Application of a Gel Polymer Process for Profile Modification and Conformance Control at Injection Wells and for Water Shut-off at Producing Wells

By

Jay Portwood - jtportwood@eoga.net
Dee Biswas – dbiswas@sitelark.com
Company Background

- Formed in 2007 by people with 40 years of combined experience working with polymer processes
- Candidate selection, project engineering and design, and field implementation
- People, products, and specialized equipment to manage projects from concept to completion
Locations

→ Dallas, TX (Headquarters)
→ Meeteetse, WY (Rockies and W. Coast Regions)
→ Healdton, OK (S. Mid-con & N. TX Regions)
→ Plainville, KS (N. Mid-con & E. U.S. Regions)
→ Coahoma, TX (Permian Basin Region)
What is a polymer gel?

99% Water + Polymer + Cross-linker = Immobile Gel

- used for profile modification and in-depth conformance control at injection wells

- used to shut-off excessive water at producing wells in natural waterdrive reservoirs and waterfloods
Injection Well Profile Modification Treatments

a.k.a.

Conformance Control
Injection Redistribution
Sweep Improvement
Factors that determine recovery efficiency

**Vertical Sweep Efficiency**: the volume of rock that is contacted in the vertical plane

**Areal Sweep Efficiency**: the volume of rock that is contacted in the horizontal plane

**Displacement Efficiency**: the volume of mobile oil displaced from the contacted rock
Injector Treatments
SECONDARY/TERTIARY RECOVERY

Vertical Sweep Ideal Case

Injector

Injected fluid

Producer
**Injection “cycling”**

- **By-passed oil (low K)**
- **Swept layer (high K)**
- **By-passed oil (low K)**

[Diagram](www.getmoreoil.com)
Realty

By-passed oil

By-passed oil
When $K_{vh}$ is high... 

*near-wellbore* treatment will result in *less* incremental recovery.
When $K_{vh}$ is high... *in-depth* treatment will result in *more* incremental recovery
When $K_{vh}$ is low... near-wellbore treatment will result in more incremental recovery.
Injection water is diverted to other areas of the reservoir and sweeps by-passed oil to the producing wells.
Injection drive fluid is diverted to other areas of the reservoir and sweeps by-passed oil to the producing wells.
Data needed to assess pro-mod treatment

- Base map showing producer & injector well locations
- Geological maps (isopach, structure, HCPV, etc.)
- Reservoir rock & fluid properties
- Geological description
- Core reports
- Historical tabular oil & water production data by well
- Historical tabular injection rate & pressure data by well
- Injection profile logs
- Openhole logs
- Wellbore diagrams
- Well histories
Sizing the job
What is the Swept PV??

By-passed oil
WOR Method
Matrix Breakthrough (larger swept PV)

Cumulative Oil vs. WOR

Oil Response

Water Breakthrough

Swept MPV 140,000 Bbls

WOR

BOPD & BWPD

Cum. Oil Bbls.

- WOR
- Begin Water Injection
- BOPD
- BWPD

www.getmoreoil.com
Swept MPV
140,000 bbls
assign proportionate share to surrounding injectors
Volumetric Method
Example Injector-centered Pattern
Estimate “serviceable” area

Area = 10 acres
Estimate thief height in “serviceable” area from injection profile log
100% of Flow Capacity into only 14.3% of Pay
Calculate Moveable Pore Volume ("MPV") of high K layer (thief) over the "serviceable" area.
More difficult to estimate swept MPV of fractures using Volumetric Method (geometry unknown)
How much of the MPV do we want to fill with polymer? More if $K_{vh}$ is high, and less if $K_{vh}$ is low.
General treatment procedure

1) No well modification required to accommodate job
2) Rig up polymer blending and injection unit to water source and wellhead
3) Inject treatment (“bullhead”-style) with entire producing interval exposed to polymer
4) Polymer injected as a liquid with delayed gelation allows for deep placement of large volumes
5) Polymer will follow the path of least resistance (i.e. high permeability swept rock)
6) Over-displace polymer solution from wellbore
7) SI well for several days to allow gel time to form
8) Reactivate well
First indicator of change is decreased injectivity at treated well (higher injection pressure is required to inject water into lower permeability rock)
Phosphoria Injection Pattern

