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ANNUAL REPORT

# SURFACTANT-ENHANCED ALKALINE FLOODING FIELD PROJECT

By Troy R. French

Work Performed for
U. S. Department of Energy
Under Cooperative Agreement DE-FC22-83FE60149

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Project SGP41, FY92 Annual Research Plan

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## TABLE OF CONTENTS

**Page**



## TABLES



## ILLUSTRATIONS

# SURFACTANT-ENHANCED ALKALINE FLOODING FIELD PROJECT

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## ABSTRACT

The site selected for conducting a field pilot test using surfactant-enhanced alkaline flooding methods is Hepler (KS) oil field. Hepler field is in Crawford and Bourbon counties. This near-term application of a promising enhanced oil recovery (EOR) technology in a fluvial-dominated deltaic type reservoir is consistent with U. S. Department of Energy oil research strategy. This report is the annual report for FY1992 that covers final site selection and the optimization of slug sizes and chemical (especially polymer) concentrations.

With large pore volumes and high polymer concentrations, injection of chemical formulations produced extremely good oil recovery in core tests conducted in Berea sandstone cores. After chemical flooding, final core oil saturations were as low as 5% PV. For economic reasons, smaller volumes of chemicals will be injected during the field test. Because of the limits on field injection pressure, which is determined by depth and overburden pressure, polymer viscosity will also be reduced for field application. The results of core tests with smaller slug sizes, in Berea sandstones cores with permeabilities representative of the reservoir, showed that total oil recovery up to 71% OOIP can be achieved by injection of smaller chemical slugs. Final oil saturations, after waterflooding and chemical flooding, were as low as 23% PV.

Field cores were obtained from four locations on the lease site. The evaluation of field cores and the evaluation of maps of permeability, porosity, oil saturation, and stratigraphy resulted in changing the location for the pilot to an area northeast of the location originally selected. Oil recovery tests with the field cores are in progress.


## INTRODUCTION

NIPER is beginning a DOE-industry sponsored field pilot test using surfactant-enhanced alkaline flooding technology, which was developed by NIPER. Surfactant-enhanced alkaline flooding is an EOR method that was patented by NIPER in 1989.[1] This near-term application of a promising EOR technology in a fluvial-dominated deltaic type reservoir is consistent with DOE's oil research strategy and has been given high priority by DOE.[2]

The objectives of the project are to demonstrate the feasibility of the technology by conducting a field pilot test. The benefits of conducting the project include: (1) information and data that will help to demonstrate the applicability of surfactant-enhanced alkaline flooding as a cost-effective EOR method, (2) transfer of the surfactant-enhanced alkaline flooding technology that has been developed under the sponsorship of the DOE to the petroleum industry, and (3) information regarding procedures for designing and applying this technology that will assist independent producers in sustaining production from mature producing oil fields rather than abandoning marginal wells.

The site selected for the field test is in Hepler (KS) oil field. Hepler field is in Crawford and Bourbon counties, Kansas. (see Fig. 1). The field was discovered in 1917. Since 1948, cumulative production was 969,761 bbl oil.[3] In 1980, 85 wells were counted in the field.[4] The 1988 production was 19,731 bbl for 52 active wells, and net pay was reported to vary from 10 to 29 ft. The geology of the Hepler site is typical of many Class I reservoirs.[5-6] The Tucker sand of Hepler field is a Class I, fluvial dominated deltaic depositional environment. Factors to be considered are the effects of low permeability and depositional compartmentalization. Low permeability and compartmentalization are typical of Midcontinent Class I reservoirs. High oil saturations make these areas especially attractive targets for the operators of the field site.

The operator of the field is Russell Petroleum Company, which operates several oil and gas fields in Texas, Oklahoma, and Kansas. The company also owns Oilfield Research Laboratory in Chanute, Kansas, which it has operated since 1959. The company has prior experience in chemical flooding, having successfully conducted chemical (polymer) floods at several of its properties.

Results from laboratory tests conducted with oil and brine from Helper field were encouraging. The crude oil is viscous and non-acidic; yet, it was mobilized by the chemical formulations described in previous reports. Significant amounts of the oil were mobilized under simulated reservoir conditions. Consumption of alkali was measured with field core and was very low. Surfactant loss, measured with field core, was also acceptable.[7]

This report is an annual report that covers final site selection and the optimization of slug sizes and chemical (especially polymer) concentrations.

