Abstract

During the past 45 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. The purpose of this report is to help disseminate this knowledge to operating companies interested in EOR flooding or to CO₂ Sequestration Communities interested in storing CO₂ in EOR projects.

In 2015, Merchant Consulting published CMTC-440075-MS “Life beyond 80 – A look at Conventional WAG Recovery beyond 80% HCPV Injection in CO₂ Tertiary Floods”. The primary objective of the report was to target all 10 CO₂ Recovery Methods used today including “Conventional WAG Techniques” which have been used in over 90% of all the Enhanced Oil Recovery projects implemented to date. These include projects in the Permian Basin in Texas, Colorado, Oklahoma, and Wyoming. The paper presents answers to the question “What is life after 80% HCPV Injected?” 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.

Conventional WAG History in CO₂ Tertiary Oil Projects:

To achieve CO₂ Injection beyond 80% HCPV Injection requires proper CO₂ WAG Management. The purpose of this report is to provide both the EOR and CO₂ Sequestration Communities an understanding of the “History of Conventional WAG” and how it has changed from first introduced in the Lab in the 1950’s, to how it was implemented and developed in the 1980’s by the Major Oil Companies in the Permian Basin, and how Conventional WAG is being managed today in the field.
Introduction – CO₂ Flooding

CO₂ Flood History
The Permian Basin has had over 85+ years of oil production history and produced over 30 billion barrels of oil and represents the 3rd largest petroleum producing area in the United States after the Gulf of Mexico and Alaska. In 1972, CO₂ injection was first introduced commercially in the Sacroc Field. Today, over 1.3 billion barrels have been produced with CO₂ and accounts for over 250,000 BOPD from over 17,000 production wells and 14,000 CO₂ injection wells, through 4,500 miles of pipeline.

What makes CO₂ Tertiary Oil Recovery Work?
The reason why CO₂ works is simple. The CO₂ acts as a solvent when injected into the reservoir and swells the Residual Oil (oil left after water flood) and reduces its viscosity. This causes the Residual Oil to swell and become mobile and be produced.

The amount of Tertiary Oil Recovered and the amount of CO₂ Trapped or Sequestered is dependent on the rock type. In addition to mobilizing residual oil saturation, a portion of the CO₂ becomes trapped. In the Petrophysical world, this is known as Relative Permeability Hysteresis or Trapping of the Non-wetting Phase. In this case CO₂ is the non-wetting phase. As demonstrated above, this phenomenon occurs in Water Wet Rocks (Sandstones), Intermediate Wet Rocks (Sandstones or Carbonates), and in Oil Wet Rocks (Dolomites and Limestone formations).
**CO₂ Tertiary Recovery Methods**

**Introduction**

CO₂ Tertiary Recovery Processes to date encompass “Ten” Recovery Methods. Four of these methods are used in the Permian Basin. Conventional WAG Techniques have been used in over 90+% of the CO₂ floods around the World. The Seminole field example presented in this report is an example of a field operated under Conventional WAG that targets both the Main Pay and ROZ zones.

**Carbon Sequestration Options: Ten Recovery Methods for EOR**

Most Enhanced Oil Recovery Projects use one of the following ten operating methods: Conventional WAG Recovery, ROZ Recovery, Gravity-stabilized Recovery, Double Displacement, Gas-cycling Huff-and-Puff, Heavy Oil-California, Shale Oil (Bakken, Wolfcamp), Horizontal Well Pattern Development, and CO₂ Gas Drive w/ Nitro Boost. 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%-50% 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. 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. In California the Wilmington field had three CO₂ pilots in 14 API Gravity Crude. Recovery was comparable with West Texas Operations. Shale Oil with CO₂ is still under investigation. Horizontal Well CO₂ floods are operational in Aneth field in Utah and Weyburn field in Canada. The Gravity Drainage case with added Nitro-Boost was developed for rate acceleration cases where nitrogen follows CO₂ Injection.
**CO₂ Storage - Mis-conceptions about EOR**

Over the years, there have been many mis-conceptions and half truths developed about EOR and its ability to store CO₂.

The **first mis-conception** about CO₂ flooding deals with ranges of Tertiary Oil Recovery reported over the years. In the 1990’s, most all of the major oil companies reported tertiary oil recovery in the range of 10%-12% OOIP with a 30%-40% HCPV CO₂ slug size. By 2000, this number grew to 18% OOIP recovery with an 80% slug size. Today, expected recoveries in certain fields are expected to exceed 26% OOIP with 190% HCPV CO₂ injected. However, NOT all fields will achieve this level of oil recovery. Each CO₂ project must be judged on its own merits.

The **second mis-conception** about CO₂ flooding deals with the amount of CO₂ Storage in EOR operations. Normal EOR operations have always stored or trapped CO₂ in the reservoir. Tertiary recovery is a displacement process. For the EOR process to work, CO₂ must be cycled through the reservoir, similar to water flood operations. The CO₂ acts as a solvent to swell the remaining oil left after water flood and decreases the oil’s viscosity; thus, allowing the tertiary oil to flow. Three phase relative permeability dictates the amount of CO₂ trapped in the formation due to phase trapping. From existing CO₂ flood evaluations, this equates to the amount of CO₂ purchased and represents approximately 30%-40% of the Hydrocarbon-Pore-Volume. With extended WAG with CO₂ volumes exceeding 125% HCPV, the storage capacity could increase to 50%-60% HCPV, but involves large volumes of CO₂ through-put with little incremental gain in oil recovery.

The **third mis-conception** deals with throughput Injection Rate and Injection Pressure (Water Injection or CO₂ Injection). All reservoirs have a Maximum Through-put Rate that can be injected into the reservoir. The maximum amounts of CO₂ that can be stored in a reservoir are based on a number of factors. These include: The total number of production and injection wells available, pattern configuration, current reservoir pressure, fracture pressure, injection flow capacity (permeability-thickness (kh) of each injection well), and relative permeability. Most water flood operations operate at or near fracture pressure. The same is true for CO₂ floods. The objective is to provide maximum CO₂ throughput rate across the reservoir at a level that maintains good seal integrity.

