Polymer Flooding – Field Development Projects in Statoil

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Outline

• Field development projects
  – The gain of applying polymer technology
  – EOR qualification steps
  – Hurdles and important tasks
• Example
  – Polymer injection test at Heidrun field
Ongoing Polymer flooding development projects in Statoil

- Heidrun, NCS
  First NCS offshore polymer injection test 2010!

- Bressay, UK
- Mariner, UK

- Petrocedeno, Brazil
- Peregrino, Brazil

- Johan Sverdrup, NCS
- Dalia, Angola
Oil recovery improvement by polymer injection

\[ M = \frac{\lambda_w}{\lambda_o} = \frac{\mu_o k_{rw}^*}{\mu_w k_{ro}^*} \]

- **Fluid systems where M > 1** (water has higher mobility than oil):
  - Improve the microscopic sweep efficiency (reduced fractional flow of water) without altering the residual oil saturation
  - Reduce viscous fingering
  - Improve macroscopic sweep efficiency if severe reservoir heterogeneities exists

- **Fluid systems where M ~ 1** (approximately equal mobility for both water and oil)
  - Improve the macroscopic sweep efficiency if significant reservoir heterogeneity exists
Theory of polymer flooding

- Fluid systems where $M > 1$ (water has higher mobility than oil):
  - Accelerate the microscopic sweep efficiency (reduced fractional flow of water)
  - Reduce viscous fingering
  - Improve macroscopic sweep efficiency if severe reservoir heterogeneities exists

Theoretical gain of oil at 0.8 watercut for waterflooding vs. 5 cp polymerflooding is 15%
Viscosity of heavy crude oil

- Acetone: 0.3
- Water: 0.9
- Mercury: 1.5
- Grane: 12
- Olive Oil: 81
- Tomato Puree: 176
- Honey: 3000
Theory of polymer flooding cont.

- Fluid systems where $M \sim 1$ (no viscous fingering):
  - Improve the macroscopic sweep efficiency if significant reservoir heterogeneity exists

![Layers with strong contrast in permeability](image)

- Waterflooding
- Waterflooding with polymers
Building a toolbox for offshore EOR

- Screening
  - CO₂ injection
  - Surfactant flooding
  - Microbial

- Lab
  - Design water for injection
  - Polymer flooding
  - Water diversion by chemicals

- Large-scale test
  - Yard tests polymer and chemical flow diversion
  - Single-well chemical tracer tests Heidrun, Snorre, Gullfaks & Oseberg
  - Injection tests: Heidrun polymer (2010), Snorre diversion (2010)

- Multi-well pilots
  - Oil-Water separation tests, 2013
  - WJSTP silicate flow diversion pilot on Gullfaks
  - Na-silicate flow diversion pilot on Snorre

- Commercial deployment
  - Norne Field: Full-field Microbial EOR
Polymers for enhanced oil recovery

- Purpose: Increase the viscosity of water used in waterflooding

- Two main classes used for polymer flooding:
  - HPAM (Hydrolyzed polyacrylamide)
  - Biopolymers (Xanthan)
Requirements for EOR polymers

- High viscosity under reservoir conditions
- Good solubility and filterability (injectivity)
- Stable during injection and in the reservoir (no loss of viscosity)
- Compatible with injection chemicals
- Environmentally acceptable (green)
- Minor impact on the oil-water separation process
HPAM

- Synthetic polymer
- High molecular weight, 2 – 20 million Dalton
- High viscosity at low concentration
- Sensitive to temperature, salinity and hardness
- "Cheap"
- More than 90 % of polymer floods performed with HPAM
Polymer flooding – Improvement options (desalination of injection water)

- Desalination of injection water can significantly improve HPAM efficiency.

- Qualification programs for nano-filtration (NF) and reverse osmosis (RO) technologies ongoing.

- NF plants for removal of sulphate from sea water already in operation at Statoil installations.

