Feasibility of Oil Recovery by Chemical Flooding through Horizontal Wells
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Abstract
A laboratory and economic study on Badri crude oil production by polymer, surfactant and surfactant/polymer flooding from a horizontal well in a scaled five-spot sandpacked model was conducted. Crude oil from Gupco* Badri Field was used in the displacement tests. The grain size distributions of the used sand are similar to those of the Badri formation. Surfactant and polymer slug concentrations were 1.0% by weight and 500 PPM, respectively. Physical properties of the surfactant and polymer solutions were experimentally determined to select those most suited for the displacement runs. The suitability of the enhanced oil recovery predictive models** developed by the department of energy (U.S.A), to predict the experimental data and assess the feasibility of oil recovery by chemical flooding was investigated. Results show that the maximum oil recovery is obtained from the sandpack model by polymer flooding with a slug size equal to 30% of the pore volume. A good agreement exists between the experimental data and values calculated from the software. The economic study revealed the feasibility of oil recovery from Badri oil field by polymer flooding through a horizontal well configuration.

Introduction
The current focus on horizontal drilling, which began in the late 1970's, resulted from the improvements achieved in directional drilling techniques coupled with the need to increase oil production. During the eighties, the concept of horizontal drilling has gradually become widely accepted as a method for improving the efficiency of hydrocarbon extraction. More recently, it has been applied to conventional oil and gas reservoirs to provide economic production of marginal reserves.

By definition, a horizontal well is one, which reaches 90% for a horizontal formation or reaches the dipping angle for an inclined formation. Its drilling cost per foot is 1.4 times the cost of a deviated well and its production is four times that of a vertical well.

Enhanced oil recovery (EOR) has been hampered by its unfavorable economy and, technically, by the lack of local knowledge of the reservoir characteristics. As the value of injected chemicals is significantly higher than that of water or gas, the economic considerations prohibit their massive use. Most of the EOR projects also require a substantial infill-drilling program. A lighter and more economical horizontal drilling program can, in many cases, replace infill-drilling.

If we consider the basic principle of EOR, all processes practically aim at increasing the absolute or relative oil mobility. However, the global mobility of the oil results from the combined effect of the intrinsic mobility (relative permeability divided by viscosity) and that of the flow geometry. By improving flow geometry, horizontal wells can harmoniously complement EOR processes.

Horizontal well technology is recently being applied to the production of crude oil by thermal recovery, gas injection, waterflooding, chemical flooding and to the exploitation of conventional reservoirs. Laboratory studies on the recent applications of horizontal well technology are rather scarce, despite of the increasing number of horizontal wells drilled worldwide. Egyptian oil companies have also drilled several horizontal wells to increase the productivity of their oil reservoirs. Elfie reports that, the two horizontal wells in the Khaldah Hayat and Salam oil fields in Egypt have a potential productivity of about 10 times that of vertical wells. Higher productivity of low permeability reservoirs.

* Gulf of Suez Petroleum Company.
** The models are available in computer software format.
is attained when the horizontal well bore is connected to the natural vertical fractures. Gupco drilled a horizontal well in July field (J-69). The horizontal well (J-69) demonstrates how a horizontal well solves the sweep problem of trapped oil, and recovers more than 5.0 MMBO\textsuperscript{a}. The Badri horizontal well (A-16) is used to overcome occurring gas conning problems. In the Issran oil field operated by General Petroleum Company (GPC), steam flooding through horizontal wells will be conducted\textsuperscript{21}.

This study focuses on the improvement of oil recovery through horizontal wells by surfactant and/or polymer flooding. The investigation aims at assessing the effects of the following factors on oil recovery: formation heterogeneity, horizontal well eccentricity (well position above, at or below the formation central axis), oil in-place, surfactant and/or polymer slug size, ratio of the perforated horizontal well length to the vertical well distance in the five-spot model, and horizontal well configuration. The volumetric and displacement efficiencies, taking into consideration the effect of viscous and capillary forces, are also studied to determine the displacement mechanisms.