The **fourth mis-conception** about CO₂ flooding deals with the Total CO₂ Storage Capacity of a reservoir. To date, all CO₂ floods operate with the intent to minimize the amount of CO₂ purchased. Under these conditions, CO₂ is purchased up-front and cycled through the reservoir until the revenue from the oil and hc-gas production doesn’t have the ability to support the cost to recover the oil (abandonment). This date has been very elusive to determine. Of all the CO₂ projects operated to date, most are still operating today. A limited few projects have been shut-in due to a low oil price environment, but could be returned back to production if given the right economic conditions.

The **fifth mis-conception** about CO₂ flooding deals with CO₂ Storage Timing. Is it at the beginning? Does it occur during EOR CO₂ operations? Or, is it at the end of EOR operations? For those advocating a switch from EOR to CO₂ Storage two-thirds though or near the end of the EOR project should think through the physics. You can’t fool Mother Nature. The amount of CO₂ TRAPPED, STORED, OR SEQUESTERED is dependent on the Composition of the Residual Oil Saturation and Phase Trapping of the Non-Wetting Phase, which occurs throughout the life of CO₂ injection, with 75% of CO₂ storage occurring during the first one-third of the project’s life. After this initial period, most of the CO₂ that is injected is re-cycle CO₂ from the CO₂ recovery plant. CO₂ purchases near the end of the life of an EOR project are minimal.

The **last mis-conception** deals with achieving Total CO₂ Storage Potential of the reservoir. Currently there are ten methods used by the industry to recover oil with CO₂. All target the remaining tertiary oil. None target the water. The Eleventh Recovery Method which targets CO₂ storage removes both the CO₂ and Water from the reservoir. In a World where there is an infinite amount of CO₂ available for storage, the remaining water in the reservoir becomes a commodity target along with the oil. Under this scenario, the objective will be to displace as much of the remaining oil plus water from the reservoir and replace it with CO₂. Since seal integrity will always be maintained below formation parting fracture pressure, the additional storage capacity provided by removing both the oil and water would far exceed EOR storage operations alone.
Conventional WAG Techniques

Conventional WAG Techniques have been used in over 90% of the CO₂ Floods implemented today. They are designed to work well in reservoirs that are developed on pattern spacing. These include: Five-spot, Nine-spot, and Chickenwire pattern development. The objective is to “Level Load” produced gas production to a CO₂ Recovery Plant inlet gas rate, which extends field life and recovers more tertiary oil.

Today, most operators have adopted the Tapered WAG approach to optimize WAG management.

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 or Hybrid WAG Injection
4. Simultaneous CO₂ Injection (Limited use)

What is WAG Management?

Through the 1980’s and 1990’s, Amoco, Shell, Arco, Exxon, 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. The results are presented below.

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 Turek, 1,102. 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 1990’s, Tapered and Hybrid WAG Operations were adopted to improve the overall recovery process 2,3,4,5, 6,104,105. During the WAG process, CO₂ and Water are injected into the reservoir in alternating CO₂ and water slug sizes time periods. For Constant WAG operating schemes, the half cycle slug size is typically fixed for example at 1.0% HCPV CO₂ for the Gas Cycle and 1.0% H₂O for water. For Tapered Wag projects, WAG Ratios change with time. “Wetting the WAG” or increasing water half cycle volume with time improves conformance by slowing the gas in the fast zones. The water half cycle can be increased or decreased to improve overall conformance or adjusted to “Level Load” gas production to a Plant inlet rate.
**Conventional WAG History**

**Lab Experiments in the 1950’s and 1960’s**

Conventional Water-Alternating-Gas (WAG) was originally discovered in the 1950’s when Caudle and Dyes introduced water in Lab experiments to decrease gas mobility. During the 1960’s over 150 small scale Miscible and Immiscible projects were implemented across the United States by labs and oil companies interested in developing Enhanced Oil Recovery for additional recovery of oil beyond Waterflood operations.

**Permain and Rocky Mountain Basins History of “WAG”**

- **1950’s and 1960’s**
  - Conventional Water-Alternating-Gas (WAG) was originally discovered in the 1950’s when Caudle and Dyes introduced water in Lab experiments to decrease gas mobility.
  - During the 1960’s over 150 small scale Miscible and Immiscible projects were implemented across the United States by labs and oil companies interested in developing Enhanced Oil Recovery for additional recovery of oil beyond Waterflood operations.

**CO₂ Flooding in 1970’s**

**First Commercial Scale CO₂ Flooding in 1970’s**

Chevron, who operated the Sacroc Unit in the Permian Basin, was the first field to inject CO₂ as a commercial project in 1972. Chevron injected CO₂ over the total unit with less than 15% in any one pattern and sold the property in 1992 to Pennzoil. Pennzoil ramped up CO₂ Injection and implemented a 300 acre pilot in the middle of the field of which 1/3 of the total field’s production out of 55,000 acres was being produced from the pilot area. In 1998, Pennzoil sold the field to Devon and Devon then sold the field to Kinder Morgan in 2000. Kinder Morgan then ramped-up CO₂ injection to over 900 MMSCFIPD. The result was a Tertiary oil response growth from 9,600 BOPD to over 30,000 BOPD.

**Permain Basin - 1970’s to 2017**

**“First Commercial CO₂ Flood - 1972” Sacroc Unit in Kelly Snyder Field**

**Sacro Unit – Historical Performance**

**Chevron Ownership**

- First Commercial CO₂ flood in 1972
- 1992 - 1999

**Pennzoil Operatorship**

- Kinder Morgan Operations
- 2000 to Present

Over the course of CO₂ Tertiary History, the Sacroc Unit has had several operators over time

Chevron should be commended for implementing the first Commercial CO₂ flood in 1972

Pennzoil and Devon operated in the 1990’s, but lacked the capital to make large scale investments

Kinder Morgan which in 2003 ramped up CO₂ Purchases bringing oil production to 30,000 BOPD in 2017
Chevron should be commended for implementing the first Commercial CO₂ flood in the United States, but only sprinkled CO₂ over the total reservoir limit.

Pennzoil in 1996 implemented a 300 acre Centerline Pilot Project which produced one third of the fields 9,600 BOPD production. In 1998, Pennzoil sold the field to Devon who later sold the field to Kinder Morgan in 2000.

