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FOSSIL ENERGY

THE UTILIZATION OF THE MICROFLORA INDIGENOUS TO AND PRESENT IN OIL-BEARING FORMATIONS TO SELECTIVELY PLUG THE MORE POROUS ZONES THEREBY INCREASING OIL RECOVERY DURING WATERFLOODING

Annual Report
January 1, 1996 to December 31, 1996

By
Lewis R. Brown
Alex A. Vadie

September 1997

Performed Under Contract No. DE-FC22-94BC14962

Hughes Eastern Corporation
Jackson, Mississippi

National Petroleum Technology Office
U. S. DEPARTMENT OF ENERGY
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ABSTRACT

This project is a field demonstration of the ability of in-situ indigenous microorganisms in the North Blowhorn Creek Oil Field to reduce the flow of injection water in the more permeable zones thereby diverting flow to other areas of the reservoir and thus increase the efficiency of the waterflooding operation. This effect is to be accomplished by adding microbial nutrients to the injection water. Work on the project is divided into three phases, Planning and Analysis (9 months), Implementation (45 months), and Technology Transfer (12 months). This report covers the third year of work on the project.

During Phase I, two wells were drilled in an area of the field where approximately twenty feet of Carter sand were found and appeared to contain oil bypassed by the existing waterflood. Cores from one well were obtained and used in laboratory core flood experiments. The schedule and amounts of nutrients to be employed in the field were formulated on the basis of the results from laboratory core flood experiments..

The field demonstration (Phase II) involves injecting nutrients into four injector wells (test) and comparing the performance of the surrounding producer wells to the producers surrounding four untreated injector wells. The addition of nutrients to the four test injector wells was begun on Nov. 21, 1994, Feb. 27, 1995, Jan. 16, 1995, and Feb. 27, 1995 for test patterns 1, 2, 3, and 4, respectively. One of the test injectors (pattern 3) has received only potassium nitrate and sodium dihydrogen phosphate while the other three test injectors have received molasses also.

Three new wells have been drilled and completed. Cores obtained from these wells have shown the presence of injected nutrients (nitrate ions and phosphate ions) indicating their wide distribution in the reservoir. Electron microscopic examination of these cores have shown the presence of large numbers of bacteria suggesting that they are being stimulated to multiply by the added nutrients.

Statistical analysis of data on some of the components of the produced fluids from the wells indicates a reduction in sulfide content due to the inhibition of sulfate-reducing bacteria by the injection of nitrate ions into the reservoir and/or the action of nitrate-reducing bacteria.

Two of the four injector wells in the test patterns are experiencing an increase in injection pressure and a decrease in fluids pumped indicating resistance caused by microbial growth in the reservoir.

Based on improved oil production and/or water:oil ratios, 8 of the 15 producing wells in the four test patterns are responding favorably to the microbially enhanced oil recovery process while 8 of the 9 producers in the four control patterns have continued their natural decline in performance. The only exception has been due to an increase in the volume of water injected into a nearby injector well.

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EXECUTIVE SUMMARY

This project is designed to demonstrate that a microbially enhanced oil recovery process (MEOR), developed in part under DOE Contract No. DE-AC22-90BC14665, will increase oil recovery from fluvial dominated deltaic oil reservoirs. The process involves stimulating the in-situ indigenous microbial population in the reservoir to grow in the more permeable zones thus diverting flow to other areas of the reservoir, thereby increasing the effectiveness of the waterflooding operations. This five and one-half year project is divided into three phases, Phase I, Planning and Analysis (9 months), Phase II, Implementation (45 months) and, Phase III Technology Transfer (12 months). Phase I was completed and reported in the first annual report. This third annual report covers the findings in months 16-27 of Phase II.

The field demonstration (Phase II) involves injecting nutrients into four injector wells (test) and comparing the performance of the surrounding producer wells to the producers surrounding four untreated injector wells. The addition of nutrients to the four test injector wells was begun on Nov. 21, 1994, Feb. 27, 1995, Jan. 16, 1995, and Feb. 27, 1995 for test patterns 1, 2, 3, and 4, respectively. One of the test injectors (3) has received only potassium nitrate and sodium dihydrogen phosphate while the other three test injectors have received molasses also.

This year, three wells were drilled and cores therefrom are being examined for evidence of microbial activity in the reservoir. Thus far, nitrate ions and phosphate ions have been found along with large numbers of bacteria as determined by electron microscopy. These findings are solid evidence that the nutrients being injected into the reservoir are being distributed widely and are stimulating the microflora to multiply. Further evidence of microbial growth in the reservoir is demonstrated by the fact that two of the four injector wells receiving nutrients (test pattern injectors) are experiencing an increase in injection pressure and a concurrent reduction in fluid injected.

Based on improved oil production and/or water:oil ratios, 8 of the 15 producing wells in the four test patterns are responding favorably to the MEOR process while 8 of the 9 producers in the four control patterns have continued their natural decline in performance. The one exception has been shown to be the result of increased water injection into a nearby injector well.

INTRODUCTION

The use of microorganisms to enhance oil recovery (MEOR) was first proposed by Beckmann in 1926 [1] but it was ZoBell who first actively researched the concept [2-5]. Some MEOR methods rely on in-situ indigenous microbial populations while other methods require injection of microbial cultures into the formation. In some MEOR methods, it is the by-products of microbial activity that enhance the oil recovery but other methods rely on the growth of the microorganisms to achieve the desired result.

This five and one-half year project is designed to demonstrate that the microflora indigenous to petroleum reservoirs can be stimulated to grow in the more permeable zones of the reservoir thereby diverting flow to other areas and thus increasing the effectiveness of waterflooding operations. The concepts involved in this project were developed in part as a result of work performed under DOE Contract No DE-AC22-90BC14665. Work on this project is divided into three phases of nine months, forty-five months, and twelve months, respectively. This Third Annual Report will describe the work completed during a twelve-month period of Phase II.

Phase I, with a duration of nine months, has been completed. Two wells were drilled in an area of the field where approximately twenty feet of Carter sand were expected and where bypassed oil could reasonably be expected to exist. Cores from one well were obtained and employed in laboratory core flood experiments in order to design the protocol for Phase II (Implementation). The schedule and amounts of nutrients employed in the field were formulated on the basis of these laboratory data.

Phase II, with a duration of forty-five months is now half completed. The first of four injection skids was built and injection of nutrients into the injector for the first test pattern began on November 21, 1994. The nutrients being injected are potassium nitrate and sodium orthophosphate and molasses. Injection of nutrients into test patterns two, three, and four were begun on February 27, 1995, January 16, 1995, and February 27, 1995, respectively.

Preliminary geological and petrophysical characterizations of the reservoir have been made. Baseline data on the inorganic constituents and microbial population have been obtained for fluids from all of the test and control wells. This Third Annual Report covers work completed during the third year of the project.

DISCUSSION

1. OBJECTIVE AND OVERALL PLAN OF WORK

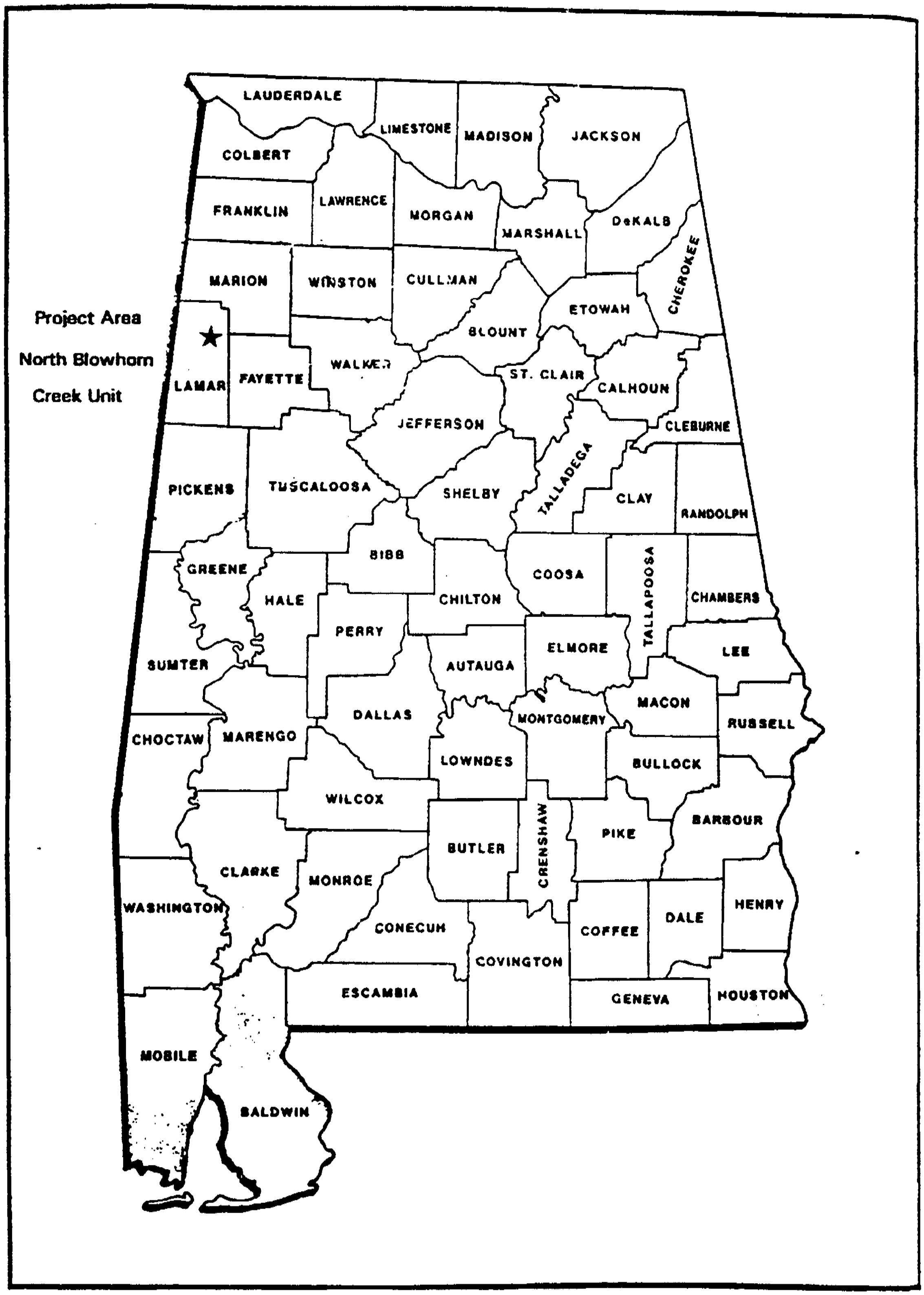
The objective of this work is to demonstrate the use of indigenous microbes as a method of profile control in waterfloods. It is expected that as the microbial population is induced to increase, the expanded biomass will selectively block the more permeable zones of the reservoir thereby forcing injection water to flow through the less permeable zones which will result in improved sweep efficiency.

This increase in microbial population is accomplished by injecting a nutrient solution into four injectors. Four other injectors will act as control wells. During Phase I, two wells were drilled and one was cored through the zone of interest. The cores were employed in core flood experiments in order to arrive at the optimum nutrient formulation. During Phase II, nutrient injection began, the results are being monitored, and adjustments to the nutrient composition made. Phase III will focus on technology transfer of the results.

One expected outcome of this new technology will be a prolongation of economical waterflooding operations, i.e. economical oil recovery should continue for much longer periods in areas of the reservoir subjected to this selective plugging technique.

2. DESCRIPTION OF OIL RESERVOIR FOR FIELD TRIAL

The North Blowhorn Creek Oil Unit (NBCU) is located in northwest Alabama about 125 kilometers (seventy-five miles) west of Birmingham, AL (see Map 1). The field is in what is known geologically as the Black Warrior Basin. The producing formation is the Carter Sandstone of Mississippian Age at a depth of about 700 meters (2300 feet). The field was discovered in 1979 and initially developed on 3.24 x 10^5 m^2 (80 acre) spacing. The field was unitized into a reservoir-wide unit in 1983 and in-fill drilled to 1.62 x 10^5 m^2 (40 acre) spacing. Waterflooding of the reservoir began in 1983. The initial oil in place in the reservoir was about 2.5 million m^3 (16 million barrels), of which 874,430 m^3 of oil (5.5 million barrels) had been recovered by the end of 1995. To date, North Blowhorn Creek is the largest oil field discovered in the Black Warrior Basin. Oil production peaked at almost 480 m^3/d of oil (3000 BOPD) in 1985 and has since steadily declined. Currently there are 20 injection wells and 32 producing wells. Current production is about 46 m^3/d of oil (290 BOPD), 1700 m^3/d of gas (60 MCFD), and 635 m^3/d of water (3100 BWPD). The current water injection rate is about 650 m^3/d of water (4150 BWPD). About 1.6 m^3 of oil (10 MMBO) will be left unrecovered if some method of enhanced recovery is not proven to be feasible.



Map 1. Project Area Geographical Locator Map.

3. Phase II. IMPLEMENTATION

a. Design of Field Demonstration

(1). Test patterns for field demonstration

Although the test patterns for the field demonstration were given in last year's Annual Report they will be repeated here for sake of completeness. The wells included in the patterns are as follows.

TP # 1

Injection-Production Pattern:

Injection Well:	NBCU 2-14 No.1
Production Wells:	NBCU 2-11 No.1*
	NBCU 2-15 No.1
	NBCU 11-3 No.1*
	NBCU 2-13 No.1*

CP #1 (Control Set)

Injection Well:	NBCU 2-4 No.1
Production Wells:	NBCU 35-13 No.1
	NBCU 35-14 No.1
	NBCU 2-3 No.1*
	NBCU 2-5 No.1*
	NBCU 3-1 No.1*

TP #2

Injection-Production Pattern:

Injection Well:	NBCU 34-9 No.2
Production Wells:	NBCU 34-7 No.2*
	NBCU 34-16 No.2
	NBCU 34-15 No.1*
	NBCU 34-15 No.2*
	NBCU 34-10 No.1*

CP #2 (Control Set)

Injection Well:	NBCU 34-7 No.1
Production Wells:	NBCU 34-2 No.1
	NBCU 34-6 No.1
	NBCU 34-7 No.2*
	NBCU 34-10 No.1*

TP #3

Injection-Production Pattern:

Injection Well:	NBCU 11-5 No.1
Production Wells:	NBCU 10-8 No.1
	NBCU 11-6 No.1
	NBCU 11-4 No.1
	NBCU 11-3 No.1*
	NBCU 2-13 No.1*

CP #3 (Control Set)

Injection Well:	NBCU 3-2 No.1
Production Wells:	NBCU 3-3 No.1
	NBCU 3-1 No.1*
	NBCU 3-1 No.2*
	NBCU 34-15 No.1*
	NBCU 34-15 No.2*

TP #4

Injection-Production Pattern:

Injection Well:	NBCU 2-6 No.1
Production Wells:	NBCU 2-11 No.2
	NBCU 2-3 No.1*
	NBCU 2-5 No.1*
	NBCU 2-11 No.1*

CP #4 (Control Set)

Injection Well:	NBCU 3-8 No.1
Production Wells:	NBCU 3-1 No.1*
	NBCU 3-1 No.2*
	NBCU 3-9 No.1
	NBCU 2-5 No.1*

* Indicates wells included in more than 1 injection or control pattern.

(2). Feeding regime

After a careful evaluation of the field results and additional core flood experiments conducted in the laboratory, it was decided to modify the feeding regimes as shown in Tables I and II.

Table I. Feed and feeding regime from November 1994 - April 1996

	PATTERNS			
NUTRIENTS	1	2	3	4
KNO_3	0.12%(w/v) Mondays	0.12%(w/v) Mondays	same as 1	same as 2
NaH_2PO_4	0.034%w/v) Wednesday Fridays	0.034%(w/v) Fridays	same as 1	same as 2
MOLASSES		0.1%(v/v) Wednesdays	same as 1	same as 2

Table II. Feed and feeding regime from April 1996 - present.

	PATTERNS			
NUTRIENTS	1	2	3	4
KNO_3	0.12%(w/v) Mondays	same as before	same as before	0.06%(w/v) Mondays
NaH_2PO_4	0.034%(w/v) Wednesdays	same as before	same as before	0.017%w/v) Wednesdays
MOLASSES	0.2%(v/v) Fridays	same as before	same as before	0.3%(v/v) Fridays

(3). Core flood experiments

Several core plugs that had been employed in core flood experiments were removed from their holders and representative portions of the cores submitted to Halliburton Energy Services, Duncan, OK, for electron microscopic examination as follows. The core samples were oven dried at 110^{0}C and oil residues extracted with progressive soaks in chloroform. A very thin coating of gold was placed on the surface of each sample using an argon plasma coater.

One of the core plugs had been treated with simulated injection water only. The page of the Halliburton Report describing the examination of this core sample by scanning electron microscopy is shown in Figure 1.

Another core examined by electron microscopy had been treated with simulated injection water containing nitrate, phosphate, and molasses. Results of these analyses are given in Figures 2 and 3. As may be observed, bacteria are prevalent in the core sample from the core plug treated with injection water containing bacterial nutrients-----nitrate, phosphate, and molasses and theirgrowth probably caused the reduced flow through this core plug.

New core plugs were prepared from cores obtained from NBCU 34-3 No.2 in April, 1994, and stored anaerobically. The purpose of performing additional core flood experiments was to determine if altering the feeding regime employed in the field would be beneficial.

In two of the test cores, the nitrate and phosphate concentrations were 0.13% and 0.034%, respectively. One of these two had molasses at a concentration of 0.20% injected on day five. An additional test core had molasses, nitrate, and phosphate concentrations of 0.30%, 0.065%, and 0.017%, respectively. The molasses was injected on day five, also. Initially each core was flooded with simulated injection water for fourteen consecutive days. After the experiment began, effluent was collected and observed for color, microbial growth, odor, presence of petroleum, sediment, and turbidity and the flow rate through the core recorded. The injection schedule and concentration of nutrients are given below and were repeated every seven days.

DAY	17-A	16-B	17-B	18-A
1	N	N	N	w
2	w	w	w	w
3	P	P	P	w
4	w	w	w	w
5	P	C	C	w

17-A
N=1.3g/L KNO_3
P=0.034g/L NaH_2PO_4

16-B
N=1.3g/L KNO_3
P=0.034g/L NaH_2PO_4
C=0.2g/L molasses

17-B
N=0.065g/L KNO_3
P=0.017g/L NaH_2PO_4
C=0.3g/L molasses

w = simulated injection water
218.0 mg/L $CaCl_2$
54 .1 mg/L $MgCl_2$
91 .4 mg/L $BaCl_2$
36 .7 mg/L Na_2SO_4
698 .2 mg/L $NaHCO_3$
2958 .0 mg/L $NaCl_2$

On occasion, the cores were flushed by slightly increasing the pressure of the influent. Results of these experiments are given in Figures 4-7. As expected, the flow rate of injection water containing molasses was reduced more rapidly than the flow rate through cores flooded with injection water alone or supplemented with only nitrate and phosphate.