## DISCUSSION

The selection of the Hepler field site and the optimization of alkaline surfactant chemical formulations for use at the site were described in previous reports.[7-9] Each of the chemical systems was optimized to provide the lowest possible interfacial tension (IFT) with Hepler oil.

### *Corefloods*

After testing several commercially available surfactants, Chevron Chaser XP-100 relatively expensive surfactant, was selected. XP-100 was extremely effective for mobilization of Hepler crude oil. The chemical formulation that was selected was a mixture containing 0.5% active XP-100, 0.45% active STPP (sodium tripolyphosphate), and 1.2% $NaHCO_3$ (1.6% $NaHCO_3$ also gave low IFT) in water (from a water supply well at the Hepler site).

With large pore volumes and high polymer concentrations, this chemical formulation produced extremely good oil recovery in core tests conducted in Berea sandstone cores. After chemical flooding, final core oil saturations were as low as 5% PV. For economic reasons, smaller volumes of chemicals will be injected during the field test. Because of the limits on field injection pressure, which is determined by depth and overburden pressure, polymer viscosity will also be reduced for field application. The results of core tests with smaller slug sizes of the injected chemicals and lower polymer concentrations are shown in Table 1.

The adverse effect of decreasing permeability on oil recovery was previously discussed.[8] The permeabilities of the Berea sandstones cores used for the corefloods shown in Table 1 vary from 86 to 122 mD, which is representative of field permeabilities. The maximum total oil recovery efficiency (waterflood + chemical flood) achieved in this series of corefloods was 71% OOIP.

In corefloods RP-19 through RP-23, the main chemical slug contained surfactant, alkali, and polymer. In each case, the main chemical slug was preceded by an alkaline preflush and followed with polymer, the concentration of which was graded to increasingly lower viscosities. In coreflood RP-19, chemical flooding was commenced after waterflooding, and the total oil recovery was 57.2% of OOIP (original oil in place). In coreflood RP-20 there was no waterflood; chemical flooding was commenced at initial oil saturation. In this coreflood, total oil recovery was 53.9% of OOIP, which was slightly less than that for coreflood RP-19 where chemical flooding was preceded by a waterflood. Coreflood RP-21 was a repeat of RP-20, except that polymer concentration and viscosity were further reduced. Oil recovery was 54.0% of OOIP which was almost identical to oil recovery from coreflood RP-20.

Coreflood RP-21R was commenced in the same core as RP-21 by injecting an additional 0.20 PV of the same chemical formulation. This increased total oil recovery from 54.0 to 61.5% of OOIP, is an increase of 7.5%, and indicated that oil recovery was increased by increasing the size of the chemical slugs that are injected, but the amount of increase in oil production was not proportionate to the increase in the chemical slug sizes, which were effectively double for coreflood RP-21R.

Coreflood RP-22 shows the result of injecting a smaller chemical slug with increased surfactant concentration. In this coreflood, one-half of the volume of main chemical slug used in the other corefloods was injected, but the surfactant concentration was doubled from 0.5 to 1.0%. The total amounts of surfactant, polymer, and alkali injected were the same for both corefloods. The total amounts of alkali and polymer were maintained equal for other corefloods by replacing some of the drive water slug with water that contained polymer and alkali. Therefore, the total amounts of injected chemicals were equal to the amounts injected in the prior floods. This flood can be directly compared to RP-21. Oil recoveries from the two corefloods were very similar--54.0% from coreflood RP-21 and 52.4% from coreflood RP-22.

Previous experiments have shown conclusively that an alkaline preflush increases the amount of Hepler oil recovered during surfactant-enhanced alkaline flooding.[8] Coreflood RP-23 is the same as coreflood RP-19, except that the alkaline preflush was slightly viscosified. Comparison of corefloods RP-19 and RP-23 shows that oil recoveries were almost identical, 57.2 and 58.3%, respectively. Therefore, even though an alkaline preflush increased oil recovery, viscosifing the preflush accomplished little, but the result in a heterogeneous reservoir may be quite different.