![Effect of salinity at low hardness](image)
Biopolymers - Xanthan

- High molecular weight: 2 – 50 million Dalton
- High resistance to temperature
- Less sensitive to salinity and hardness
- Very sensitive to bacterial degradation - Need for biocide
- Expensive
Polymer: Stability under injection and in the reservoir

- Chemical degradation: Hydrolysis, oxidation

- Mechanical degradation: Breakdown at high rate, shear

- Biological degradation: Bacterial degradation (not a problem at high temperatures)

- Salinity: Precipitation and flocculation in reaction with mono- and divalent-ions (Na⁺, Ca²⁺, Mg²⁺,…)

- Temperature: HPAM degrades at ≤ 80 °C, Xanthan at ≤ 90 °C
Additional polymer injection issues

- Logistics and mixing offshore
- Compatibility with other injection chemicals
- Shear during injection to minimize degradation
- Production challenges
  - Interference of polymer with oil and production chemicals
- HSE issues
  - Polymer breakthrough in producers
  - No discharge of HPAM to sea (re-injection of produced water)
  - Water management (cleaning of produced water)
Offshore Polymer/LPS Injectivity Test with Focus on Operational Feasibility and Near Wellbore Response in a Heidrun Injector

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OUTLINE

• Heidrun field
• Objectives polymer and LPS injection test
• Polymer and cross-linker
• Yard test
• Logistics and operations
• Sampling and analysis program
• Results
• Conclusions
HEIDRUN

- Discovered 1985, on production since 1995, life time 2045
- Floating tension leg platform + subsea tie-ins
- Water injection: SW, SRP, PWRI
- Planned for 56 well slots + 5 tie-ins
- Oil in place 432 MSm³ (2 717 Mbbl)
- Reserves: 177 MSm³ (1 113 Mbbl) oil + gas
- Recovery factors in the range of 10 % to 60 %
- Polymer or linked polymer solution (LPS) injection could increase oil recovery on Heidrun
OBJECTIVES POLYMER AND LPS INJECTION TEST

• Objective I
  – Determine logistical and operational feasibility of polymer/LPS injection
    • Transport, Mixing, Storage, Pumping

• Objective II
  – Observe reservoir and near well bore response
    • Pressures and temperatures versus polymer loading and injection rates
HOW POLYMERS IMPROVE OIL RECOVERY

• Polymer
  – Hydrolysed polyacrylamide (HPAM)
  – Mobility improvement: Polymer increases viscosity of injected water from 0.38 cp to ~ 2.0 cp - much closer to reservoir oil viscosity (2 – 4 cp)

• Linked polymer solution (LPS)
  • LPS is HPAM cross linked with aluminium to form nano-sized particles
  • Diversion: Nano-sized LPS particles can block water “channels” in the reservoir and divert flow to non-swept areas
  • Mobility improvement: As for HPAM
HSE DATA POLYMER AND CROSS-LINKER

• Polymer
  – Hydrolysed polyacrylamide (HPAM)
  – Health: Green, Safety: Green, Environment: Red*
  – Material is very slippery when wet

• Cross-linker
  – Aluminum Citrate
  – Health: Green, Safety: Green, Environment: Green

*) Approval from Norwegian Pollution Control Authority to inject max. 3 600 kg HPAM classified as red chemical in a Heidrun water injector during 2010
YARD TEST AT ULLRIGG, STAVANGER, AUG. 2008

• Objective:
  – Reveal logistical and operational considerations which may have implications for the offshore test

• Main conclusions:
  – Polymer mixing unit to be improved before the offshore injection pilot
  – Centrifugal pumps onshore, on board the supply vessel, and on the platform need to be replaced or by-passed
  – Dilute the cross linker solution to give accurate dosing
HEIDRUN POLYMER AND LPS INJECTION TEST SEPT. 2010

- Mix 5 000 ppm HPAM “mother” solution onshore in Kristiansund

- Ship “mother” solution offshore and store at Heidrun platform

- Inject “mother” solution downstream wellhead choke to final polymer conc. of 300 ppm and 600 ppm in SRP water

