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FOSSIL ENERGY

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POST WATERFLOOD CO_2 MISCIBLE FLOOD IN LIGHT OIL, FLUVIAL-DOMINATED DELTAIC RESERVOIR

FY 1993 ANNUAL REPORT

By
Darrell W. Davis

March 1995

Performed Under Contract No. DE-FC22-93BC14960

Texaco Exploration and Production Inc.
New Orleans, Louisiana

DEPARTMENT OF ENERGY
UNITED STATES OF AMERICA

Bartlesville Project Office
U. S. DEPARTMENT OF ENERGY
Bartlesville, Oklahoma

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Prepared for
U.S. Department of Energy
Assistant Secretary for Fossil Energy

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Bartlesville Project Office
P.O. Box 1398
Bartlesville, OK 74005

Prepared by
Texaco Exploration and Production Inc.
New Orleans, LA 70160

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"POST WATERFLOOD CO_2 MISCIBLE FLOOD IN LIGHT OIL FLUVIAL DOMINATED DELTAIC RESERVOIR"

DE-FC22-93BC14960

Abstract

The "Post Waterflood CO_2 Miscible Flood in Light Oil Fluvial Dominated Deltaic Reservoir" is a Class I DOE-sponsored field demonstration project of a CO_2 miscible flood project at the Port Neches Field in Orange County, Texas. The project will determine the recovery efficiency of CO_2 flooding a waterflooded and a partial waterdrive sandstone reservoir at a depth of 5800'. The project will also evaluate the use of a horizontal CO_2 injection well placed at the original oil-water contact of the waterflooded reservoir. A PC-based reservoir screening model will be developed by Texaco's research lab in Houston and Louisiana State University will assist in the development of a database of fluvial-dominated deltaic reservoirs where CO_2 flooding may be applicable. This technology will be transferred throughout the oil industry through a series of technical papers and industry open forums.

Major work necessary to establish results from the project have been accomplished, with the initiation of CO_2 injection into the waterflooded fault having began on September 22, 1993. Six producing wells and four CO_2 injection wells have been worked over and made ready for CO_2 operations. The six producing wells (Stark #8, Kuhn #6, #14, #15-R, #33, and #38) are all currently shut-in while CO_2 injection into the four injection wells (Stark #7, #10 and Kuhn #17, #36) at a total rate of 4 MMCFPD is pressuring the Marginulina reservoir to 3400 psi, a pressure above the minimum miscibility pressure (MMP) of 3310 psia. Only one workover which was scheduled to be performed to date, the Polk "B" #2, has been delayed until further justification is obtained from project response. The horizontal CO_2 injection well will be drilled during November, 1993 and production from the producing wells should resume prior to January 1, 1994. The workover of Polk "B" #5 and the drilling of a vertical CO_2 injection well, the Polk "B" #39, will take place during 1994.

Facility construction is nearing completion, with flowline hookup of the producing wells being one of the last items to be completed. New high pressure fiberglass flowlines are being installed from each wellhead to the production manifold on the new compressor barge. This compressor barge has been equipped with a low pressure (80 psi) compressor, an intermediate pressure (500 psi) injection compressor, a CO_2 injection pump, and a CO_2 injection manifold on the upper deck to handle purchased and produced CO_2 volumes. The lower deck has been equipped with low pressure and intermediate pressure test and working separators and flow measurement equipment. The CO_2 is currently bypassing

the CO_2 injection pump and flowing directly into the injection wells at a wellhead pressure of 1100 psig. This CO_2 injection pump will be started in the very near future as wellhead pressures and the CO_2 pipeline pressure of 1150 psig equalize. Texaco is currently purchasing 4 MMCFPD, 233 tons/day, of CO_2 from the supplier Cardox, a Division of Liquid Air Corporation.

The initiation of CO_2 injection required that all regulatory and environmental concerns be addressed and strictly adhered to. The installation of a 4-1/2 mile 4" CO_2 pipeline through a coastal wetland area required an Army Corps of Engineers permit and a categorical exclusion to N.E.P.A. regulations. This line was installed parallel to a number of other pipelines and in accordance to landowner requests, thus minimizing surface damages. The initial project area of the reservoir also required unitization proceedings to satisfy all mineral interest owners. The successful initiation of injection was a team effort between Texaco, DOE, Texas Parks and Wildlife, U.S. Fish and Wildlife Service, Texas Railroad Commission, Texas Air Quality Control Board, and many other regulatory bodies.

The project is being monitored by periodic bottomhole pressure surveys and compositional reservoir simulation runs. The reservoir pressure was at 2450 psig at the start of CO_2 injection and is currently 2700 psig after one month of CO_2 injection. The compositional model developed for the project area closely matches this performance and everything is looking favorable for a January 1, 1994 initiation of production. Close management supervision and reservoir simulation results indicate that injection of water into the Kuhn #17 well may be advantageous to increasing the response from the project. This will allow for wells to be opened prior to this January 1, 1994 date.

An additional compressor barge is being equipped for other wells in the Port Neches Field not related to the CO_2 project under a separate Texaco initiative to consolidate tank batteries in the field. Upon this barge however, the third and final proposed CO_2 compressor has been set. This additional compressor is an intermediate pressure injection compressor identical to the one on the other barge, capable of compressing CO_2 from 500 psig to injection pressures of 2200 psig. All three compressors are used compressors which Texaco transferred to the project at book value and then repaired. New stainless steel air coolers and state-of-the-art emission control equipment were placed on each of these compressors.

Technology transfer of the results of this project began with a presentation in Houston at an Improved Oil Recovery luncheon and was documented by a writer of the Oil and Gas Journal[1] who attended the meeting. DOE's Contractor Review meeting held July 19-22, 1993 also gave Texaco the opportunity to share our project with other industry participants. Texaco also presented an SPE paper at the Annual SPE convention in Houston earlier this month[2] documenting the development of the PC-based CO_2 screening model. Two papers involving this project have also been selected by the 1994 Improved Oil Recovery Symposium committee and will be presented April 17-20, 1994 in Tulsa. At this meeting Texaco's project design will be discussed and the PC-based screening program will be released.

Executive Summary

The Port Neches (Marg. Area 1) Unit consists of 235.1 acres of the tertiary age Marginulina sandstone reservoir in Orange County, Texas. This Anahuac reservoir sand was deposited in a fluvial-dominated near shoreline deltaic environment in the late Oligocene, early Miocene, series of the Houston Embayment system. It is a fining upward sequence of highly permeable sand interbedded and surrounded by calcareous shales. The reservoir trap was formed when the sandstone was uplifted by salt after deposition, thus forming a complex array of faulting.

The reservoir was initially divided into five fault blocks with similar reservoir properties of 30% porosity and 3000 md permeability. Upon investigation of this reservoir for potential enhanced oil recovery, it was seen that three of these five fault blocks experienced pressure declines equivalent to that of the producing fault block, thus indicating communication between the blocks. This information was provided to a geologist who then reviewed the data and developed a different interpretation of the reservoir compartmentalization. The 235.1 acre Port Neches (Marg. Area 1) reservoir thus became one large fault block. With the acquisition of further data in the field, however, a fault is indeed seen to be running through the center of the first project area. Structure maps and reservoir simulation gridding is currently being modified to accomodate for this fault.

This faulting is seen to be important due to its possible effects upon the flow of CO_2 through the reservoir. The project was designed with the located fault being considered, thus insuring that injection and production occurs on both sides of the fault. The integrity of surrounding faults has been demonstrated by the depletion of reservoir pressure below 100 psig prior to the initiation of waterflood operations during 1965, but a determination as to whether or not the new fault identified is sealing or that pressures are simply being equalized somewhere at the northern limits of the fault, has yet to be determined. A radioactive tracer placed in the Kuhn #36 on July 22, 1993 will provide valuable information concerning this question.

Results from the Port Neches (Marg. Area 1) CO_2 flood offers a great opportunity to the petroleum industry to evaluate the economics of CO_2 floods and the potential tertiary reserves of their producing fields. The reservoir has been extensively waterflooded and is currently at an average oil saturation of 31%, only 1% above the residual oil saturation to waterflood of 30%. The core data from the Stark "B" #10 has provided much needed absolute and relative permeability data which has now been incorporated into the reservoir simulator. Using this new data into the reservoir simulator, the following concerns and possible solutions exist:

(1) As a result of the average oil saturation being very close to the residual oil saturation, the peak in oil production is delayed from 1996 to 1997 due to limited amounts of moveable oil and limited availability of CO_2.

(2) The injection of saltwater into the Kuhn #17 at a rate of 2000 BWPD will allow for an additional 2000 BFPD to be pulled out of the northern portion of the reservoir, thus accelerating the peak in oil production.

As a result of these observations, a large slug of CO_2 will be injected into the Kuhn #17 well during the next month and then the well will be converted to water injection. With these changes made, it is felt that the production forecast previous shown in the Project Management Plan of July, 1993 can be obtained. These projections shown as Figures 1-4 to 1-7 are included within this text to serve as a guide for project performance tracking.

Introduction

The Port Neches CO_2 Project will concentrate upon the tertiary oil recoveries which can be obtained from two sections of a reservoir which are at different stages of depletion. The large waterflooded fault block has an average remaining oil saturation of 31% while the small partial waterdrive fault block has an oil saturation of 43%. A summary of reservoir properties is as follows:

	Waterflooded Area 1	Partial Waterdrive Area 2
Acreage	235.1	30.0
Orig. Oil Sat.	80 %	80 %
Curr. Oil Sat.	31 %	43 %
Orig. Oil-in-place	10.5 MMBO	1.4 MMBO
Cumulative Prod.	5.7 MMBO	0.6 MMBO
Orig. Solution Gas	450 scf/bbl	450 scf/bbl
Curr. Solution Gas	11 scf/bbl	325 scf/bbl
Orig. Res. Press	2700 psi	2700 psi
Final Primary Press.	100 psi	1800 psi
Orig. FVF	1.28 RB/STB	1.28 RB/STB
Curr. FVF	1.08 RB/STB	1.23 RB/STB
Estimated Tertiary	2.0 MMBO	0.3 MMBO
Project Initiation	1993	1994

As a result of the Project Area 1 being near residual oil saturation, project response will be delayed until a point where the CO_2 contacted oil bank begins to produce. Higher withdrawals can be made in the reservoir by applying water injection away from the major producers. As CO_2 breaks through to the producing wells, a continuous CO_2 injection can then be initiated in these remote areas. Proper management of the flood by the application of CO_2 and/or water at specified points in the reservoir based upon project performance, can reduce the overall CO_2 utility from 20 MCF/BO to a number approaching 7 MCF/BO. This conversion of wells from CO_2 to water injection wells will be an easy field procedure, as both water and CO_2 injection lines have been hooked up to each of the injectors. The dynamic nature of CO_2 breakthrough will require that the reservoir model be run throughout the project, with updates and adjustments made based upon the project performance.