- 30 acres
- 51,000 bbls
- 29,000 bbls

www.getmoreoil.com
Selective Polymer Treatments Improve Oil Recovery in Five Mature Southern Oklahoma Waterfloods

Portwood (EOGA), Lackey (Citation), & Abel (Citation)
Producing Well Water Shut-off Treatments
Data needed to assess WSO treatment

- Reservoir rock & fluid properties
- Geological description (how water gets to the wellbore)
- Core reports
- Historical tabular oil & water production data
- Static SI and producing fluid level
- Openhole logs
- Wellbore diagram
- Well history
Gel polymer for WSO at producing wells

→ Most effective when K contrast is high (fracture flow)
→ Natural waterdrive or waterflood reservoirs
→ Out-of-zone stimulation treatment
→ 3-dimensional coning
→ Channeling through matrix
→ Casing leaks
Typical High Water-cut Well

Flat water and declining oil indicate max pump capacity, and increasing fluid level.
Distance Matters!
deep placement = more oil
(but how deep?)

Productivity Index (PI) estimates maximum flow capacity at
zero pressure gradient

- High PI = large flow features = large PV = large gel volume
- Low PI = small flow features = small PV = small gel volume
General treatment procedure

1) Pull production equipment
2) Install tubing & packer above top perforation or openhole section
3) Aggressively acidize well
4) Rig up polymer blending and injection unit to water source and wellhead
5) Inject treatment ("bullhead"-style) with entire producing interval exposed to polymer
6) Polymer will follow the path of least resistance (i.e. offending water flow conduits)
7) Over-displace polymer solution from wellbore
8) SI well for several days to allow gel time to form
9) Reactivate well
Lower K layers start to contribute more oil.
Combining Continuous Improvements in Acid Fracturing, Propellant Stimulation, and Polymer Technologies to Increase Production and Develop Additional Reserves in a Mature Oil Field

Whisonant (Marathon) & Hall (Marathon)
New Well

Phosphoria Dolomite (Wyoming) – Daily Rate vs Time

Pre-polymer PI = 32 BPD per psi drawdown
Estimated maximum producing rate = 24,000 BPD
Incremental Oil from Decline Curve = 3,500 Bbls
Cumulative Water Reduction = -350,000 Bbls
Phosphoria Formation – Candidate Selection, CRM, Gel Polymer Treatment Model
Components of the Methodology

**Step I** – Production Diagnostics, Data Analysis, Data Preparation, Sector Selection
- Production Diagnostics, WOR vs Cumulative Production, CRM, Core Analysis, Upscale Simulation Layers

**Step II** – Estimation of Depth and Volume of Treatment
- Apparent Viscosity using Viscoelastic Model, Couple with Fluid Flow Model, Generate Depth and Volume of Gel Polymer Injected

**Step III** – Apply Gel Polymer Footprint in the Numerical Sector Model and Compare Effects of Continued Waterflood OR Fracture Modeling
- Calibrate Numerical Model to Current Watercut conditions, Upload Gel polymer Footprint, Run two Cases to Compare (a) Continued Waterflood and (b) Waterflood after Treatment
Phosphoria Formation – Gel Polymer Treatment (Fractured Producer)
Zero Time Cumulative Oil
Production Diagnostics – 5713

WOR vs. Time

Log-log Plot

coning

channeling

Time (days)
History Match – 5713 fracture distribution – run 1

Ratio = 1
History Match – 5713 watercut – run 2

Ratio = 1.5
History Match – 5713 watercut – run final

Ratio = 6
Treatment Volume 5713

- Treatment Volume:
  - 3,000 bbls
  - 10,000 bbls

Graph shows:
- Post Treatment PI Change
  - Oil PI Change
  - Water PI Change

www.getmoreoil.com
Phosphoria Dolomite (Wyoming) – Daily Rate vs Time

Pre-polymer PI = 32 BPD per psi drawdown
Estimated maximum producing rate = 24,000 BPD
Incremental Oil from Decline Curve = 3,500 Bbls
Cumulative Water Reduction = -350,000 Bbls
Phosphoria – Gel Polymer Treatment (Injector)
CRM Results – Gains Matrix - Phosphoria