**Experimental Work:**

**Fluid and Rock Properties**

Crude oil, formation water and rock were obtained from the Badri oil Field (GUPCO). The surfactant and polymer fluids are BAN\textsubscript{2} (a locally manufactured surfactant) and Polyacrylamide (PAM), respectively. The interfacial tension between the surfactant solutions and Badri crude oil were measured by a Spinning Drop Tensiometer model-300. Rheological properties were measured using a Rotary Viscometer (Rotovisco RV-12 Viscometer) at different temperatures. Permeability, porosity and grain size distributions of the formation used were also experimentally determined.

**Experimental Set-up**

A schematic of the experimental setup is shown in Fig. 1. It consists of:

1. A scaled five spot sandpack model,
2. Oil, brine and chemical solutions reservoirs,
3. Nitrogen cylinder,
4. Pressure gauges,
5. Oil bath.

The five spot model consists of an inner and an outer square box with dimensions 52.0x52.0x13 cm for the outer box and 43.0x43.0x6.0 cm for the inner box. The outer box is connected to the constant temperature oil bath. Outside and inside diameters of the horizontal and vertical wells are 0.72 cm and 0.40 cm respectively. The density of perforations is 8/cm. The horizontal and vertical wells are wrapped with screens to prevent sand inflow. The model scaling calculations are summarized in Table 1, which indicates that the calculated scaling parameters are in agreement with practical ranges. Equality of the vertical and horizontal permeabilities is assumed. The scale-up parameters were originally conceived for vertical wells and the selected horizontal well diameter was taken equal to that of the vertical well, based on the modeling techniques suggested by Chang et al\textsuperscript{20}.

**Experimental Procedure.** The model is first packed with sand and then saturated with formation water (132,440 PPM salinity). The formation water is then displaced by crude oil at the actual reservoir temperature of 70°C until the reservoir saturation conditions are attained. The following schemes are subsequently used for displacing the oil in-place:

a. Waterflooding under varying conditions of formation heterogeneity, perforated length ratio\textsuperscript{a} and well configuration.

b. Injecting surfactant and/or polymer solutions into the sandpack and displacing them by approximately four pore volumes of seawater at different starting oil saturation levels.

**Results and Discussions:**

**Physical Properties.** Measurements of interfacial tension between crude oil and chemical solutions and viscosity of crude oil and chemical solutions are plotted on Figs. 2 through 7. Fig. 2 indicates that the lowest value of interfacial tension corresponds to 1.0% by weight of surfactant concentration. Figs. 3 and 4 illustrate the effects of salinity and temperature on interfacial tension. Fig. 3 indicates that the lowest value of interfacial tension is obtained at a NaCl concentration of 10% by weight. Fig. 4 shows that the interfacial tension between crude oil and surfactant solution reaches its minimum value at the reservoir temperature of 70°C. Figs. 5 through 7 indicate that the rheological behavior of crude oil, surfactant and polymer solutions is pseudo-plastic at the experimental temperatures.

**Effect of formation heterogeneity on oil recovery by conventional water flooding.**

Due to the wide variation in permeability of the Badri formation (heterogeneity), four displacement runs were carried out using four different porous configurations to study the effect of heterogeneity on oil recovery by waterflooding. Table 2 shows the characteristics of the four studied formation packings. Fig. 8 shows that, formation (FB4) gives the highest oil recovery because of the well-sorted grain size, which leads to the highest obtainable permeability level.

**Effect of horizontal well eccentricity on oil recovery.**

Three runs were conducted to study the effect of well eccentricity (horizontal well position above, at or below the

\textsuperscript{a} The perforated length ratio is a dimensionless oil string length parameter characterizing the experimental five spot sandpack model and expressed as fraction of the distance separating two consecutive vertical injection wells.
Formation central axis) on oil recovery. The results are plotted on Fig. 9, which indicates that the highest oil recovery is obtained for the centered position of the horizontal well. This increase in oil recovery is due to the delayed water breakthrough.

Effect of the perforated length ratio (horizontal perforated well length related to the horizontal distance between vertical injection wells).

Three runs were conducted to study the effect of the perforated length ratio parameter on oil recovery by conventional waterflooding. The results are plotted on Fig. 10. Latter shows that the highest oil recovery is attained when a perforated length ratio of 0.810 is used. This optimum perforated length ratio achieves the best combination of a large contact area between well and producing formation, in addition to a sweep efficient flow pattern of oil and displacing water. This leads to a better exploitation of reserves in comparison to production operations from vertical wells.

