary) - % OOIP

- Conventional WAG Model
- Waterflood Base Prediction
- Historical Oil Recovery (Primary and Secondary) - % OOIP

[Figure 3b. – Historical Oil Recovery Performance]

When conducting Tertiary CO₂ predictions, Historical Primary plus Secondary Waterflood Performance is a key parameter to achieving high Tertiary Oil Recovery. The Primary and Secondary waterflood oil recovery performance shown above is considered “Good” waterflood response when Primary plus Secondary Recovery exceed 40% OOIP. When waterflood performance is less than 40%, Tertiary Performance Predictions should be scaled-down to match historical performance.
Optimization Case Comparisons - Case Studies (20% HCPV to 80% HCPV Injected)

Future Predictions under any type of Recovery Mechanism are a very important aspect of any type of Economic Analysis. For Optimization, the factors which influence CO₂ Flood Economics are: (1) Oil and He-gas Price, (2) CO₂ Plant and Pipeline Capital Investment Costs, (3) CO₂ Purchase Costs (including Pipeline Tariffs), (4) CO₂ Plant Processing Costs, (5) Field Operating Costs (Workover and Lift), and (6) Overhead.

Tertiary Oil Recovery (No Economics)

Tertiary Oil Recovery under CO₂ Injection is a function of the total amount of CO₂ Injected. As shown in Figure 4a, comparing total CO₂ HCPV injection between cases assuming a 1.0 BOPD cutoff (No Economics), Reservoir Recovery for the three operating methods are statistically the same. When economics are applied to each of the cases, Figure 4b, the amount of Tertiary Oil Recovered and Present Value Economics are different between cases. Based on Economics, a 30% HCPV CO₂ Slug is Economically Optimum for Continuous CO₂ Injection, a 50% HCPV CO₂ Slug is Economically Optimum for Constant WAG Injection, and a 70% HCPV CO₂ Slug is Economically Optimum for Tapered WAG Injection.

Economic Comparison - Tertiary Oil Rate and Oil Recovery

Oil Production Rate and Tertiary Oil Recovery comparing the three Economic cases are shown above on Figures 5a and 5b. The total amount of CO₂ injected determines the amount of Tertiary Oil Recovered. The greater the amount of CO₂ injected, the greater the Tertiary Oil Recovery. The objective in a CO₂ flood is to accelerate the CO₂ Injection as quickly as possible, without fracturing the reservoir. Continuous Injection accomplishes this goal. Constant WAG Injection has the ability to control reservoir sweep, extending CO₂ Flood life. Tapered WAG Injection combines the best of both. In addition to accelerating the front end Economics, it also recovers the most tertiary reserves.
CO₂ Production and its associated Plant Investment is a major component in Economic analysis. A tapered WAG operating scenario extends tertiary oil recovery beyond Continuous and Constant WAG operations by controlling CO₂ production by “Level-loading Inlet Plant Rate CO₂ Production” to a plant inlet rate to control costs.

The Total CO₂ Slug Size consists of two parts. The CO₂ Purchase portion always occurs at the start of the project. The Recycle Portion, which is the CO₂ recovered through production, is processed through a plant and injected back into the reservoir. The volume purchased and the purchase times for injection are dependent on the total CO₂ slug injected. In Tapered WAG designs, CO₂ is purchased throughout the life of the CO₂ flood. As shown above, the amount of CO₂ purchased declines as the tertiary flood matures.

CO₂ Sequestration
The amount of CO₂ Purchased in EOR operations is also the amount of CO₂ Sequestered in CO₂ Sequestration projects. As shown above in Figure 7b, this amount is typically in the range of 30% to 40% of the total HCPV injected. Separate from CO₂ Retention, which is the amount of CO₂ retained as a percent of total amount of CO₂ injected, the amount of CO₂ stored in the reservoir or sequestered is always 100% of the CO₂ purchased volume.
The key to Optimization is the ability to control CO₂ processing costs. This is accomplished by injecting water as a mobility control agent. For this study, increasing half cycle water volumes occurred every 10% HCPV Inj CO₂. This resulted in a nearly flat CO₂ production response to “Level Load” CO₂ Gas Production Rate to a “Plant Inlet Rate”.

**Economic Comparison – Gross CO₂ Utilization and Net CO₂ Utilization**

**Economic Comparison – CO₂ Retention**

CO₂ Utilization is an efficiency measure of how much CO₂ is used to recovery a barrel of Tertiary Oil. Gross Utilization is defined as the Cumulative Total amount of CO₂ Injected per total amount of Tertiary Oil Produced, typically 10 to 20 MSCF/BO. Net CO₂ Utilization is defined as the Cumulative Purchased amount of CO₂ per total amount of Tertiary Oil Produced, typically in the range of 5-10 MSCF/BO.