It is anticipated that the smaller fault block will produce at a higher yield (barrels oil per MMCF CO_2) than the larger fault block due to its higher initial oil saturation. This yield factor is an important parameter in CO_2 flooding operations because it is what determines the economics of the project. This Project Area 2 will be initiated during 1994 after the interpretation of recently acquired 3-D seismic data allows for proper placement of the vertical CO_2 injection well to be drilled. The Polk "B" #39 will be drilled in this fault block at a point where injection can be optimized. The single producer, Polk "B" #5, will then be capable of producing at high rates without the fear of a drop in reservoir pressure below the minimum miscibility pressure.

Figure 1-4

Project Area Production

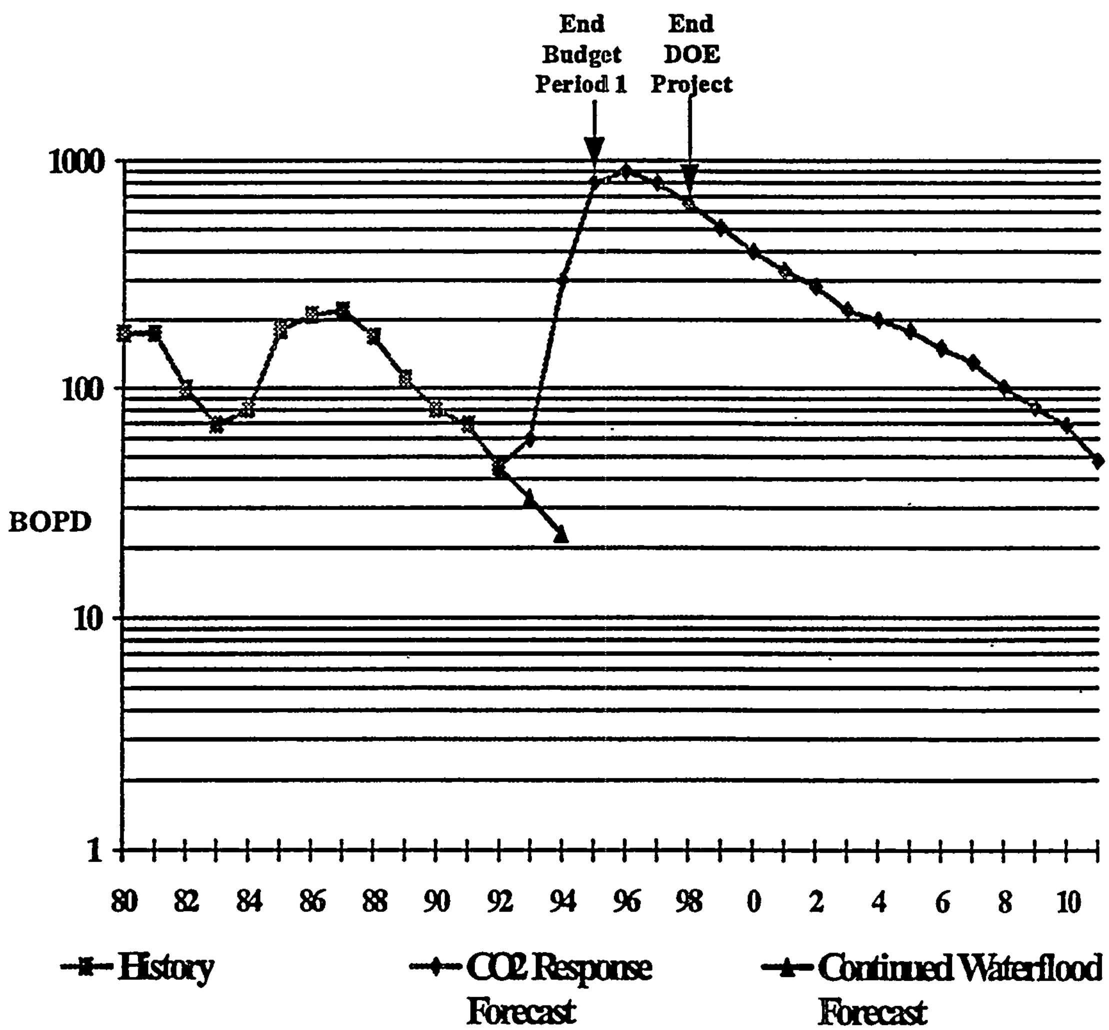


Figure 1-5

Short Term Production Forecast

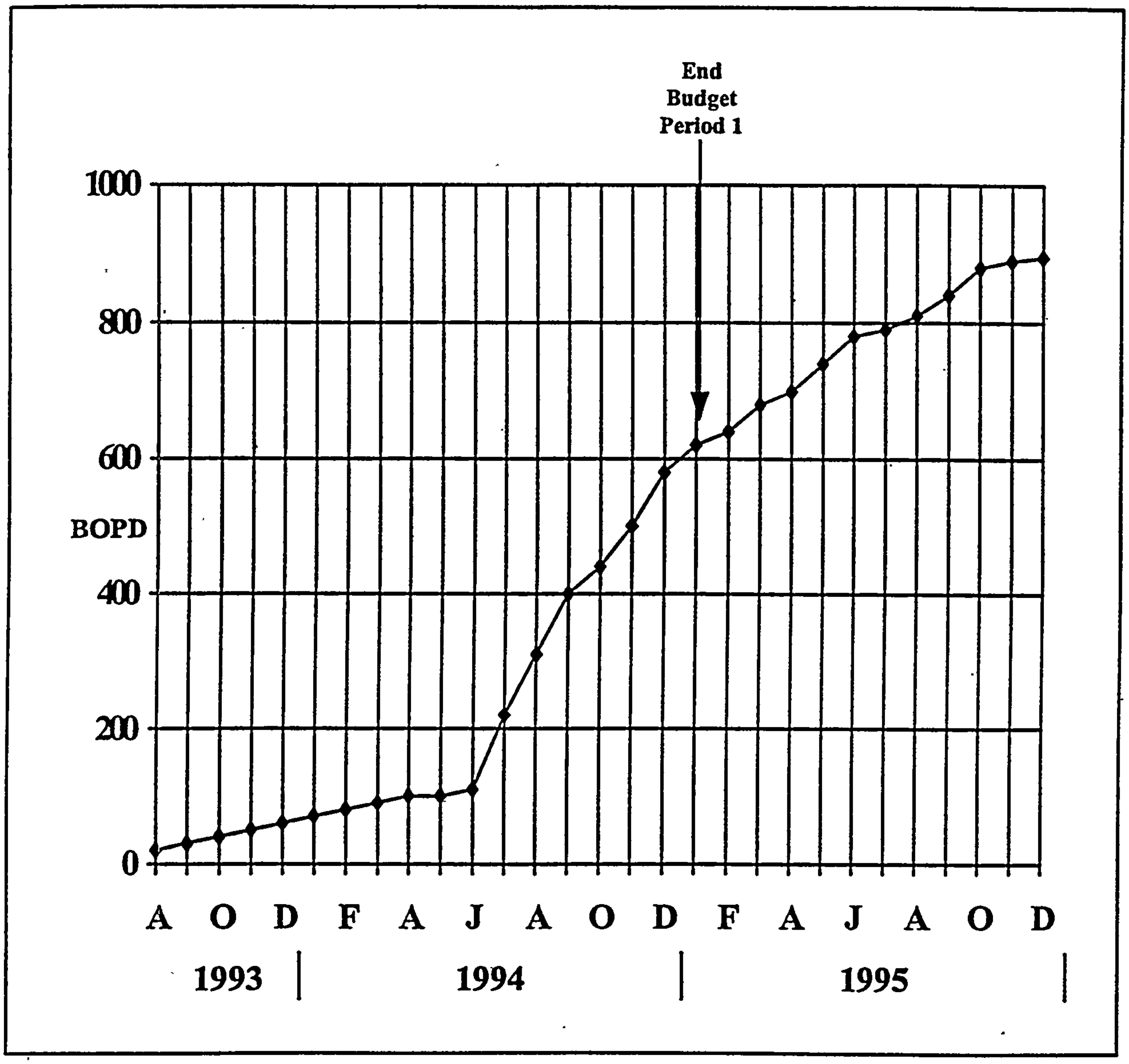


Figure 1-6

CO_2 Production/Injection Forecast

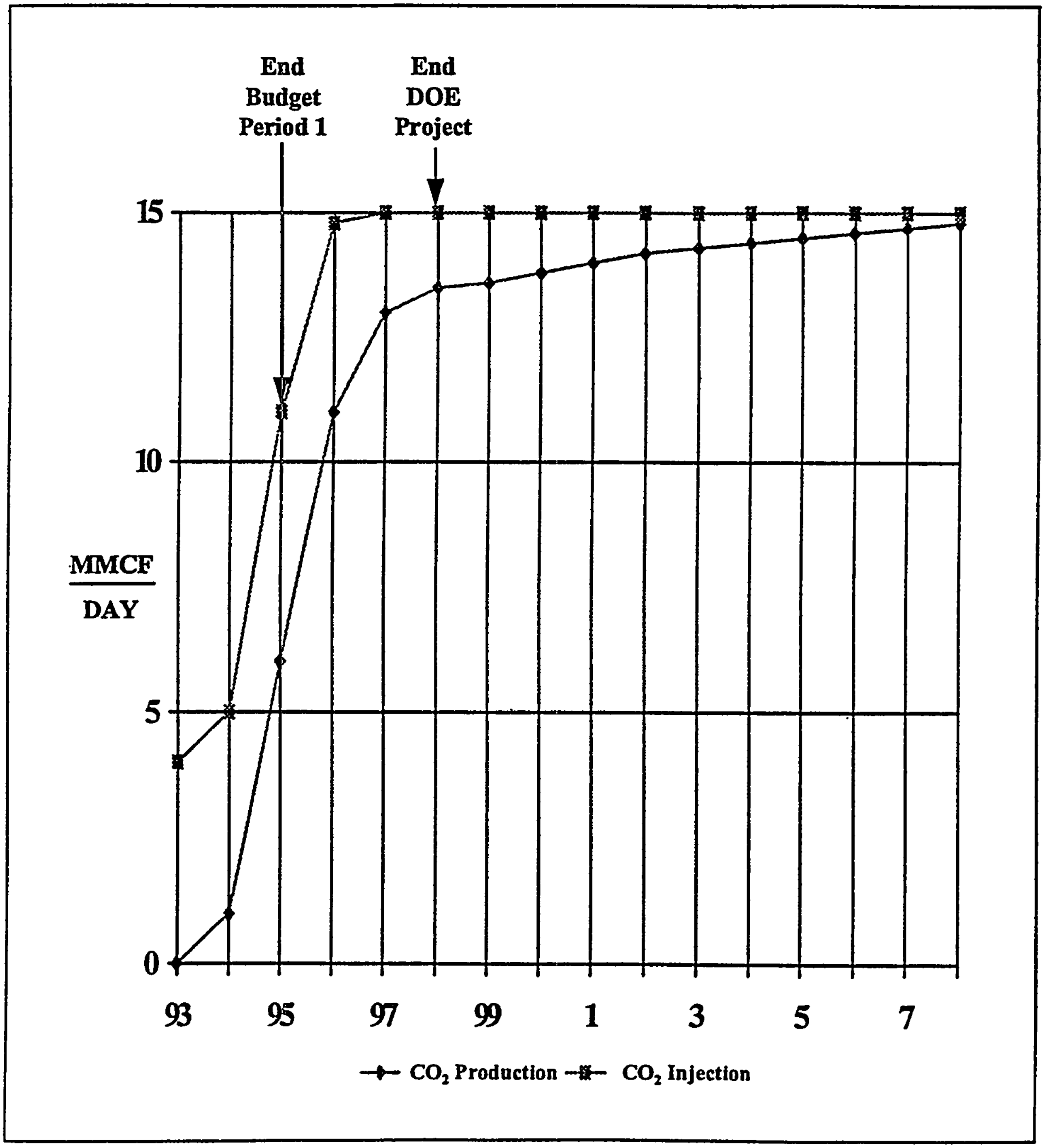
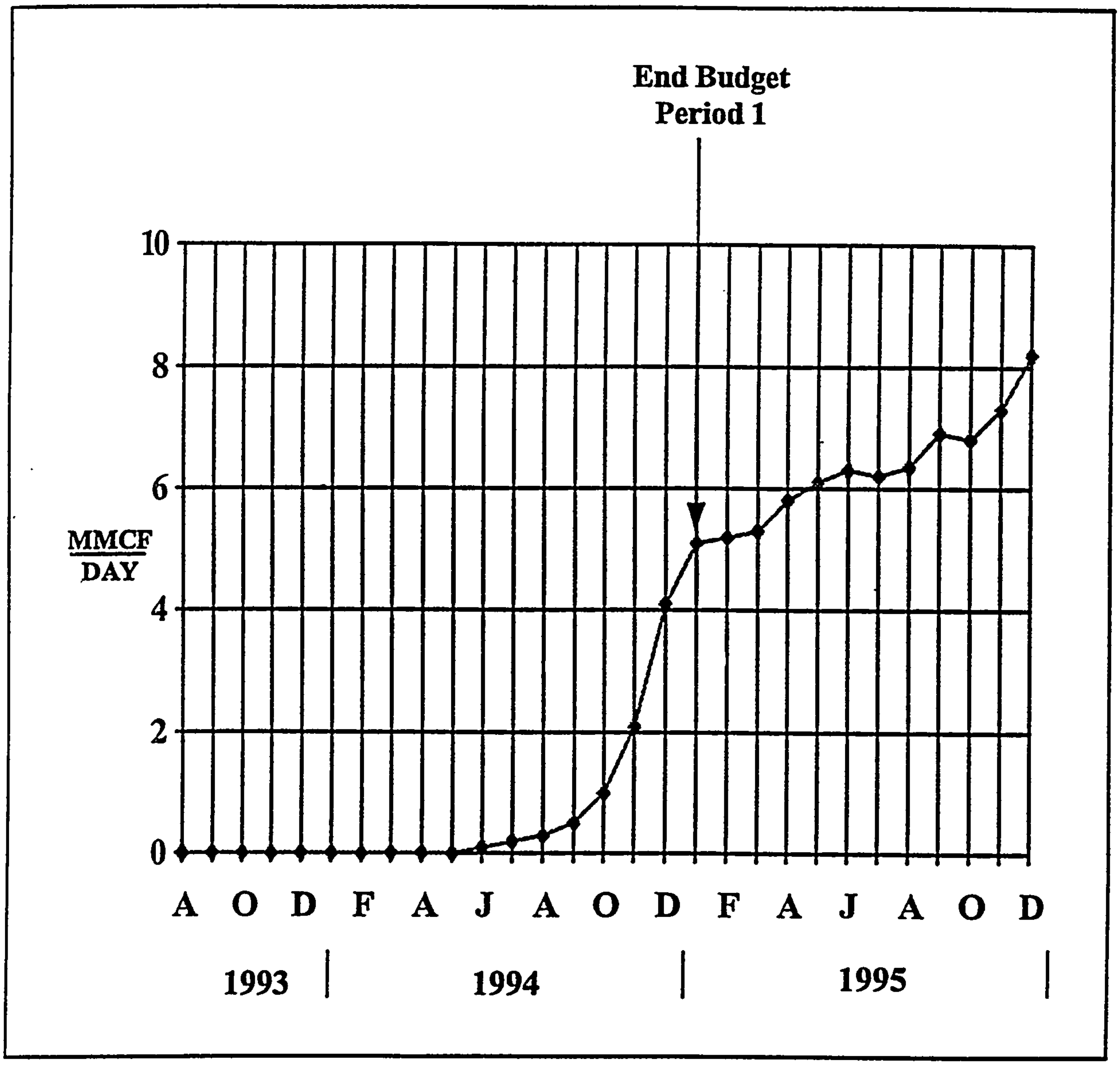
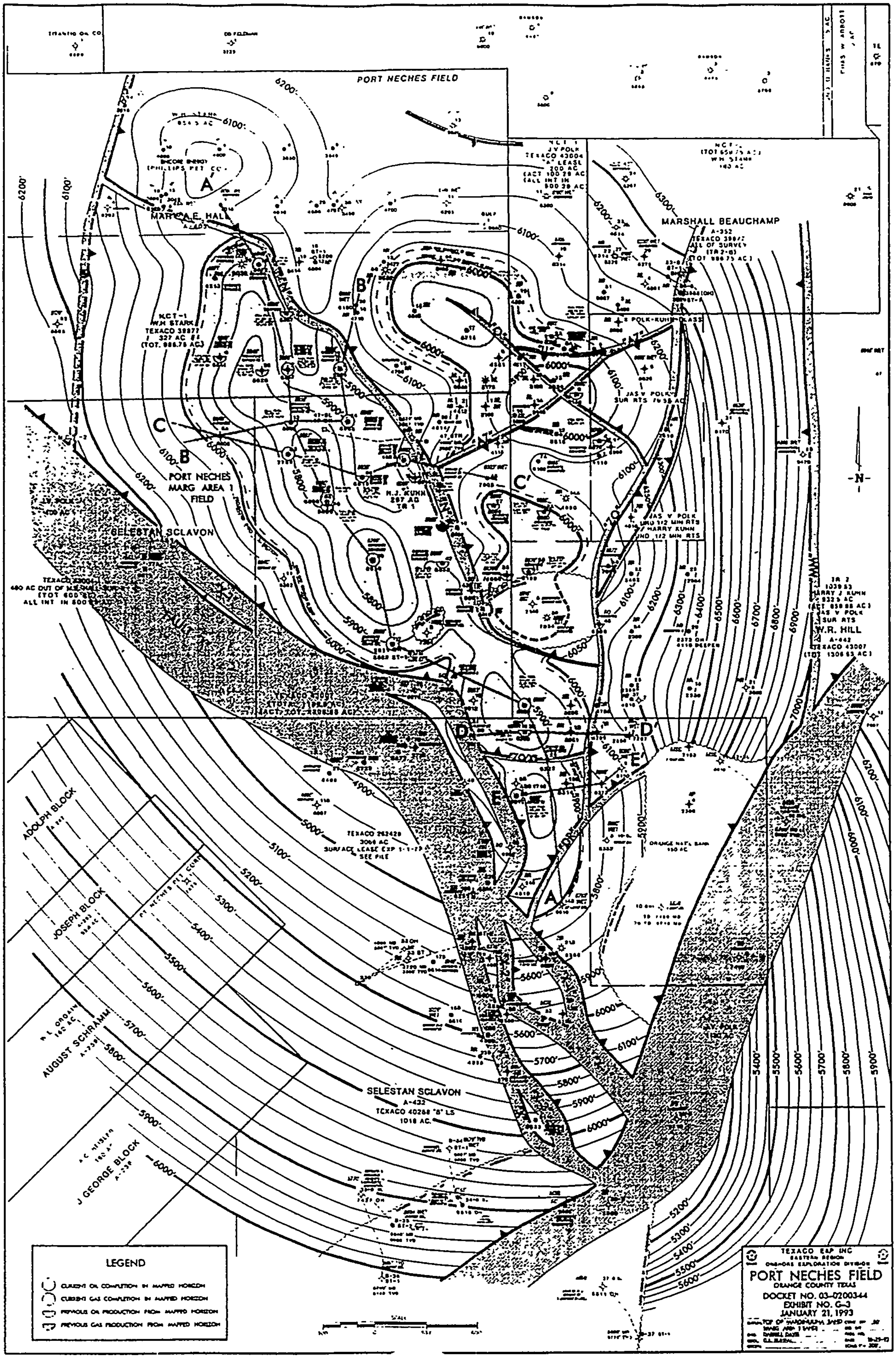
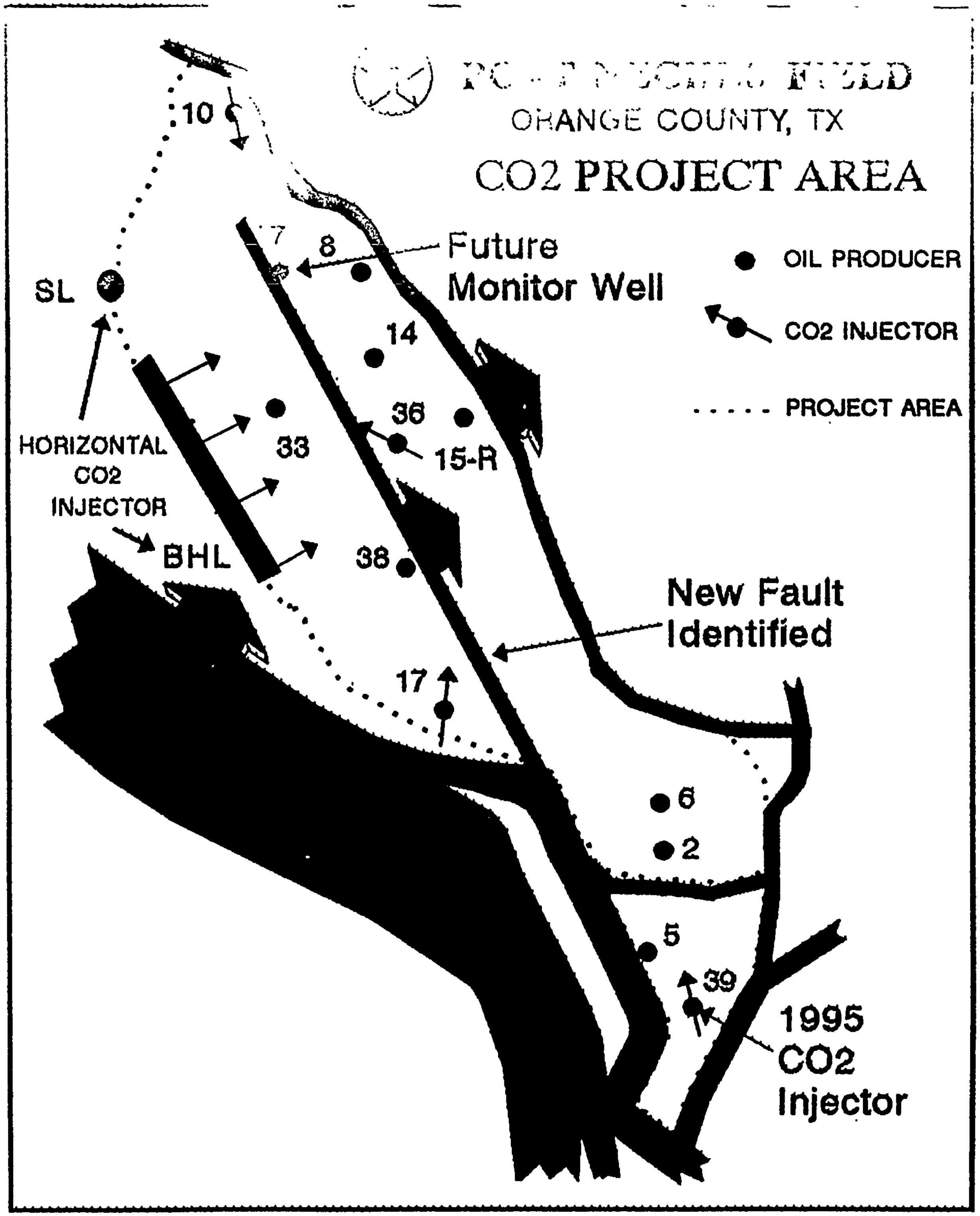


