Using Polymer-Alternating-Gas to Maximize CO$_2$ Flooding Performance for Light Oils
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Abstract
Carbon dioxide has been used commercially to recover oil from reservoir by enhanced oil recovery technologies for over 40 years. Currently, the CO$_2$ flood is the second most applied enhanced oil recovery (EOR) processes in the world behind steam flood. Water alternating gas (WAG) injection has been a popular method to control mobility and improve volumetric sweep efficiency for CO$_2$ flooding. The average improved recovery is about 9.7% with range from 6% to 20% for miscible WAG injection. Despite all of the success of WAG injection, sweep efficiency during CO$_2$ flooding is a typically challenge to reach higher oil recovery and better application of the technology.

The paper proposes a new combination method, named as polymer-alternating-gas (PAG), to improve the volumetric sweep efficiency of WAG process. The feature of this new method is that polymer is added to water during WAG process to improve mobility ratio. In a PAG process, polymer flooding and immiscible/miscible CO$_2$ injection are combined.

To analyze the feasibility of PAG, couples model considering both miscible and polymer flooding process are built to study the performance of PAG. In this paper, sensitivity of polymer adsorption and concentration are studied. Feasibility of PAG in reservoirs with different permeability, different Dykstra-Parsons permeability variation coefficient (VDP), and different fluid are also studied. A reservoir model from typical section of North Burbank Unit is used to compare the performance between PAG, WAG and polymer flooding. This study demonstrates that PWAG can significantly improve recovery for immiscible/miscible flooding in homogeneity or heterogeneity of reservoir.

Introduction
Although CO$_2$ flooding is a well-established EOR technique, its density and viscosity nature is a challenge for CO$_2$ projects. Low density (0.5 to 0.8 g/cm$^3$) causes gas to rise upward in reservoirs and bypass many lower portions of the reservoir. Low viscosity (0.02 to 0.08 cp) leads to poor volumetric sweep efficiency. In heterogeneous reservoirs with high-permeability zones and natural fractures, the condition is even worse (Zhang et al. 2010).

Almost all commercial miscible gas injection projects use WAG to control mobility of gas and alleviate fingering problems. Recovery of WAG is better than gas injection alone, and 80% of commercial WAG projects in the US are economic (Christensen et al. 1998). However, recent studies show that most of the fields could not reach the expected recovery factor from the WAG process, especially for reservoirs with high-permeability zones or there are naturally fractured (Christensen et al. 2001).

Gel application is considered the most aggressive type of conformance control. Gel acts as a blocking agent to reduce channeling through fractures or high-permeability zones of reservoirs (Ali and Schechter 2013). The most applied gel system in the oil industry for conformance control is hydrolyzed polyacrylamide (HPAM) with Cr (μ) acetate. Woods et al. (1986) presented one of the earliest successful gel treatments for Lick Creek field in Arkansas. Hild and Wackowski (1999) reported a successful gel treatment at the Rangely Weber Sand Unit in northwestern Colorado. In this treatment, a large-volume (10,000 bbl) chromic-acetate acrylamide polymer gel was applied to improve CO$_2$ flooding performance. The cost of the gel treatment was estimated to be around USD 6 to 8/bbl, and the project return rate was 365%. Karaoguz et al. (2007) and Topguder (2010) reported several field applications of gel in Bati Raman field. In General, gels can treat water coning successfully in reservoir with vertical fracture. However, water coning through matrix reservoir is very difficult to be treated successfully with gels. On the other hand, conventional foams are considered effectively in matrix rock and are not applicable in reservoir fracture channels with aperture widths on the order of greater than 0.5 mm (Robert 2007).

Bond and Holbrook (1958) first proposed the idea of using foam for mobility control. Since then, CO$_2$ foam with surfactant
has been used as an effective mobility-reducing agent for CO₂ flooding in the oil recovery process. One of the largest full-scale field demonstrations of foam for gas mobility control was the Foam-assisted water alternating gas (FAWAG) project in the Snorre field on the Norwegian Continental Shelf from 1997 to 2000 (Blaker et al. 2002). Unfortunately, field experiences showed that conventional foam with surfactant injected in water had some significant limitations. Énick et al. (2012) concluded the problems of FAWAG: (1) the dilution of CO₂ foam by subsequently injected water; (2) the inability of foam to be effective in formations containing fractures or extremely high-permeability open flow paths; (3) the very short propagation of the CO₂ from the injection well, cold weather ice and hydrate formation, unacceptably large decreases in injectivity associated with coinjection, and other unspecified “operational problems.”