- Inject cross linker, AlCit, downstream wellhead choke at 300:10 and 600:20 polymer:Al ratio in SRP water
Dissolution Test April 2009

- Polymer slicing unit for wetting the polymer powder
- Capacity 100 kg/h powder

Upgrading Onshore Facilities

- Stainless steel tanks with paddles to mature and store the “mother” solution
- Screw pump for loading the polymer solution to the supply vessel
- Tanks and lines tested for iron, < 5 ppm
- Required 700 m$^3$ of 5 000 ppm “mother” solution (3 500 kg powder)
- Polymer powder from May 2009 rejected; filter ratio 3 – 3.7 (1.5 recommended in API 63)
  - Freshly produced polymer delivered 5 days later
SAMPLING AND ANALYSIS PROGRAM

• High quality polymer solution is challenging
  – Shear degradation, chemical degradation and biological degradation
• Quality control (QC) of polymer powder
  – Water content, insoluble particles, viscosity and filter ratio
• Quality control (QC) of polymer “mother” solution and diluted solutions (300 ppm, 600 ppm)
  – Viscosity, filter ratio, iron content, pH, temperature, and samples for chemical analysis
• Supply vessel with screw pumps identified
• No need for biocide in “mother” solution
  – 3 months before bacterial activity
• Insignificant degradation over time in a 3 weeks rolling test
• The vessel’s mud tanks inspected and re-washed
• “Mother” solution in the platform’s completion storage tanks and mixing tanks
  – Total volume available 300 m³
• Vessel and platform lines and tanks tested for iron
  – < 10 ppm
• Three batches of “mother” solution a 230 Sm³
• Shipped offshore in 3 separate trips
• Injection batches:
  1. 300 ppm polymer
  2. 300 ppm polymer + 10 ppm x-linker
  3. 600 ppm polymer; 600 ppm polymer + 20 ppm x-linker
• Sampling for QC (viscosity, filter ratio, iron)
  – Before and after mixing onshore
  – After pumping to vessel
  – When arriving offshore
  – During injection
• Well injectivity tested before and after injection
INJECTION VISCOSITY AT WELLHEAD - OFFSHORE

Sample point 3: Polymer feed location upstream cross-linker feeding
Sample point 5: Well-head

Polymer Solution Viscosity for Samplepoint 3 (red) and Samplepoint 5 (blue)

Solution Viscosity (cP)

Polymer/Al-Cit Ratio and Injection Rate (m3/d)

Polymer 300 ppm
LPS (300 ppm:10 ppm)
Polymer 600 ppm
LPS (600 ppm:20 ppm)
FILTER RATIO DATA AT WELLHEAD - OFFSHORE

Filter Ratio for Samplepoint 3 (red) and Samplepoint 5 (blue)

Polymer/Al-Cit Ratio and Injection Rate (m3/d)

Polymer 300 ppm
LPS (300 ppm:10 ppm)
Polymer 600 ppm
LPS (600 ppm:20 ppm)
INJECTIVITY BEFORE AND DURING POLYMER & LPS INJECTION

- Polymer and LPS injectivity improved compared to water injectivity before the test due to dual fracturing at lower injection rate.

- Polymer and LPS injection giving approx. 20 bars lower downhole pressure at rates below 150 m³/h (= 3 600 m³/D).
INJECTIVITY BEFORE AND AFTER POLYMER & LPS INJECTION

- After a shutdown the dual fracture system closed, and injectivity and WHP is back to same level as before the test
- The polymer/LPS test has not harmed the injectivity
CONCLUSIONS

- Storage, mixing, transport and injection of polymer solution in harsh climate is possible without destroying the polymer.

- Maintaining polymer viscosity required proper planning and stringent quality control.

- Polymer and LPS injection has not harmed, but improved well injectivity due to dual fracturing.

- No viscosity degradation occurred in the tubing during injection.

- No discharge of “red” polymer to sea.
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Thank you for your attention!
There's never been a better time for good ideas