Surfactant Flooding Strategy

As a normal trend, it was customary to start the enhanced oil recovery process using chemicals after completion of the waterflooding operation. In this study, it was attempted to investigate the effect of varying the onset timing of chemical injection (surfactant or polymer) on oil recovery. The aim thus focused on determining the most favorable remnant oil in-place fraction (or simply the oil saturation level) which maximizes oil recovery by chemicals (surfactant and/or polymer) flooding. The oil recovery by plain waterflooding does not exceed 66.0% (Fig. 8), and the remaining oil is thus 34% of the initial oil in-place. The start of chemical injection at oil in-place levels equal to 100, 78, 67 and 34% of the initial oil in-place was, therefore, investigated.

The experimental data of surfactant flooding with varying oil in-place levels are plotted on Fig. 11. It appears that the cumulative oil recovery gradually increases with increasing oil in-place between 34 and 67% and then decreases. The highest oil recoveries are thus obtained when the oil in-place has dropped down to 67% of its initial maximum saturation value. This is consistent with results plotted on Fig. 12, which indicates that the volumetric, displacement efficiencies, and the capillary number reach their maximum values at an oil in-place level of 67%.

Effect of surfactant slug size on oil recovery. Since the cost of chemicals in an enhanced oil recovery process is significant, the feasibility of enhanced oil recovery can best be appraised by determining the economically optimum slug size, based on an operations expense versus oil recovery gain consideration.

Five displacement runs were conducted to study the recovery of Badri crude oil by surfactant using five surfactant slug sizes, i.e. 10, 20, 30, 40 and 50%PV. The concentration of the surfactant was 1.0% by weight dissolved in 0.5% by weight of a sodium chloride solution. The obtained results are plotted on Fig. 13. Latter shows that oil recovery by surfactant flooding, with a slug size equals to 20% of the pore volume, attains its highest value. Since the oil recovery achieved, using a 20% slug size is only slightly higher than that obtained for a 10% slug size value, the use of a 10% surfactant slug size is economically justified.

Polymer flooding strategy

The experimental results of polymer flooding at an oil in-place stage of 34, 67 and 78% of its initial saturation value are plotted on Fig. 14. This figure indicates that the cumulative oil recovery reaches its maximum when polymer injection starts at a current oil in-place level equal to 67% of its initial level. It is also observed that the injection of surfactants, immediately after waterflooding, recovers the least oil, the starting value of oil in-place being equal to 34% of the initial oil in-place. Hence, the efficiency of an oil rejection process is strongly affected by the amount of oil available in the reservoir at the onset of the polymer injection operation. These results are consistent with those obtained from the surfactant flooding experiments.

Effect of polymer slug size on oil recovery. The results of polymer flooding (at 500PPM concentration) are plotted on Fig. 15, which indicates that oil recovery increases with increasing slug size. However, increasing the polymer slug size from 30% to 40% of the pore volume improves oil recovery only slightly. From an economical point of view, using a slug size in excess of 30% is thus not justified.

Surfactant/Polymer flooding

The results of the displacement runs are plotted on Fig. 16, which indicates that the oil recovery increases with increasing displacement slug size. It also appears that a change in slug sizes from 10/20% to 20/10% does not affect oil recovery. Thus, the highest oil recovery is obtained when using a slug size of 0/30% (ref. Fig. 15). This means that the use of a 30% polymer slug size gives the maximum oil recovery.

The higher oil recovery obtained when using polyacrylamide (i.e. water-soluble polymers) probably results from an increase in viscosity of the displacing water. The polyacrylamide adsorbed along the permeable channels of the reservoir also reduces water fingering and consequently improves sweep efficiency.

Effect of horizontal well configuration (either injector or producer) on oil recovery

The results of the displacement runs are plotted on Fig. 17, which indicates that the highest oil recovery is
obtained when using a horizontal well as producer in a waterflood/polymer flooding operation. The use of a horizontal well as producer leads to favorable flow patterns of the fluids and delays the water breakthrough. This favorable oil displacement situation does not occur when the horizontal well is operated as injector.