(4). Tracer studies

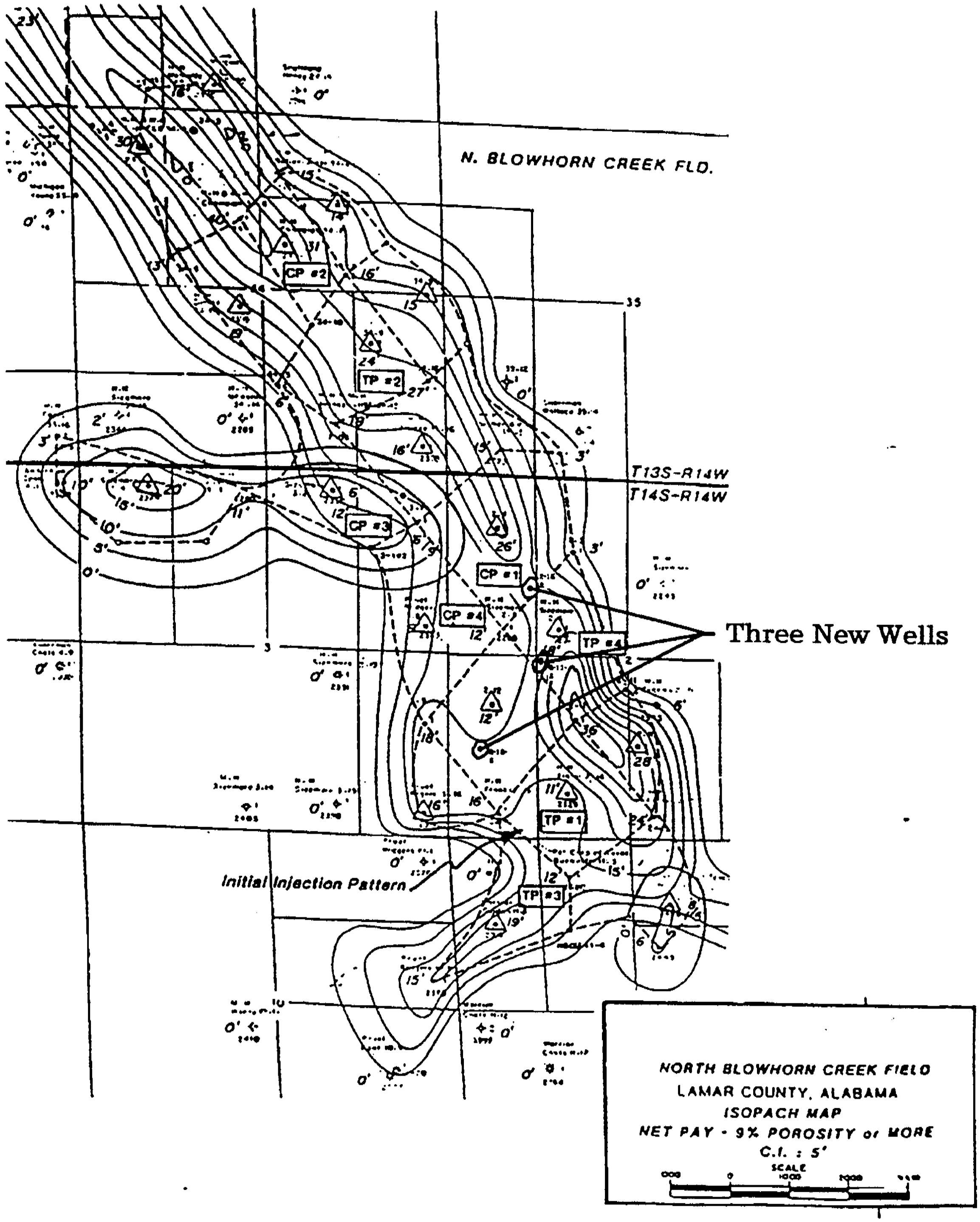
As reported in the 1995 Annual Report, a Tritium tracer survey was initiated in test pattern 1 in April, 1994. Two curies of Tritium were injected into the 2-14 No.1 and water samples from the four offset producers were monitored for tracer breakthrough. The tracer was first detected in NBCU 2-13 No.1 on October 12, 1994 and continued to be detectable through October 1996. Tracer was first detected in the NBCU 11-3 No.1 on October 18, 1995 and continued to be detectable through October 1996. No other wells have produced detectable amounts of the tracer.

(5). Drilling of three additional wells

Three new wells were drilled into the Carter reservoir sand during the Fall of 1996. The purpose of the three wells was to help evaluate the nutrient induced in-situ growth of microorganisms by analysis of recovered core samples and produced fluids. The locations of the wells can be seen on the Carter Sand Isopach map (see Map 2).

The first well drilled was the NBCU 2-5 No.2 which started drilling on October 11 and reached a total depth of 701 m (2300 ft) on October 17. The well encountered 7.3 m (24 ft) of net Carter sand between 668 and 676 m (2192 and 2218 ft) and 13.1 m (43 ft) of core were recovered. The Dual Induction and Density-Neutron log sections are shown in Figure 8 and the conventional core analysis is shown in Figure 9. The core analysis indicates that, as a general rule, the lower permeability rock retains a higher oil saturation while the high permeability rock is better swept resulting in a lower oil saturation. Visual observation of the core indicated much remaining oil in the low permeability rock. The well was cased for production, perforated from 668.4 to 676.0 m (2193 to 2218 ft) and fracture stimulated. At the end of the year the well was awaiting installation of rod pumping equipment and initiation of production testing.

The second well drilled was the NBCU 2-13 No.2 which started drilling on October 22 and reached a total depth of 703 m (2305 ft) on October 30. The well encountered 6.4 m (21 ft) of net Carter sand between 664 and 672 m (2180 and 2205 ft) and 9.7 m (32 ft) of core were recovered. Sections of the Dual Induction and Density-Neutron logs are shown in Figure 10 and the conventional core analysis is shown in Figure 11. The core analysis indicates much higher permeability in the upper ten feet of the sand than in the lower portion. As in the previous well, the higher permeability rock generally has lower oil saturation than the lower permeability rock which is harder to sweep by waterflood. Visual observation of the core indicated much remaining oil, as was observed in the previous well. The well was cased for production and perforated from 665-668 m and 669-670 m (2182-2192 ft and 2195-2199 ft). A packer and tubing were run and the well was swab tested at a rate of 76 m^3 (480 bbls) of fluid per day with 15-25% oil. Because the well initially swabbed at a high fluid rate, no fracture stimulation was performed. If, after placing the well on pump, the fluid rate is not sustained, a fracture stimulation will be performed.



Map 2. Location of Three New Wells.

As of the end of the year, rod pumping equipment had been installed, and the well was shut-in awaiting installation of electric power.

The third well drilled was the NBCU 2-11 No.3 which started drilling on November 6 and reached a total depth of 703 m (2306 ft) on November 13. The well encountered 11 m (36 ft) of Carter sand between 659.6 and 670.6 m (2164 and 2200 ft). The sand was much thicker than anticipated. Previous maps had indicated only 5.5 m (18 ft) of sand at this location. Log sections are shown in Figure 12. A 9.7 m (32 ft) core was recovered which revealed significant remaining oil saturation, along with some portions which had obviously been swept by the waterflood. The conventional core analysis is shown in Figure 13. It is believed the water swept sections will provide the best opportunity to observe microbial growth as a result of nutrient injection into the NBCU 2-6 No. 1 well about 152 m (500 ft) north of this well. The well was cased for production, perforated from 659.6 to 670.6 m (2164 to 2200 ft), a packer and tubing run and the well was fracture stimulated. As of the end of the year a flowline to the central production facility had been installed and flow testing had begun.

The chemical and microbiological analyses of core samples from the three newly drilled wells were begun in the fourth quarter of 1996. A total of 16 one-foot (approx.) sections of the core from each well was obtained for the chemical and microbiological analyses. Each of ten sections from each core was placed in a large open plastic bag and immediately placed in an anaerobic container and held under anaerobic conditions. Six additional sections were each placed in a closed plastic bag and stored in a one-gallon plastic container (aerobic).

Five sections of cores from each well were examined for the presence of nitrate ions and phosphate ions. Nitrate ions were present in four of the five sections from Well 2-5 No.2, three of the five sections from Well 2-13 No.2, and all five of the sections from Well 2-11 No.3. Phosphate ions were present in three of the sections from Well 2-5 No.2, none of the sections from Well 2-13 No.2, and one of the sections from Well 2-11 No.3. Electron microscopic examinations of four sections of core from Well 2-5 No. 2 revealed many microbial cells in three of the sections. X-ray diffraction analyses indicated that there was no barium in any of the above mentioned samples.

Although the analyses of cores from the three newly drilled wells are just beginning, it is clear that the nutrients being injected into the test wells are being widely distributed in the reservoir and the abundance of microbial cells in samples suggests that they are actively multiplying in the reservoir formation.

b. <u>Geological Characterization of Core Samples</u>

The following geological characterization of Core Cut No. 7 (depth 2323 ft.) is typical of the 20 feet of recovered core from well 34-3 No.2 (drilled in April, 1994).

The rock is very well-sorted (Compton's classification). The sample is a massive sandstone, moderately well-lithified with a siliceous cement. Occasional ferroan dolomite is present. The grains are randomly oriented (no preferred orientation). The sample is grain, rather than matrix, supported.

The sample contains approximately 95% low quartz as indicated by observation and point counting of thin section S.E.M.(Scanning Electron Microscope) observations, E.D.S. (Energy Dispersive Spectra) analysis, and x-ray diffraction analysis. Most quartz grains are monocrystalline, exhibiting conchoidal fractures, and showed more recent quartz overgrowths. The sample contains approximately 3% ferroan dolomite as indicated by the staining of thin sections for calcite/dolomite. The ferroan element is indicated by thin section observation and E.D.S. analysis. The ferroan dolomite appears as microscopic hombohedral crystals that are an average of less than 2 μm in diameter. The sample contains approximately 2% or less of a minor amount of an authigenic clay mineral, probably a variety of kaolinite, as indicated by thin section and E.D.S. analysis. This clay mineral appears to be a pore filling or lining.

The sample has an average porosity of approximately 25% as determined by point counting of thin sections impregnated with a blue epoxy. Most porosity was intercrystalline existing within the three dimensional network of detrital quartz grains. Pore sizes varied from microscopic (250 μm or less) to 2 mm in diameter.

In summary, the sample appears to be a massive, fine-grained, moderately mature, quartzarenite (a sand stone) (Folk's classification) with abundant quartz, minor amounts of feldspar, perhaps kaolinite, with a minor calcitic cement component, probably ferroan dolomite.

c. <u>Petrophysical Study of Core Samples</u>

Petrophysical properties of recovered core samples in Phase I have been previously reported (see Annual Report 1995). Study of petrophysical properties of collected cores from three additional wells drilled in Phase II are in progress.

d. <u>Analysis of Injection and Production Fluids</u>

Fluids from both injector wells and producer wells of all patterns, were collected monthly in one and one-half gallon containers and brought to the laboratory for analysis. Oil and water were separated and a portion of the oil sample analyzed for its aliphatic profile by gas chromatography (GC). The remainder of the oil sample was used for measurement of gravity, viscosity, and interfacial tension (IFT). Additionally, the water samples were analyzed for surface tension (ST), pH, microbial content, and several inorganic ions. Furthermore, production rates of produced fluids (oil, gas, and water) from the producer wells in all patterns were measured weekly by the field lease operator.

(1) Petrophysical analyses

The following characteristics of produced fluids from selected wells have been measured and representative values given in Table III.

-Gas chromatography (GC) to determine the aliphatic profile of oil from producer wells in all patterns

Table III. Petrophysical analysis of selected test and control wells in all patterns.

PATTERN 1

Test Wells

WELL 2-15 No. 1

	Gravity API	Viscosity cP	Surface Tension W-air dyne/cm	Interfacial Tension O-W dyne/cm	pH
Range	33-31	2.4-2.1	57-62	25-30	9.4-8.8
Trend	downward	downward	upward	upward	downward

WELL 2-13 No. 1

	Gravity API	Viscosity cP	Surface Tension W-air dyne/cm	Interfacial Tension O-W dyne/cm	pH
Range	37-30	2.25-1.95	63-57	22-21	8.3-7.4
Trend	downward	downward	downward	downward	downward

Control Well

WELL 3-1 No. 1

	Gravity API	Viscosity cP	Surface Tension W-air dyne/cm	Interfacial Tension O-W dyne/cm	pH
Range	37-31	2.4-1.6	57-60	22.5-29	8.2-8
Trend	downward	downward	upward	upward	downward

PATTERN 2

Test Well

WELL 34-7 No. 2

	Gravity API	Viscosity cP	Surface Tension W-air dyne/cm	Interfacial Tension O-W dyne/cm	pH
Range	31-32	2.6-2.4	62-57	25-17.5	8.4-7.9
Trend	steady	downward	downward	downward	downward

Control Well

WELL 34-2 No. 1

	Gravity API	Viscosity cP	Surface Tension W-air dyne/cm	Interfacial Tension O-W dyne/cm	pH
Range	33-32	1.75-1.8	61-58	24.5-22	8.5-8
Trend	steady	steady	downward	downward	downward

PATTERN 3

Test Wells

WELL 10-8 No. 1

	Gravity API	Viscosity cP	Surface Tension W-air dyne/cm	Interfacial Tension O-W dyne/cm	pH
Range	25-27.5	5.2-4	63-62	23-25	8.3-7.8
Trend	upward	downward	steady	steady	downward

WELL 11-4 No. 1

	Gravity API	Viscosity cP	Surface Tension W-air dyne/cm	Interfacial Tension O-W dyne/cm	pH
Range	34-26	1.7-4.5	63-60	17-27	8.2-7.7
Trend	downward	upward	steady	upward	downward

Control Well

WELL 3-3 No. 1

	Gravity API	Viscosity cP	Surface Tension W-air dyne/cm	Interfacial Tension O-W dyne/cm	pH
Range	27.5-30	3.4-2.2	62-60	27.5-22.5	7.9-8.6
Trend	upward	downward	steady	downward	upward

PATTERN 4

Test Well

WELL 2-11 No. 2

	Gravity API	Viscosity cP	Surface Tension W-air dyne/cm	Interfacial Tension O-W dyne/cm	pH
Range	34-32	1.8-2.4	61-60	25-22.5	7.8-8
Trend	steady	upward	steady	downward	steady

Control Well

WELL 3-9 No. 1

	Gravity API	Viscosity cP	Surface Tension W-air dyne/cm	Interfacial Tension O-W dyne/cm	pH
Range	31-32	1.7-2.1	63-58	22.5-227	8-7.9
Trend	steady	upward	downward	steady	steady

-Gravity (API) of oil (at room temperature) produced from selected wells in test and control patterns
-Viscosity of oil (at reservoir temperature) produced from selected wells in test and control patterns
-Interfacial tension (IFT) for produced and separated oil-water system from selected wells in test and control patterns
-Surface tension (ST) of air-water systems as in IFT
-pH of produced water

(2). Microbial populations

Statistical analyses of the data on the microbiological population of the injection fluids from the eight injector wells and fluids from the producing wells in all eight patterns have been completed and average values given in Table IV. Unless stated otherwise, the means from the Analysis of Variance Test (ANOV) were compared using the Duncan's Multiple Range Test (p=0.05). The results of these analyses are as follows.

Table IV. Average results of microbial analyses.

Parameter	1ST Twelve Months	
	Control	Test
PCA (Aerobic)	190,000 ± 73,000	270,000 ± 75,000
PCA (Anaerobic)	120,000 ± 60,000	190,000 ± 63,000
Oil (Aerobic)	160,000 ± 68,000	170,000 ± 62,000
Oil (Anaerobic)	150,000 ± 65,000	240,000 ± 70,000

When comparisons were made on data collected over the entire length of time that the wells have been monitored, there was no significant difference between the wells in the control patterns and the wells in the test patterns in terms of

1. aerobic heterotrophs
2. anaerobic heterotrophs
3. aerobic oil-degrading microorganisms
4. anaerobic oil-degrading microorganisms

When the data from the first six months of monitoring were compared to data from the last six months of monitoring, there was no significant difference between control wells in terms of

1. aerobic heterotrophs
2. anaerobic heterotrophs
3. aerobic oil-degrading microorganisms
4. anaerobic oil-degrading microorganisms

When data from the first six months of monitoring were compared to data from the last six months of monitoring, there was no significant difference between test wells in terms of

1. aerobic heterotrophs
2. anaerobic heterotrophs
3. aerobic oil-degrading microorganisms
4. anaerobic oil-degrading microorganisms

When data from the control wells were compared to data from the test wells for the second six months, there was no significant difference between them in terms of

1. aerobic heterotrophs
2. anaerobic heterotrophs
3. aerobic oil-degrading microorganisms
4. anaerobic oil-degrading microorganisms

As may be seen from the above, no significant changes in the microbial population of production water have occurred.

(3). Inorganic ions

Statistical analyses of the data on the chemical composition of the injection fluids from the eight injector wells and fluids from the producing wells in all patterns have been completed and average values given in Table V. Unless stated otherwise, the means from the Analysis of Variance Test (ANOV) were compared using the Duncan's Multiple Range Test (p=0.05). The results of these analyses are as follows.

Table V. Average results of inorganic analyses.

Parameter	1st Six Months		2nd Six Months	
	Control	Test	Control	Test
Chloride	3,114.33 ± 141.48	3,062.20 ± 157.19	1,758.53 ± 73.21	1567.07 ± 68.70
Hardness	174.51 ± 11.06	175.47 ± 9.95	181.97 ± 8.56	182.72 ± 7.98
Potassium	5.70 ± 0.27	6.36 ± 0.38	5.87 ± 0.39	5.35 ± 0.42
Sulfate	64.25 ± 4.38	63.78 ± 4.49	38.39 ± 2.70	31.25 ± 2.29
Sulfide	0.75 ± 0.10	0.91 ± 0.11	0.52 ± 0.05	0.43 ± 0.04

When comparisons were made on data collected over the entire length of time that the wells have been monitored, there was no significant difference between the wells in the control patterns and the wells in the test patterns in terms of

1. sulfide content
2. sulfate content
3. potassium content
4. hardness
5. chloride content

When the data from the first six months of monitoring were compared to data from the last six months of monitoring, there was no significant difference between control wells in terms of

1. potassium content
2. hardness

The concentration of chloride, sulfate, and sulfide were significantly greater in the first six months than they were in the second six months.

When data from the first six months of monitoring were compared to data from the last six months of monitoring, there was no significant difference between test wells in terms of

1. potassium content
2. hardness

The concentration of chloride, sulfate, and sulfide were significantly greater in the first six months than they were in the second six months.

When data from the control wells were compared to data from the test wells for the second six months, there was no significant difference between them in terms of

1. sulfide content
2. sulfate content
3. potassium content
4. hardness
5. chloride content

To date, neither nitrate nor phosphate has been detected in any of the producing wells.

It was interesting to note that sulfide content of the fluids from both the control wells and the test wells were significantly lower (within 5% level of probability) in the last six months than in the first six months. Chloride and sulfate concentrations were likewise significatly lower in the second six months.

While it is perhaps premature to draw any permanent conclusions it is tempting to speculate that this decrease in sulfide content is a result of (1) the injection of nitrate into the reservoir and (2) enhanced activity by nitrate-reducing microorganisms in the reservoir. Both of the above have been reported in the literature to have an adverse impact on sulfate-reducing bacteria which produce sulfide from sulfate and this would certainly be an added bonus when using the MEOR process. A recent article [6] indicated that treatment of the core with 0.71 mM nitrate inhibited sulfate reduction. In our field demonstration, nitrate concentrations being employed are in the range of 3-11 mM.

e. Criteria for Evaluating Success

The criteria under which the success of the project will be measured are as follows:

- Decrease in water:oil ratio (WOR)
- More sustainable production
- Proof of stimulation of indigenous microorganisms
- Better understanding of reservoir and reservoir formation as a microbial environment for the future methods of selecting reservoir candidates for MEOR.
- Increase in Productivity Index in producing wells, and decrease in Injectivity of injection wells.
- Overall decrease in cost per barrel of oil produced.
- Increase in productive life of the reservoir which translates into lower residual oil in place.

Plots of production fluids rate and WOR versus time will show any sustained increase or decrease in oil production, and decrease/increase in water production. Microorganisms, as by-product of their metabolism, produce surfactants which cause a reduction in IFT and also may effect the wettability of the reservoir formation. They also will produce gases which may effect the acidity of the reservoir water and/or decrease the viscosity of reservoir oil. Plots of reservoir oil gravity versus time may present some indication of the integrity of reservoir oil under the MEOR process. Plots of injection pressure and volume of injected water in time will present an indication of the continuity of the operation and injectivity of the injection well. Finally, gas chromatographic data will indicate changes in the historic aliphatic profile of the oil.

f. Performance of MEOR Process in all Patterns

The project was initiated in January of 1994 and is approximately half completed. The starting nutrient injection date for test pattern 1 was Nov. 21, 1994; test pattern 2 was Feb. 27, 1995; test pattern 3 was Jan. 16, 1995, and test pattern 4 was Feb. 27, 1995.

In evaluating performance, both oil production rate and water:oil ratio (WOR) were considered. The impact of the MEOR process was characterized as positive if the oil production rate increased, is holding steady, or there has been a noticeable decrease in the rate of decline. Similarly, the impact of the MEOR process was characterized as positive if the WOR is decreasing, holding steady, or there has been a noticeable reduction in the rate of increase. Overall, the performance of the test wells was characterized as Positive Response or No Response, while the performance of the control wells was characterized as Natural Decline or shut-in unless it is included in a test pattern in which case the status is given as that shown in the test pattern (see

Tables VI and VII). The performance of wells in all patterns is given in Figures 14-34). It should be pointed out that there was a severe drop in production in February 1996 due to a severe freeze which shut down field operations for about a week.

Table VI. Performance of test wells in all patterns.

PATTERN	WELL NO.	STATUS	REMARKS
1	2-11 No. 1	Positive Response	
1	2-15 No. 1	No Response	
1	11-3 No. 1	No Response	
1	2-13 No. 1	Positive Response	
2	34-7 No. 2	No Response	
2	34-16 No. 2	Positive Response	
2	34-15 No. 1	Positive Response	
2	34-15 No. 2	Positive Response	This well is also a control well in pattern 3
2	34-10 No. 1	No Response	
3	10-8 No. 1	No Response	
3	11-6 No. 1	Positive Response	
3	11-4 No. 1	No Response	
3	11-3 No. 1	No Response	This well is also a test well in pattern 1
3	2-13 No. 1	Positive Responce	This well is also a test well in pattern 1
4	2-11 No. 2	Positive Response	
4	2-11 No. 1	Positive Response	This well is also a test well in pattern 1
4	2-3 No. 1	Positive Response	This well is also a control well in pattern 1
4	2-5 No. 1	No Response	This well is also a control well in pattern 1

Table VII. Performance of control wells in all patterns.