To overcome the issues of gas breakthrough and gravity segregation, a new combination method was proposed. This new method, termed as PAG, combines features of CO₂ flooding with polymer flooding to produce a chemically enhanced WAG flooding. Coupling of polymer with CO₂ is expected to improve the efficiency of the current WAG. The main feature of PAG is that polymer is injected with water in the whole WAG process. Zhang et al (2010) conducted the polymer injection chased with gas alternative water (PGAW) experiment based on Saskatchewan crude. They stated that coupled CO₂ and polymer injection gave better recovery and efficiency than WAG and polymer flooding. Majidaie et al. (2012) carried out the first coupled CO₂ and polymer injection simulation study for light oil based on a synthetic and homogeneous model. This study showed that PAG and WAG have almost the same recovery. And he also mentioned that chemical slug of polymer with surfactant and alkali would significantly increase oil recovery.

**Workflow of PAG Modeling**

In this study, we discussed PAG flooding in light oils based on synthetic models. The commercial software CMG-WINPROP and STARS were used. It is a simulator could model both has injection process and polymer flooding. The main steps in the study are as follows:

1. Build synthetic reservoir models and introduce fluid characterization used in study
2. Define polymer parameters
3. Sensitivity study of polymer parameters
4. Feasibility study of PAG in different reservoir and fluid conditions
5. Use PAG to improve gas flooding in TR59 of North Burbank Unit (Case study)

**Synthetic Reservoir Model and Fluid Characterization**

The reservoir model used in this study consists of 21x21x6 grid blocks. Grid dimensions are 50 ft x 50 ft x 10 ft, resulting in a reservoir 1050 ft length, 1,050 ft width and 60 ft thick. The reservoir is thick enough to see the effect of gravity segregation. The reservoir is located 3,000 ft beneath the surface and has no dip. The reservoir is heterogeneous and consists of a sandstone formation. Fig. 1 shows the synthetic reservoir model. The vertical injection and production wells are diagonally located in the model. In all simulations the injection rate is fixed at 1,340,000 ft³/day for gas injection well and 800 bbl/day for water injection well, and the bottom-hole pressure (BHP) at the production well is fixed at 1350 psi during EOR process. Table 1 presents the input reservoir rock and fluid properties used for the simulation study.

![Fig. 1—3D View of the Synthetic Reservoir Model (Top Depth, ft)](image-url)
Five oil samples were used to study the feasibility of PAG in miscible and immiscible flooding and different oil viscosity. Viscosity of each oil sample at reservoir condition is 3, 9, 30, 90, and 200 cp, respectively. Fig. 2 shows correlation between oil viscosity and pressure. Fig. 3 shows the correlation between mix parameter $\omega$ and pressure for these five samples. Mix parameter $\omega$ controls the transition between immiscible and miscible. A value of $\omega=1$ results in a piston-like displacement of oil by the injected gas. If $\omega=0$, the displacement is similar to an immiscible displacement (except for the treatment of relative permeability). Compared with oil sample #2, oil sample #1 has higher value of mix parameter at the same pressure, which means oil simple #1 has better miscible possibility. The minimum miscible pressure for each oil sample is 1700, 1700, 2500, 2500, and 2500 psi, respectively. In this study, the highest injection pressure at injectors is set to 2,100 psi, which means that miscible flooding is possible for oil sample #1 and #2 and oil sample #3-5 would be used for immiscible flooding study.

![Fig. 2—Correlation between oil viscosity and pressure](image-url)
Parameters for Polymer Flooding. Rock adsorption and polymer viscosity are two important parameters for polymer flooding. As lack of polymer test, polymer viscosity and adsorption were assumed in this simulation. The correlation between polymer viscosity and polymer concentration is shown in Fig. 4. Fig.5 shows three correlations between polymer concentration and polymer adsorption. For Function 1, the maximum adsorption is 10 ug/ (g rock); for Function 2, the maximum adsorption is 50 ug/ (g rock); for Function 3, the maximum adsorption is 200 ug/ (g rock). We also assumed a residual resistance factor (RRF) value of 1.5 at 0.50 lb/stb in this study.
Sensitivity Study of Polymer Parameters
To have a sensible study, we assumed that the simulation model data are based on a water flooded reservoir with water cut 98%. Base case was defined by water alternating gas injection. PAG case was defined by the injection of chemical slug which contains polymer alternating gas injection. The reservoir performance during PAG process was compared with WAG and continuous gas (CO₂) injection (CGI). A sensitivity analysis was performed on critical parameters that affect the process significantly, including polymer adsorption, polymer concentration.