For coreflood RP-24, injection strategy was changed. The main chemical formulation was the same as that for the other corefloods, except that it did not contain polymer. This injection strategy was tested because of the interaction that occurs between XP-100 and polymers. Polymer-surfactant interaction (phase separation, precipitation, and viscosity loss) occurs between XP-100 and biopolymers and polyacrylamides.[10] No satisfactory method has been found to completely eliminate the interaction.

Oil recovery from coreflood RP-24 was greater than that for any of the other corefloods reported in table 1. Total oil recovery was 71.0%; final oil saturation after chemical flooding was 23.5%. Higher oil recoveries were obtained in higher permeability cores and with higher polymer concentrations, but this was the best recovery achieved with small slugs of chemicals that had viscosities low enough for application in Hepler field. It was previously suggested that for the field test, we should inject alkali, surfactant, and polymer in a single slug;[7] however, the current plan is to inject polymer as a separate slug that follows injection of alkali and surfactant.

### *Surfactants*

The corefloods in Table were conducted with a chemical system that contained 0.5% active Chevron Chaser XP-100, 0.45% active STPP (sodium tripolyphosphate), and 1.2% $NaHCO_3$ (1.6% $NaHCO_3$ also gave low IFT) in WSW water. Chevron Chemical has now ceased production of Chaser XP-100 surfactant, although a large supply still remains in inventory. In the event that sufficient XP-100 is not available, a similar surfactant, Chaser CF-100 will be used for the project. CF-100 is similar to XP-100, except for higher salt tolerance . The dynamic IFT behavior of this system at several sodium bicarbonate concentrations is shown in Fig. 2. Optimum sodium bicarbonate concentration is in the 1.2 - 1.6% range, which is about the same as for XP-100.

### *Polymers*

Figure 3 shows the viscosities at several shear rates for two solid partially hydrolyzed polyacrylamide polymers. Viscosities are very similar for the two polymers. Above 800 ppm polymer, the viscosities are almost identical. Allied Colloid Alcoflood 1135 polymer has been selected for the field project. It is possible that Alcoflood 1115, which has a lower molecular weight, will be used if reservoir permeability is lower than anticipated. Current plans are to inject Alcoflood 1135 polymer as a separate slug behind the alkaline surfactant formulation.

### *Environmental Assessment*

A survey was conducted for endangered flowering plant species, Mead's milkweed (*Asclepias meadii* Torr.) and the Western prairie fringed orchid (*Platanthea praeclara* Shevik & Bowles). The survey was conducted by the Coordinator-Botanist, Kansas Natural Heritage Inventory, Kansas Biological Survey (The University of Kansas, Lawrence, Kansas), personnel from Russell Petroleum (Chanute, Kansas), and IITRI/NIPER (Bartlesville, Oklahoma). No endangered species were found at the site. Surface water samples and soil samples taken from the project site by IITRI/NIPER personnel to establish a base line prior to implementing the field pilot project. These samples were analyzed and will provide a record of the condition of the soil and surface waters prior to project implementation.

Confirmation letters concerning the environmental impact of the Hepler field pilot EOR project have been received from the following agencies: Kansas State Historical Society, Kansas Wildlife & Parks Operations Office, Pittsburg, (Crawford County, Kansas) Chamber of

Commerce, State of Kansas Department of Health and Environment, Department of The Army, Kansas City District, Corps of Engineers, Kansas Biological Survey (above), the Kansas Geological Survey (concerning groundwater), and the Kansas Corporation Commission (concerning groundwater protection by surface casing). Writing of the Environmental Assessment (EA) Report began during July 1992. This EA will request a finding of no significant impact (FONSI) from the DOE PETC for the Hepler field pilot EOR project.

A categorical exclusion (CX) was approved by the U. S. Department of Energy (DOE) Pittsburgh Energy Technology Center (PETC) and returned to IITRI/NIPER. The CX is for the drilling of evaluation wells in the producing pattern in Hepler field, under the class of actions at B3.7, "Siting construction, and operation of new infill exploratory and experimental (test) oil, gas and geothermal wells, which are to be drilled in a geological formation that has existing operating wells." The CX is part of new Department of Energy Regulations approved in late May 1992, and was necessary before DOE funds could be allocated for expenditure at the field site.[11]

The details of the environmental assessment will be submitted to the DOE as a separate report.