PATTERN	WELL NO.	STATUS	REMARKS
1	35-13 No. 1	Natural Decline	
1	35-14 No. 1	Shut-in	Due to uneconomical production rate
1	2-3 No. 1	Positive Response	This well is also a test well in pattern 4
1	2-5 No. 1	No Response	This well is also a test well in pattern 4
1	3-1 No. 1	Natural Decline	
2	34-2 No. 1	Natural Decline	
2	34-6 No. 1	Shut-in	Due to uneconomical production rate
2	34-7 No. 2	No Response	This well is also a test well in pattern 2
2	34-10 No. 1	No Response	This well is also a test well in pattern 2
3	3-3 No. 1	Natural Decline	
3	3-1 No. 1	Natural Decline	This well is also a control well in pattern 2
3	3-1 No. 2	Positive Response	Due to increase in water injection
3	34-15 No. 1	Positive Response	This well is also a test well in pattern 2
3	34-15 No. 2	Positive Response	This well is also a test well in pattern 2
4	3-1 No. 1	Natural Decline	This well is also a control well in pattern 1
4	3-1 No. 2	Positive Response	This well is also a control well in pattern 3
4	3-9 No. 1	Natural Decline	
4	2-5 No. 1	Natural Decline	This well is also a control well in pattern 1

Performance of the injection well 2-14 No.1

Injection pressure is increasing and injection volume is decreasing. This performance may be an indication of selective plugging in test pattern 1 (see Figure 35).

Performance of the injection well 34-9 No. 2

Injection pressure is increasing and injection volume is decreasing. This performance may be an indication of selective plugging in the test pattern 2 (see Figure 36).

Performance of the injection well 11-5 No. 1

Injection pressure and the injection volumes have increased (see Figure 37).

Performance of the injection well 2-6 No. 1

Injection pressure increased and the injection volume increased over the last six months (see Figure 38).

Although gravity, viscosity, surface tension, interfacial tension, and pH of produced fluids have been monitored, drawing conclusions concerning these parameters would be premature.

CONCLUSIONS

Five significant conclusions can be drawn at this time, even though this project is less than 60% complete.

1. It is concluded that the nutrients being injected into the reservoir are being widely distributed in the reservoir formation. *This conclusion is based on the finding of nitrate ions and phosphate ions in some of the core samples from three recently drilled wells in the oil field.*

2. It is concluded that the microflora in the reservoir formation have been stimulated to multiply as a result of the nutrient additions to the reservoir. *This conclusion is based on the finding of large numbers of bacteria in the core samples described above by electron microscopic examination.*

3. It is concluded that the addition of nitrate into the reservoir may be causing a reduction in the sulfide content of produced fluids. *This conclusion is based on the statistical analysis of data on the sulfide content of produced fluids from the field and on the fact that nitrate and the action of nitrate-reducing bacteria inhibit the production of sulfide by sulfate-reducing bacteria.*

4. It is concluded that the microbial growth is taking place in the reservoir since two of the four injector wells receiving nutrients (test patterns) are experiencing an increase in injection pressure and a decrease in fluid volume injected. *This conclusion is based on an evaluation of the performance of the injector wells.*

5. It is concluded that the MEOR process being demonstrated in this project has already had a positive effect on 8 of the 15 producing wells in the four test patterns while 8 of the 9 wells in the four control patterns have continued their natural decline in performance. The one exception is due to increased water injection in a nearby control injector well. *This conclusion is based on oil production data and the water:oil ratio of produced fluids.*

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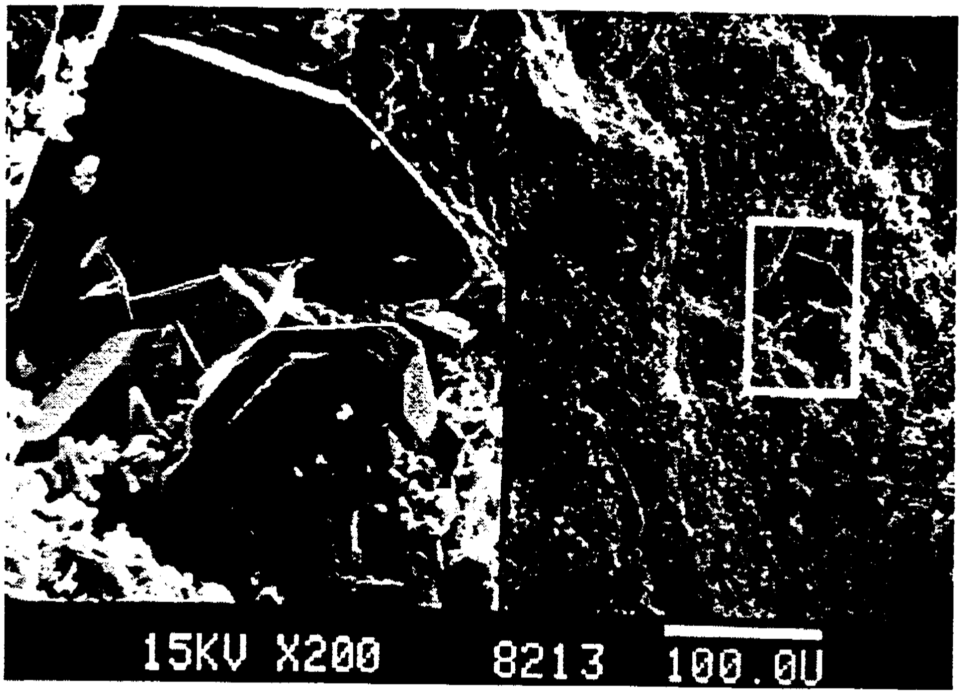
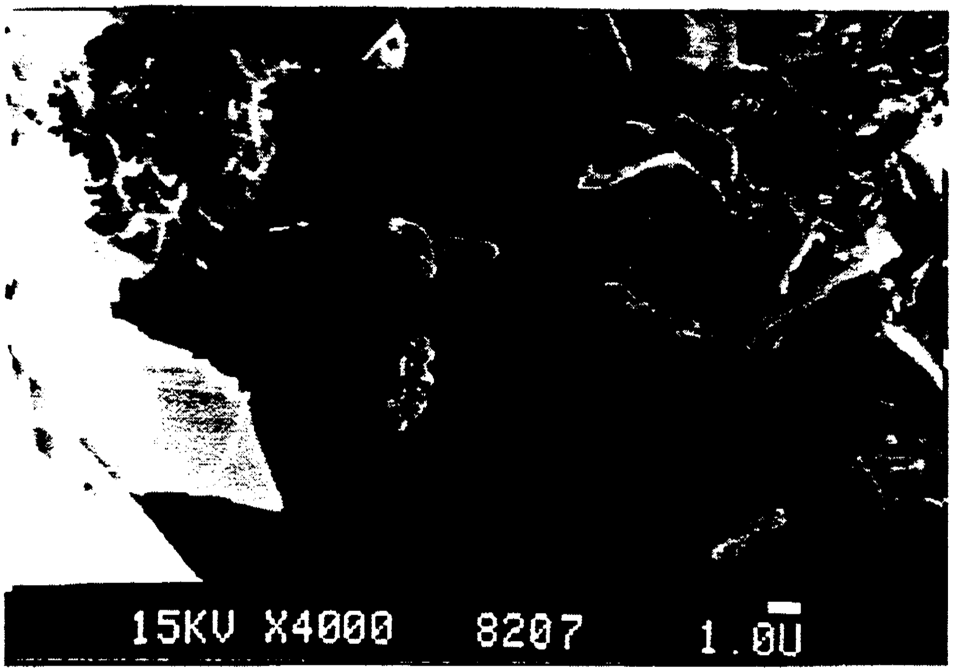
6. Reinsel, M.A., J.T. Sears, P.S. Stewart, and M. J. McInerny. 1996. Control of microbial souring by nitrate, nitrite or glutaraldehyde injection in a sandstone column. J. Ind. Microbial. 17:128-136.

APPENDIX



Sample 3-5; Negative 8213; Magnification 200X/1000X. No bacteria were observed in this sample. This sample has a basic framework of 100-250 micron sized quartz grains exhibiting abundant secondary quartz overgrowth. Porosity is estimated to be very good, but there is some restriction from increased clay content. The photomicrograph shows the increased clay presence and details kaolinite and a trace of chlorite around small authigenic quartz grains.

Figure 1. A copy of the page from the Halliburton Report on the core sample from a control core plug treated with simulated injection water only.



Sample 5-8A; Negative 8207; Magnification 4000X. The photomicrograph shows the presence of rod shaped bacteria on the surface of a secondary quartz grain, These bacteria are not present as large clumps in the sample, but are scattered as small groups throughout the sample. The structure of this sample is similar to previous sample. Porosity is estimated to be very good.

Figure 2. A copy of a page from the Halliburton Report on the core sample from a core plug treated with injection water containing nitrate, phosphate, and molasses.

Sample 5-8A; Negative 8208; Magnification 4000X. The photomicrograph shows rod shaped bacteria on the surface of a secondary quartz grain.

Figure 3. A copy of a page from the Halliburton Report on another section of the core plug sample described in Figure 2.

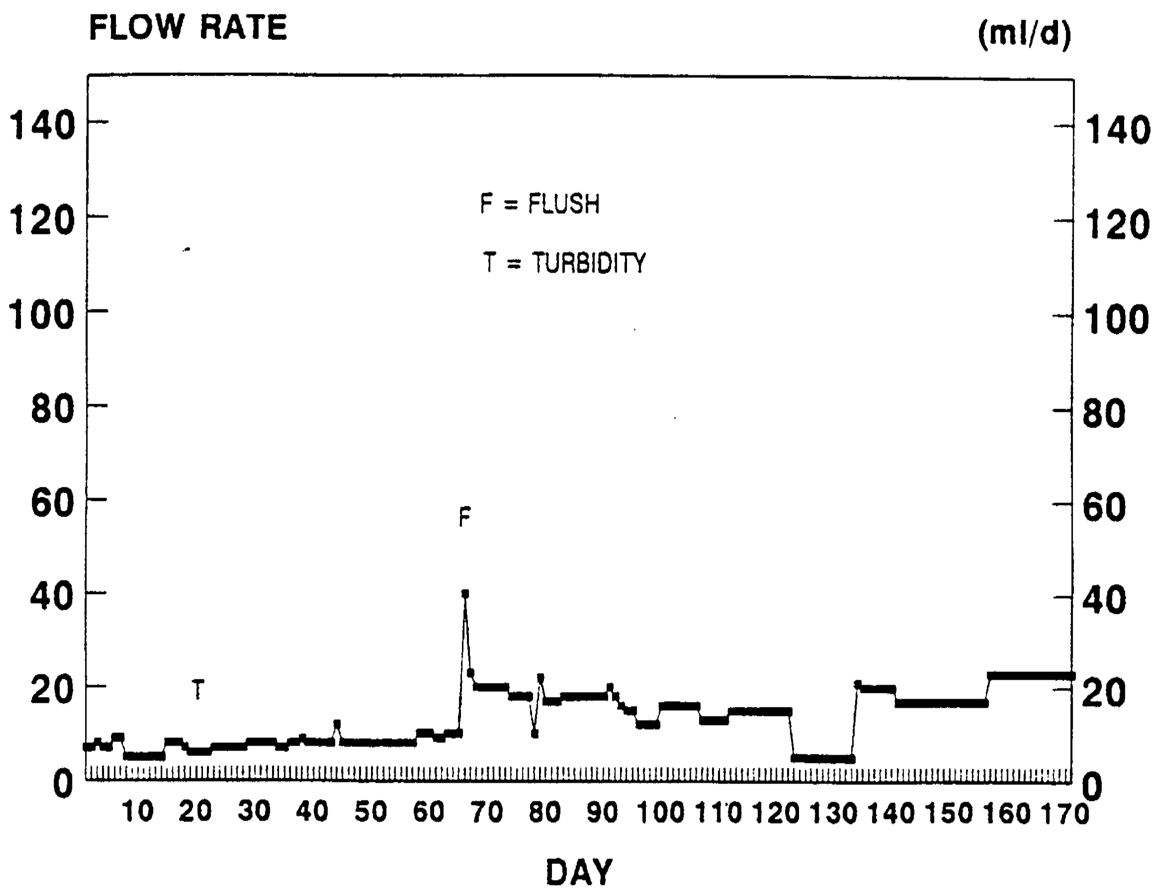


Figure 4. Flow of injection water containing nitrate and phosphate through Core 17 A.

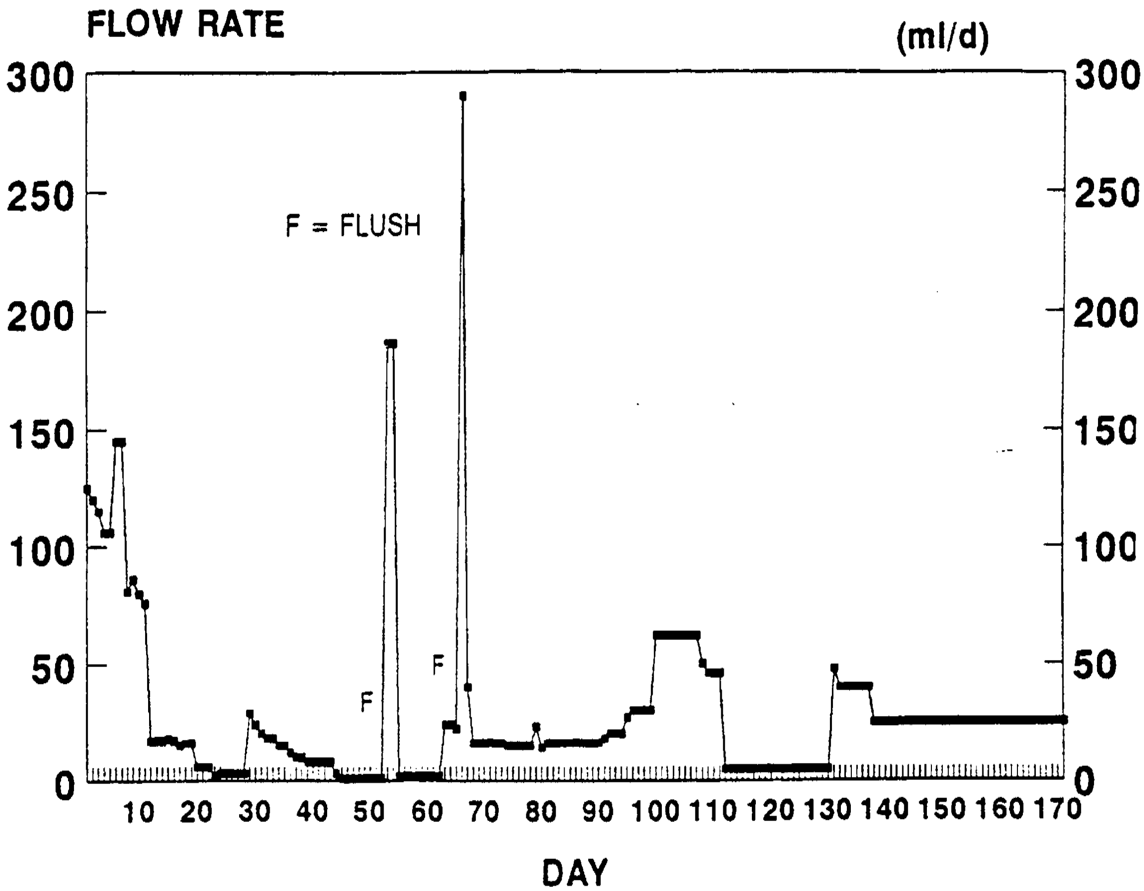


Figure 5. Flow of injection water containing nitrate, phosphate, and molasses through Core 16 B.

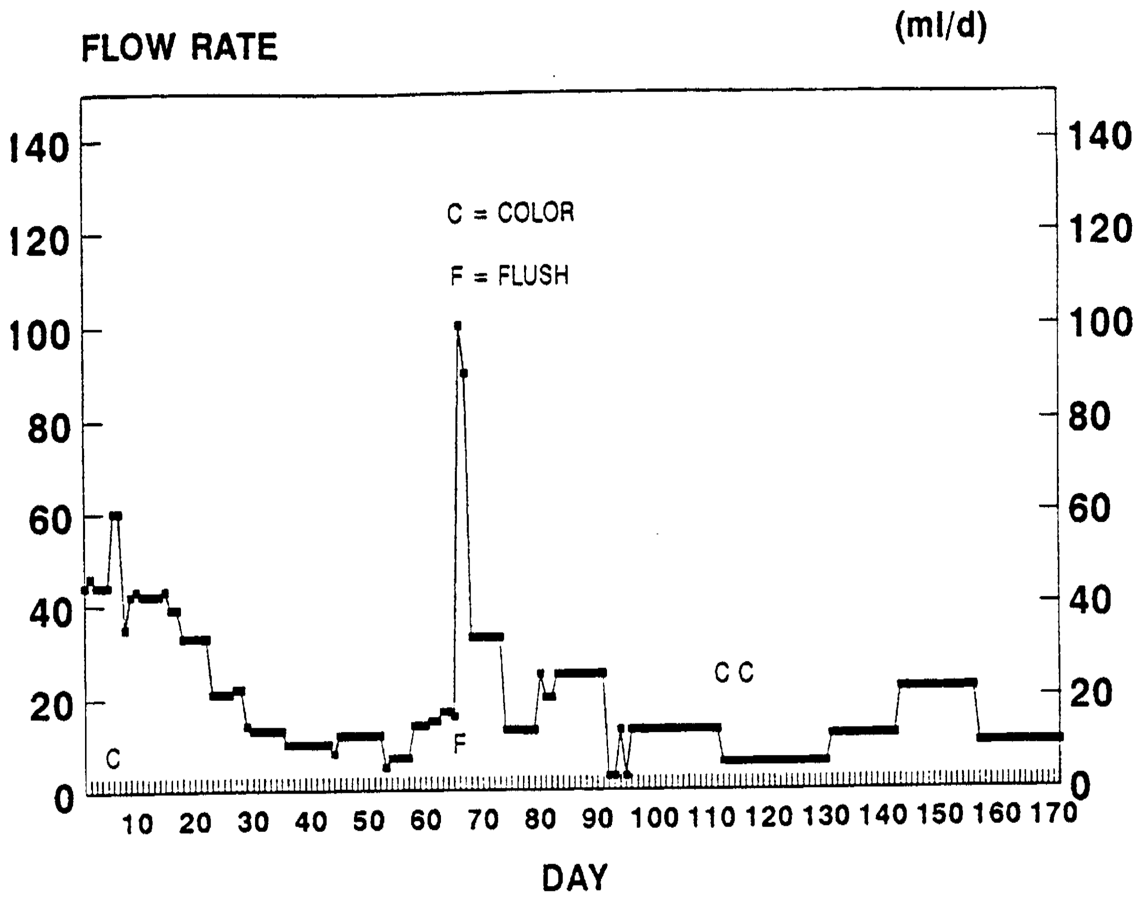


Figure 6. Flow rate of injection water containing nitrate, phosphate, and molasses through Core 17 B.

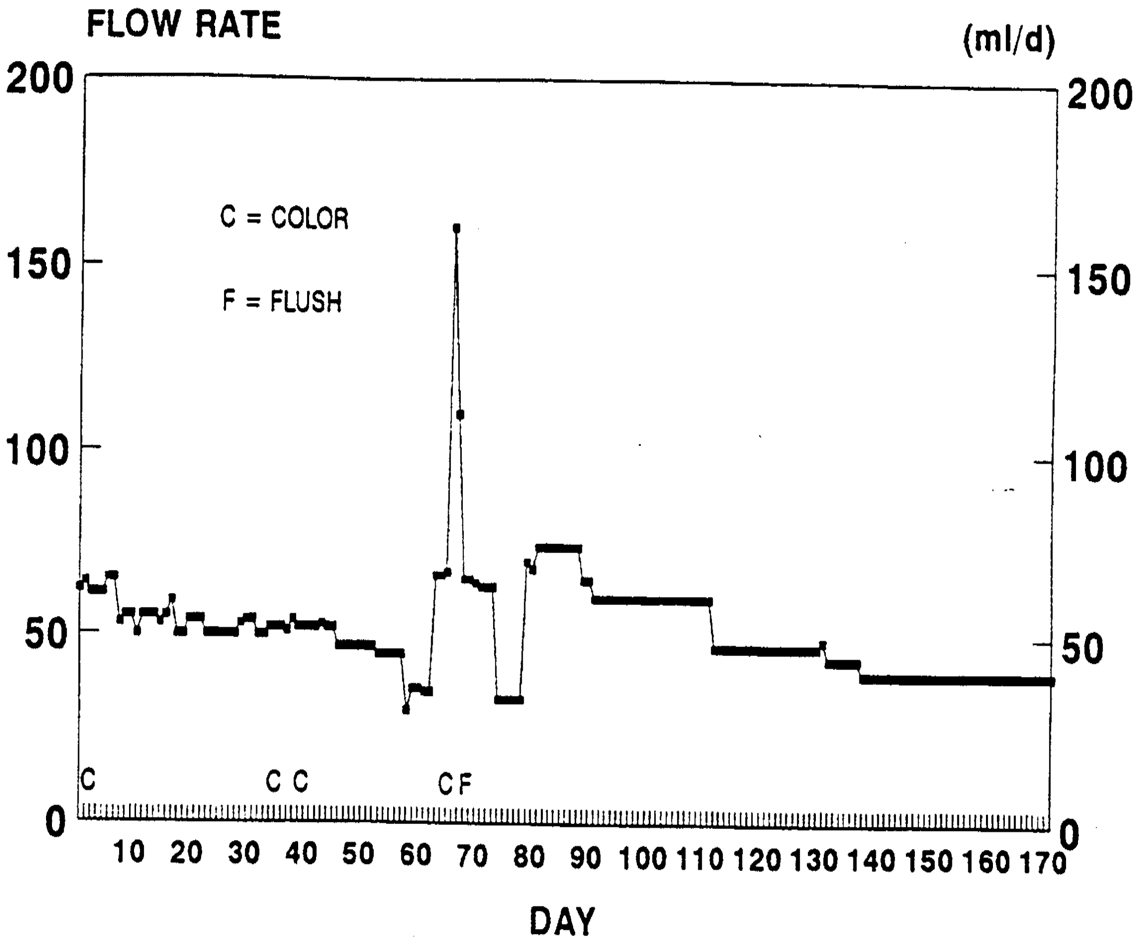


Figure 7. Flow of injection water only through Core 18 A (Control).