Polymer Adsorption. Three processes have been run with different adsorption functions in Fig. 5. Polymer concentration was set to 0.2 lb/stb. PAG has been injected for 20 years with WAG ratio 1:1 (3:3 months) and fluid injection rate 0.1 pore volume per year (0.05 pore volume of gas and 0.05 pore volume of water). Fig. 6 and Fig. 7 indicate that reducing polymer adsorption would significantly increase oil rate and reduce water cut. With higher adsorption, the enhanced oil recovery will be decreased (Fig. 8). Polymer retention leads to loss of polymer from solution, which causes the mobility control effect to be lost. If the polymer slug is small, and concentration of injected polymer solution is also low, retention may lead to polymer flooding fail. From these three run processes, it can be seen that with smaller polymer adsorption, the higher peak oil rate and higher oil recovery.
Fig. 6—Oil production rate with different polymer adsorption function

Fig. 7—Water cut with different polymer adsorption function
**Polymer Concentration.** Compared with WAG, one main purpose of PAG process is to control the water viscosity by adding polymer into injected water to lower the water mobility, especially, for high permeability river channel reservoir. The biggest benefit of polymer flooding is from the viscosity increasing of water phase, which improves the water-driving. Higher polymer concentration leads to higher viscosity. **Fig. 9-11** show simulation results of WAG and PAG process with different polymer concentrations. The three PAG process have the same injected polymer slug size. The higher the polymer concentration is, the more oil can be recovered (Fig. 11). Practically, polymer concentration cannot be increased without upper limit. With polymer concentration increasing, the viscosity will be highly increased. As a result, the injecting pressure will correspondingly increase if the injection rate is kept stable. If the pressure is too high, the reservoir rock will be fractured.
Feasibility Study of PAG in Different Reservoir and Fluid Conditions
To address what types of fluids and reservoirs are the candidates for PAG flooding, Feasibility study was carried out on fluid viscosity, reservoir permeability and VDP.

Reservoir with permeability 500 md and VDP 0.70 was used for feasibility study in fluid viscosity. Oil sample #2 was used for feasibility study in both homogenous and heterogeneous models.

Fluid Viscosity. Polymer flooding is usually used for reservoir fluid with viscosity range 10-150 cp, while CO₂ flooding prefers light oil with viscosity below 10 cp. A sensitivity study of the reservoir performance due to oil viscosity was conducted on the PAG model by changing the oil viscosity values. Five oil viscosity values (3, 9, 30, 90 and 180 cp) were studied. During PAG process, concentration of 0.20 lb/stb was set for these five cases. Fig. 12 shows that: (1) lower viscosity would lead to higher recovery of waterflooding, WAG and PAG; (2) oil recovery from PAG process is 16-24% higher than that of water flooding; (3) oil recovery from PAG process is 10-13% higher than that of WAG; (4) PAG could significantly increase recovery in both miscible and immiscible flooding.
Homogenous Formation. Permeability ranges from 50-1,000 md was studied. Table 2 shows the polymer injection concentrations for formations with different permeability. Fig. 13 shows that: (1) No significant difference in waterflooding recovery when permeability varies from 50-1,000 md; (2) PAG does not improve recovery when permeability is lower than 500 md. The main reason is WAG could reach very high recovery (more than 60%) for homogenous formation with low permeability, while polymer has injectivity problem in such a low permeability formation; (3) Oil recovery from PAG process is 7-15% higher than that from WAG when permeability is higher than 500 md in homogenous formation.

<table>
<thead>
<tr>
<th>Permeability, md</th>
<th>50</th>
<th>100</th>
<th>200</th>
<th>500</th>
<th>1,000</th>
</tr>
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<tbody>
<tr>
<td>Polymer concentration, lb/stb</td>
<td>0.05</td>
<td>0.05</td>
<td>0.1</td>
<td>0.2</td>
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**Heterogenous Formation.** Vertical heterogeneity of formation would lead to CO₂ fast breakthrough, especially for high VDP formation with high permeability layer at the top. In this paper, two groups of heterogenous models were studied. One group model has average permeability of 100 md with BHP of 100 psi, the other one has average permeability of 500 md with BHP of 1,600 psi. VDP values range from 0.5-0.9 for both group models. Polymer concentration was set to 0.2 lb/stb for all the cases.

**Fig. 13** shows that: (1) lower VDP would lead to higher recovery of waterflooding, WAG and PAG; (2) oil recovery from PAG process is 18-29% higher than that from waterflooding; (3) oil recovery from PAG process is 7-13% higher than that from WAG; (4) Compared with WAG, increment of recovery from WAG decreases with the increasing VDP value. It means that higher polymer concentration is needed for high permeability formation with high VDP value.