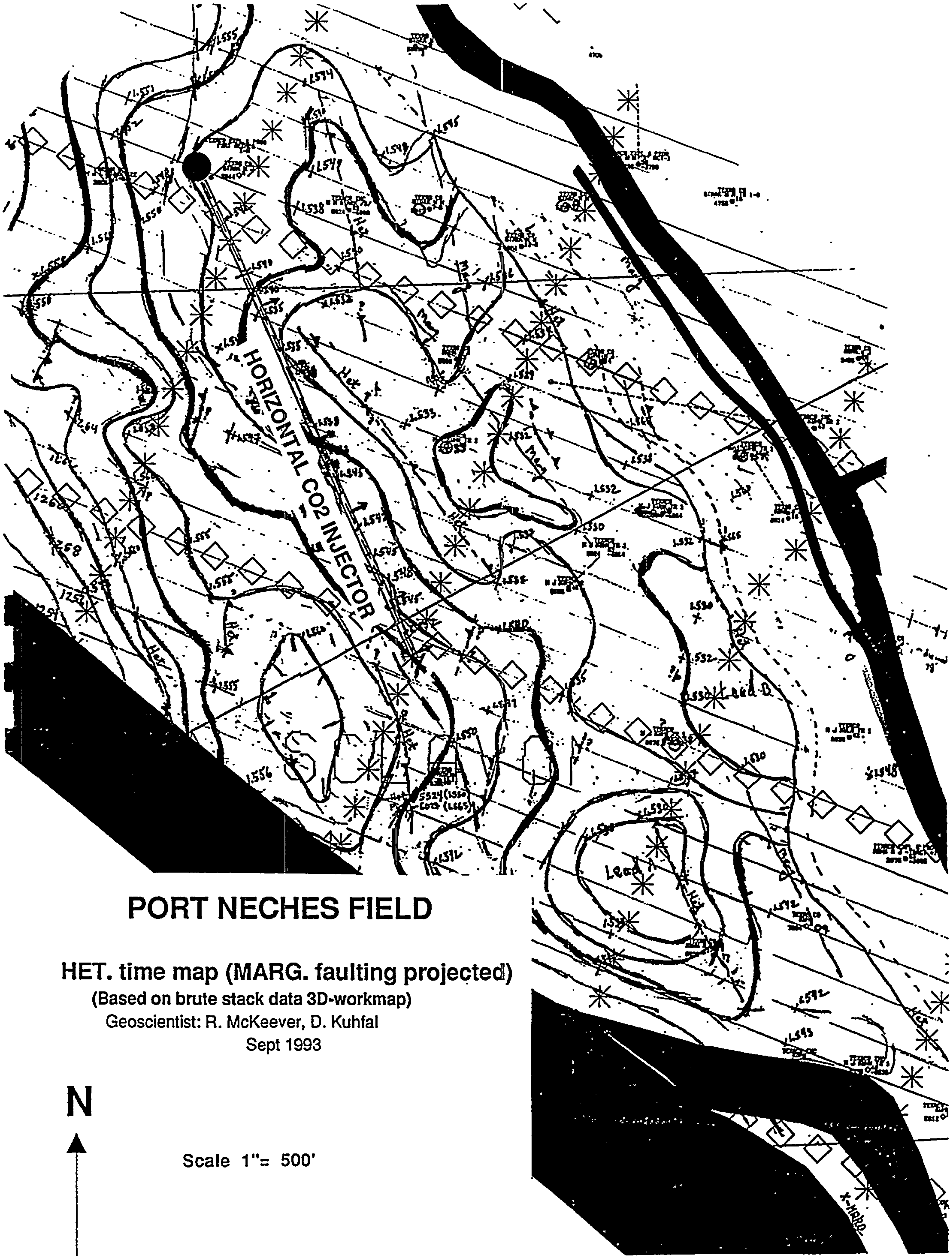
Figure 1-7

Short Term CO_2 Production Forecast




PORT NECHES FIELD
MARSHALL BEAUCHAMP
A-952
PORT NECHES
MARG AREA 1
FIELD
SELESTAN SCLAVON
SELESTAN SCLAVON
A-432
TEXACO 40268 "B" LS
1018 AC.
W.R. HILL
ADOLPH BLOCK
JOSEPH BLOCK
AUGUST SCHRAMM
J GEORGE BLOCK
TEXACO 262428
3066 AC
SEE FILE
ORANGE NAT'L BANK
-N-
LEGEND
TEXACO E&P INC
PORT NECHES FIELD
ORANGE COUNTY TEXAS
DOCKET NO. 03-0200344
EXHIBIT NO. G-3
JANUARY 21, 1993


ORANGE COUNTY, TX
CO2 PROJECT AREA
OIL PRODUCER
CO2 INJECTOR
PROJECT AREA
Future
Monitor Well
New Fault
Identified
1995
CO2
Injector
HORIZONTAL
CO2
INJECTOR
BHL
SL
10
7
8
14
36
15-R
33
38
17
6
2
5
39



PORT NECHES FIELD

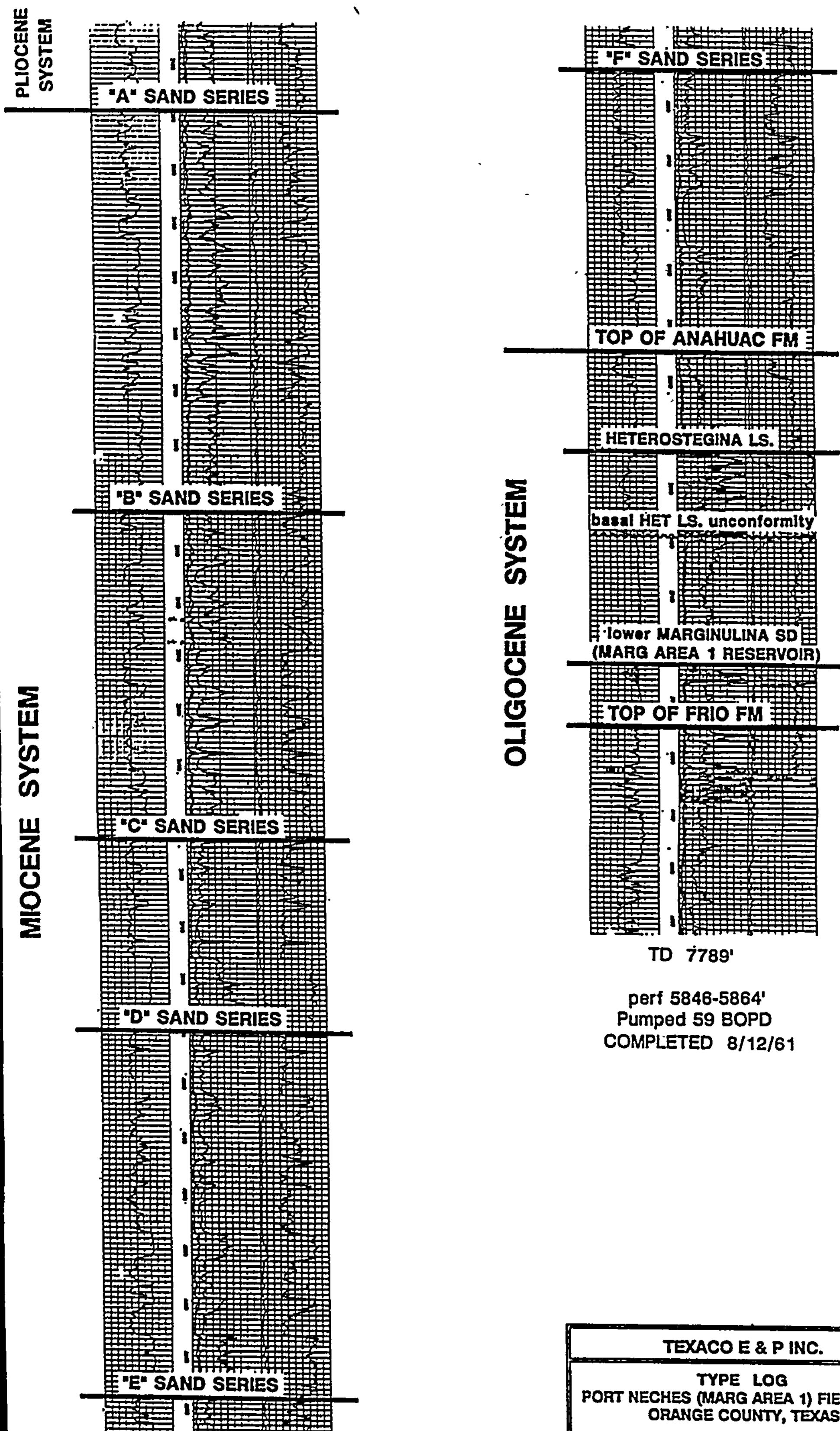
HET. time map (MARG. faulting projected)
(Based on brute stack data 3D-workmap)
Geoscientist: R. McKeever, D. Kuhfal
Sept 1993