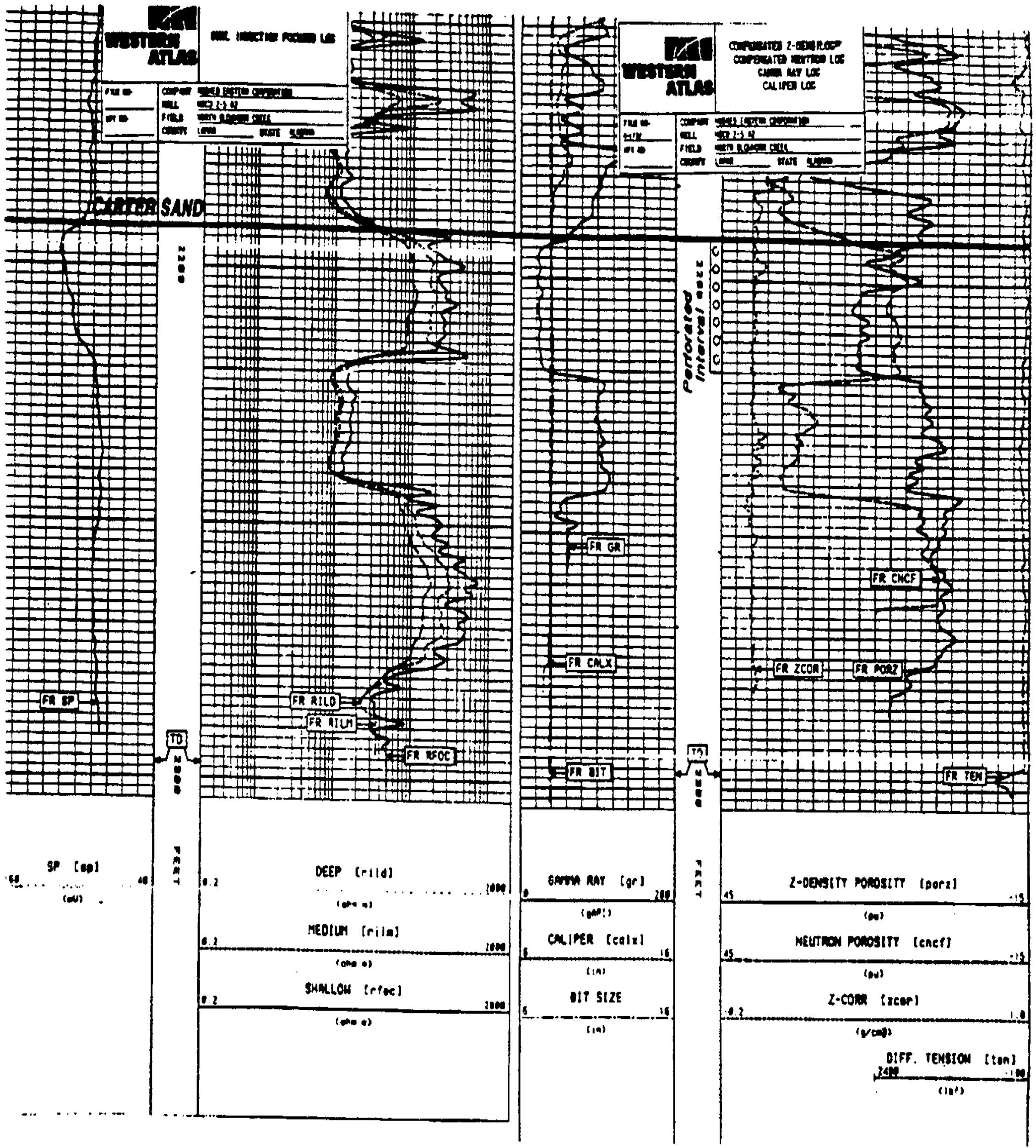


Figure 8. NBCU 2-5 No.2 log sections.

HUGHES EASTERN COPORATION
NBCU 2-5 #2

LAMAR COUNTY ALABAMA

CORETECH

CONVENTIONAL CORE

FILE NO.: 96102C
PERMIT NO:
LAB: Jackson, MS
ANALYST: McGlaun

SMP NO.	DEPTH FEET	PERM md (Kl)	PERM md (Ka)	FLD POR	HEL POR	OIL% PORE	WTR% PORE	PROB PROD	DESCRIPTION	Scfw%	FLU	GRN DEN
OCT. 16, 1996 HUGHES EASTERN CORPORATION				43 FEET CORED								
1	2185.0 - 85.5			1.6		0.8	81.9	LP	SHALE DRK GRY SD LAMS		NO	
2	2186.0 - 86.5			1.7		0.0	75.9	LP	SHALE DRK GRY SD LAMS		NO	
3	2187.0 - 87.5			2.8		2.0	91.0	LP	SHALE DRK GRY SD LAMS		NO	
4	2188.0 - 88.5			2.7		0.0	84.6	LP	SHALE DRK GRY SD LAMS		NO	
5	2189.0 - 89.5		*7.5	3.7	6.5	3.0	91.0	LP	SHALE DRK GRY SD LAM S/ASPH		FT	2.70
6	2190.0 - 90.5		*7.9	3.7	3.7	0.0	70.7	LP	SHALE DRK GRY SD LAM S/ASPH		FT	2.69
7	2191.0 - 91.5			10.1		12.2	63.4	LP	SHALE DRK GRY SD LAMS		FT	
8	2192.0 - 92.5			2.4		0.0	52.8	LP	SHALE DRK GRY SD LAMS		FT	
9	2193.0 - 93.5		*6.5	2.3	3.7	0.0	56.5	LP	SD GRY/WHT VFG S/SHLY S/ASPH		FT	2.70
10	2194.0 - 94.5		*4.2	2.5	4.5	0.0	51.6	LP	SD GRY/WHT VFG S/SHLY S/ASPH		FT	2.68
11	2195.0 - 95.5		*7.2	4.8	4.3	31.3	26.1	OIL	SD GRY/WHT VFG S/SHLY S/ASPH		FT	2.70
12	2196.0 - 96.5		7.80	12.4	8.5	23.8	46.4	OIL	SD BRN VFG S/SHLY S/ASPH	51	FT	2.62
13	2197.0 - 97.5		36.00	12.2	14.6	11.3	31.9	OIL	SD BRN/GRY VFG S/SHLY ASPH	46	YELLOW	2.61
14	2198.0 - 98.5		22.00	15.9	14.8	11.0	28.2	OIL	SD BRN/GRY VFG ASPH	54	YELLOW	2.63
15	2199.0 - 99.5		10.70	9.2	12.3	5.2	12.9	OIL	SD BRN/GRY VFG ASPH	53	YELLOW	2.68
16	2200.0 - 0.5		0.70	3.6	4.3	31.7	28.1	LP	SD BRN/GRY VFG ASPH		YELLOW	2.74
17	2201.0 - 1.5		0.40	2.9	2.5	42.7	25.6	LP	SD BRN/GRY VFG ASPH		YELLOW	2.78
18	2202.0 - 2.5		20.00	15.4	13.8	15.2	36.1	OIL	SD BRN/GRY VFG ASPH	51	YELLOW	2.64
19	2203.0 - 3.5		24.00	13.4	13.9	15.4	35.9	OIL	SD BRN/GRY VFG ASPH Api 30.5	49	YELLOW	2.63
20	2204.0 - 4.5		8.90	12.7	12.1	20.4	38.3	OIL	SD BRN/GRY VFG ASPH SHLY LAM	54	YELLOW	2.63
21	2205.0 - 5.5		9.70	16.1	12.4	13.9	33.1	OIL	SD BRN/GRY VFG ASPH SHLY LAM	53	YELLOW	2.63
22	2206.0 - 6.5		26.00	14.0	14.9	14.7	26.1	OIL	SD BRN/GRY VFG ASPH	51	YELLOW	2.62
23	2207.0 - 7.5		11.60	17.3	12.9	11.6	23.3	OIL	SD BRN/GRY VFG ASPH SHLY LAM	54	YELLOW	2.62
24	2208.0 - 8.5		32.00	14.7	15.4	13.9	29.3	OIL	SD BRN/GRY VFG ASPH	48	YELLOW	2.61
25	2209.0 - 9.5		50.00	19.5	15.4	7.2	18.8	OIL	SD BRN/GRY VFG ASPH SHLY LAM	44	YELLOW	2.63
26	2210.0 - 10.5		10.30	15.5	13.5	13.1	26.2	OIL	SD BRN/GRY VFG ASPH	54	YELLOW	2.66
27	2211.0 - 11.5		18.00	12.3	13.9	17.2	36.2	OIL	SD BRN/GRY VFG ASPH	52	YELLOW	2.65
28	2212.0 - 12.5		13.00	10.9	12.9	10.8	32.3	OIL	SD BRN/GRY VFG ASPH SHLY LAM	52	YELLOW	2.63
29	2213.0 - 13.5		13.00	12.4	12.5	17.4	34.7	OIL	SD BRN/GRY VFG ASPH SHLY LAM	52	YELLOW	2.69
30	2214.0 - 14.5		13.00	12.3	11.8	9.6	13.4	OIL	SD BRN/GRY VFG ASPH Api 29.5	52	YELLOW	2.64
31	2215.0 - 15.5		38.00	8.8	14.4	8.0	18.7	OIL	SD BRN/GRY VFG ASPH	47	YELLOW	2.68

Figure 9. NBCU 2-5 No.2 conventional core analysis.

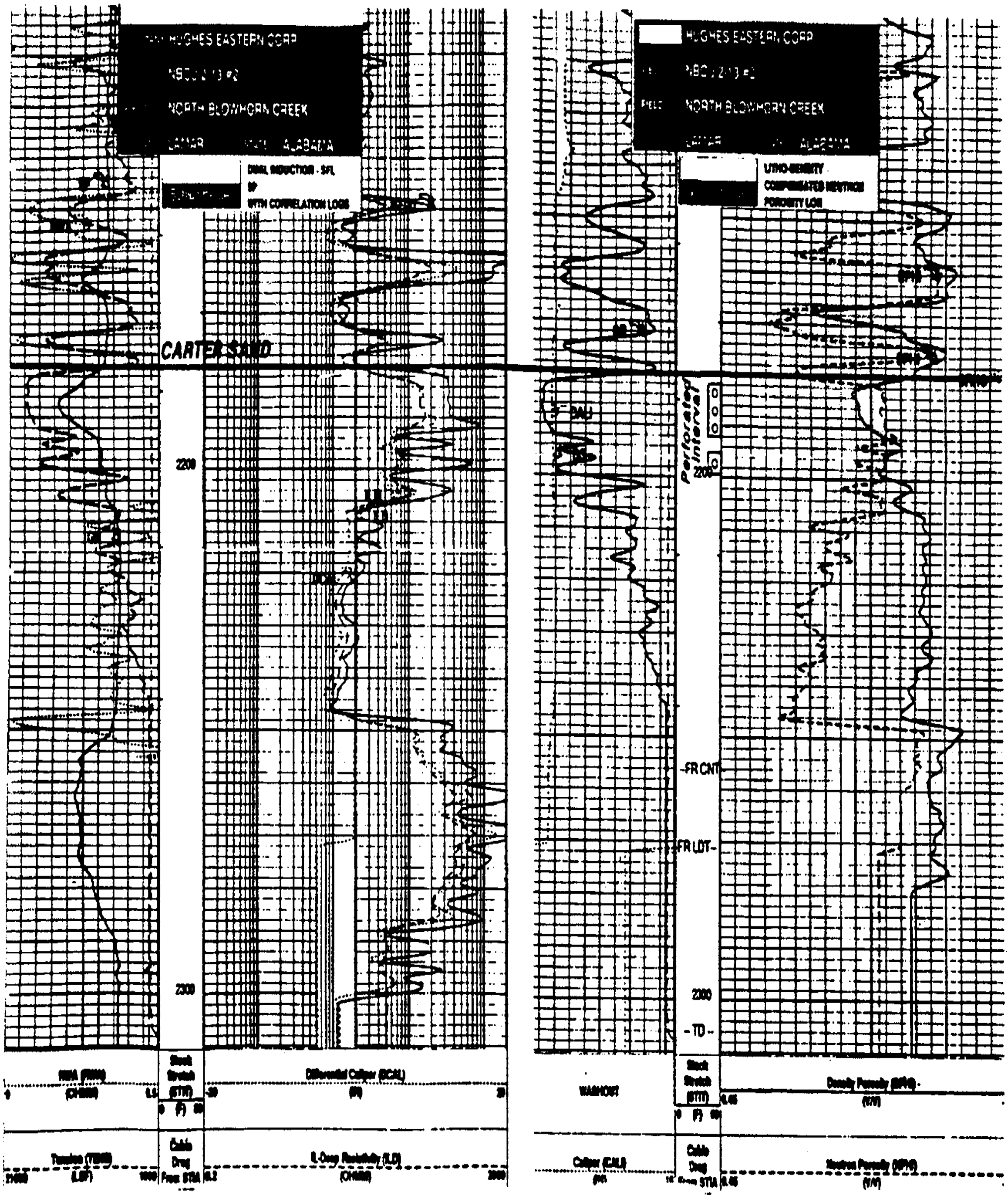


Figure 10. NBCU 2-13 No.2 log sections.

HUGHES EASTERN CORPORATION
NBCU 2-13 #2
2-14S 14W
NORTH BLOWHORN CREEK
LAMAR COUNTY ALABAMA

CORETECH

FILE NO.: 96104C
PERMIT NO:
LAB: Jackson, MS
ANALYST: McGlaun

SMP NO.	DEPTH FEET	PERM md (90)	PERM md (Ka)	FLD POR	HEL POR	OIL% PORE	WTR% PORE	PROB PROD	DESCRIPTION	Sat%	FLU	GRN DEN
10-28-96 HUGHES EASTERN CORP 43 FEET CORED												
	2172.0 - 173.0								SHALE DK GRY		NO	
	2173.0 - 174.0								SHALE DK GRY		NO	
	2174.0 - 175.0								SHALE DK GRY		NO	
1	2175.0 - 176.0		1.00	1.2	2.4	0.0	62.6	LP	SD GRY/ WHT VFG		NO	2.71
2	2176.0 - 177.0		0.70	1.0	1.8	0.0	63.7	LP	SD GRY/ WHT VFG		NO	2.74
3	2177.0 - 178.0		0.70	0.4	0.7	0.0	60.3	LP	SD GRY/ WHT VFG SH LAMS		NO	2.71
4	2178.0 - 179.0		0.70	0.6	0.3	0.0	51.9	LP	SD GRY/ WHT VFG SH LAMS		NO	2.69
5	2179.0 - 180.0		1.50	2.6	3.9	0.0	56.3	LP	SD GRY/ WHT VFG SH LAMS		NO	2.69
	2180.0 - 181.0								SHALE DK GRY		NO	
	2181.0 - 182.0								SHALE DK GRY		NO	
	2182.0 - 183.0								SHALE DK GRY		NO	
	2183.0 - 184.0								SHALE DK GRY		NO	
6	2184.0 - 185.0		22.00	7.2	8.6	16.4	31.6	OIL	SD BRN VF- FG ASPH	42	YELLOW	2.63
7	2185.0 - 186.0		141.00	11.9	13.9	9.8	24.3	OIL	SD BRN VF- FG ASPH	33	YELLOW	2.59
8	2186.0 - 187.0		50.00	11.1	12.6	20.1	21.3	OIL	SD BRN VF- FG ASPH	40	YELLOW	2.60
9	2187.0 - 188.0		87.00	12.8	13.3	14.5	22.0	OIL	SD BRN VF- FG ASPH	39	YELLOW	2.58
10	2188.0 - 189.0		86.00	13.6	14.4	9.7	19.8	OIL	SD BRN VF- FG ASPH	39	YELLOW	2.60
11	2189.0 - 190.0		91.00	13.0	14.7	5.2	23.7	OIL	SD BRN VF- FG ASPH	38	YELLOW	2.60
12	2190.0 - 191.0		101.00	13.3	14.9	11.9	24.5	OIL	SD BRN VF- FG ASPH	37	YELLOW	2.60
13	2191.0 - 192.0		43.00	10.8	11.6	15.2	18.1	OIL	SD BRN VF- FG ASPH	41	YELLOW	2.62
14	2192.0 - 193.0		107.00	13.1	14.9	11.7	24.7	OIL	SD BRN VF- FG ASPH	38	YELLOW	2.62
15	2193.0 - 194.0		44.00	12.8	12.6	12.9	20.5	OIL	SD BRN VF- FG ASPH	43	YELLOW	2.63
16	2194.0 - 195.0		7.30	8.7	9.5	20.2	21.9	OIL	SD BRN FG ASPH S/SHLY	51	YELLOW	2.63
17	2195.0 - 196.0		1.00	7.6	6.8	16.9	26.3	OIL	SD GRY/ BRN VFG V/SHLY S/ASPH	58	YELLOW	2.64
18	2196.0 - 197.0		4.40	2.9	2.6	8.6	31.6	OIL	SD GRY VFG SH LAMS S/ASPH		FT YEL	2.66
19	2197.0 - 198.0		28.00	9.4	9.1	15.9	26.3	OIL	SD BRN VFG ASPH	42	YELLOW	2.61
20	2198.0 - 199.0		34.00	9.1	9.9	7.7	22.3	OIL	SD BRN VFG ASPH	41	YELLOW	2.62
21	2199.0 - 200.0		11.10	8.9	9.8	11.6	24.7	OIL	SD WHT/GRY VFG	49	YELLOW	2.59
22	2200.0 - 201.0		7.00	3.3	5.3	17.0	23.9	OIL	SD WHT/GRY SHLY LAMS S/ASPH	46	YELLOW	2.63
23	2201.0 - 202.0		4.80	8.1	9.4	29.2	24.4	OIL	SD BRN VFG ASPH	54	YELLOW	2.63
24	2202.0 - 203.0		4.60	9.7	9.5	18.6	21.9	OIL	SD BRN VFG ASPH	54	YELLOW	2.62
25	2203.0 - 204.0		1.90	7.6	8.0	30.5	22.7	OIL	SD WHT/GRY VFG S/ ASPH	56	FT YEL	2.60
	2204.0 - 205.0								SHALE DK GRY		NO	
26	2205.0 - 206.0		1.30	5.8	5.4	0.0	21.4	LP	SD WHT/ GRY VFG V/SH LAMS	56	NO	2.63
27	2206.0 - 207.0		1.30	7.5	7.8	27.0	23.2	OIL	SD GRY VFG S/SHLY ASPH	58	YELLOW	2.64
28	2207.0 - 208.0		1.90	7.6	7.4	18.5	24.1	OIL	SD GRY VFG S/SHLY	55	YELLOW	2.63
29	2208.0 - 209.0		2.40	7.8	7.9	29.8	21.2	OIL	SD GRY VFG S/SHLY S/ASPH	56	YELLOW	2.63
30	2209.0 - 210.0		1.60	3.4	3.9	9.4	23.1	OIL	SD GRY VFG S/SHLY S/ASPH	57	YELLOW	2.66
	2210.0 - 215.0								SHALE DK GRY			

Figure 11. NBCU 2-13 No.2 conventional core analysis.