In 2000, Kinder Morgan implemented a multi-phase Tertiary Development Plan that increased CO₂ Injection to over 800 MMSCFIPD, which resulted in a 30,000 BOPD Response still seen in 2017.
**CO₂ Flooding in 1980’s**

In the 1980’s, major oil companies including Shell, Amoco, Texaco, Arco, Phillips, Oxy, and Exxon implemented CO₂ projects in many of the large fields located across the Permian Basin, Rockies, and Gulf Coast Regions. As reported by the major oil companies, expected tertiary recovery was typically in the 8% to 12% OOIP range. Optimum slug size for most projects was projected to be in the 30% to 40% HCPV CO₂ injection range.

In the 1980’s, Major Oil Companies also implemented different types of CO₂ Recovery Methods to both experiment and determine which process works best. Each will be discussed below.

**Permian and Rocky Mountain Basins History of “WAG”**

1980’s Large Scale Permian Basin and Rocky Mountain Expansions

- Slaughter field three projects plus Wasson ODC Unit – Amoco’s Tapered WAG
- Wasson field Denver Unit – Shell’s Continuous Injection area plus DUWAG
- Wasson field Willard Unit - Arco’s Area Wide WAG went to Individual Patterns
- Seminole field – Amerada Hess’s Constant WAG scheme
- Rangely field – Chevron’s Wide Area WAG scheme
- Bairoil (Lost Soldier and Wertz field) – Amoco’s Tapered WAG
CO₂ Flooding in 1980’s (Amoco – Tapered WAG)

Amoco initiated CO₂ injection into four floods in the mid 1980’s. These included: Slaughter Estate Unit, Central Mallet Unit, and Frazier Unit in Slaughter field plus Wasson ODC in Wasson field. All initially were operated under a constant WAG. During this time frame, extensive modelling was conducted to determine a method that could optimize the WAG process and extend oil recovery. The result was “Tapered WAG” which provided the means to “Level Load” total gas production from the field to a maximum “Plant Inlet Gas Rate”. In 1989, Amoco implemented this new technology into all four projects, achieving total success.

As this technology improved, advancements in CO₂ flood design have been implemented into more improved reservoir management practices. In the 1990’s, Constant WAG was being replaced with Tapered WAG operations and tertiary oil recovery increased to 18% of a field’s Original Oil-in-Place. Today, most fields implemented during the 1980’s have surpassed the 40% HCPV injection, advancing to or passing earlier HCPV CO₂ predictions.

“Tapered WAG Management” can provide Reservoir Engineers with a “Reservoir Management Tool” that can properly manage WAG, but only through proper “Reservoir Management Practices”
CO₂ Flooding in 1980’s Wasson Field (Shell, Arco, and Amoco)
Shell, in the Denver Unit of Wasson field took a different approach to understanding CO₂ management. It first divided the Denver Unit up into three project areas. The main area was a Continuous Injection project where they targeted 4% HCPV/per year, the second project area was a Constant WAG injection area (DUWAG Area) where they targeted 2% HCPV/year CO₂ and 2% HCPV/year Water. The final injection area in the western part of the unit was poorer quality reservoir and remnants of a gas cap. As technology improved, advancements in CO₂ flood design were implemented into reservoir management practices by Shell through the 1990’s. The nine-spot inverted line drive configuration was changed to more of a direct line drive after conformance issues were identified in the field based on performance and pattern adjustments could better control conformance issues.

1980’s Tertiary CO₂ Flooding
Permian Basin (Wasson Field)

The Wasson field recovers Tertiary Oil from the San Andres Formation about 5,500 ft. deep from various leases and operators located across this large field and contains a large Residual Oil Zone (ROZ).  

Arco, in the Willard Unit first implemented an area wide switching program based on making large area switches. The reservoir responded with some injectors taking 4% HCPV where others may have had 1% HCPV injected. Due to pattern imbalance issues, Arco then switched to an individual pattern WAG management program.

1980’s Tertiary CO₂ Flooding
Permian Basin (Wasson Field)

Amoco, in 1989, at the same they implemented Tapered WAG in Slaughter field, implemented a Tapered WAG at Wasson ODC Unit to “Level Load” gas production to its Ryan Holmes Plant Gas Rate Limit. As a result, the benefit of modifying to a Tapered WAG extended Tertiary Oil Recovery way beyond all of Amoco’s original model predictions.
CO₂ Flooding in 1980’s (Amerada Hess – Seminole San Andres Unit – Constant WAG)
The best example of CO₂ Tertiary Recovery is the Seminole San Andres Unit in the Permian Basin. The field has undergone Primary, Secondary Waterflood, CO₂ Tertiary operations in the Main Pay, and in 1996 initiated CO₂ Tertiary operations in the Residual Oil Zone (ROZ).

The Seminole field was discovered in 1936 with water injection operations initiated in 1971. Under Primary Recovery the field would have only recovered 12.8% of its Original Oil-in-Place (OOIP). With Secondary Waterflood operations, the field would have recovered 42.7% of its Original Oil-in-Place.

Tertiary CO₂ Injection operations into the Main Pay Zone was initiated in 1983. Under CO₂ Injection the field’s Main Pay Section is expected to recover an additional 24% of its Original Oil-in-Place (OOIP).
Seminole San Andres Unit – (Main Pay Oil Zone Example)
Primary, Secondary, and CO₂ Tertiary Main Pay Oil Recovery as a percent of Original Oil-in-Place (OOIP) are shown below. Under Primary Operations, the field would have recovered 12.8% of its OOIP before abandoning operations. Water flood operations would have increased oil recovery to 42.7% OOIP (Primary plus Secondary). Tertiary operations with CO₂ in the Main Pay zone would have increased oil production by 24% OOIP. Total Primary+Secondary+Tertiary (MP) = 66.6% OOIP.

Seminole San Andres Unit – (Main Pay – Amerada Hess WAG Management)
The Main Pay Zone was developed on Inverted a Nine-spot Pattern development. In 1983, the field initiated CO₂ injection into a phased-in pattern development across the field. By 1987, 95% of the CO₂ flood had been completed south to the town of Seminole. Amerada Hess’s WAG Management was based on a 2:1 WAG Ratio with 3.0% HCPV CO₂ Half cycles and 6.0% HCPV Water Half Cycle. The field has maintained or increased the water to better control gas breakthrough over time.