Gain's Matrix Plot - > 0.1

Copyright SiteLark LLC 2012

www.getmoreoil.com
Fraction of Water Injected

Fraction Water Injected
Phosphoria Formation

www.getmoreoil.com
Total Liquid Produced

Cumulative Liquid
Phosphoria Formation

www.getmoreoil.com
(Produced – Injected)
Step I – Data Preparation -- Layered Reservoir Properties

No Treatment

Oil viscosity ~ 200 cp
Mobility Ratio ~ 133
Kv/kh ~ 0.1

Effects of viscous fingering and permeability contrast

<table>
<thead>
<tr>
<th>No of Layers</th>
<th>Thickness (ft)</th>
<th>Porosity</th>
<th>Permeability (mD)</th>
<th>Connate Water Saturation</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>1.05</td>
<td>0.12</td>
<td>49.38</td>
<td>1.05</td>
</tr>
<tr>
<td>2</td>
<td>16.10</td>
<td>0.14</td>
<td>3.20</td>
<td>16.10</td>
</tr>
<tr>
<td>3</td>
<td>33.13</td>
<td>0.18</td>
<td>537.82</td>
<td>33.13</td>
</tr>
<tr>
<td>4</td>
<td>10.03</td>
<td>0.15</td>
<td>366.93</td>
<td>10.03</td>
</tr>
<tr>
<td>5</td>
<td>19.83</td>
<td>0.20</td>
<td>1161.71</td>
<td>19.83</td>
</tr>
<tr>
<td>6</td>
<td>17.62</td>
<td>0.12</td>
<td>912.36</td>
<td>17.62</td>
</tr>
<tr>
<td>7</td>
<td>13.42</td>
<td>0.12</td>
<td>142.21</td>
<td>13.42</td>
</tr>
<tr>
<td>8</td>
<td>7.47</td>
<td>0.12</td>
<td>150.52</td>
<td>7.47</td>
</tr>
<tr>
<td>9</td>
<td>12.83</td>
<td>0.12</td>
<td>43.77</td>
<td>12.83</td>
</tr>
<tr>
<td>10</td>
<td>22.87</td>
<td>0.12</td>
<td>110.41</td>
<td>22.87</td>
</tr>
</tbody>
</table>
Step II – Estimate Depth and Volume of Invasion

Apparent viscosity calculation for different flow regimes (shear thinning, shear thickening, Newtonian)

$$\mu_{app} = \mu_w + \left( \mu_p^0 - \mu_w \right) \left[ 1 + \left( \lambda \gamma_{eff} \right)^2 \right]^{(n_1-1)/2} + \mu_{max} \left[ 1 - \exp \left( - \left( \lambda_2 \tau \gamma_{eff} \right)^{n_2-1} \right) \right]$$

Pressure Drop calculation in a layered system

$$\Delta p = \frac{q_t}{0.007081 h \lambda_p} \ln \left( \frac{r_p}{r_w} \right) + \frac{q_t}{0.007081 h \lambda_w} \ln \left( \frac{r_w}{r_p} \right)$$

Delshad, M. et al. 2008; Stavland, A et. al. 2010

www.getmoreoil.com
Step II -- Depth and Volume of Invasion

![Graph showing depth and volume of invasion with data points and lines for Perm (14-7), volume (14-7), and radius (14-7).]
Step III – Comparison of Performance

No Treatment

Case I – continued waterflood

Case II – waterflood post treatment

Treatment
Step III -- Comparison of Oil Rates

IBO ~ 50 M STB in 10 years

www.getmoreoil.com
Step III -- Comparison of Watercut
Questions?