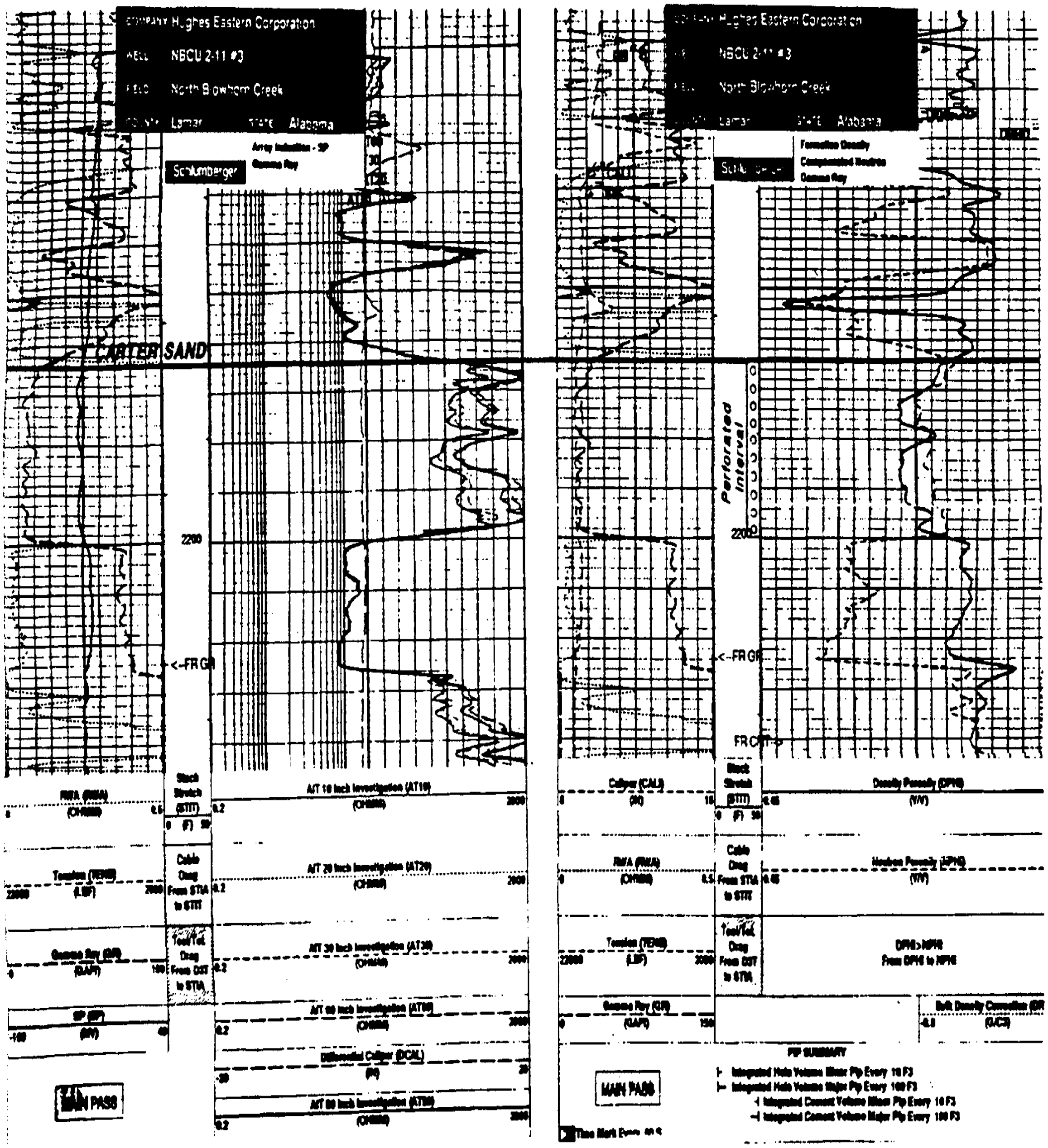


Figure 12.   NBCU 2-11 No.3 log sections.

CoreTech, Inc.

Jackson, Mississippi
1-800-748-9031 watts - 601-939-3200 tel. - 601-939-0903 fax.

Core No.1 2170.0-2202.0

Hughes Eastern Corp.		961102
NBCU 2-11 #3	Final Report	2-14S-14W
North Blowhorn Creek		Water
Lamar Co., AL		McGlaun

Smp. No.	Depth Feet	Perm md.	He Por%	Fluid Por%	So%	Sw%	Prob. Prod.	Ob.%	Gb.%	Description	Flu	Grain Density
1	2170.0 - 70.5	2.57	6.6	9.3	23.6	15.7	OIL	2.2	5.6	SD BRN VFG SHY LAMS S/ASPH	Y	2.62
2	2171.0 - 72.0	2.93	6.8	10.3	14.1	16.7	OIL	1.4	6.9	SD BRN VFG SHY LAMS S/ASPH	Y	2.61
3	2172.0 - 73.0	39.11	6.3	7.6	32.6	32.6	OIL	2.5	2.6	SD BRN VFG SHY LAMS S/ASPH	Y	2.81
4	2173.0 - 73.5	2.64	6.2	7.6	28.8	19.2	OIL	2.2	4.0	SD BRN VFG SHY LAMS S/ASPH	Y	2.61
5	2174.0 - 75.0	3.75	7.1	11.0	22.2	15.4	OIL	2.4	6.9	SD BRN VFG SHY LAMS S/ASPH	Y	2.60
6	2175.0 - 75.5	2.92	5.6	9.1	17.5	48.6	OIL	1.6	3.1	SD BRN VFG SHY LAMS S/ASPH	Y	2.63
7	2176.0 - 77.0	8.92	11.9	14.5	12.4	23.9	OIL	1.8	9.3	SD BRN VFG SHY LAMS S/ASPH	Y	2.61
8	2177.0 - 77.5	13.29	12.1	14.3	2.4	14.5	OIL	0.3	11.9	SD BRN VFG SHY LAMS S/ASPH	Y	2.64
9	2178.0 - 79.0	12.82	11.8	18.9	8.2	17.5	OIL	1.5	14.0	SD BRN VFG SHY LAMS S/ASPH	Y	2.60
10	2179.0 - 79.5	14.21	13.6	16.6	10.6	23.2	OIL	1.8	11.0	SD BRN VFG S/ASPH	Y	2.60
11	2180.0 - 81.0	18.57	13.7	17.1	12.0	31.9	OIL	2.0	9.6	SD BRN VFG S/ASPH	Y	2.62
12	2181.0 - 82.0	23.02	13.1	17.0	10.4	33.2	OIL	1.8	9.6	SD BRN VFG S/ASPH	Y	2.60
13	2182.0 - 82.5	48.28	15.9	15.9	17.9	32.1	OIL	2.8	7.9	SD BRN VFG S/ASPH	Y	2.60
14	2183.0 - 83.5	13.61	11.5	12.4	10.5	28.7	OIL	1.3	7.6	SD BRN VFG S/ASPH	Y	2.69
15	2184.0 - 84.5	34.91	14.6	17.7	9.9	19.0	OIL	1.7	12.6	SD BRN VFG S/ASPH	Y	2.66
16	2185.0 - 86.0	11.41	11.0	11.6	20.4	23.2	OIL	2.4	8.9	SD BRN VFG S/ASPH	Y	2.64
17	2186.0 - 86.5	7.78	10.8	11.6	10.3	17.5	OIL	1.2	8.4	SD BRN VFG S/ASPH	Y	2.66
18	2187.0 - 88.0	13.98	12.2	14.5	8.0	24.0	OIL	1.2	9.8	SD BRN VFG S/ASPH (29.5 API)	Y	2.63
19	2188.0 - 88.5	16.21	12.8	14.8	7.8	28.2	OIL	1.2	9.5	SD BRN VFG S/ASPH	Y	2.62
20	2189.0 - 90.0	31.78	13.1	15.2	9.9	41.1	OIL	1.5	7.5	SD BRN VFG S/ASPH	Y	2.63
21	2190.0 - 90.5	35.08	13.7	15.6	2.9	24.3	OIL	0.4	14.5	SD BRN VFG SHY LAMS S/ASPH	Y	2.62
22	2191.0 - 92.0	61.02	14.6	13.8	6.0	26.7	OIL	0.8	12.0	SD BRN VFG SHY LAMS S/ASPH	Y	2.61
23	2192.0 - 93.0	61.02	13.9	16.6	13.8	26.0	OIL	2.3	10.0	SD BRN VFG SHY LAMS S/ASPH	Y	2.59
24	2193.0 - 94.0	41.88	12.9	14.6	11.1	15.8	OIL	1.6	10.7	SD BRN VFG SHY LAMS S/ASPH	Y	2.60
25	2194.0 - 94.5	51.86	10.7	15.4	11.9	14.8	OIL	1.8	11.3	SD BRN VFG SHY LAMS S/ASPH	Y	2.51
26	2195.0 - 95.5	2.42	12.7	9.2	17.6	23.0	OIL	1.6	5.5	SD BRN VFG SHY LAMS S/ASPH	Y	2.80
27	2196.0 - 97.0	1.35	11.0	16.2	15.9	21.3	OIL	2.6	10.2	SD BRN VFG SHY LAMS S/ASPH	Y	2.60
28	2197.0 - 98.0	54.38	13.6	15.0	13.8	21.5	OIL	2.1	9.7	SD BRN VFG SHY LAMS S/ASPH	Y	2.60
29	2198.0 - 98.5	2.44	11.5	11.3	16.2	29.2	OIL	1.8	6.2	SD BRN VFG SHY LAMS S/ASPH	Y	2.66
30	2199.0 - 99.5	4.56	9.9	11.5	10.4	28.4	OIL	1.2	9.3	SD BRN VFG SHY LAMS S/ASPH	Y	2.61
0	2200.0 - 101.5									SHALE DK GRY	0	

Figure 13. NBCU 2-11 No.3 conventional core analysis.

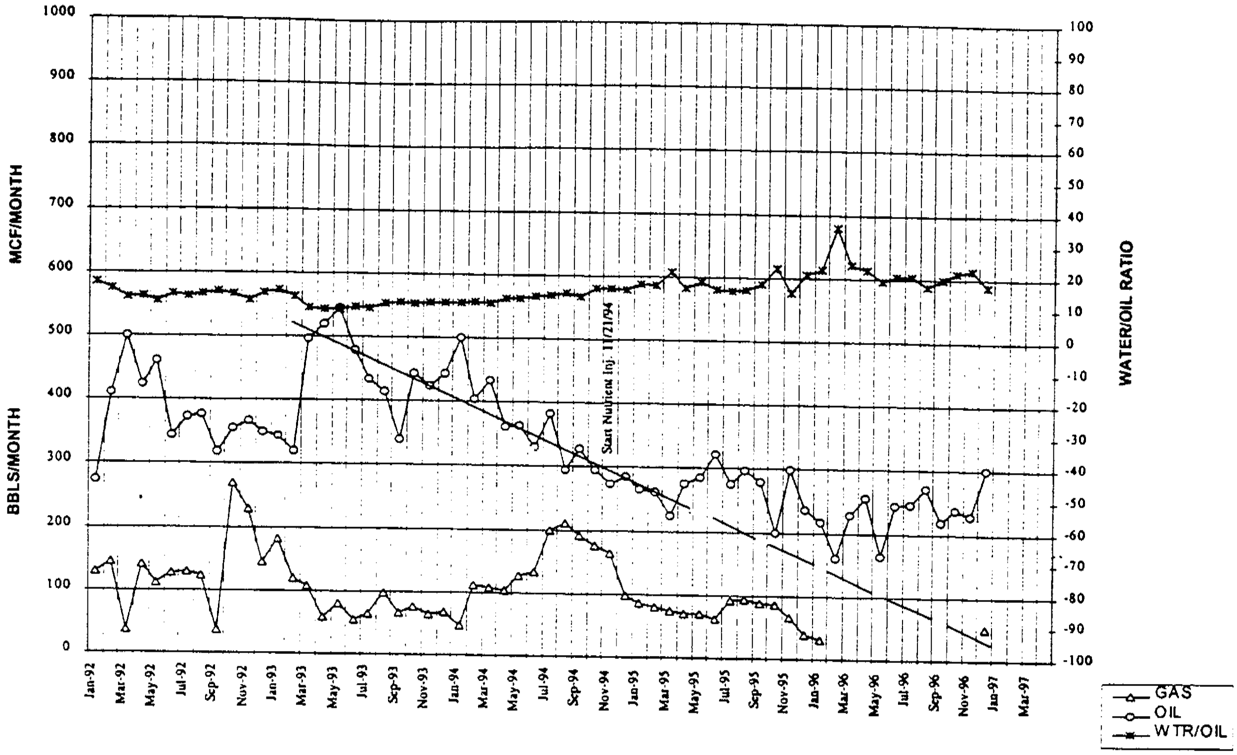


Figure 14. Performance of well 2-11 No.1 (test pattern 1).

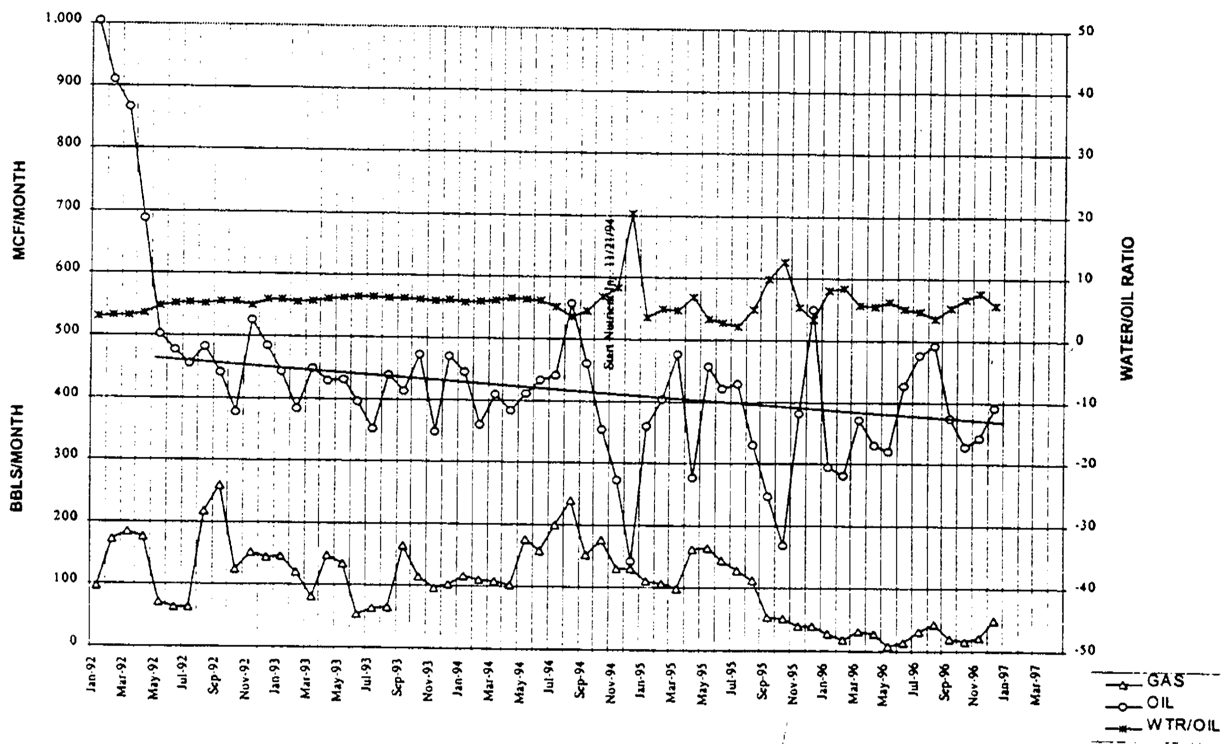


Figure 15. Performance of well 2-15 No.1 (test pattern 1).

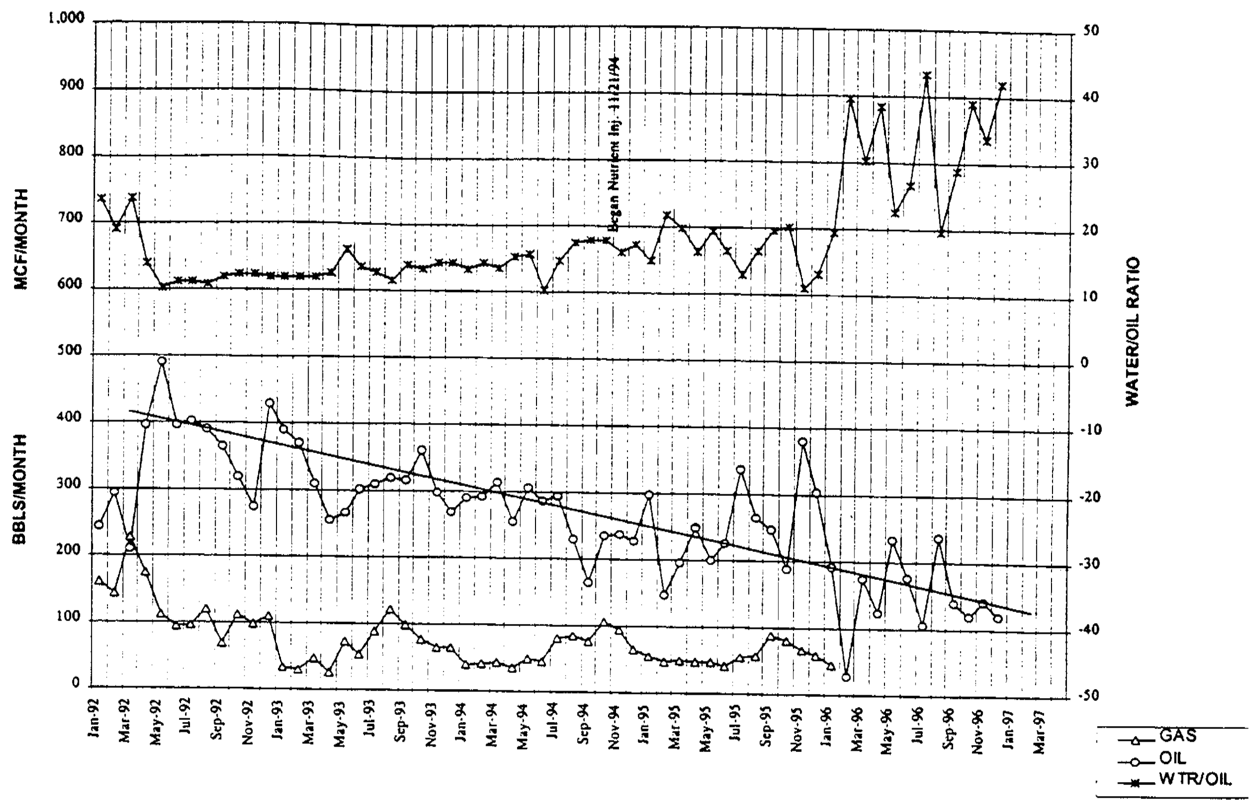


Figure 16. Performance of well 11-3 No.1 (test patterns 1,3).

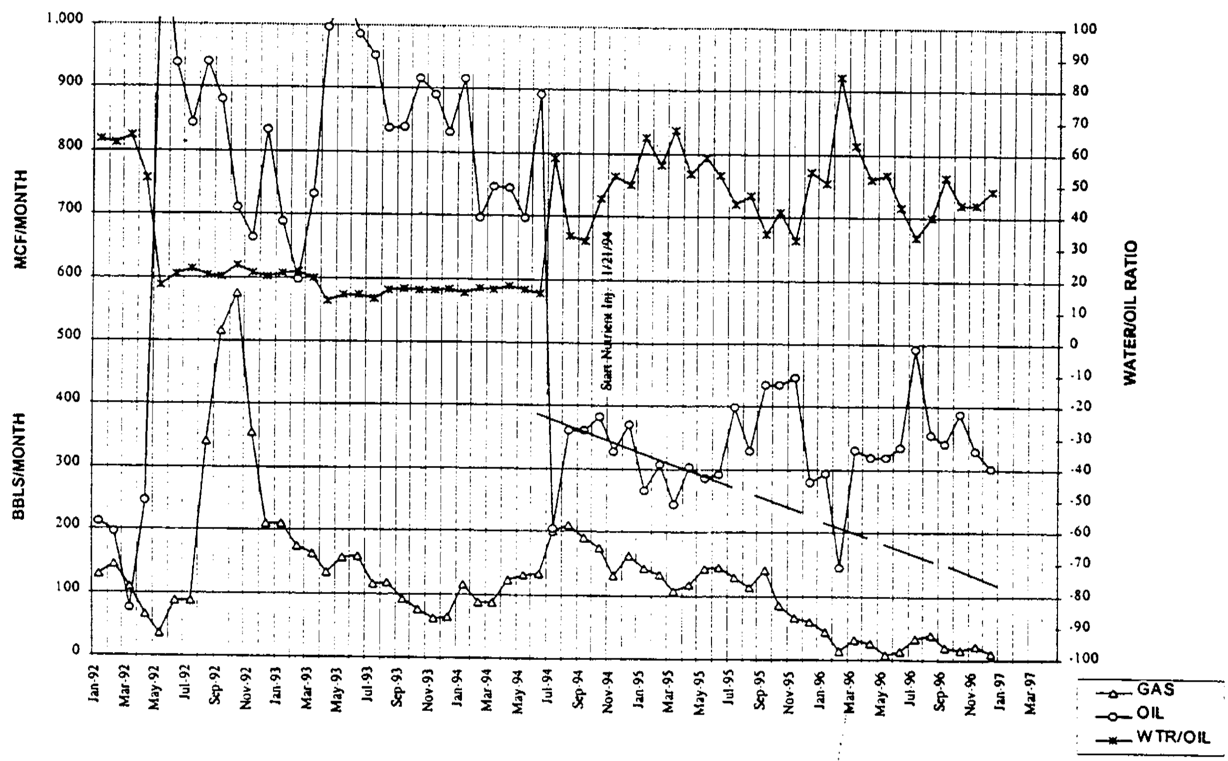


Figure 17. Performance of well 2-13 No.1 (test patterns 1,3).