### *Field Cores*

Field cores were obtained from four locations on the lease site. The evaluation of field cores and the evaluation of maps of permeability, porosity, oil saturation, and stratigraphy resulted in selection of an alternate location for the pilot project. The location where the pilot will be conducted is in the N1/2 SW1/4 NE1/4 S30 T27S R22E of the field operator's property. This location is northeast of the location that was originally selected.[12] The project well pattern is shown in Fig. 4. Wells J-2, J-4, H-2, and H-4 will be used as injectors. Oil recovery tests with the field cores from wells J-4, H-4, and G-5 are in progress.

## SUMMARY

The site selected for conducting a field pilot test using surfactant-enhanced alkaline flooding methods is Hepler (KS) oil field. Hepler field is in Crawford and Bourbon counties. This near-term application of a promising EOR technology in a fluvial-dominated deltaic type reservoir is consistent with U. S. Department of Energy oil research strategy. This report is an annual report that covers final site selection and the optimization of slug sizes and chemical (especially polymer) concentrations.

With large pore volumes and high polymer concentrations, injection of chemical formulations produced extremely good oil recovery in core tests conducted in Berea sandstone cores. After chemical flooding, final core oil saturations were as low as 5% PV. For economic reasons, smaller volumes of chemicals will be injected during the field test. Due to the limits on field injection pressure, which is determined by depth and overburden pressure, polymer viscosity will also be reduced for field application. The results of core tests with smaller slug sizes, in Berea cores with permeabilities representative of the reservoir, showed that total oil recovery up to 71% OOIP can be achieved by injection of smaller chemical slugs. Final oil saturations, after waterflooding and chemical flooding, were as low as 23% PV.

Field cores were obtained from four locations on the lease site. The evaluation of field cores and the evaluation of maps of permeability, porosity, oil saturation, and stratigraphy resulted in changing the location for the pilot project to an area northeast of the location that was originally selected. Oil recovery tests with the field cores are now in progress.

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**TABLE 1. - Summary of coreflood injection strategies and results - Hepler (KS) oil**

| Coreflood | Core type[1] | K, md | Preflush solution Composition | Preflush solution Vol., PV | First chemical formulation injected Composition | First chemical formulation injected Vol., PV |
|---|---|---|---|---|---|---|
| RP-19 | Berea[1] | 96 | pH 8.3 STPP/carbonate mixture | 0.10 | 0.5 g STPP + 1.2 g $NaHCO_3$ + 0.5 g. XP-100 / 100 mL and 2000 ppm Flopaam 3230S polymer $\mu$ = 20.0cP | 0.20 |
| RP-20 | Berea[1] | 92 | same as above | 0.10 | same as above | 0.20 |
| RP-21 | Berea[1] | 87 | same as above | 0.10 | same as above, except 1200 ppm Flopaam 3230S polymer | 0.20 |
| RP-21R | Berea[1] | 87 | same as above | 0.10 | same as above | 0.20 |
| RP-22 | Berea[1] | 122 | same as above | 0.10 | same as above, except 1.0 g. XP-100 / 100 mL | 0.10 |
| RP-23 | Berea[1] | 77 | same as above, except 600 ppm Flopaam 3230S polymer, $\mu$=3.3cP | 0.10 | 0.5 g STPP + 1.2 g $NaHCO_3$ + 0.5 g. XP-100 / 100 mL and 2000 ppm Flopaam 3230S polymer | 0.10 |
| RP-24 | Berea[2] | 86 | same as above, except no polymer | 0.10 | same as above, except no polymer | 0.20 |