**Fig. 14**—Comparison of oil recovery among waterflooding, PAG and WAG for models with different VDP in high permeability formation
**Fig. 15** shows that: (1) lower VDP would lead to higher recovery of waterflooding, WAG and PAG; (2) oil recovery from PAG process is 21-25% higher than that from water flooding; (3) oil recovery from PAG process is 3-11% higher than that from WAG; (4) Compared with WAG, increment recovery from WAG increases with the increasing VDP value. It means that lower permeability formation with high VDP value is a good candidate for PAG flooding.

![Comparison of oil recovery among waterflooding, PAG and WAG for models with different VDP in low permeability formation](image)

**Case Study**

We applied PAG to improve the volumetric sweep efficiency of the WAG process in TR59 of the North Burbank Unit. High heterogeneity and high permeability at the top layers are the two main challenges for gas flooding in North Burbank Unit. Performance among polymer flooding, WAG and PAG were compared.

**Introduction of North Burbank Unit.** The North Burbank Unit, located on the northeastern Oklahoma Cherokee platform (**Fig. 16**), was originally discovered in 1920. It has an extensive history of activity, including primary depletion, produced gas cycling, and water and polymer flooding to the point of very high water cut at current conditions (**Fig. 17**). The North Burbank Unit has a cumulative production of 332 million bbl of oil out of an estimated 824 million bbl of original oil in place. The current oil production rate in the North Burbank Unit is approximately 1,400 BOPD from 360 active wells at a water cut of 99.5%. Significant reserves are currently available for post-secondary production. CO₂ flooding is a good choice considering that the minimum miscibility pressure (MMP) in the North Burbank Unit is lower than the fracturing pressure and CO₂ is available from a purely anthropogenic source. High heterogeneity and high permeability at the top layers are the two main challenges of the North Burbank Unit.
Reservoir Model. Building a full-field 3D geologic model of the North Burbank Unit presented several unique challenges, including having permeability/porosity logs and secondary production/injection data for only a few wells. In this paper, typical section 59 was chosen to demonstrate how PAG improves recovery in field. For the purpose of modeling, the ST59 is characterized by a gridded network with permeability and porosity parameters specified for each block. For this model, the 0.5 × 0.5-mi reservoir section is divided into 60 grid blocks in the x-direction, 60 grid blocks in the y-direction, and 6 grid blocks in the z-direction. In the x- and y-directions, the grid blocks are 44 ft in length. The grid blocks in the z-direction vary from 7 to 32 ft thick, which results in a pay zone of 89 ft. Fig. 18 shows x-horizontal permeability (kh) in the model. The vertical permeability (kv) is 0.01 times the x-horizontal permeability, while y-horizontal permeability is 3 times the x-horizontal permeability. Table 4 presents the input reservoir rock and fluid properties used for the simulation.
Table 4—Reservoir Rock and Fluid Properties

<table>
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<tr>
<th>Parameter</th>
<th>Values</th>
<th>Parameter</th>
<th>Values</th>
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</thead>
<tbody>
<tr>
<td>Size of Model, ft</td>
<td>2,640×2,640×88.9</td>
<td>Water Density, lb/ft³</td>
<td>62.97</td>
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<tr>
<td>Number of Grid</td>
<td>60×60×6</td>
<td>Water Viscosity, cp</td>
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<tr>
<td>VDP</td>
<td>0.85</td>
<td>Oil Density, lb/ft³</td>
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<td>kv/kh</td>
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<td>Oil Viscosity, cp</td>
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<td>Porosity</td>
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<td>Initial Oil Saturation</td>
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<tr>
<td>Initial Pressure, psi</td>
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<td>Initial Water Saturation</td>
<td>0.20 to 0.39</td>
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<tr>
<td>Permeability, mD</td>
<td>6 to 230</td>
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</tbody>
</table>

Fluid model, Well pattern and Other Parameters Used in Model. After matching experimental data, a black oil fluid model was generated from pressure-volume-temperature (PVT) software. In this model, following mix parameter curve (Fig. 19) was used after matching WAG production between compositional model and pseudo-miscible model. Polymer parameters are from Fig.4 and Fig.5 (Function 2).
After optimizing the WAG, following parameters was sued for PAG study. Well pattern was shown in Fig. 20. Fluid Injection rate is 0.1 pore volume per year (gas and water injection rate is the same 0.05 pore volume per year). WAG ratio is 1:1 (90 days water injection alternating with 90 days gas injection).