N

Scale 1"= 500'

TYPE LOG

TEXACO NO. 33 KUHN

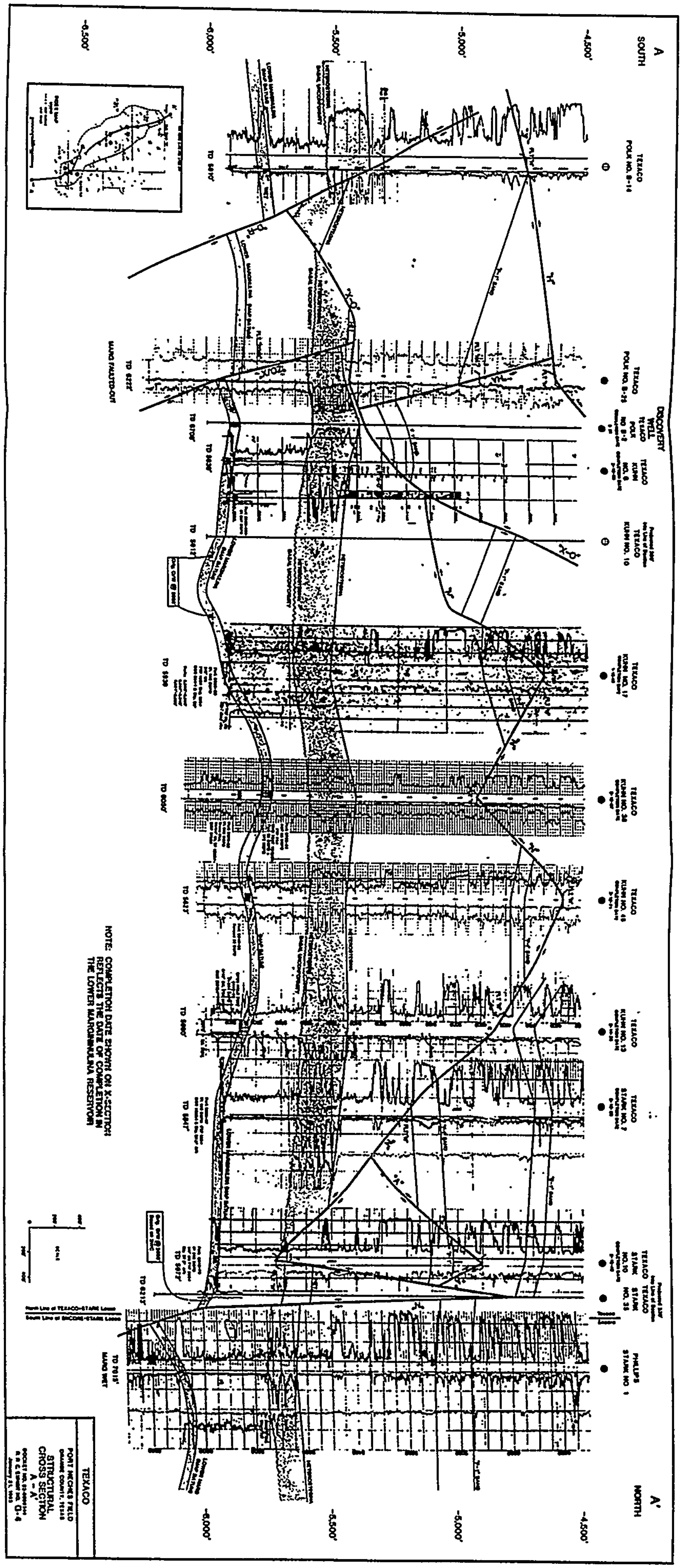


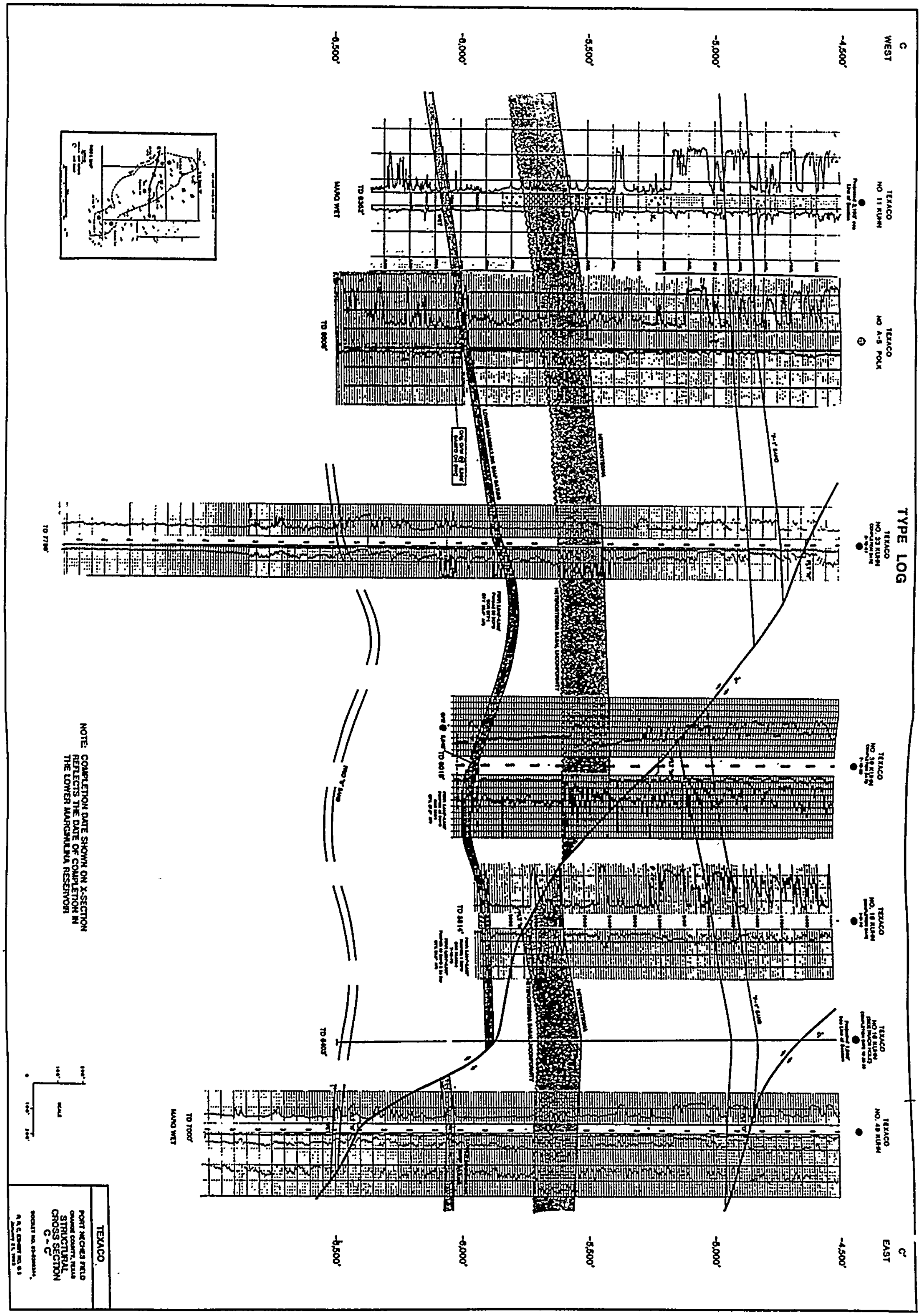
TEXACO E & P INC.