Seminole San Andres Unit – (Residual Oil Zone (ROZ) Example)
A Residual Oil Zone (ROZ) is created when oil within the original oil column migrates away from the field over geologic time creating a ROZ interval. In addition to the Main Pay Zone, the Seminole field contains a very large Residual Oil Zone (ROZ). The size of the ROZ is about the same size at the residual oil remaining in the Main Pay. CO₂ Injection commenced in 1996 into the ROZ. Injection into the ROZ will extend field life beyond the 2050’s.

Bibliography References: 58 thru 65
The Residual Oil Zone is responding well to CO₂ Injection. Since the ROZ reserves have never been tied to any Basin Study Estimates, these reserves are “NEW” bookable reserves. Future Performance is based on ROZ reservoir characterization unique to the Seminole field. Tertiary Performance is expected to be similar to that of the Main Pay or better, which depends on the quality of the ROZ pay section.

**Residual Oil Zone (ROZ) Enhanced Oil Recovery Potential**

Compared to other types of oil recovery mechanisms, CO₂ is the best method designed to recover tertiary oil from Residual Oil (ROZ) Zones. Residual Oil Zones have been identified across the World. The Permian basin is the first region to identify it, characterize it, and now exploit it. Advanced Resources International has estimated the ROZ in the Permian Basin could contain as much as 30 Billion barrels of recoverable tertiary oil from the ROZ. The Wyoming Enhanced Oil Recovery Institute has estimated the state of Wyoming may contain as much as 800 to 1,200 million barrels of ROZ potential in the Big Horn Basin of Wyoming, not counting potential in other basins in the region.

Anthropogenic CO₂ through CO₂ sequestration could expand this target to areas of the World that contain ROZ zones, but lacked the CO₂ to make the projects economically attractive.
**CO₂ Flooding in the 2000’s (New Millennium)**

In the 21st Century, the benefit of controlling the CO₂ WAG process has extended oil recovery to new levels. As previously shown, the Seminole Main Pay CO₂ flood in the Permian Basin is expected to recover 24% of its Original Oil-in-Place with a 140% HCPV injection of CO₂, not counting the additional recovery from the ROZ.

However, not all CO₂ floods are alike; Tertiary Oil Recovery from sandstone reservoirs are different from recovery from carbonate reefs just as un-fractured reservoirs are different from fractured reservoirs.

Tertiary Oil Recovery with CO₂ has also weathered Four Oil Price Adjustment Periods with the last one in 2015 dropping 45% just like the one back in 1986 that also dropped oil price by 45%. Today, over 90% of the CO₂ Floods that were put on in the 1980’s are still producing today. This could only be accomplished through good Reservoir Management Practices including the “Pattern Review Process” where WAG adjustments are made.
CO₂ Flooding in the Rocky Mountains (WAG Management Decisions (The Good, the Bad, and the Ugly))

Different Operators in the 1980’s developed different WAG philosophies depending on the reservoir pattern configuration, formation dip, reservoir pressure, miscibility pressure, etc. As technology improved, advancements in CO₂ flood design were implemented into reservoir management practices to improve overall performance. However, companies should be aware that NOT all reservoirs are alike even though they were formed in the same geologic time period with similar producing characteristics.

The example shown below illustrates the fact that not all reservoirs are alike. The Rangely Weber Unit in Wyoming produces from the Weber Sand which is similar in geologic age to Bairoil’s Tensleep Reservoir producing section. In addition, CO₂ Tertiary WAG performance at 60% CO₂ HCPV Injected recovers about 9% OOIP in both fields.

NOT ALL FORMATIONS ARE THE SAME

In 2010, Merit Company, who operated the field, modified Amoco’s five-spot pattern 9:1 WAG scheme to Rangely’s 1:1, 2:1, and 3:1 WAG scheme by dividing the unit up into thirds. From 2010 to 2014, 14 million barrels of water went down the creek that was supposed to be used for WAG Management. The overall effect gassed out 37% of the wells in the Lost Soldier field that deteriated Amoco’s Gross CO₂ Utilization WAG efficiency rating of 13 MSCF/BO to over 40 MSCF/BO under Merit’s operatorship.

Fortunately BAD WAG Practices can be fixed.....
Life beyond 80% HCPV - (Tertiary Oil Recovery, CO₂ Gross and Net Utilization)

Since 1972, over 130+ Commercial CO₂ floods have been operated in the United States with the majority 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

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Table 3. - Clearfork Formation – Limestone (Tight - Low Permeability)

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Table 4. - Devonian Formation – Tripolitic Chert

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Table 5. - Canyon Reef Formation – Karsted Limestone (High Permeability)

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<th>State</th>
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<th>Life beyond N5x HCPV inj (Net CO₂ Utilization)</th>
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<td>Canyon Reef</td>
<td>Sharon Ridge</td>
<td>Sharon Ridge</td>
<td>T: 10  E: 3  S: 8</td>
<td>T: 10  E: 3  S: 8</td>
</tr>
<tr>
<td>Texas</td>
<td>Canyon Reef</td>
<td>Crockett</td>
<td>Crockett</td>
<td>T: 10  E: 3  S: 8</td>
<td>T: 10  E: 3  S: 8</td>
</tr>
</tbody>
</table>

Table 6. - Strawn, Morrow, Delaware, Springer, Marmaton, and Yates (Fluvial Deltaic, Point Bar, Turbidite)