**Fig. 20—Well pattern**

**PAG Versus Polymer Flooding and WAG:** In the production history of NBU, surfactant/polymer flooding and polymer flooding have been carried in 1980s. The commercializing surfactant/polymer pilot in Tract 97 is considered economic unfavorable particularly in areas of high heterogeneity (Joseph 1983, and Moffitt et al. 1993). While the freshwater polymer flood project at NBU block A (included 84 producers and 36 injectors) is technically and economically successful, even with the large drop in oil prices in 1986. In this project, 4.2 million lb of polyacrylamide and 4.0 million lbm of 2.9 aluminum citrate crosslinking were injection and incremental oil recovery exceeded 2.5 MMSTB of oil (Tracy and Dauben 1982, Joseph and Paul 1982, Zornes et al. 1986, Moffitt et al. 1993). It is worth to compare the performance between polymer flooding and gas flooding in this field.

To identify which injection method yields a better recovery, four different schemes were conducted (Fig. 21). Pattern-1 (polymer flooding) injects polymer of 0.10 lb/stb with water for twenty years. Pattern-2 (polymer-water flooding) injects polymer of 0.10 lb/stb with water for ten years then follow with water injection for ten years. Pattern-3 (WAG) uses WAG injection for twenty years. Pattern-4 (PAG) injects polymer of 0.06 lb/stb with water and alternative with gas for twenty years. Same volume of polymer was injected for pattern-2 and pattern-4.

We forecasted oil production rate for the four different EOR processes (Fig. 22). The peak oil rate by PAG is much higher than WAG and polymer flooding. Polymer flooding could produce 16.39% OOIP after water flooding, while this value is 12.67% for polymer-water flooding (Fig. 23 and Table 5). It shows that this reservoir also is a good candidate for polymer flooding. Pattern-2 and pattern-4 use the same polymer consumption, while recovery from pattern-4 is 7% higher than recovery from pattern-2. Recovery after PAG injection is 19.70%, which is 4-12% higher than other injection method. It indicates combining polymer and gas injection is better than other methods mentioned above.

![Fig. 19—Correlation between mix parameter ω and pressure](image-url)
Table 5—Summary of different methods

<table>
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<tr>
<th>Method</th>
<th>Recovery %</th>
<th>Polymer Consumption $10^6$ lb</th>
<th>Oil Increased $10^6$ stb</th>
<th>Polymer Utilization lb/stb</th>
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<tr>
<td>Polymer Flooding</td>
<td>16.39</td>
<td>2.25</td>
<td>1.56</td>
<td>1.44</td>
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<tr>
<td>Polymer-Water Flooding</td>
<td>12.67</td>
<td>1.13</td>
<td>1.20</td>
<td>0.94</td>
</tr>
<tr>
<td>WAG</td>
<td>8.72</td>
<td>0.00</td>
<td>0.84</td>
<td>0.00</td>
</tr>
<tr>
<td>PAG</td>
<td>19.70</td>
<td>1.24</td>
<td>1.89</td>
<td>1.18</td>
</tr>
</tbody>
</table>

Fig. 21—Slug patterns of four different schemes

Fig. 22—Oil production rate with different injection slugs
Conclusions
A new EOR method, named PAG, was proposed to improve the efficiency of conventional WAG process. The following conclusions were made for this study:

1. PAG is very sensitive with polymer adsorption. Lower adsorption would lead to higher recovery.
2. Increase polymer concentration would increase oil recovery in PAG process when injectivity problem occurs.
3. Based on recovery from different type of oil, it indicates that PAG could significantly increase recovery in both miscible and immiscible flooding.
4. Oil recovery from PAG process is 7-15% higher than that of WAG when permeability higher than 500 md in homogeneity reservoir.
5. PAG could improve WAG perform in both high and low permeability heterogeneity reservoir with VDP vary from 0.5-0.9.
6. Case study shows that oil recovery increased by PAG in TR59 is forecasted to be 20%, which is 12% higher than WAG. Polymer utilization is about 2.10 lb/stb, which is economically feasible.

Nomenclature

EOR  Enhanced oil recovery
FAWAG  Foam-assisted water alternating gas
Kv  Vertical permeability
Kh  Horizontal permeability
MMP  Minimum miscibility pressure
PVT  Pressure-volume-temperature
PAG  Polymer-alternating-gas
RRF  Residual resistance factor
VDP  Dykstra-Parsons permeability variation coefficient
WAG  Water alternating gas

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References