TYPE LOG
PORT NECHES (MARG AREA 1) FIELD UNIT
ORANGE COUNTY, TEXAS

DOCKET NO. 03-0200344

EXHIBIT NO. G-1
January 21, 1993


A
SOUTH
A'
NORTH
-4,500'
-5,000'
-5,500'
-6,000'
-6,500'
DISCOVERY WELL
NOTE: COMPLETION DATE SHOWN ON X-SECTION REFLECTS THE DATE OF COMPLETION IN THE LOWER MARGINULINA RESERVOIR
TEXACO
STRUCTURAL CROSS SECTION
A - A'


C
WEST
C'
EAST
TYPE LOG
-4,500'
-5,000'
-5,500'
-6,000'
-6,500'
TEXACO NO. 11 KUHN
TEXACO NO. A-5 POLK
TEXACO NO. 37 KUHN
TEXACO NO. 38 KUHN
TEXACO NO. 18 KUHN
TEXACO NO. 16 KUHN
TEXACO NO. 48 KUHN
TD 8006'
TD 7700'
MARG WET
NOTE: COMPLETION DATE SHOWN ON X-SECTION
REFLECTS THE DATE OF COMPLETION IN
THE LOWER MARGINULINA RESERVOIR
SCALE
TEXACO.
PORT NECHES FIELD
ORANGE COUNTY, TEXAS
STRUCTURAL
CROSS SECTION
C - C'

Port Neches Marginulina Sandstone Relative Permeability

Sw	Lab Krw(oil)	Krw(air)	
0.133	0.00000	0.00000	
0.315	0.02700	0.01868	
0.355	0.03500	0.02421	<==Draw Graph
0.396	0.04200	0.02905	on Semi-log
0.458	0.05500	0.03804	to get Sw,obs
0.532	0.07300	0.05049	at each Krw
0.597	0.09000	0.06225	below
0.635	0.10300	0.07124	
0.656	0.11000	0.07609	
0.674	0.11400	0.07885	
0.680	0.11600	0.08024	
1.000		1.00000	

Lab Kro(oil)	Kro(air)	
1.00000	0.69169	
0.36800	0.25454	
0.28900	0.19990	<==Draw Graph
0.22000	0.15217	on Semi-log
0.13600	0.09407	to get Sw,obs
0.06100	0.04219	at each Krw
0.01900	0.01314	below
0.00570	0.00394	
0.00200	0.00138	
0.00034	0.00024	
	0.00000	

INPUT DATA

Swi(field)	0.200
Swi(lab)	0.133
Sor(field)	0.300
Sor(lab)	0.346
Kair	3730
Koil	2580

Water Curve Is Adjusted

Swi,obs	Krw	Sw,obs	Sw,adj
0.133	0.001	0.133	0.200
0.133	0.005	0.225	0.285
0.133	0.010	0.265	0.322
0.133	0.020	0.325	0.377
0.133	0.030	0.400	0.446
0.133	0.040	0.452	0.494
0.133	0.050	0.522	0.559
	0.060	0.570	0.603
	0.070	0.623	0.652
	0.080	0.680	0.705
	0.090	0.725	0.746
	0.100	0.755	0.774

Oil Curve Is Adjusted

Swor,obs	Kro	Sw,obs	Sw,adj
0.654	0.001	0.660	0.706
0.654	0.005	0.630	0.674
0.654	0.010	0.605	0.648
0.654	0.020	0.578	0.619
0.654	0.030	0.560	0.599
0.654	0.040	0.540	0.578
0.654	0.050	0.522	0.559
0.654	0.060	0.501	0.536
0.654	0.070	0.483	0.517
0.654	0.080	0.470	0.503
0.654	0.090	0.450	0.482
0.654	0.100	0.440	0.471
0.654	0.200	0.350	0.375
0.654	0.300	0.300	0.321
0.654	0.400	0.255	0.273
0.654	0.500	0.200	0.214
0.654	0.600	0.160	0.171
0.654	0.700	0.120	0.128
0.654	0.800	0.080	0.086
0.654	0.900	0.050	0.054
0.654	1.000	0.000	0.000

Port Neches Marginulina Sandstone Relative Permeability

INPUT DATA

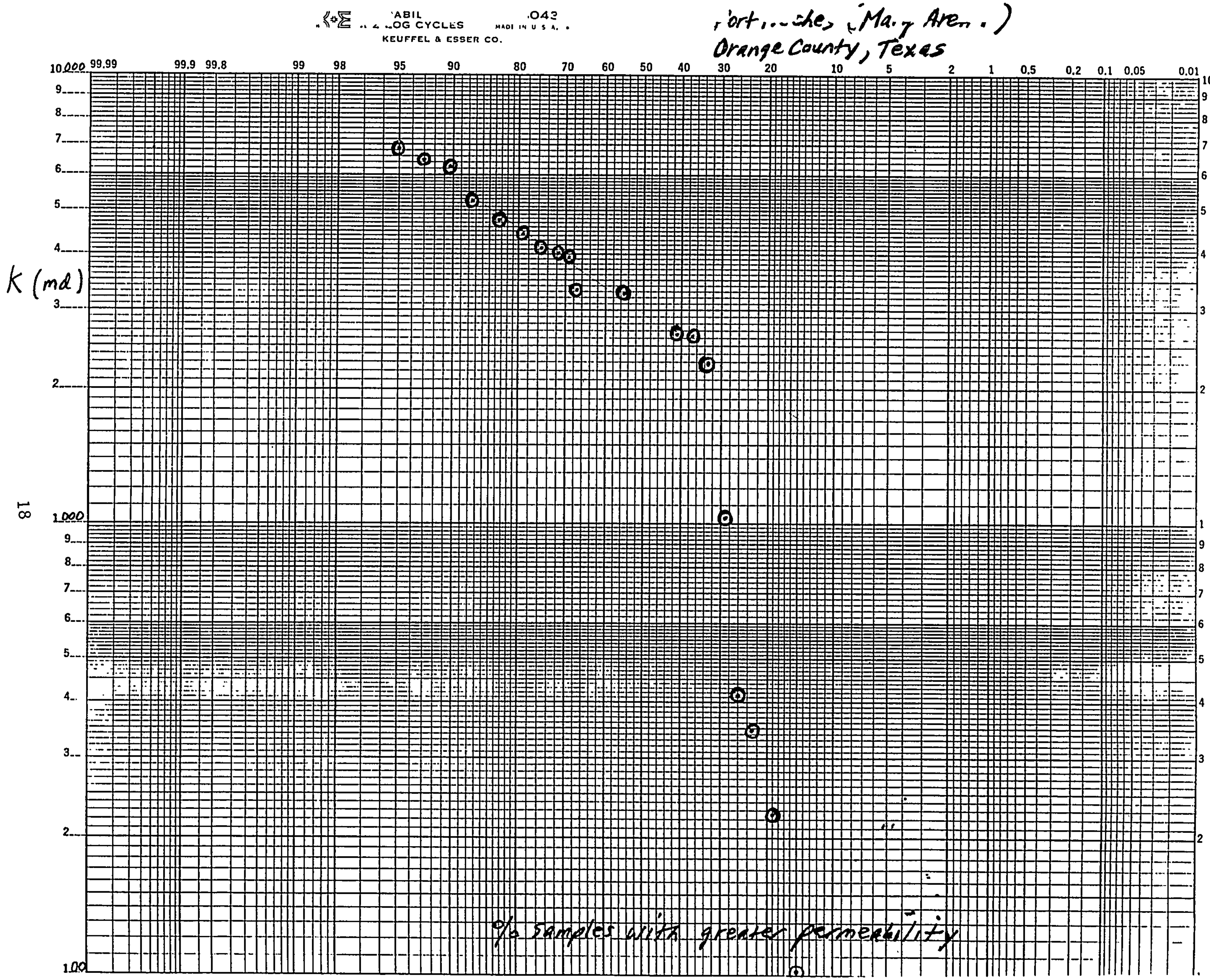
Swi(field)	0.200
Swi(lab)	0.133
Sor(field)	0.300
Sor(lab)	0.346
Kair	3730
Koil	2580

Sg	Krg(oil)	Krg(air)
0.000	0.00000	0.00000
0.035	0.00450	0.00311
0.054	0.00820	0.00567
0.076	0.01300	0.00899
0.105	0.02100	0.01453
0.138	0.03000	0.02075
0.184	0.04700	0.03251
0.225	0.06700	0.04634
0.268	0.09000	0.06225
0.299	0.10900	0.07539
0.337	0.13900	0.09614
0.357	0.15500	0.10721
0.384	0.18500	0.12796
0.412	0.22000	0.15217
0.430	0.24000	0.16601
0.445	0.27000	0.18676
0.455	0.29000	0.20059
0.478	0.33500	0.23172
0.532	0.47700	0.32994

<=Final Results=>

Kro(oil)	Kro(air)
1.00000	0.69169
0.73000	0.50493
0.62000	0.42885
0.52000	0.35968
0.42000	0.29051
0.32000	0.22134
0.22300	0.15425
0.16100	0.11136
0.11200	0.07747
0.08400	0.05810
0.05800	0.04012
0.04800	0.03320
0.03600	0.02490
0.02600	0.01798
0.02000	0.01383
0.01600	0.01107
0.01400	0.00968
0.00800	0.00553

<==Must Match
Kro @ Swi



K&E ... LOG CYCLES .043
KEUFFEL & ESSER CO.
MADE IN U.S.A.
ort...ches (Ma.. Area.)
Orange County, Texas
K (md)
% samples with greater permeability

SIMULATED FORMATION BRINE

Constituents	Concentration, ppm
Sodium Chloride ($NaCl$)	60,000
Potassium Chloride (KCl)	5,000
Calcium Chloride ($CaCl_2$)	10,000
Magnesium Chloride ($MgCl_2 \cdot 6H_2O$)	5,000

SUMMARY OF GAS-OIL RELATIVE PERMEABILITY TEST RESULTS

Texaco, Inc.
Stark "B" No. 10 Well

Port Neches Field
Orange County, Texas

				Initial Conditions		Terminal Conditions			Oil Recovered,	
Sample I.D.	Depth, feet	Permeability to Air, millidarcies	Porosity, percent	Water Saturation, percent pore space	Effective Permeability to Oil, millidarcies	Oil Saturation, percent pore space	Effective Permeability to Gas, millidarcies	Relative Permeability to Gas,* fraction	percent pore space	percent oil in place
24	5983.8	3730	31.4	13.3	2580	33.5	1230	0.477	53.2	61.4

*Relative to the effective permeability to oil at initial water saturation.