TABLE 1. - Summary of coreflood injection strategies and results - Hepler (KS) oil--continued

| Coreflood | Second chemical formulation injected | | $So_{wf}$,% | $So_{cf}$,% | Recovery efficiency, % | |
|---|---|---|---|---|---|---|
| | Composition | Vol.,PV | | | C F[3] | Total[4] |
| RP-19· | Graded concentration of Flopaam 3230S<br>μ = 14.6 cP to 5.8 cP | 0.15 | 45.8 | 35.4 | 22.8 | 57.2 |
| RP-20· | same as above | 0.15 | N.A. | 37.4 | N.A. | 53.9 |
| RP-21· | same as above, except<br>μ = 10.0 cP to 7.2 cP | 0.15 | N.A. | 37.0 | N.A. | 54.0 |
| RP-21R· | same as above | 0.15 | N. A. | 31.0 | N.A. | 61.5 |
| RP-22· | same as above, except<br>μ of alk polymer = 7.0 cP | 0.15 | N.A. | 38.8 | N.A. | 52.4 |
| RP-23· | same as above, except<br>μ = 14.6 cP to 5.8 cP | 0.15 | 40.5 | 33.0 | 18.4 | 58.3 |
| RP-24 | graded concentration of Alcoflood 1135<br>μ = 19.4 cP to 5.8 cP | 0.30 | 37.1 | 23.5 | 36.6 | 71.0 |

1 Cores were saturated with synthetic brine containing 1.022 g NaCl, 0.033 g $CaCl_2$, and 0.0694 g $MgCl_2 \cdot 6H_20$ / 100 mL.