<table>
<thead>
<tr>
<th>State</th>
<th>Formation</th>
<th>Field</th>
<th>Lease</th>
<th>Current Economic (Tertiary)</th>
<th>Life beyond N5x HCPV inj (Net CO₂ Utilization)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Texas</td>
<td>Strawn</td>
<td>Kirt</td>
<td>Kite</td>
<td>T: 10  E: 3  S: 8</td>
<td>T: 10  E: 3  S: 8</td>
</tr>
<tr>
<td>Oklahoma</td>
<td>Morrow</td>
<td>Florida</td>
<td>Florida</td>
<td>T: 10  E: 3  S: 8</td>
<td>T: 10  E: 3  S: 8</td>
</tr>
<tr>
<td>Texas</td>
<td>Delaware Flats</td>
<td>Two runs</td>
<td>T: 10  E: 3  S: 8</td>
<td>T: 10  E: 3  S: 8</td>
<td></td>
</tr>
<tr>
<td>Texas</td>
<td>Delaware Flats</td>
<td>Fort Gaudine</td>
<td>Fort Gaudine</td>
<td>T: 10  E: 3  S: 8</td>
<td>T: 10  E: 3  S: 8</td>
</tr>
<tr>
<td>Texas</td>
<td>Delaware Flats</td>
<td>El Mar</td>
<td>El Mar</td>
<td>T: 10  E: 3  S: 8</td>
<td>T: 10  E: 3  S: 8</td>
</tr>
<tr>
<td>Texas</td>
<td>Delaware Flats</td>
<td>East Ford</td>
<td>East Ford</td>
<td>T: 10  E: 3  S: 8</td>
<td>T: 10  E: 3  S: 8</td>
</tr>
<tr>
<td>Texas</td>
<td>Springer</td>
<td>Northwood Paddy</td>
<td>Northwood Paddy</td>
<td>T: 10  E: 3  S: 8</td>
<td>T: 10  E: 3  S: 8</td>
</tr>
<tr>
<td>Texas</td>
<td>Marmaton</td>
<td>Hondo Okeham</td>
<td>Hondo Okeham</td>
<td>T: 10  E: 3  S: 8</td>
<td>T: 10  E: 3  S: 8</td>
</tr>
<tr>
<td>Texas</td>
<td>Yancey</td>
<td>North Valley</td>
<td>North Valley</td>
<td>T: 10  E: 3  S: 8</td>
<td>T: 10  E: 3  S: 8</td>
</tr>
<tr>
<td>California</td>
<td>Savannah</td>
<td>Elkhorn</td>
<td>Elkhorn</td>
<td>T: 10  E: 3  S: 8</td>
<td>T: 10  E: 3  S: 8</td>
</tr>
</tbody>
</table>

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

<table>
<thead>
<tr>
<th>State</th>
<th>Formation</th>
<th>Field</th>
<th>Lease</th>
<th>Current Economic (Tertiary)</th>
<th>Life beyond N5x HCPV inj (Net CO₂ Utilization)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Wyoming</td>
<td>Tensleep</td>
<td>Virl</td>
<td>Virl</td>
<td>T: 10  E: 3  S: 8</td>
<td>T: 10  E: 3  S: 8</td>
</tr>
<tr>
<td>Wyoming</td>
<td>Tensleep</td>
<td>Lost Soldier</td>
<td>Lost Soldier</td>
<td>T: 10  E: 3  S: 8</td>
<td>T: 10  E: 3  S: 8</td>
</tr>
<tr>
<td>Wyoming</td>
<td>Mesaverde Almond</td>
<td>Patrik, Drew, Monell</td>
<td>Patrik, Drew, Monell</td>
<td>T: 10  E: 3  S: 8</td>
<td>T: 10  E: 3  S: 8</td>
</tr>
<tr>
<td>Colorado</td>
<td>Weber SS</td>
<td>High-pump</td>
<td>High-pump Weber Unit</td>
<td>T: 10  E: 3  S: 8</td>
<td>T: 10  E: 3  S: 8</td>
</tr>
<tr>
<td>Texas</td>
<td>Erskine</td>
<td>Sprague</td>
<td>Sprague</td>
<td>T: 10  E: 3  S: 8</td>
<td>T: 10  E: 3  S: 8</td>
</tr>
</tbody>
</table>

Table 8. - Heavy Oil

<table>
<thead>
<tr>
<th>State</th>
<th>Formation</th>
<th>Field</th>
<th>Lease</th>
<th>Current Economic (Tertiary)</th>
<th>Life beyond N5x HCPV inj (Net CO₂ Utilization)</th>
</tr>
</thead>
<tbody>
<tr>
<td>California</td>
<td>Ranger</td>
<td>Wilmington (Chesmore)</td>
<td>FSP, ENF, FDS</td>
<td>T: 10  E: 3  S: 8</td>
<td>T: 10  E: 3  S: 8</td>
</tr>
<tr>
<td>Aramco</td>
<td>Draze</td>
<td>Mesquite Sand</td>
<td>Lek Green</td>
<td>Lek Green Unit</td>
<td>T: 10  E: 3  S: 8</td>
</tr>
</tbody>
</table>

Conclusion

With more than forty-five 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 necessary 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 a14 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 C₉ 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.

References

Conventional WAG CO₂ Flood History


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105. John D. Rogers,*SPE, and Reid B. Grigg, SPE, New Mexico Petroleum Recovery Research Center.: “A Litature Analysis of the WAG Injectivity Abnormalities in the CO₂ Process” SPE Report (SPE 73830) was revised for publication, first presented at 2000 SPE/DOE IOR Symposium, Tulsa Apr 3-5 2000

106. Pennzoil’s Sacroc Development Team (1994-1998): Dr. Ghasem Bayat, Tony Benvegno, Claud Picka, Jack Horkowitz, Tom Wingate, Don Hartman; Team was Responsible for Sacroc’s Centerline Project plus two other pilot programs that was responsible for 1/3 of Sacroc’s total 1920 BOPD Production through this time period.

107. Amoco’s Permian Basin Original Model Development Group: Jack Aulick(Manager), Reservoir Modellers: Kevin Mccollough, Steve Pennell, Burt Nelson, Gary Pariani, Dennis Edens, John Kimberling, and David Merchant, Operations: Perry Jarrell; Team was responsible for developing Amoco’s Tapered WAG Operating scheme.

Acknowledgements

I would like to express my gratitude to the members of the Carbon Management Technology Conference (CMTC) for allowing me the opportunity to be part of this CO$_2$ Conference. I would especially like to thank George Koperna of Advanced Resources International and Jose Figueroa for their support in making this effort possible.

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Merchant Consulting
Magnolia, Texas
CMTC-502866-MS  Enhanced Oil Recovery
The History of CO₂ Conventional WAG Injection Techniques developed from Lab in the 1950’s to 2017

David H. Merchant

CO₂ Storage Solutions

WEB Site: www.CO2StorageSolutions.com

Merchant Consulting

Email: merchantconsulting@comcast.net

Presented to Houston CMTC Conference

July 18, 2017
Houston, Texas
Permian Basin

Welcome to the Permian Basin?