GAS-OIL RELATIVE PERMEABILITY TEST RESULTS

Unsteady-State Method
Temperature: 71 °F

Texaco, Inc.
Stark "B" No. 10 Well
Port Neches Field
Orange County, Texas

Sample I.D.:	24
Depth:	5983.8 feet
Permeability to Air:	3730 md
Porosity:	31.4 percent
Initial Water Saturation:	13.3 percent
Effective Permeability to Oil at Initial Water Saturation:	2580 md

Gas Saturation, percent, pore space	Gas-Oil Relative Permeability Ratio	Relative Permeability to Gas,* fraction	Relative Permeability to Oil,* fraction
0.0	0.0000	0.0000	1.000
3.5	0.0062	0.0045	0.730
5.4	0.013	0.0082	0.620
7.6	0.025	0.013	0.520
10.5	0.050	0.021	0.420
13.8	0.095	0.030	0.320
18.4	0.213	0.047	0.223
22.5	0.414	0.067	0.161
26.8	0.800	0.090	0.112
29.9	1.30	0.109	0.084
33.7	2.38	0.139	0.058
35.7	3.20	0.155	0.048
38.4	5.21	0.185	0.036
41.2	8.33	0.220	0.026
43.0	11.9	0.240	0.020
44.5	16.7	0.270	0.016
45.5	20.8	0.290	0.014
47.8	41.7	0.335	0.0080
53.2		0.477	

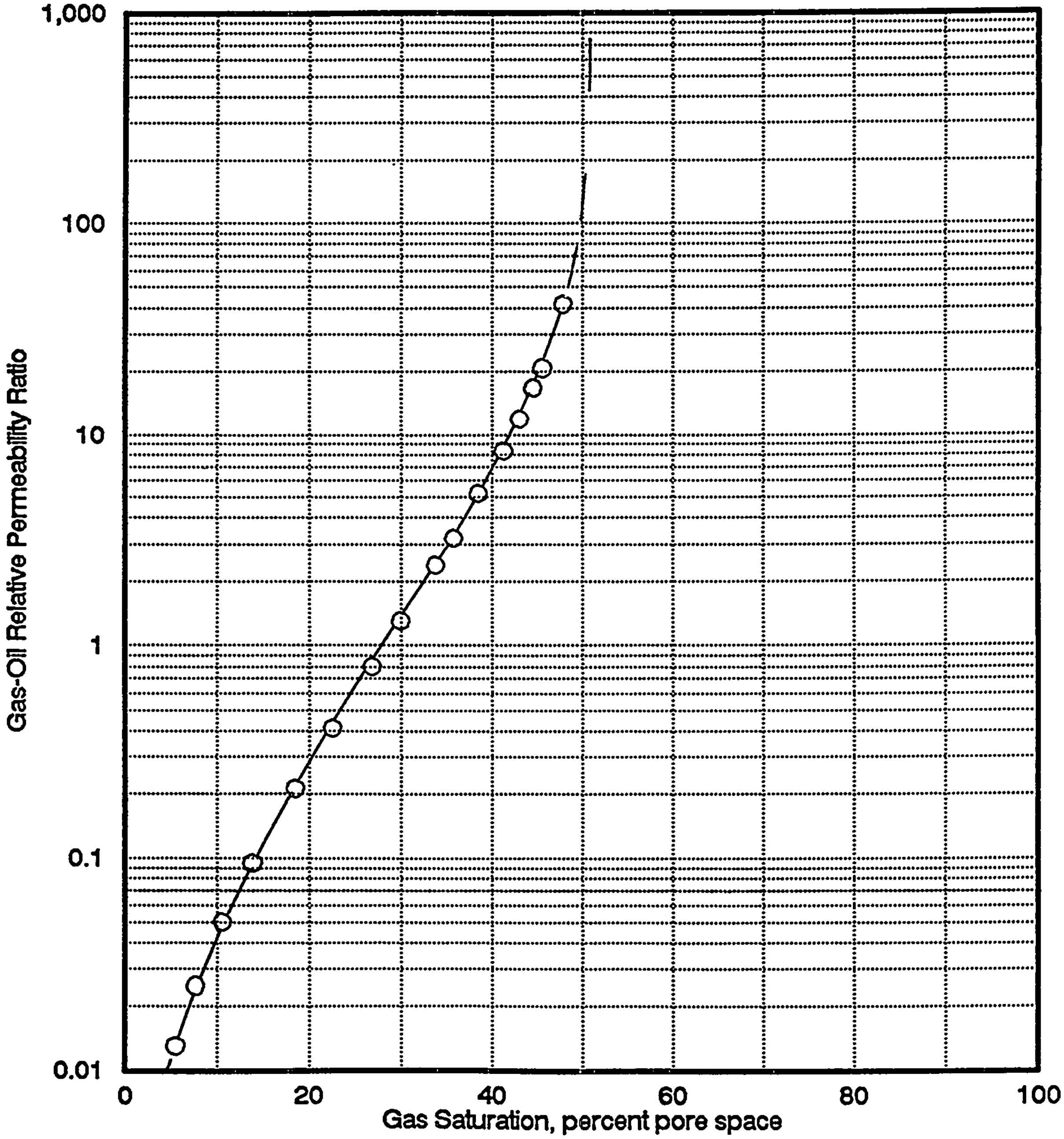
*Relative to the effective permeability to oil at initial water saturation.

GAS - OIL RELATIVE PERMEABILITY

Unsteady-State Clean Sample

Texaco, Inc.
Stark "B" No. 10 Well
Port Neches Field
Orange County, Texas

Sample I.D.:	24
Depth, feet:	5983.8
Permeability to Air, md:	3730
Porosity, percent:	31.4
Initial Water Saturation, percent:	13.3
Effective Permeability to Oil at Swi, md:	2580

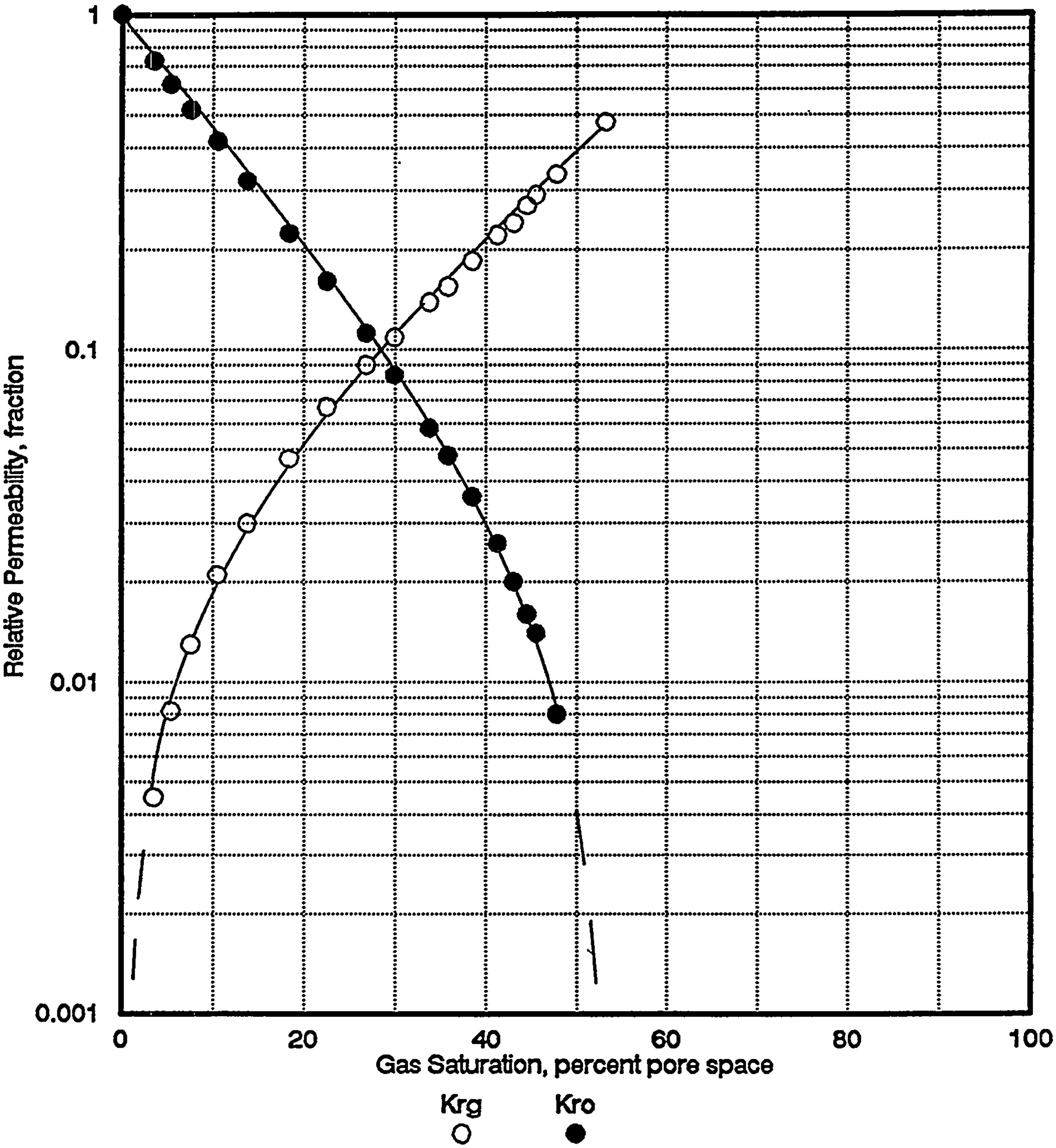


GAS - OIL RELATIVE PERMEABILITY

Unsteady-State Clean Sample

Texaco, Inc.
Stark "B" No. 10 Well
Port Neches Field
Orange County, Texas

Sample I.D.:	24
Depth, feet:	5983.8
Permeability to Air, md:	3730
Porosity, percent:	31.4
Initial Water Saturation, percent:	13.3
Effective Permeability to Oil at Swi, md:	2580



Core Laboratories

SUMMARY OF WATER-OIL RELATIVE PERMEABILITY TEST RESULTS

Texaco, Inc.
Stark "B" No. 10 Well

Port Neches Field
Orange County, Texas

				Initial Conditions		Terminal Conditions			Oil Recovered,	
Sample I.D.	Depth, feet	Permeability to Air, millidarcies	Porosity, percent	Water Saturation, percent pore space	Effective Permeability to Oil, millidarcies	Oil Saturation, percent pore space	Effective Permeability to Water, millidarcies	Relative Permeability to Water,* fraction	percent pore space	percent oil in place
24	5983.8	3730	31.4	13.3	2580	32.0	299	0.116	54.7	63.1

*Relative to the effective permeability to oil at initial water saturation.