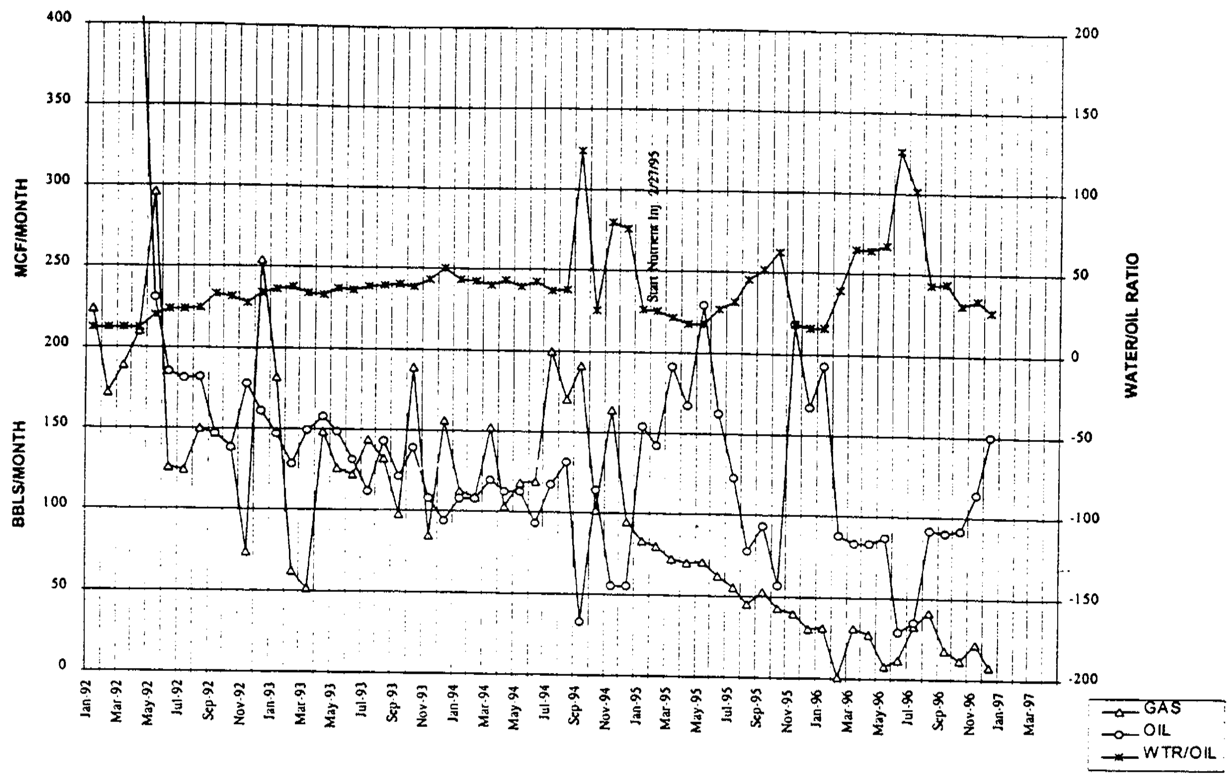


Figure 18. Performance of well 34-7 No.2 (test pattern 2 and control pattern 2).

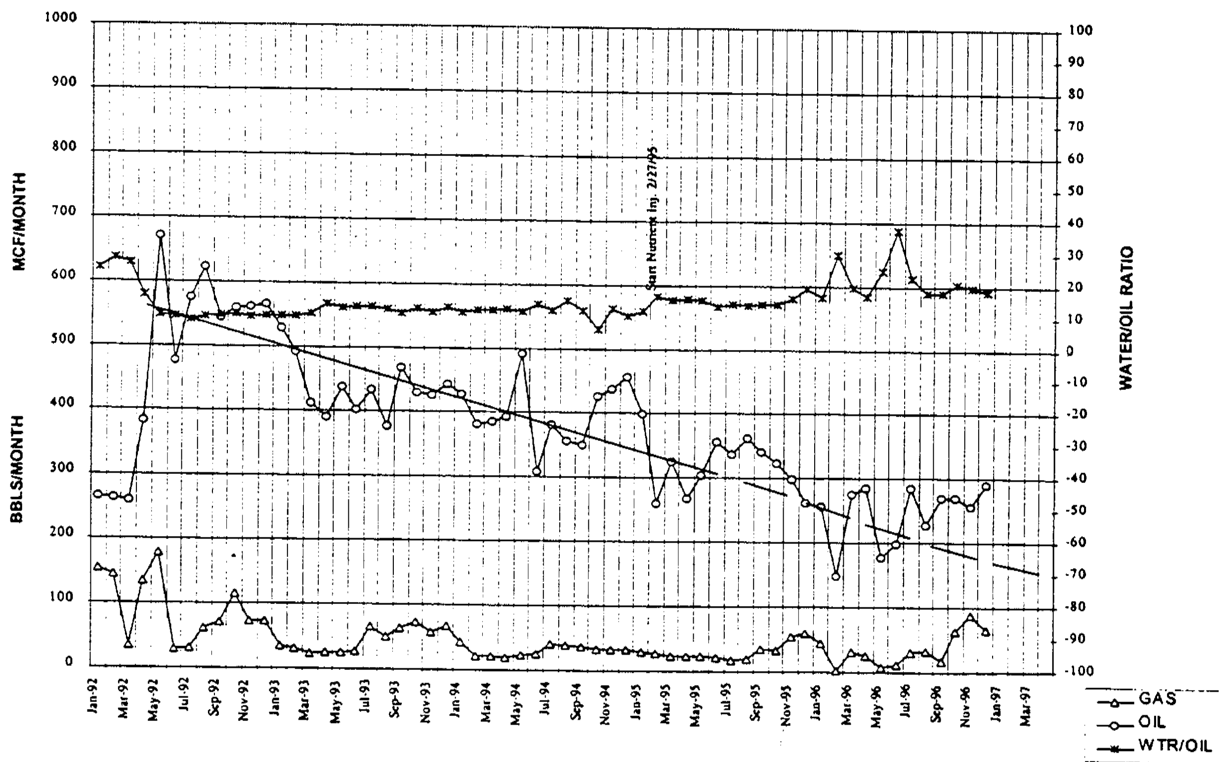


Figure 19. Performance of well 34-16 No.2 (test pattern 2).

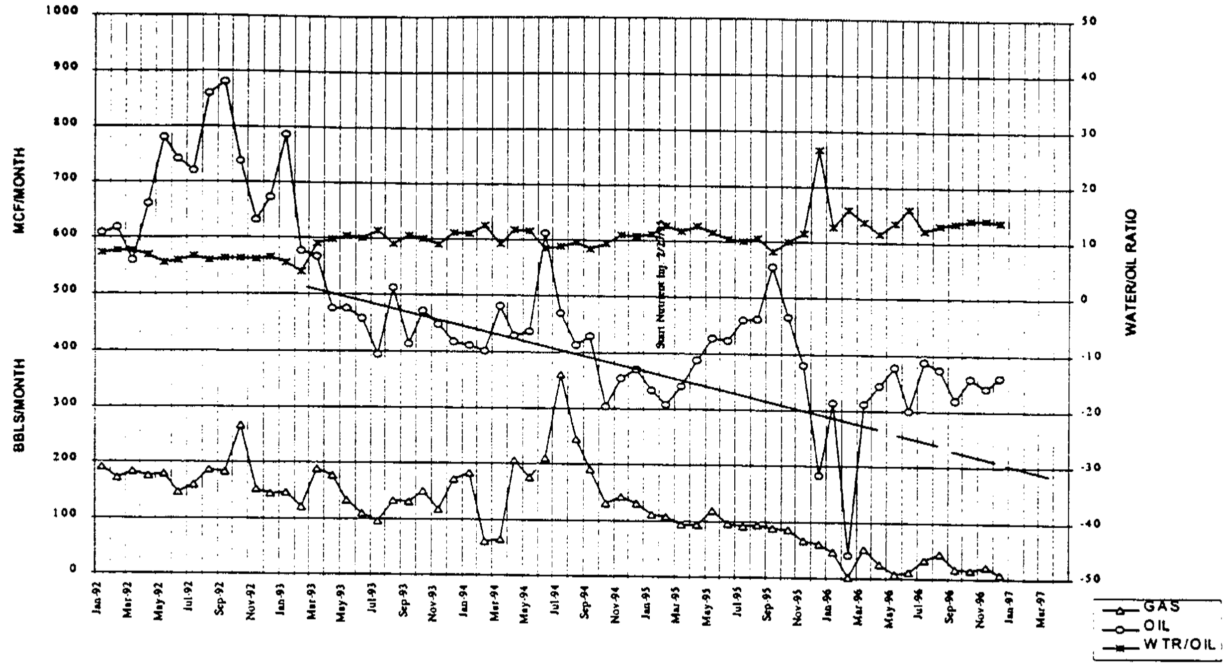


Figure 20. Performance of well 34-15 No.1 (test pattern 2 and control pattern 3).

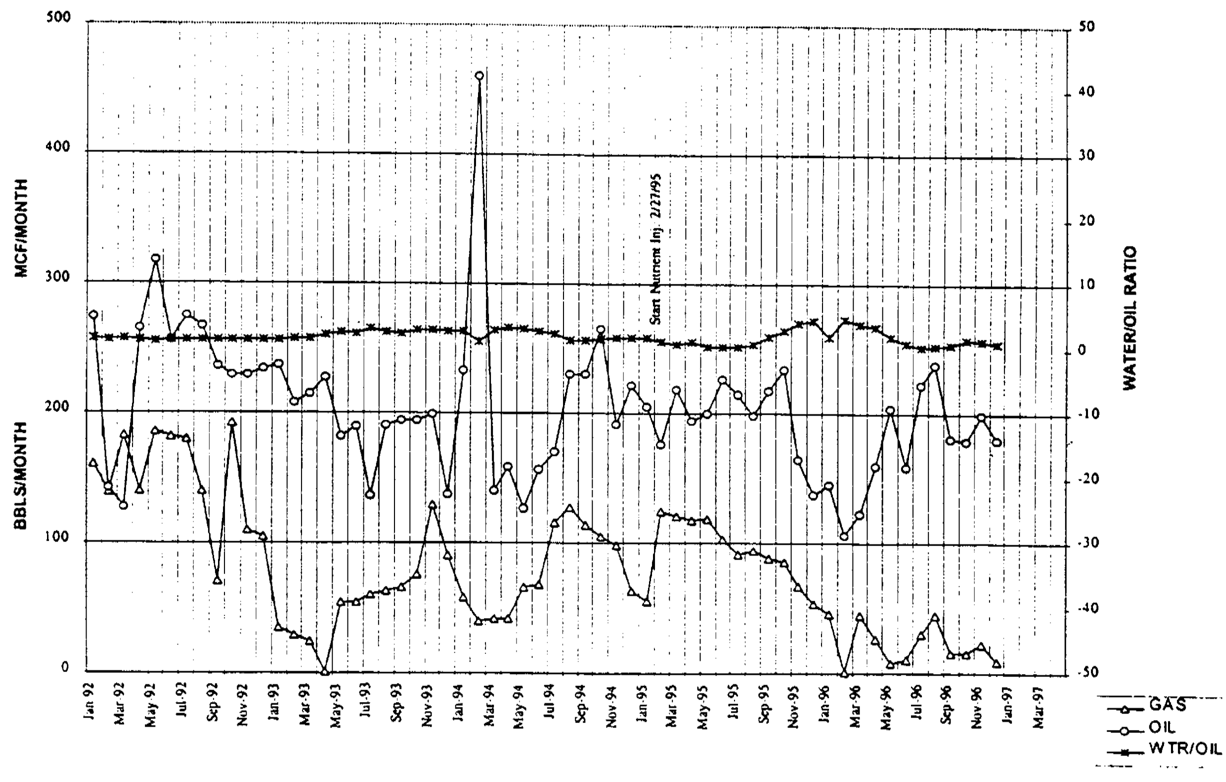


Figure 21. Performance of well 34-15 No.2 (test pattern 2 and control pattern 3).

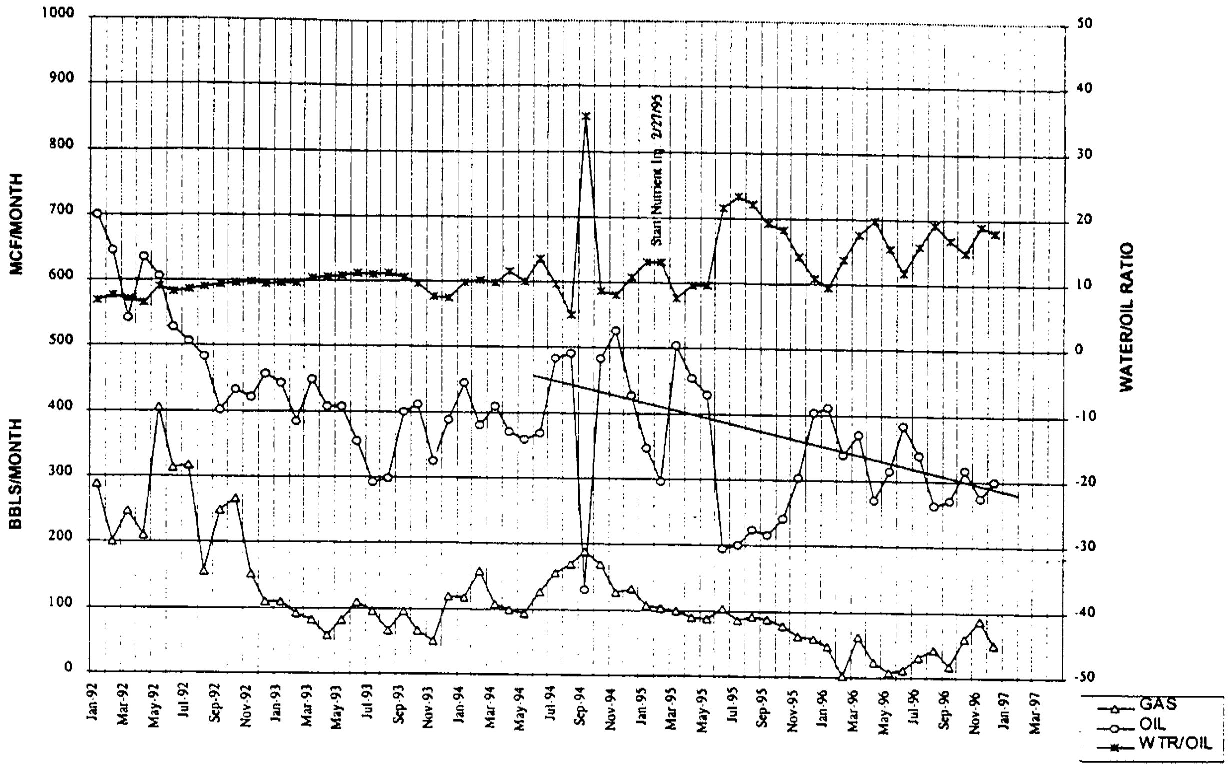


Figure 22. Performance of well 34-10 No.1 (test pattern 2 and control pattern 2).

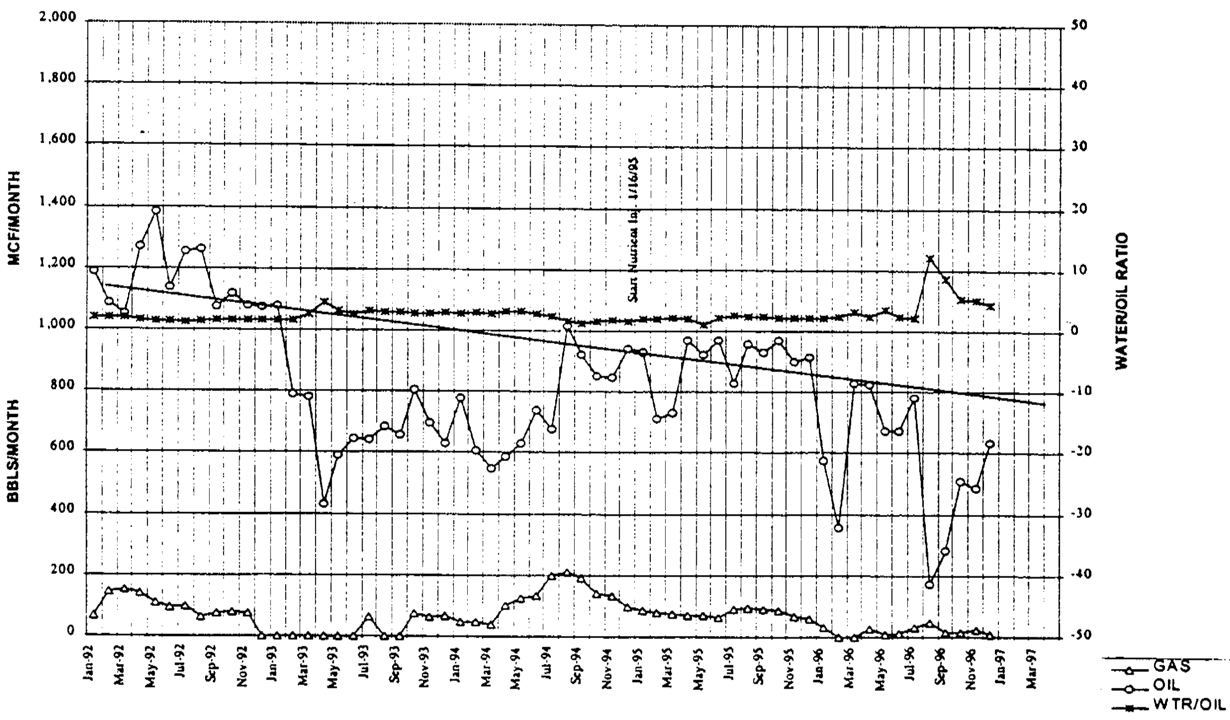


Figure 23. Performance of well 10-8 No.1 (test pattern 3).

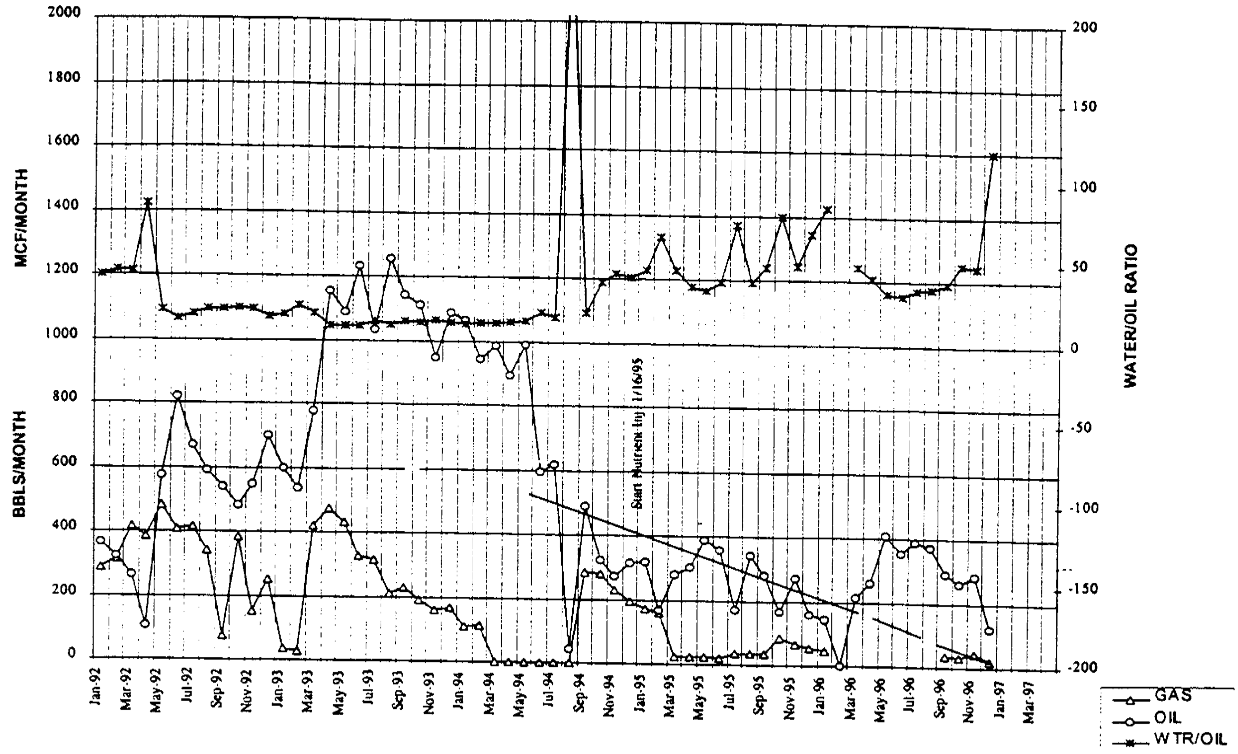


Figure 24. Performance of well 11-6 No.1 (test pattern 3).