2 Cores were saturated with lease return water.

3 Recovery efficiency = (oil produced during chemical flood / oil remaining after waterflood) X 100.

4 Recovery efficiency = (oil produced during waterflood and chemical flood / original oil) X 100.

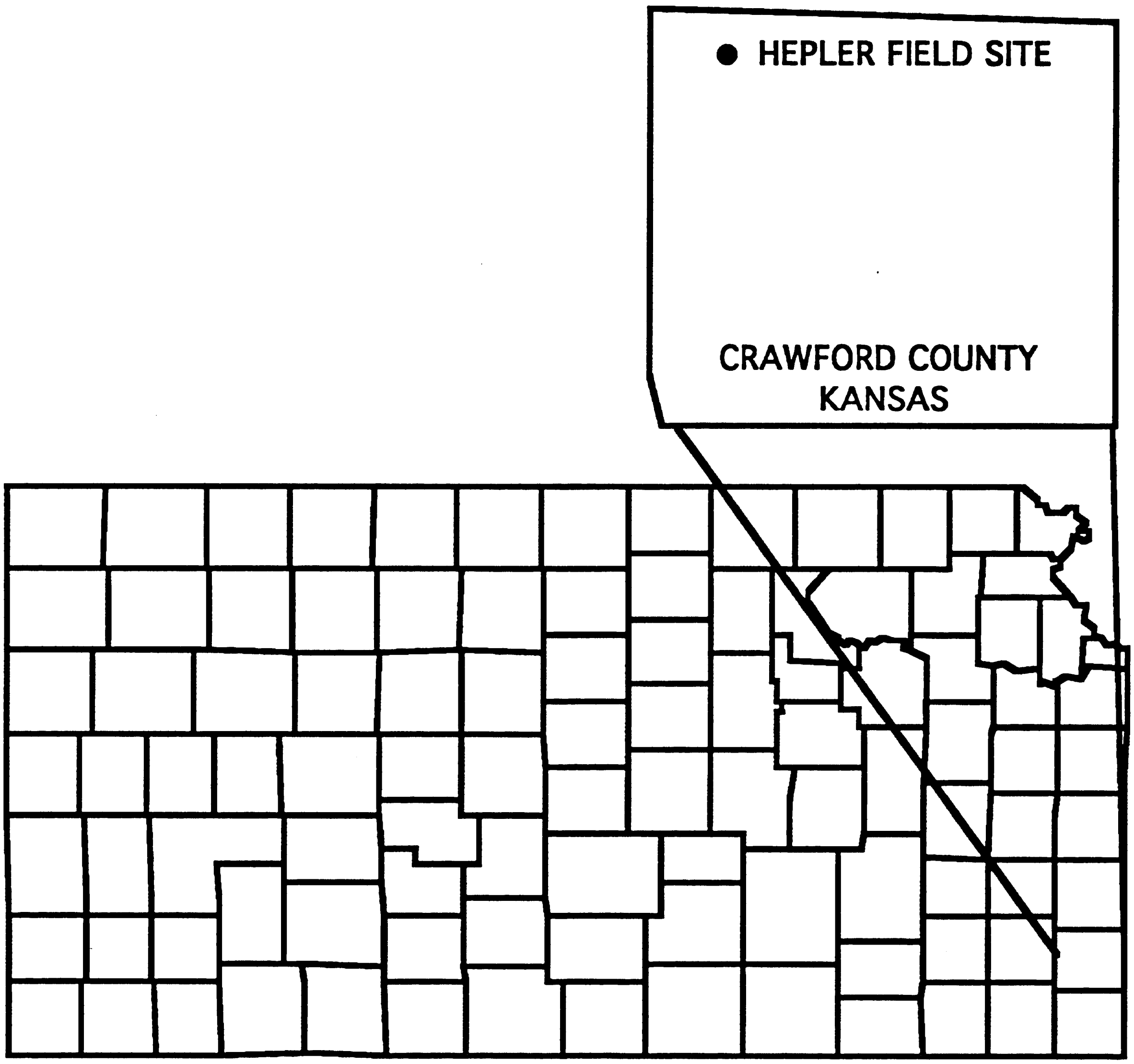


FIGURE 1. - Hepler (KS) oil field.

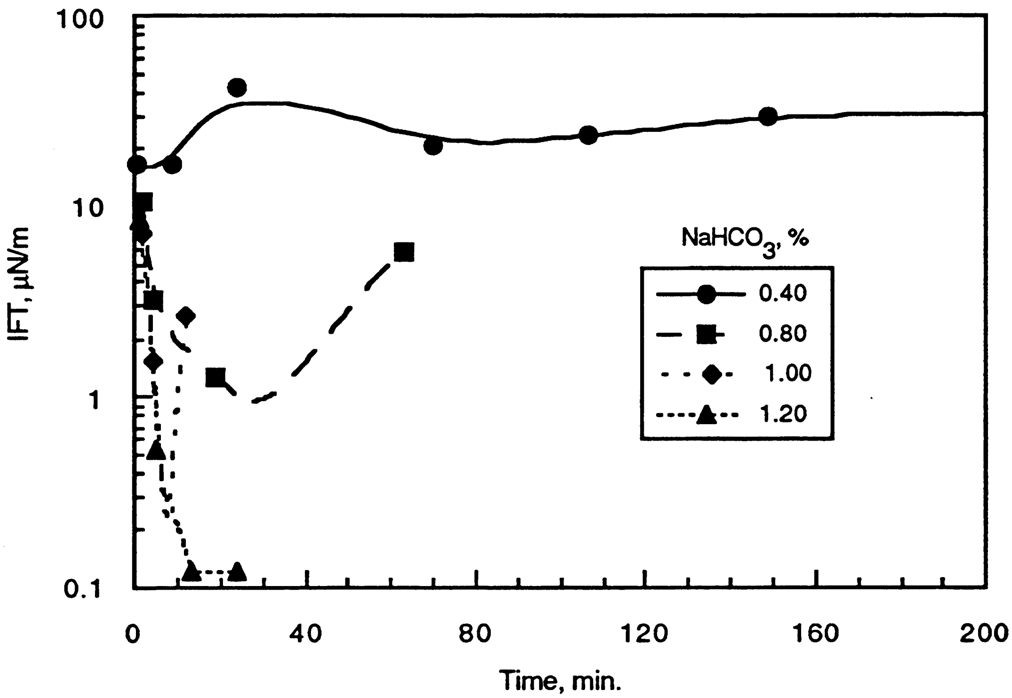


FIGURE 2. - Dynamic IFT between Hepler (KS) crude oil and a mixture of 0.1% active Chaser CF-100, 0.45% active STPP, and $NaHCO_3$ in WSW water , 23° C.