Conclusions
The following conclusions emerge from the experimental work results:

1. Oil recovery is strongly affected by the physical properties of crude oil and chemical solutions.
2. Oil recovery is higher for a polymer flooding than for a surfactant flooding operation.
3. Sorting the sandpack improves secondary oil recovery by waterflooding.
4. Increasing the perforated length ratio up to a 0.81 value improves oil recovery.
5. Oil recovery tends to decrease when the horizontal well is positioned below or above the central axis path of the formation at the advanced flooding displacement stages (when four pore volumes are injected). However, oil recovery is almost unaffected by the well position at the early displacement stages (one pore volume injected).
6. Oil recovery by surfactant or polymer flooding is significantly affected by the onset timing of the tertiary recovery operation (surfactant or polymer slug injection).
7. Replacing a vertical well by a horizontal well as a producer improves oil recovery.
8. The oil-water bank stability in surfactant and polymer flooding processes is dependent on slug size and slug injection time.

Nomenclature

- **EPRI**: Egyptian Petroleum Research Institute
- **EOR**: Enhanced Oil Recovery
- **PPM**: Parts per Million
- **IOIP**: Initial Oil in-place
- **MMBO**: Million Barrel of Oil
- **PLR**: Perforated Length Ratio = horizontal oil string length expressed as fraction of the distance separating two consecutive vertical injection wells, dimensionless
- **PV**: Pore Volume, cubic centimeter
- **WF**: Water Flooding
- **PF**: Polymer Flooding
- **a_o**: dimensionless well spacing
- **a**: interwell distance, cm
- **h**: formation thickness, cm
- **k_o**: vertical permeability, millidarcy
- **k_h**: horizontal well, millidarcy
- **r_w**: dimensionless well radius
- **r_w**: well radius, feet
- **b_d**: dimensionless well penetration
- **b**: perforated length, cm
- **M**: mobility ratio
- **k_o**: oil permeability, millidarcy
- **k_w**: water permeability, millidarcy
- **C_{pp}**: cumulative production parameter
- **S_{or}**: residual oil saturation, fraction
- **S_{wi}**: initial water saturation, fraction
- **q**: rate of flow, cc/sec
- **A**: cross sectional area, cm², or feet²
- **t**: time, hr
- **R_l**: gravity force/viscous force ratio
- **k_g**: air permeability, millidarcy

Greek Symbols

- **Δρ**: density difference of the two phases, Kg/cm³
- **θ**: sorting coefficient
- **φ**: porosity, %
- **μ_o**: oil viscosity, cp
- **μ_w**: water viscosity, cp
- **γ**: shear rate, sec⁻¹

Subscripts

- **φ**: residual oil
- **w**: initial water
- **p**: production parameter
- **D**: dimensionless
- **g**: gas
- **o**: oil
- **w**: water or well
- **v**: vertical
- **h**: horizontal

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Remark

The present article is extracted from a Ph.D. thesis entitled “Enhanced Oil Recovery by Chemical Flooding through Horizontal wells,” submitted to the Mining, Petroleum and Metallurgical Engineering Department, Faculty of Engineering, Cairo University, under the supervision of Professor Dr. M.E. EL-Sallaly, Professor Dr. M.H. Sayyouh, Professor Dr. M.H. EL-Batanony and Dr. T.M. Darwich.

References


21. General Petroleum Company, Personal contact.

### SI Metric Conversion Factors

- ft x 3.048* = E-01 = m
- dyne/cm x 1.0 = E+00 = mN/m
- md x 9.869233 = E-04 = m²
- psi x 6.894757 = E+00 = kPa

*Conversion factor is exact

### Table 1 - SCALING LABORATORY MODEL CALCULATIONS

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<thead>
<tr>
<th>Parameters</th>
<th>Laboratory Model</th>
<th>Possible Practical Range</th>
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<td>Geometrical Parameters:</td>
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<td>Dimensionless Well Spacing</td>
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<td>$a_D = \frac{a}{h \sqrt{k_h k}}$</td>
<td>10.73</td>
<td>2.0 to 20.0</td>
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<td>Dimensionless Well Radius</td>
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<td>$r_w = \frac{r_w}{h \sqrt{k_h}}$</td>
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<td>8<em>10⁻³ to 2</em>10⁻¹</td>
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<td>Dimensionless Well Penetration</td>
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<td>$b_p = \frac{b}{h}$</td>
<td>1.0</td>
<td>0.0 to 1.0</td>
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<tr>
<td>Rock and Fluid Property Parameters:</td>
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<td>Mobility Ratio</td>
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<td>$M = \frac{K_s \mu_w}{\mu_k}$</td>
<td>1.15</td>
<td>0.1 to 1.0</td>
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<td>Cumulative -Production Parameter</td>
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<tr>
<td>$C_{pp} = \frac{h \phi (1 - \frac{S_w}{S_w})}{\frac{q}{A}}$</td>
<td>Unity</td>
<td>Unity</td>
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<tr>
<td>Dynamic Parameters:</td>
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<tr>
<td>Gravity - to - Viscous Force Ratio</td>
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<td>$R_1 = \frac{k_s \Delta \rho A}{q \mu_k}$</td>
<td>119.238</td>
<td>0 to 1,000</td>
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### Table 2 - Values of Porosity, Effective Permeability and Sorting Coefficient for the Four formations.