300 miles (480 km) North South
250 miles (400 km) East West
Since 1972 over 130+ CO₂ Tertiary Projects have been implemented in the United States. Today, CO₂ projects in the United States produce over 300,000 BOPD with CO₂ transported over 4,500 miles of CO₂ pipeline.
CMTC 2015 Carbon Management Conference - THANKS

CMTC-440075-MS “Life beyond 80 – A Look at Conventional WAG Recovery beyond 80% HCPV Injection in CO2 Tertiary Floods”
D.H. Merchant, Nov 2015

Ten CO₂ Tertiary Recovery Methods

**Ten CO₂ Recovery Methods used for Tertiary Oil Recovery in the United States**

1. Conventional WAG Recovery (90%+)
2. Residual Oil Zone (ROZ) (Seminole)
3. Gravity Drainage (Yates Field)
4. Double Displacement (Yates Field)
5. Gas Cycling (Denbury, Mississippi)
6. Huff-and-Puff (100+ Projects)
7. Heavy Oil - Calif. (14+ API Gravity)
8. Shale Oil (Bakken) (Under Investigation)
9. Horizontal Well Pattern Development
10. CO₂ Gas Drive w/ Nitro Boost
Ten CO₂ Tertiary Recovery Methods

**Tertiary CO₂ Flooding**
- Conventional WAG Recovery (95%+)
- Residual Oil Zone (ROZ) (Semimobile)
- Gravity Drainage (Yates Field)
- Double Displacement (Yates Field)
- Gas Cycling (Dobsy, Mississippi)
- Huff-and-Puff (100+ Projects)
- Heavy Oil - CalE (14+ API Gravity)
- Shale Oil (Bakken) (Under Investigation)
- Horizontal Well Pattern Development
- CO₂ Gas Drive w/ Nitro Boost

**Conventional WAG w/ ROZ**
- Conventional WAG Recovery (95%+)
- Residual Oil Zone (ROZ) (Semimobile)
  - Gravity Drainage (Yates Field)
  - Double Displacement (Yates Field)
  - Gas Cycling (Dobsy, Mississippi)
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  - Heavy Oil - CalE (14+ API Gravity)
  - Shale Oil (Bakken) (Under Investigation)
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  - CO₂ Gas Drive w/ Nitro Boost

**Gravity Drainage / Double Displacement**
- Conventional WAG Recovery (95%+)
- Residual Oil Zone (ROZ) (Semimobile)
  - Gravity Drainage (Yates Field)
  - Double Displacement (Yates Field)
  - Gas Cycling (Dobsy, Mississippi)
  - Huff-and-Puff (100+ Projects)
  - Heavy Oil - CalE (14+ API Gravity)
  - Shale Oil (Bakken) (Under Investigation)
  - Horizontal Well Pattern Development
  - CO₂ Gas Drive w/ Nitro Boost

**Gas Cycling – Dobsy Resources**
- Conventional WAG Recovery (95%+)
- Residual Oil Zone (ROZ) (Semimobile)
- Gravity Drainage (Yates Field)
- Double Displacement (Yates Field)
- Gas Cycling (Dobsy, Mississippi)
- Huff-and-Puff (100+ Projects)
- Heavy Oil - CalE (14+ API Gravity)
- Shale Oil (Bakken) (Under Investigation)
- Horizontal Well Pattern Development
- CO₂ Gas Drive w/ Nitro Boost

**Huff-n-Puff (Single Well Injection)**
- Conventional WAG Recovery (95%+)
- Residual Oil Zone (ROZ) (Semimobile)
- Gravity Drainage (Yates Field)
- Double Displacement (Yates Field)
- Gas Cycling (Dobsy, Mississippi)
- Huff-and-Puff (100+ Projects)
- Heavy Oil - CalE (14+ API Gravity)
- Shale Oil (Bakken) (Under Investigation)
- Horizontal Well Pattern Development
- CO₂ Gas Drive w/ Nitro Boost

**Heavy Oil (14+ API Gravity)**
- Conventional WAG Recovery (95%+)
- Residual Oil Zone (ROZ) (Semimobile)
- Gravity Drainage (Yates Field)
- Double Displacement (Yates Field)
- Gas Cycling (Dobsy, Mississippi)
- Huff-and-Puff (100+ Projects)
- Heavy Oil - CalE (14+ API Gravity)
- Shale Oil (Bakken) (Under Investigation)
- Horizontal Well Pattern Development
- CO₂ Gas Drive w/ Nitro Boost

**Shale Oil – Bakken, Wolfcamp**
- Conventional WAG Recovery (95%+)
- Residual Oil Zone (ROZ) (Semimobile)
- Gravity Drainage (Yates Field)
- Double Displacement (Yates Field)
- Gas Cycling (Dobsy, Mississippi)
- Huff-and-Puff (100+ Projects)
- Heavy Oil - CalE (14+ API Gravity)
- Shale Oil (Bakken) (Under Investigation)
- Horizontal Well Pattern Development
- CO₂ Gas Drive w/ Nitro Boost

**Horizontal Well Development**
- Conventional WAG Recovery (95%+)
- Residual Oil Zone (ROZ) (Semimobile)
- Gravity Drainage (Yates Field)
- Double Displacement (Yates Field)
- Gas Cycling (Dobsy, Mississippi)
- Huff-and-Puff (100+ Projects)
- Heavy Oil - CalE (14+ API Gravity)
- Shale Oil (Bakken) (Under Investigation)
- Horizontal Well Pattern Development
- CO₂ Gas Drive w/ Nitro Boost

**CO₂ Gas Drive w/ Nitro Boost**
- Conventional WAG Recovery (95%+)
- Residual Oil Zone (ROZ) (Semimobile)
- Gravity Drainage (Yates Field)
- Double Displacement (Yates Field)
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CMTC-502866-MS “The Look at Conventional WAG Injection Techniques developed from Lab in the 1950’s to 2017” deals strictly with Conventional Main Pay and ROZ Reservoirs
What is Conventional WAG Management?