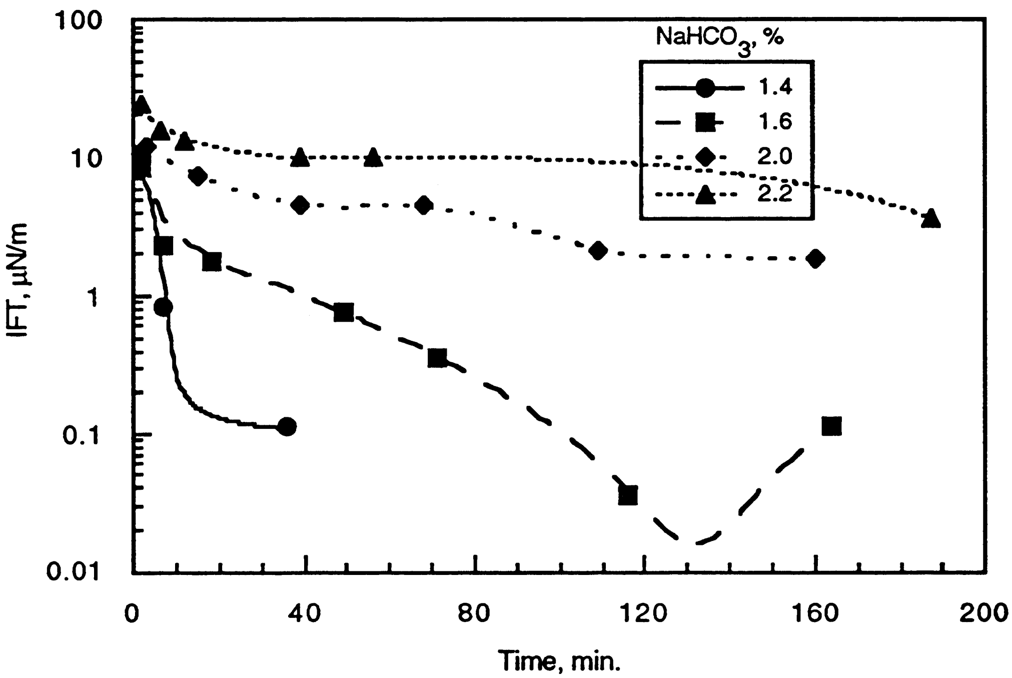


FIGURE 2 (cont.). - Dynamic IFT between Hepler (KS) crude oil and a mixture of 0.1% active Chaser CF-100, 0.45% active STPP, and $NaHCO_3$ in WSW water, 23° C.

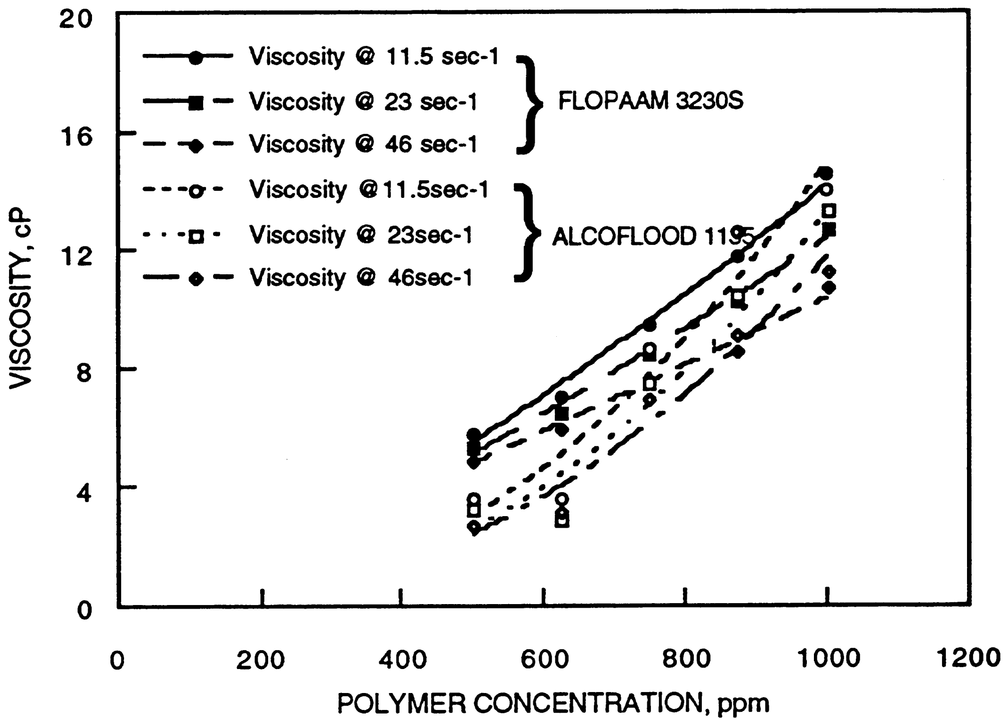

FIGURE 3. - Viscosity of polymers in Hepler (KS) field supply water, 23° C.