<table>
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<tr>
<th>Formation No.</th>
<th>Porosity, $\phi$ (%)</th>
<th>Effective Permeability, $\mu m^2$</th>
<th>Sorting Coefficient, $\phi$</th>
<th>Heterogeneity Index</th>
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<td>FB1-6130/40</td>
<td>30.90</td>
<td>1506</td>
<td>1.15</td>
<td>Poorly Sorted</td>
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<td>FB2-6120/30</td>
<td>29.57</td>
<td>1772</td>
<td>1.010</td>
<td>Poorly Sorted</td>
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<td>FB3-6160/70</td>
<td>29.90</td>
<td>3457</td>
<td>0.879</td>
<td>Moderately Sorted</td>
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<tr>
<td>FB4-6600/10</td>
<td>29.80</td>
<td>3765</td>
<td>0.667</td>
<td>Moderately Well Sorted</td>
</tr>
</tbody>
</table>

Note: The tables and equations are simplified representations of the original content to fit within the text limits.
Fig. 1 – Schematic of Experimental Set-up.

Experimenta l Set-up:
1,2,3,4 Vertical Well “Tubing”
5 Horizontal Well “Tubing”
6,7 Physical model and oil bank.
8 Pressure gauges
9,10,11 Reservoir of Crude Oil, brine and chemical solutions
12 Nitrogen Cylinder
13 Yello
14 Unstated cylinder.

Fig. 2 – Effect of surfactant concentration on interfacial tension between Badri crude oil and surfactant solution.

- 100% NaCl = 0.0%CaCl2
- 90% NaCl = 10% CaCl2
- 80% NaCl = 20% CaCl2
- Sea water
- Polymer solution in distilled

Fig. 3 – Effect of salinity (sodium chloride and calcium chloride) on interfacial tension between both BAN4 blend surfactant and crude oil for a surfactant concentration of 1.0% by wt. and a temperature of 30°C.

Fig. 4 – Effect of temperature on interfacial tension between surfactant solution and Badri crude oil.

- Concentration of surfactant = 1.0% by wt.
  - Salinity, (NaCl) = 0.5% by wt.
Fig. 8—Effect of formation heterogeneity on oil recovery by waterflooding at different pore volumes injected.

Fig. 9—Effect of well Eccentricity on oil recovery.

Fig. 10—Effect of Perforated Length Ratio on oil recovery by water flooding at different pore volumes injected.
Fig. 5 – Viscosity of Badri crude oil at different temperatures.

Fig. 6 – Viscosity of Surfactant Solution (Concentration = 1.0% by weight) at different temperatures.

Fig. 7 – Viscosity of polymer solution (concentration ~ 300 PPM) at different temperatures.
Fig. 11 - Effect of start of injection of surfactant solution followed by seawater displacement on oil recovery.

Fig. 12 - Effect of start of flood surfactant injection on volumetric and displacement efficiencies and Capillary Number.

Fig. 13 - Effect of surfactant slug size followed by seawater displacement on oil recovery at different pore volumes injected.

Fig. 14 - Effect of start of injection of polymer solution followed by seawater displacement on oil recovery.
Fig. 15 – Effect of polymer slug size followed by sea water displacement on oil recovery at different pore volumes injected.

Fig. 16 – Effect of surfactant / polymer solutions slug size ratios followed by sea water displacement on oil recovery at different pore volumes injected.

Fig. 17 – Effect of well configuration on oil recovery by water and polymer flooding at different pore volumes injected.