Conventional **Water Alternating Gas (WAG)**

90% of all CO₂ floods to date
Permian and Rocky Mountain Basins

History of “WAG”

1950’s and 1960’s

1950’s – 150 Small Scale Miscible and Immiscible Projects
1958 - Lab Experiments Caudle and Dyes introduced water to decrease solvent mobility

1970’s

1972 – Sacroc Unit (Kelly Snyder field) First Commercial Large Scale Project
1972-1979 North Cross, Two Freds, Maljamar, others

1980’s   Large Scale Permian Basin and Rocky Mountain Expansions

Slaughter field three projects plus Wasson ODC Unit – Amoco’s Tapered WAG
Wasson field Denver Unit – Shell’s Continuous Injection area plus DUWAG
Wasson field Willard Unit - Arco’s Area Wide WAG went to Individual Patterns
Seminole field – Amerada Hess’s Constant WAG scheme
Rangely field – Chevron’s Wide Area WAG scheme
Bairoil (Lost Soldier and Wertz field ) – Amoco’s Tapered WAG
Aneth field - Horizontal Well Pattern Development – Constant WAG

1990’s, 2000’s, and 2010’s

Most new CO₂ flood projects adopt the “Tapered WAG” approach to WAG Management
CO₂ Flooding in the United States
40+Years of CO₂ Flood History

1980’s – 1990’s

2000’s

2010’s

Look at how far have we come?
What is Conventional WAG Management?

**Slaughter Estate Unit - Example**

**Conventional WAG Injection Techniques**

**Definitions**

WAG Process

**Pattern Parameters**

- Original Oil-in-Place - Amount of Oil in Place (Standard conditions)
- HCPV - Amount of Oil in Place (Reservoir conditions)
- Total Slug Size - Total Amount of CO₂ Inj. (20-100% HCPV)
- Half Cycle CO₂ Slug Size - HCPV of CO₂ Inj in one cycle (0.25 - 30.00 %)
- Water Cycle CO₂ Slug Size - HCPV of H₂O Inj in one cycle (0.25 - 10.00 %)
- WAG Ratio - Ratio of Half cycle Water to Half cycle CO₂
- GWR Ratio - Ratio of Half cycle CO₂ to Half cycle H₂O

**CO₂ Tertiary floods are designed to operate best in fields that have been drilled on 5-spot, 9-spot, or Chicken-wire development patterns**
DIFFERENT OPERATORS
DIFFERENT PHILOSOPHIES (Reservoir Driven)

- Continuous CO₂ - Continuously inject CO₂ (No water)

- Constant WAG - example - 1:1 WAG with (1.0 % CO₂, 1.0% H₂O)
  Note: No change in WAG Ratio with time

- Simultaneous WAG – Hourly WAG Changes

- Tapered WAG - Combination of both continuous and WAG
  example - Continuous injection for 20% HCPV
  WAG (1.0 % CO₂, 0.10 % H₂O) for 5% HCPV
  WAG (1.0 % CO₂, 0.50 % H₂O) for 10% HCPV
  WAG (1.0 % CO₂, 1.00 % H₂O) for 20% HCPV
  WAG (1.0 % CO₂, 2.00 % H₂O) for 30% HCPV
  Chase Water Injection

“Wetting the WAG”

Note: Total Slug Size = 85% HCPV Inj. Of CO₂
Reservoir Simulation was a vital tool in understanding the WAG Process
Amoco WAG Management – 1980’s

Tapered WAG Injection

SPE Paper 26624 - Reservoir Management in Tertiary CO₂ Floods

Production Montage

Pattern Montage

Integrated Montage
Reservoir Simulation

Reservoir Model Study - San Andres 5 Spot

Single 5 Spot Pattern (10X10X6 Grid)

Injection Profiles

X-Cross Section - Oil Saturation
Reservoir Simulation

Continuous Injection

Constant WAG Injection

Tapered WAG Injection

Injection Profiles – 20% HCPV to 70% HCPV

Tapered WAG provides Mobility Control in the Fast Zones
**CO₂ Miscible Process**

**Compositionally Driven**

Multiple Contact Miscible Process (time and compositionally dependent)

Miscible Zone formed by CO₂ becoming enriched with C₂ – C₃₀
You can’t fool Mother Nature……

The amount of CO$_2$ TRAPPED, STORED, OR SEQUESTERED is dependent on the Composition of the Residual Oil Saturation and Phase Trapping of the Non-Wetting Phase, which in this case is CO$_2$. 
Tertiary CO$_2$ Flooding

“The Previous Millennium”

20$^{th}$ Century (1972 to 2000)

“Life below 80% HCPV Injected”
Permian Basin - 1970’s

“First Commercial CO₂ Flood - 1972”

Sacroc Unit in Kelly Snyder Field

EXISTING MARKETS
Year - 2000

CURRENT CO₂ SOURCES and PIPELINES

Wyoming

Canadian

LaBarge

Great Plains Coal Plant

McElmo Dome

Sheep Mountain

Bravo Dome

Jackson Dome

EXPERIMENTAL MAP

Sacroc Unit
Kelly Snyder Field

Permain
Basin

Louisiana/Mississippi

Canyon Reef Map – Sacroc Unit

• Date of Discovery: November, 1948
• Total Acreage: 55,000 acres
• Original Oil-in-place: 2.98 Billion stb
• Total Wells: 1,620 wells
• Field Unitization: March, 1953
• Water Injection: September, 1954
• CO₂ Flooding: January, 1972

The Kelly Snyder Field (Sacroc Unit) recovers Tertiary Oil from the Canyon Reef Limestone Formation about 6,700 ft. deep
Sacroc Unit – Historical Performance

Chevron Ownership

Pennzoil Operatorship

First Commercial CO₂ flood in 1972

1992 - 1999

Field Discovery
November 1948

Water Injection September 1954

CO₂ Injection January 1972

Peak Water Inj. 1,260,000 BWIPD

Peak Oil Rate 209,000 BOPD

Current Oil Rate 9,071 BOPD

Waterflood Injection Startup - 1955

Waterflood Injection Expansion CO₂ Startup - 1972

Kinder Morgan Operatorship
2000 to Present

Devon Operatorship
1999 - 2000
Sacroc Unit – Historical Performance


Pennzoil implemented a 300 acre Centerline Pilot Project in 1996 which produced 1/3 of the total field’s production over the total 55,000 acre unit boundary.