CO₂ Retention is an Engineering term used to relate the total amount of CO₂ retained in the reservoir to the total amount of CO₂ injected. It represents the percent of Cumulative CO₂ Injected minus Cumulative CO₂ Produced divided by the amount of Cumulative CO₂ Injected. As the CO₂ flood matures, the retention will decrease from 100% to some minimum value.
Life beyond 80% HCPV - Tapered WAG Injection (20% HCPV to 190% HCPV Injected)

The question becomes “What is life after 80% HCPV?” And “What effect does life after 80% HCPV have on CO₂ Utilization and CO₂ Retention in different producing formations?” The answer to those questions is shown below.

Life beyond 80% HCPV - Tertiary Oil Rate and Oil Recovery

Oil Production Rate and Tertiary Oil Recovery comparing the extended CO₂ Slug size from 20% HCPV to 190% HCPV

Figure 11a – Tertiary Oil Rate (Tapered WAG)

Figure 11b. – Tertiary Oil Recovery (Tapered WAG)

As shown above, extending Total CO₂ slug size beyond 80% HCPV extends Tertiary Oil Recovery. A 190% HCPV slug size improves Tertiary Oil Recovery to 26% OOIP.

Factors that control Tertiary Oil Recovery

The ability to achieve High Tertiary Recovery in New CO₂ floods depends on the following factors:

1. Large Original Oil-in-Place
2. Rock Type: Dolomite and Sandstone better than Limestone, Un-fractured Formations better than Fractured Formations
3. Good Pattern Development – Fields with many patterns achieve the highest tertiary recovery
4. Historical Primary and Secondary Waterflood Performance (Prim + Secondary Rec should be above 40% OOIP)
5. Primary + Secondary + Tertiary Recovery less than 70% OOIP (CO₂ will never remove all the oil)
6. CO₂ miscible with the oil (100% efficiency is best but can be operated below MMP)
7. Good Reservoir Conformance between injectors and producers
8. Good Porosity, Good Permeability, and Good k/phi distribution
9. Good Residual Oil Saturation Target (Approx. Range: Dolomites – 30%, Cherts – 25%, Sandstones – 20%)
10. Good Economics: High Oil Price, Low CO₂ Purchase Price, Low Recycle Plant and Field Capital Investments
11. CO₂ Source that is reliable and of high quality (Pipeline in close proximity)
12. Conventional WAG should be able to Sequester or STORE 30% to 40% HCPV (CO₂ Purchase Volume)
Life beyond 80% HCPV- (Tertiary Oil Recovery, CO₂ Gross and Net Utilization)

Since 1972, over 100 Commercial CO₂ floods have been operated in the United States, with 72 of these projects still active today. During this time, Engineers have reported a wide range of Tertiary Oil Recovery, Gross Utilization and Net Utilization values at varying stages of maturity. The question becomes “What would Operators report on these CO₂ floods today?” And “What would Oil Recovery, Gross Utilization and Net Utilization look like under Extended CO₂ Slug volumes?” The answer to those questions depends on Reservoir Type. Data from these CO₂ projects from various SPE and DOE reports are listed below by formation type:

### Table 2. San Andres and Grayburg Formation – Dolomite

<table>
<thead>
<tr>
<th>State</th>
<th>Formation</th>
<th>Field</th>
<th>Lease</th>
<th>Current Economic</th>
<th>Life beyond 10% HCPV</th>
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<tr>
<td>Texas</td>
<td>San Andres</td>
<td>Vazquez</td>
<td>Denton Unit</td>
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<td>Gross CO₂ Utilization (MSCF/TSTB)</td>
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### Table 3. Clearfork Formation – Limestone (Tight - Low Permeability)

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<td>Texas</td>
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<td>Auction Hill</td>
<td>Tertiary Recovery (20X10³bbl)</td>
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<td>Net CO₂ Utilization (MSCF/TSTB)</td>
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### Table 4. Devonian Formation – Tripolitic Chert

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<td>Dolomite</td>
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<td>Gross CO₂ Utilization (MSCF/TSTB)</td>
<td>Net CO₂ Utilization (MSCF/TSTB)</td>
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### Table 5. Canyon Reef Formation – Karsted Limestone (High Permeability)