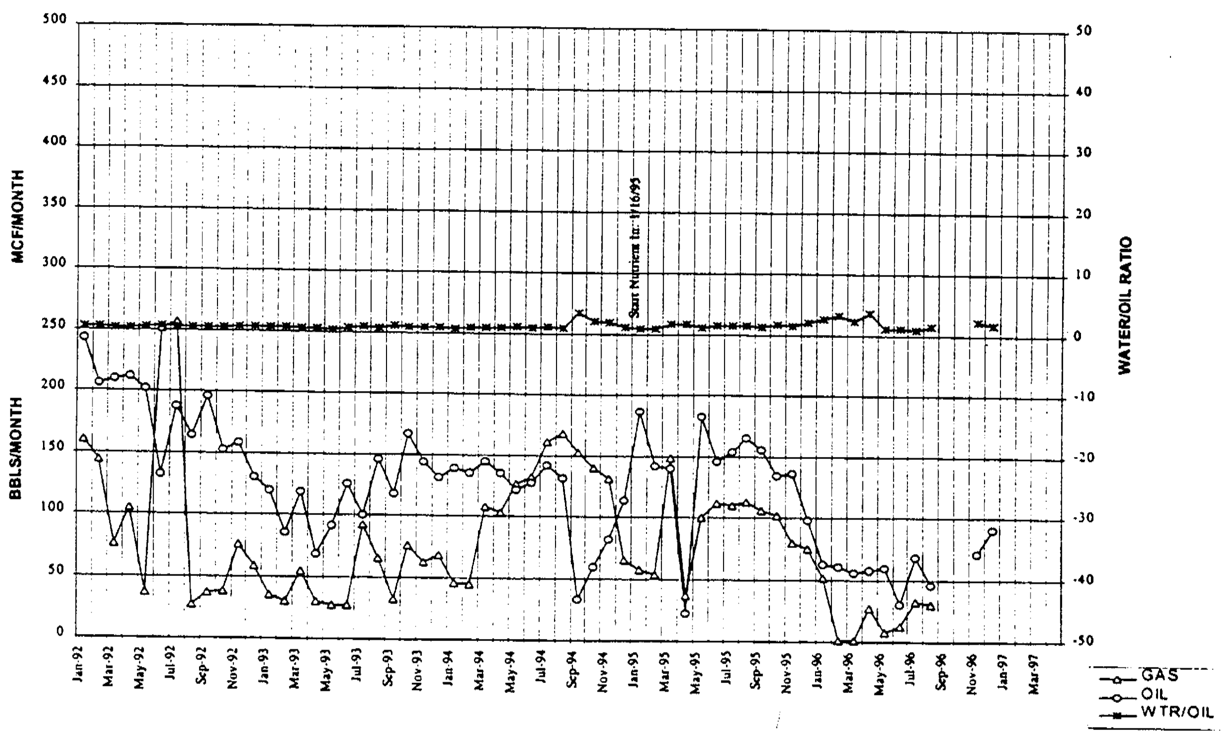


Figure 25. Performance of well 11-4 No.1 (test pattern 3).

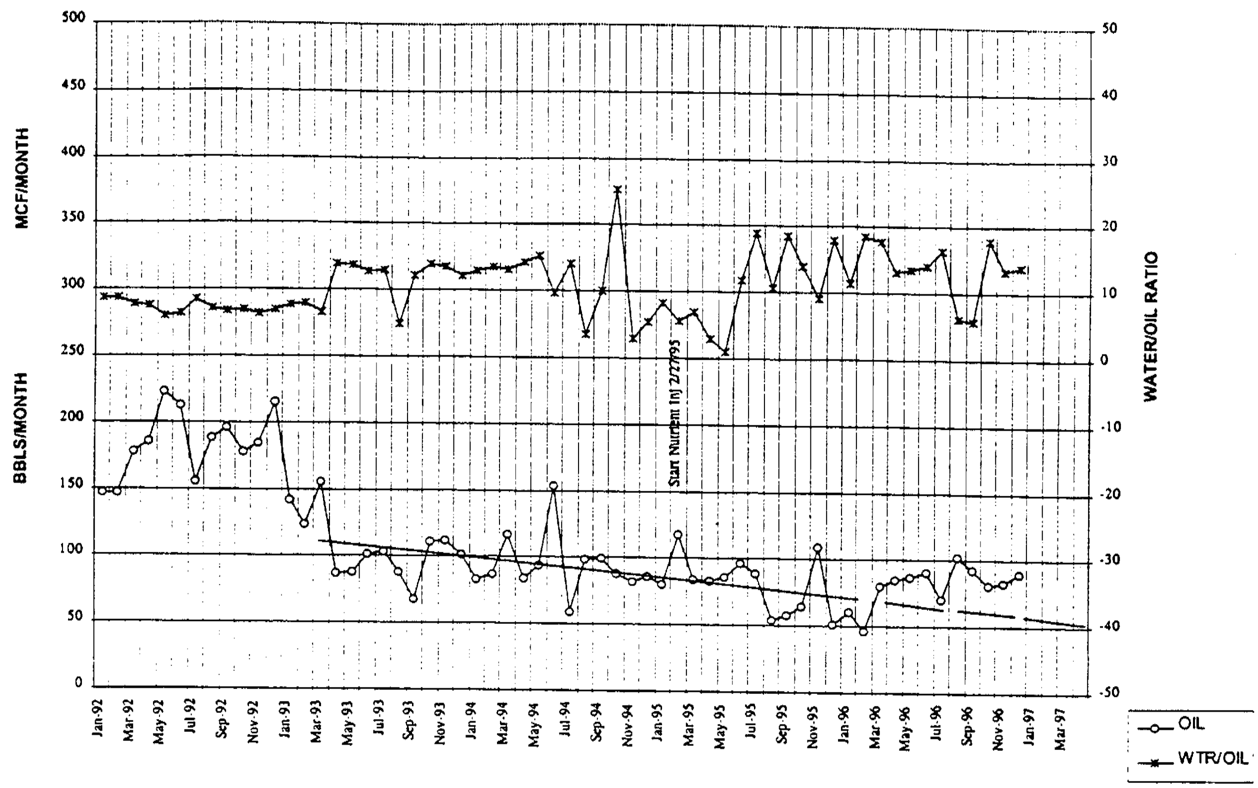


Figure 26. Performance of well 2-11 No.2 (test pattern 4).

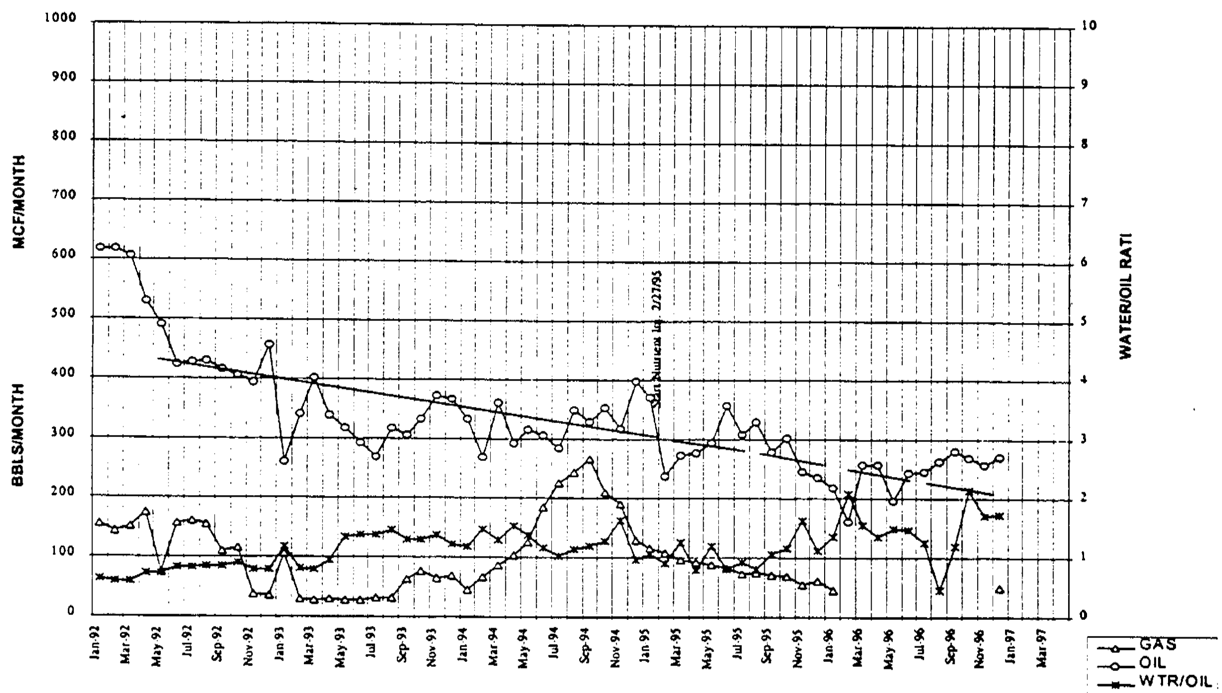


Figure 27. Performance of well 2-3 No.1 (test pattern 4 and control pattern 1).

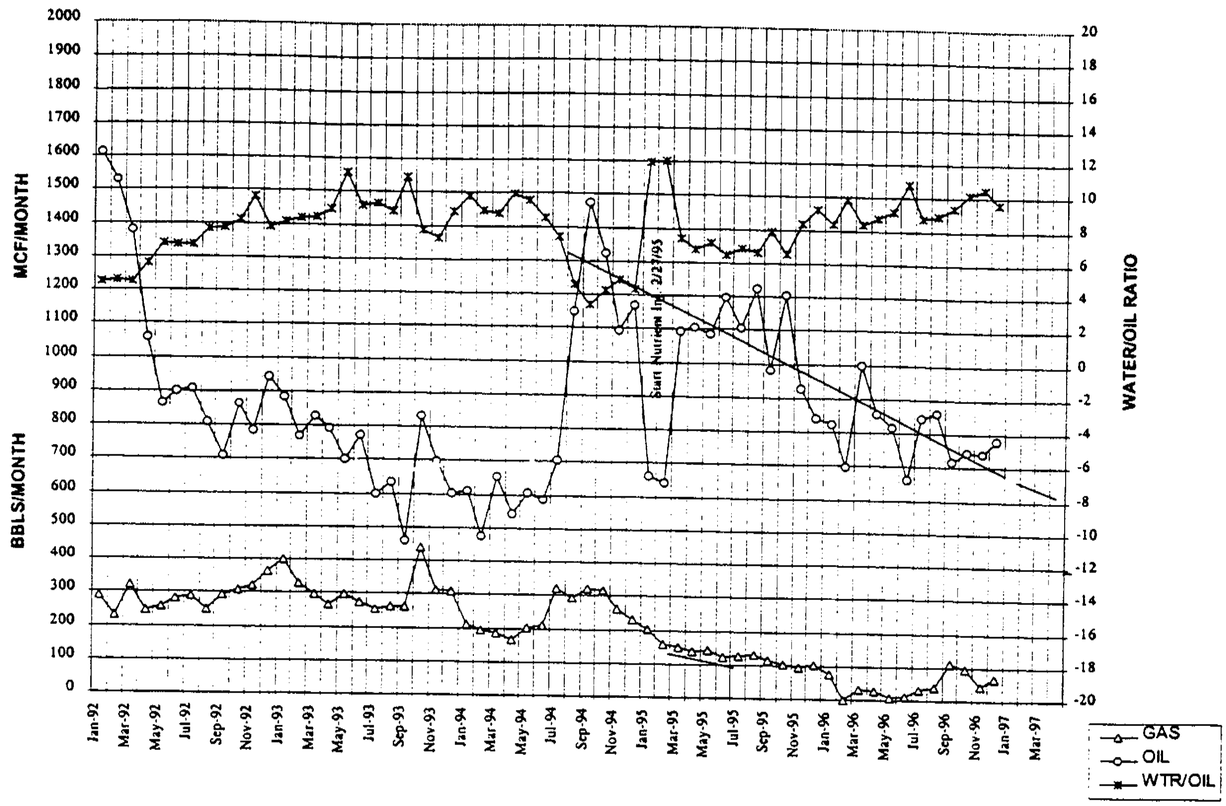


Figure 28. Performance of well 2-5 No.1 (test pattern 4 and control patterns 1,4).

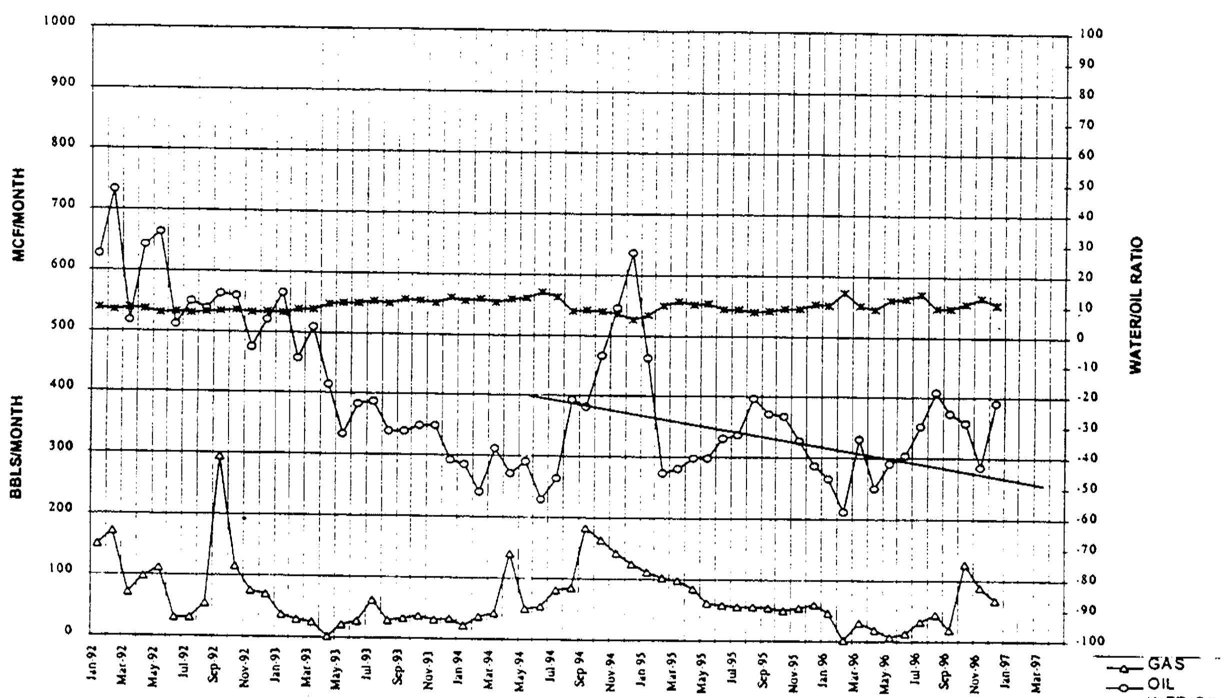


Figure 29. Performance of well 35-13 No.1 (control pattern 1).

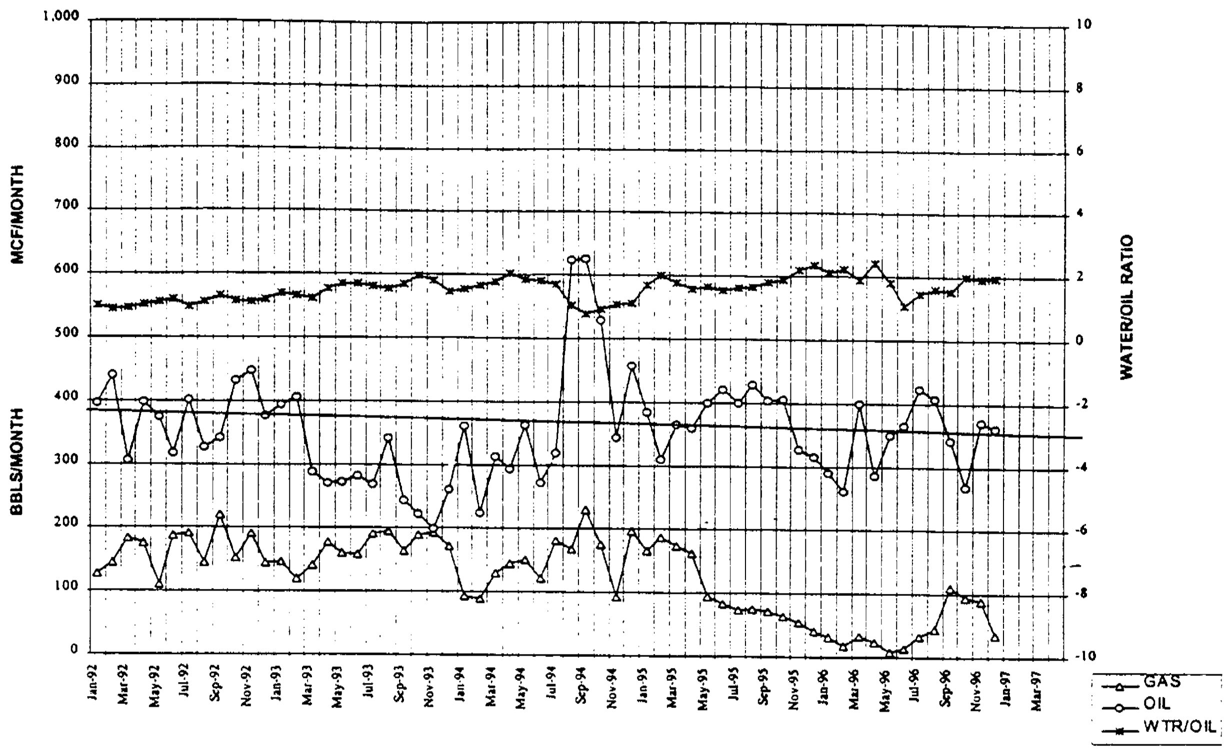


Figure 30. Performance of well 3-1 No.1 (control patterns 1,3,4).

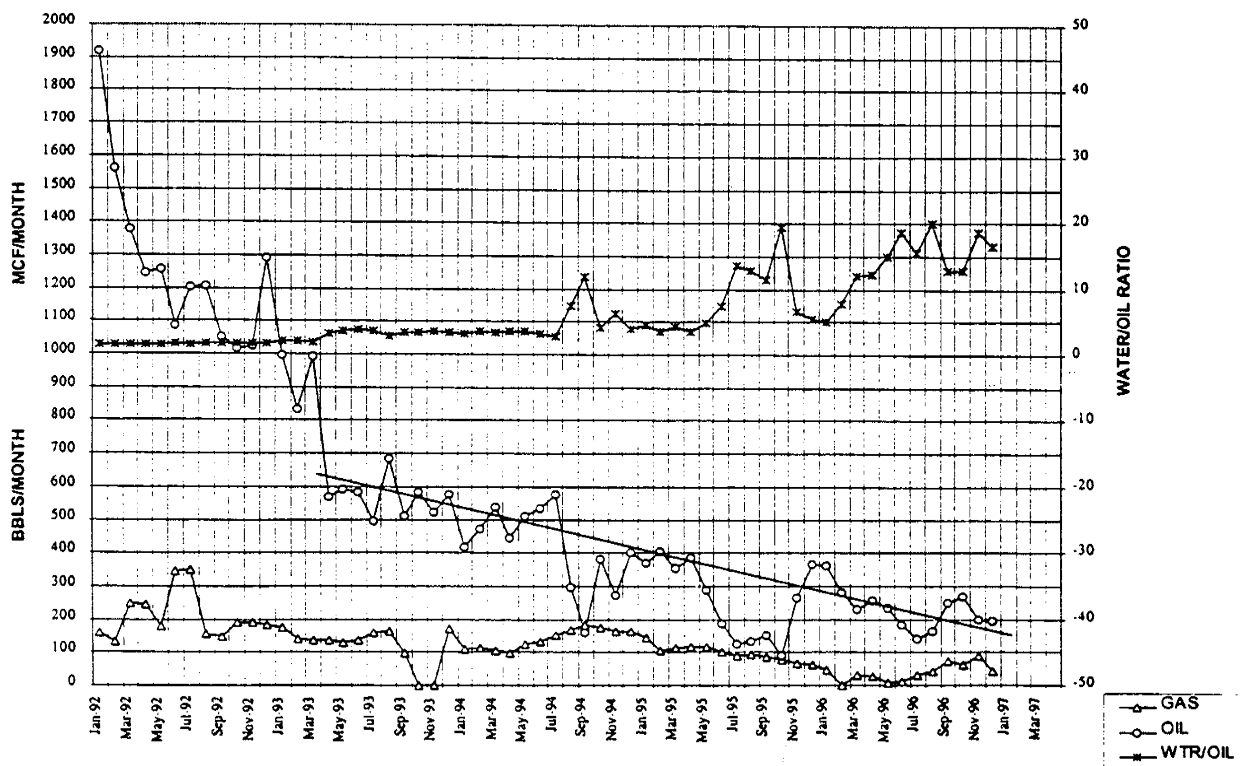


Figure 31. Performance of well 34-2 No.1 (control pattern 2).