Kinder Morgan Operatorship (2000 -Present)

Kinder Morgan implemented a phased-in Tertiary Development Plan and expanded CO₂ Injection to over 800 MMSCFIPD with a 30,000 BOPD Response. WAG Management is on an Individual Pattern Basis with Multiple Pattern Development programs developed to date.
The Slaughter and Levelland fields recover Tertiary Oil from the San Andres Formation about 5,000 ft. deep from various leases and operators located across both fields.
In 1989, Amoco converted from Constant WAG to Tapered WAG Management which provided the means to “Level Load” gas production to the Plant Inlet Gas Rate thus allowing control over the CO2 Process.
Amoco initiated a WAG increase in 1989 that “Level Loaded” gas production to the Plant Inlet Rate, which provided the ability to control gas production throughout the life of the flood, thus advancing CO$_2$ tertiary recovery beyond the 8% to 12% OOIP documented in most studies.
Amoco’s Tapered WAG Management provided the means to “Level Load” gas production to the Plant Inlet Rate, but “Over-WAGGED” causing the gas production to be less than inlet rate. To compensate Amoco then initiated individual pattern WAG adjustments to better fine tune gas production back to plant inlet rate.
The Wasson field recovers Tertiary Oil from the San Andres Formation about 5,500 ft. deep from various leases and operators located across this large field and contains a large Residual Oil Zone (ROZ).
The Denver Unit, operate by Shell, initiated a Continuous Injection Area targeting 4% CO$_2$ HCPV/year and a WAG Injection area (DUWAG) where they operated 2% HCPV/year CO$_2$ and 2% HCPV/year. The Continuous Area was converted to a Line Drive due to conformance orientation issues.

The Wasson ODC Unit, operated by Amoco initiated a WAG down with Amoco’s “Tapered WAG” operating scheme in 1989 to “Level Load” gas to the plant inlet rate.

The Willard Unit, operated by Arco initiated early on Large Area Pattern Switches, but later changed to an individual pattern approach.
1980’s

What are they doing?

CO₂ Tertiary Flood Management

Pattern Review In Progress: Control Central

1. Evaluating Individual Well Performance
2. Evaluating Individual Pattern Performance
3. Making WAG Adjustments based on Pattern Performance
Tertiary CO$_2$ Flooding

“The New Millennium”

21$^{\text{st}}$ Century (2000 and beyond)

“Life beyond 80% HCPV Injected”
Tertiary Oil Recovery

%OOIP Rec versus %HCPV Inj

Un-fractured Sandstone versus Dolomite

Permian Basin Dolomitic Limestone versus Oklahoma Un-fractured Sandstone Recovery

Homogeneous Dolomite – Seminole Unit

Seminole Field

Combined Case Comparison (CO₂ Only)

Historical and Predicted - Tertiary Oil Recovery - % OOIP

Uniform

Total Field
20 Pattern Area
10 Pattern Area

Fractured Sandstone versus Dolomite

Permian Basin Dolomitic Limestone versus Wyoming Tensleep Fractured Sandstone

Non-Uniform Pattern Sandstone – Postle field

Morrow: CO₂ Targets

"A" and "A-1"

Postle Field
Pattern Review (155)

"Actual" Oil Recoveries (Dimensionless)

Avg. of Mature Pattern History Matches (48)

Complex but Understandable

Not all Patterns and Reservoirs are alike
1980’s  **Tertiary CO\textsubscript{2} Flooding**

**Permian Basin (Seminole Field)**

**Seminole Field Location**

The Seminole field recovers Tertiary Oil from the San Andres Formation about 5,500 ft. deep which also includes a large Residual Oil Zone (ROZ).

The Field is developed on 9-spot pattern spacing.
Since CO₂ Startup in 1983 Tertiary Oil Recovery is expected to recover 24% OOIP

Since ROZ CO₂ Startup in 1996 Tertiary Oil Response had been excellent with expected ROZ Tertiary Oil Recovery comparable or better than Main Pay Tertiary Oil Recovery
Rocky Mountain Region

Seminole San Andres Unit (Permian Basin)

Un-fractured Sandstone versus Dolomite

Homogeneous Dolomite – Seminole Unit

Permian Basin Dolomite Limestone versus Oklahoma Un-fractured Sandstone Recovery

Seminole Field
Seminole San Andres Unit with Patterns Grid Overlay

Homogeneous Dolomite – Seminole Unit

Total Field
20 Pattern Area
10 Pattern Area

Bairoil Field – Lost Soldier and Wertz (Wyoming)

Permian Basin Dolomite Limestone versus Wyoming Tensleep Fractured Sandstone

Seminole Field
Combined Case Comparison (CO2 Only)
Historical and Predicted - Tertiary Oil Recovery - % OOIP

Total Field
20 Pattern Area
10 Pattern Area

Not all Reservoirs are alike
Rocky Mountain Region

Rangely Weber Unit – (Colorado)  Comparison

Bairoil Field – Lost Soldier and Wertz (Wyoming)

On the Outside they both look the same
Rocky Mountain Region

Lost Soldier Tertiary Oil Recovery Comparison at 60% HCPV Injected w/ Rangely field

On the Outside at 60% HCPV Injected they both look the same about 9% OOIP
Lost Soldier and Wertz Field Analysis
Field Level Analysis (Historical WAG Management)

At the Field Level, Historical Production Looks Normal – (Level Loaded at Plant)

In 2010, WAG Management was changed resulting in 14 MMBW of WAG Water Injection going down the creek.

By implementing Rangely's WAG management in 2010, Gas Production increased dramatically.

Montage Pattern Analysis – Mass Balance approach to Tertiary WAG Reservoir Management Optimization – Lost Soldier and Wertz fields

The GOR increase caused many of the wells in the field to gas out capable of producing only a few days a month.

Gross Utilization efficiency went from 13 MSCF/BO (Amoco) to 40 MSCF/BO

The final result was 37% of the wells in the field are off production. If returned, over 3,000 BOPD could be added.
Merit Company in 2010 modified Amoco’s five-spot pattern 9:1 WAG scheme to Rangely's 1:1, 2:1, and 3:1 WAG scheme by dividing the unit up into thirds. From 2010, Fourteen million barrels of water went down the creek that was suppose to be used for WAG Management. The result gassed out 37% of the wells in Lost Soldier field by lowering WAG efficiency from 13 MSCF/BO (Amoco) to over 40 MSCF/BO.

Fortunately, Bad WAG can be fixed...
CMTC-502866-MS  Enhanced Oil Recovery
The History of CO$_2$ Conventional WAG Injection Techniques developed from Lab in the 1950’s to 2017

Questions?

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