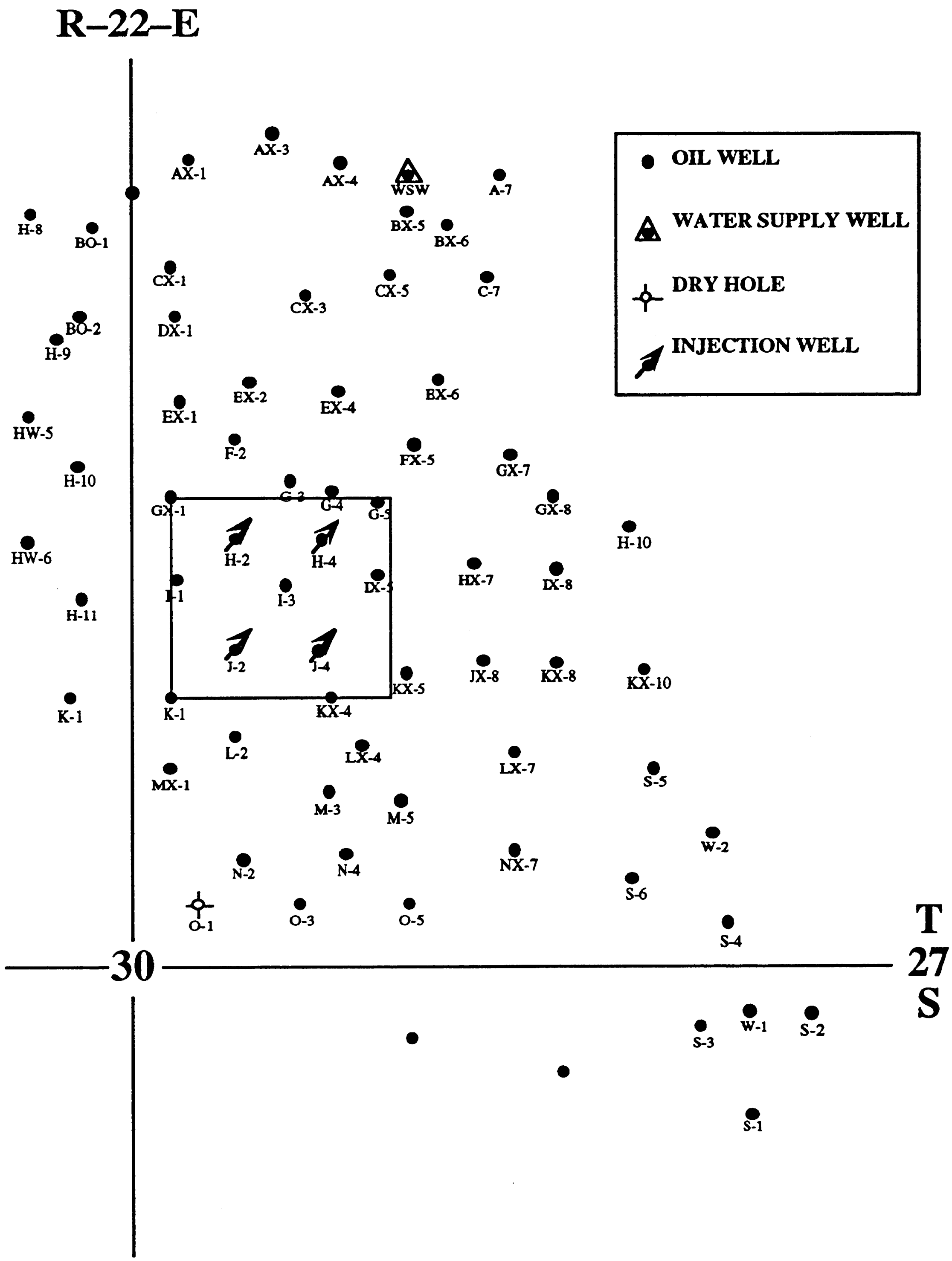


FIGURE 4. - Field site in the Elmer C lease, Hepler (KS) oil field.