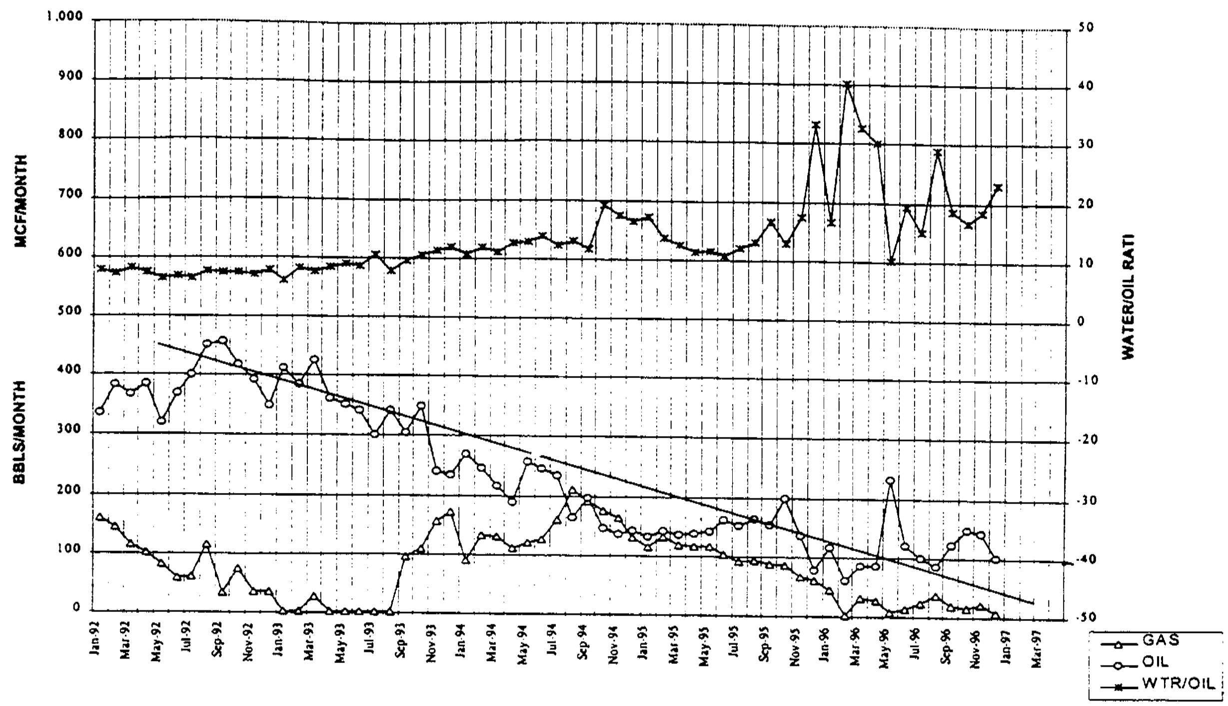


Figure 32. Performance of well 3-3 No.1 (control pattern 3).

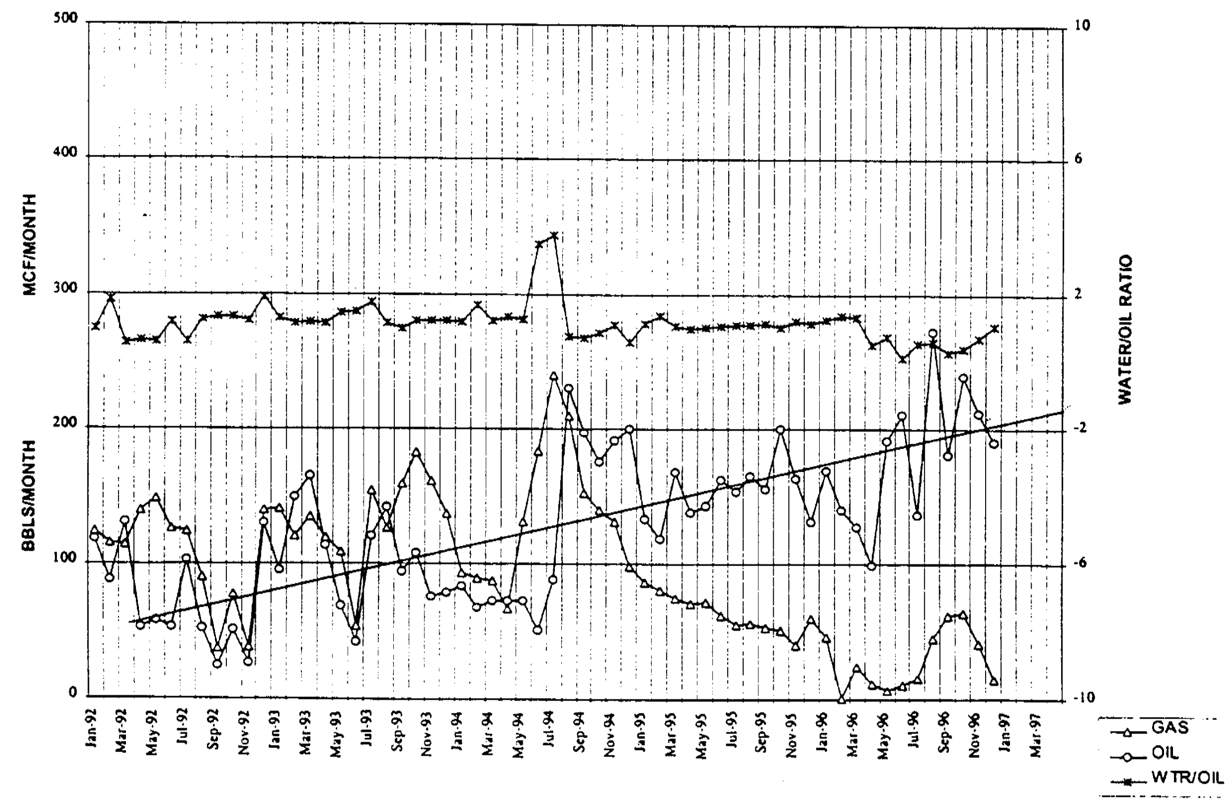


Figure 33. Performance of well 3-1 No.2 (control patterns 3,4).

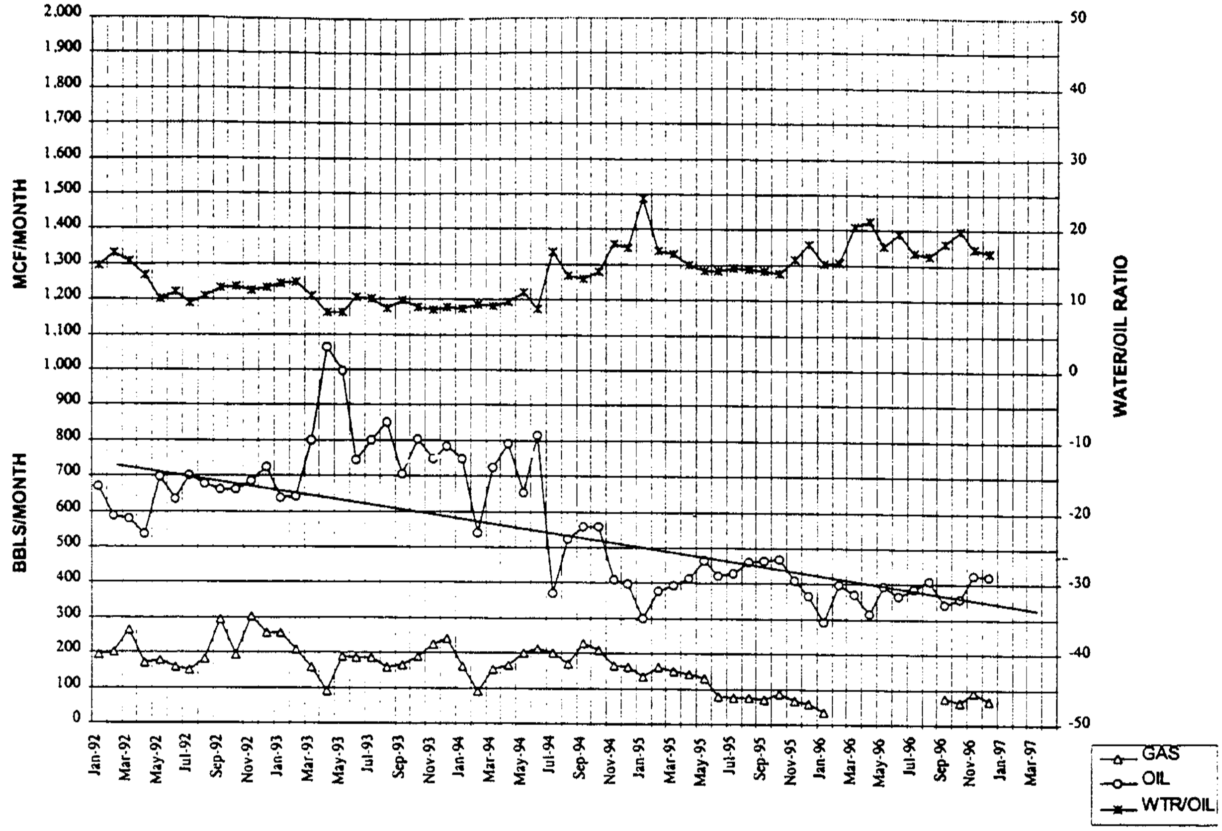


Figure 34. Performance of well 3-9 No.1 (control pattern 4).

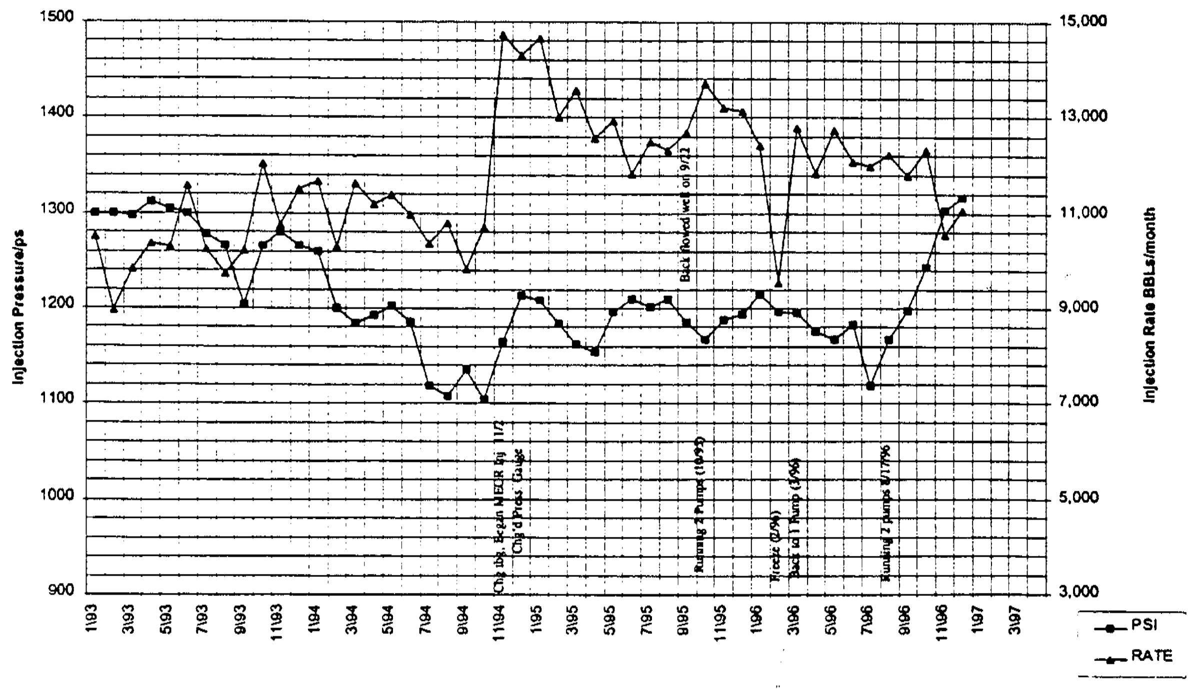


Figure 35. Performance of injection well 2-14 No.1 (test pattern 1).

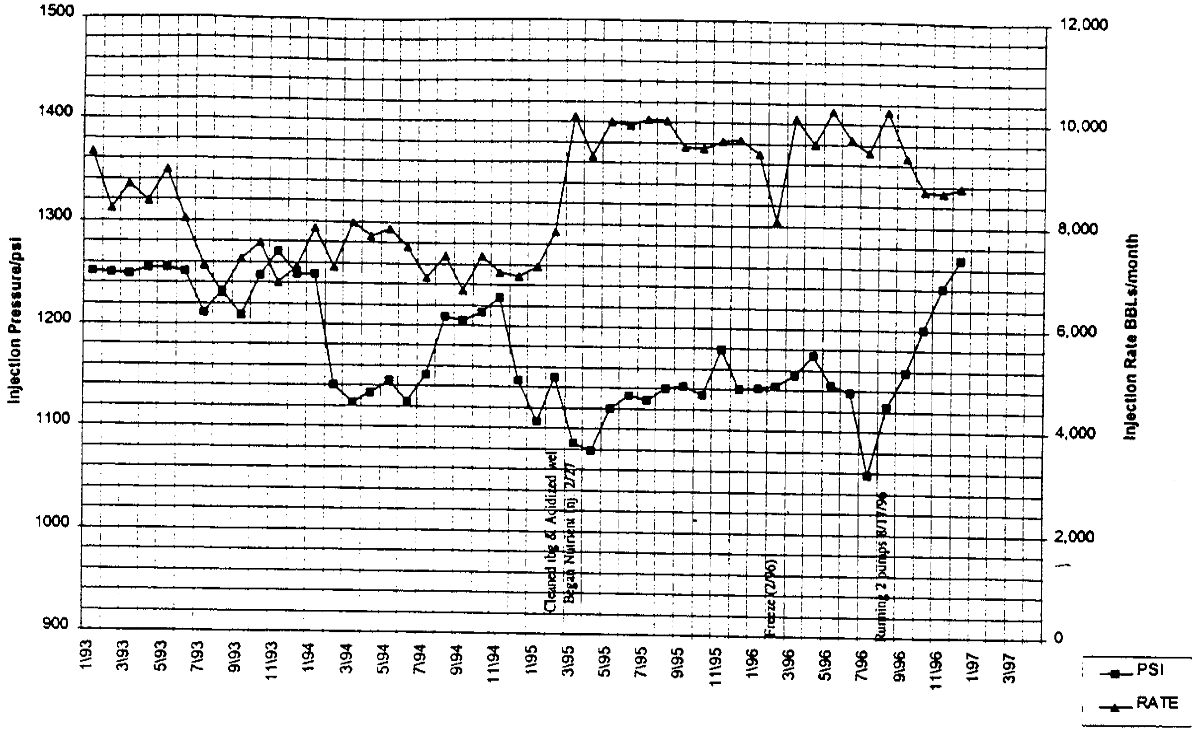


Figure 36. Performance of injection well 34-9 No.2 (test pattern 2).

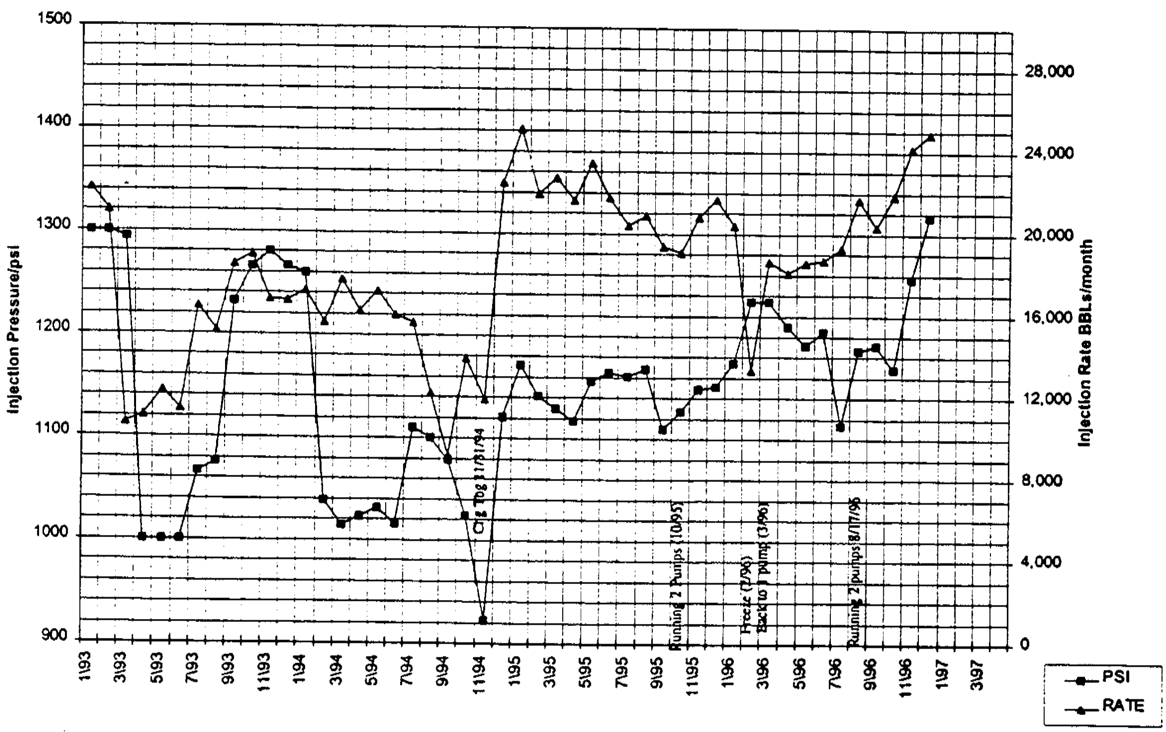


Figure 37. Performance of injection well 11-5 No.1 (test pattern 3).

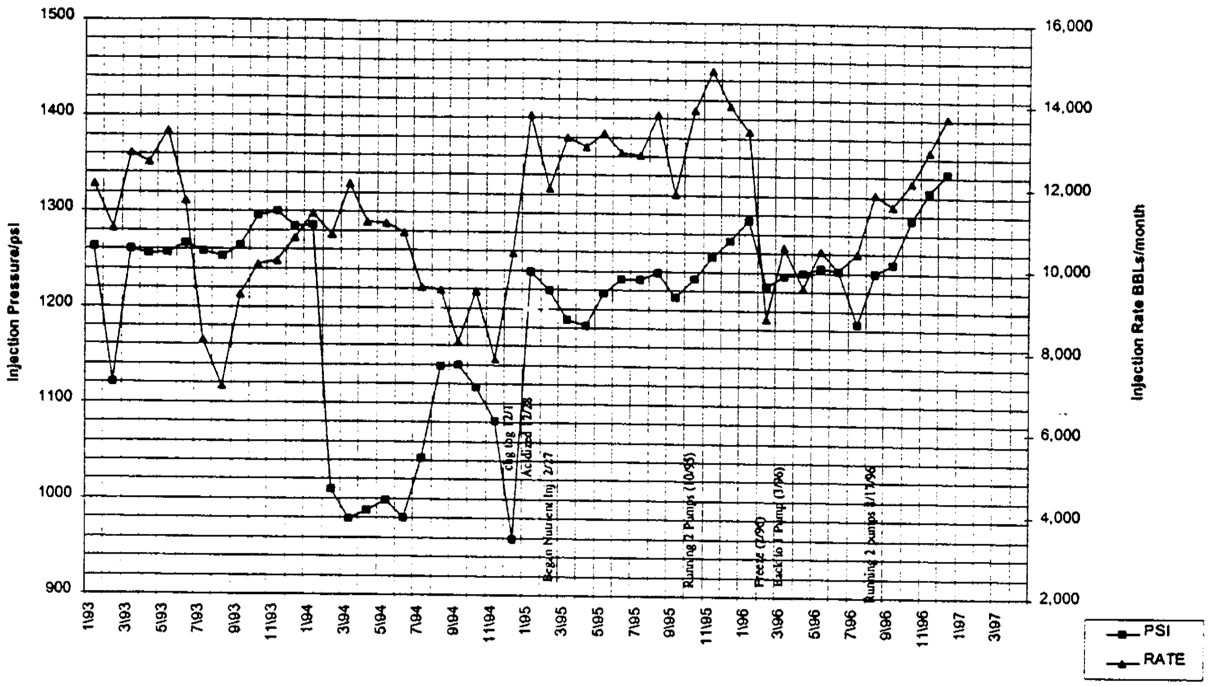


Figure 38. Performance of injection well 2-6 No.1 (test pattern 4).