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<th>State</th>
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<td>Texas</td>
<td>Canyon Reef</td>
<td>Kelly</td>
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<td>5 to 10</td>
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| Texas | Canyon Reef | Salt Creek | Salt Creek | Tertiary Recovery (20X10³bbl) | Gross CO₂ Utilization (MSCF/TSTB) | Net CO₂ Utilization (MSCF/TSTB) |
|       |           |       |       | 5 to 10         | 10 to 15              | 10 to 15               |

| Texas | Canyon Reef | South Ridge | South Ridge | Tertiary Recovery (20X10³bbl) | Gross CO₂ Utilization (MSCF/TSTB) | Net CO₂ Utilization (MSCF/TSTB) |
|       |           |       |       | 5 to 10         | 10 to 15              | 10 to 15               |

| Texas | Canyon Reef | Cogdell | Cogdell | Tertiary Recovery (20X10³bbl) | Gross CO₂ Utilization (MSCF/TSTB) | Net CO₂ Utilization (MSCF/TSTB) |
|       |           |       |       | 5 to 10         | 10 to 15              | 10 to 15               |

| Texas | Canyon Reef | Cogdell | Cogdell | Tertiary Recovery (20X10³bbl) | Gross CO₂ Utilization (MSCF/TSTB) | Net CO₂ Utilization (MSCF/TSTB) |
|       |           |       |       | 5 to 10         | 10 to 15              | 10 to 15               |
Table 6. - Strawn, Morrow, Delaware, Springer, Marmaton, and Yates (Fluvial Deltaic, Point Bar, Turbidite)

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Table 7. - Tensleep, Mesaverde Almond, Weber, Sprayberry (Fractured Sandstone)

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<td>Colorado</td>
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<td>Sprayberry</td>
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Table 8. - Heavy Oil

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<td>California</td>
<td>Ranger</td>
<td>Wilmington (Dawson)</td>
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<td>Arizona</td>
<td>Chinook_Sand</td>
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Conclusion

With more than thirty-eight years of successful enhanced oil recovery (EOR) projects in the Permian Basin (Texas), Mississippi, Wyoming, Colorado, California, Oklahoma, and several countries worldwide, carbon dioxide CO2 flooding is a proven method for extending field life. CO2 acts as a solvent to overcome forces that trap oil in tiny rock pores, helping sweep immobile oil left after primary or secondary recovery operations. Generally, CO2 is not miscible at first contact with reservoir oils, but miscibility can be developed in reservoirs above or near the Minimum Miscibility Pressure (MMP). CO2 can attain miscibility through a multiple-contact process that vaporizes or extracts both intermediate and higher molecular weight hydrocarbons from the reservoir oil. The CO2 phase picks up many intermediate hydrocarbon components from the oil, swells the oil, and reduces oil viscosity, making it mobile to move through the rock.

Advances in technology and reservoir understanding have made detailed evaluation of potential EOR candidates obtainable within months, not years. In addition, improved reservoir management and innovative investment plans have significantly reduced risks and increased rewards. Many of the original questions about CO2 flooding involved the displacement efficiency of the process, how CO2 would interact with the oil, and how much oil could be recovered. Many of these questions have been answered with better reservoir management tools. Not all fields are good candidates for CO2 Tertiary Recovery. A reservoir must contain certain characteristics for a CO2 flood to be successful. In the past, it was thought the oil must be found at depths sufficient to allow for high pressures, so that CO2 and oil develop total miscibility. This is not necessarily correct. Most CO2 floods operate at reservoir pressures that are above their minimum miscibility pressure. But today, it is not uncommon to find CO2 projects that operate below or near the minimum miscibility pressure. The CO2 still produces tertiary oil. The process is not as efficient as that operated above the minimum miscibility pressure. Most historical CO2 floods have targeted reservoirs that have a gravity of 25 API units or greater, but low API Gravity reservoirs are also targets. For example: Wilmington field in California produces 14 API Gravity crude from the Ranger formation. Three pilots were conducted in Fault Blocks I, III, and V. Eventhough economic performance was reported poor, mostly due to an inadequate CO2 source and low oil price environment, a good number of wells increased oil rate from 30 BOPD to over 300 BOPD after CO2 was injected. CO2 has the ability to affect the full C2 through C30+ compositional range. Whereas, Nitrogen, and in some cases flue gas injection, will only extract the lighter components (C2 through C6). In addition, a high percentage of intermediate hydrocarbons in the oil composition can be beneficial in making the overall recovery process more efficient. If these occur naturally in the oil, then the oil will probably contain a low value of Minimum Miscibility Pressure (MMP). If the oil has a high MMP, then additions such as propane, butane, condensate, or other types of hydrocarbons can be added to the CO2 injection stream to lower the minimum miscibility pressure and improve overall oil recovery.
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Conventional WAG CO₂ Flood History

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