WATER-OIL RELATIVE PERMEABILITY TEST RESULTS

Unsteady-State Method
Temperature: 71°F

Texaco, Inc.
Stark "B" No. 10 Well
Port Neches Field
Orange County, Texas

Sample I.D.:	24
Depth:	5983.8 feet
Permeability to Air:	3730 md
Porosity:	31.4 percent
Initial Water Saturation:	13.3 percent
Effective Permeability to Oil at Initial Water Saturation:	2580 md

Water Saturation, percent, pore space	Water-Oil Relative Permeability Ratio	Relative Permeability to Water,* fraction	Relative Permeability to Oil,* fraction
13.3	0.000	0.000	1.000
31.5	0.072	0.027	0.368
35.5	0.121	0.035	0.289
39.6	0.191	0.042	0.220
45.8	0.405	0.055	0.136
53.2	1.19	0.073	0.061
59.7	4.79	0.090	0.019
63.5	18.2	0.103	0.0057
65.6	55.3	0.110	0.0020
67.4	332	0.114	0.00034
68.0		0.116	

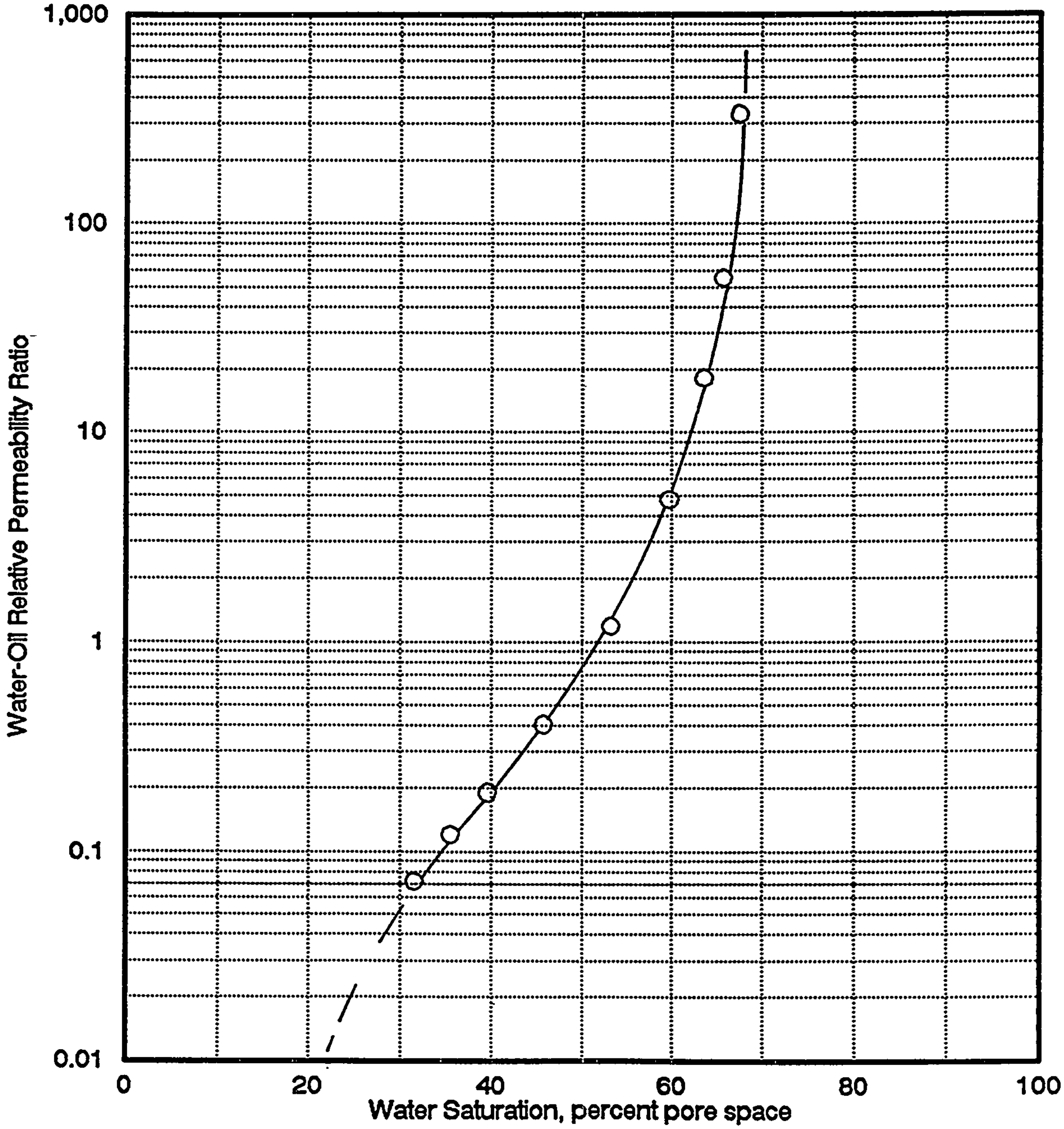
*Relative to the effective permeability to oil at initial water saturation.

WATER - OIL RELATIVE PERMEABILITY

Unsteady-State Clean Sample

Texaco, Inc.
Stark "B" No. 10 Well
Port Neches Field
Orange County, Texas

Sample I.D.:	24
Depth, feet:	5983.8
Permeability to Air, md:	3730
Porosity, percent:	31.4
Initial Water Saturation, percent:	13.3
Effective Permeability to Oil at Swi, md:	2580



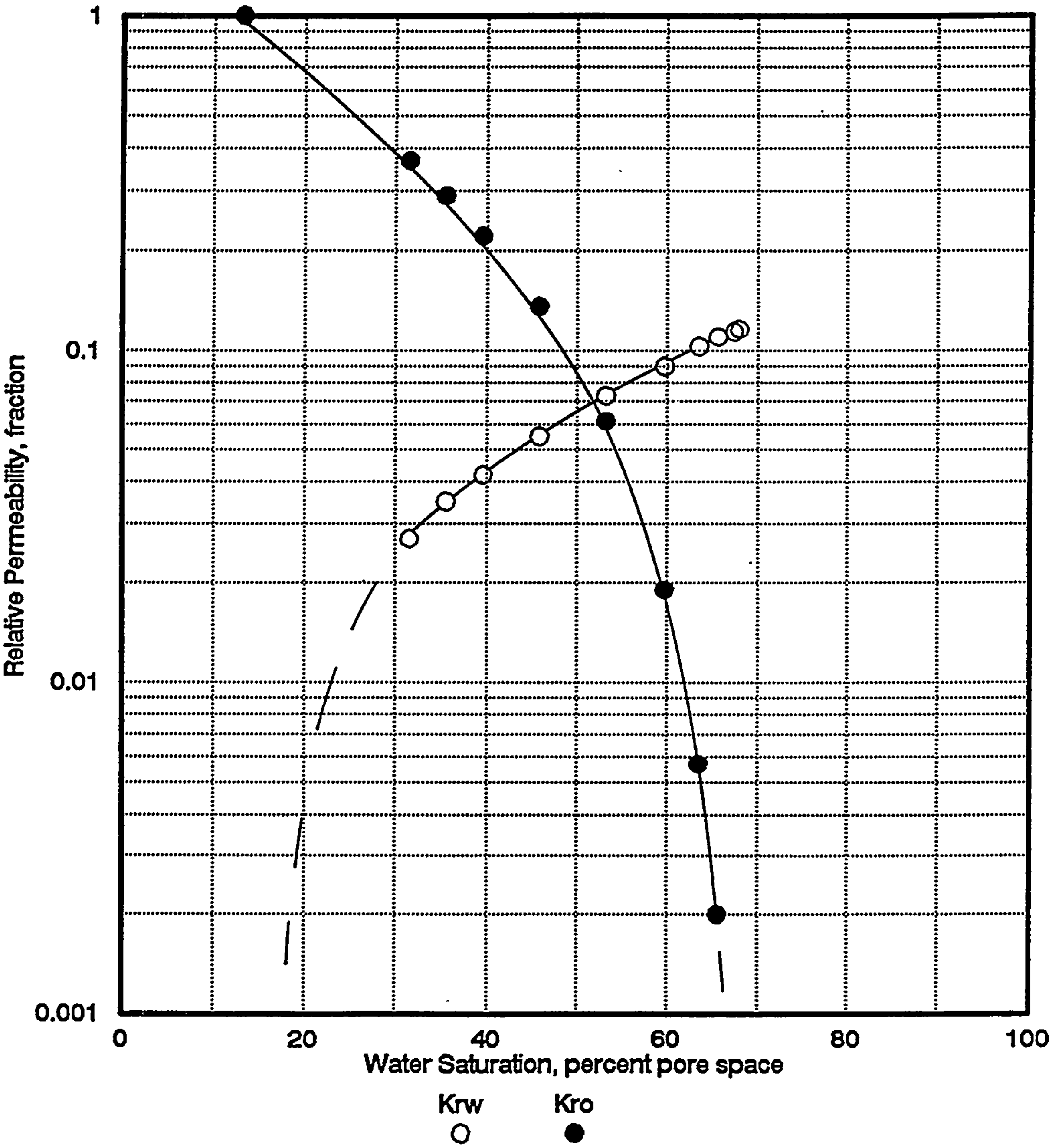
Core Laboratories

WATER - OIL RELATIVE PERMEABILITY

Unsteady-State Clean Sample

Texaco, Inc.
Stark "B" No. 10 Well
Port Neches Field
Orange County, Texas

Sample I.D.:	24
Depth, feet:	5983.8
Permeability to Air, md:	3730
Porosity, percent:	31.4
Initial Water Saturation, percent:	13.3
Effective Permeability to Oil at Swi, md:	2580



Core Laboratories

SUMMARY OF WATERFLOOD SUSCEPTIBILITY TEST RESULTS

Texaco, Inc.
Stark "B" No. 10 Well

Port Neches Field
Orange County, Texas

				Initial Conditions		Terminal Conditions			Oil Recovered,	
Sample I.D.	Depth, feet	Permeability to Air, millidarcies	Porosity, percent	Water Saturation, percent pore space	Effective Permeability to Oil, millidarcies	Oil Saturation, percent pore space	Effective Permeability to Water, millidarcies	Relative Permeability to Water,* fraction	percent pore space	percent oil in place
23	5982.8	3380	30.1	10.9	2550	34.6	305	0.120	54.5	61.2
24	5983.8	3730	31.4	7.5	2800	36.6	258	0.092	55.9	60.4

*Relative to the effective permeability to oil at initial water saturation.

WATERFLOOD SUSCEPTIBILITY TEST RESULTS

Temperature: 71°F

Texaco, Inc.
Stark "B" No. 10 Well
Port Neches Field
Orange County, Texas

Sample I.D.:	23
Depth:	5982.8 feet
Permeability to Air:	3380 md
Porosity:	30.1 percent
Initial Water Saturation:	10.9 percent
Effective Permeability to Oil at Initial Water Saturation:	2550 md

Water Input, pore volumes	Cumulative Oil Recovery, percent pore space	Average Oil Recovery*, percent pore space	Average Water Cut**, percent
0.511	51.1***	-	-
0.683	52.4	51.7	92.0
1.15	53.4	52.9	97.9
1.70	53.7	53.6	99.3
2.76	54.1	53.9	99.6
4.89	54.4	54.3	99.86
9.69	54.5	54.5	99.98

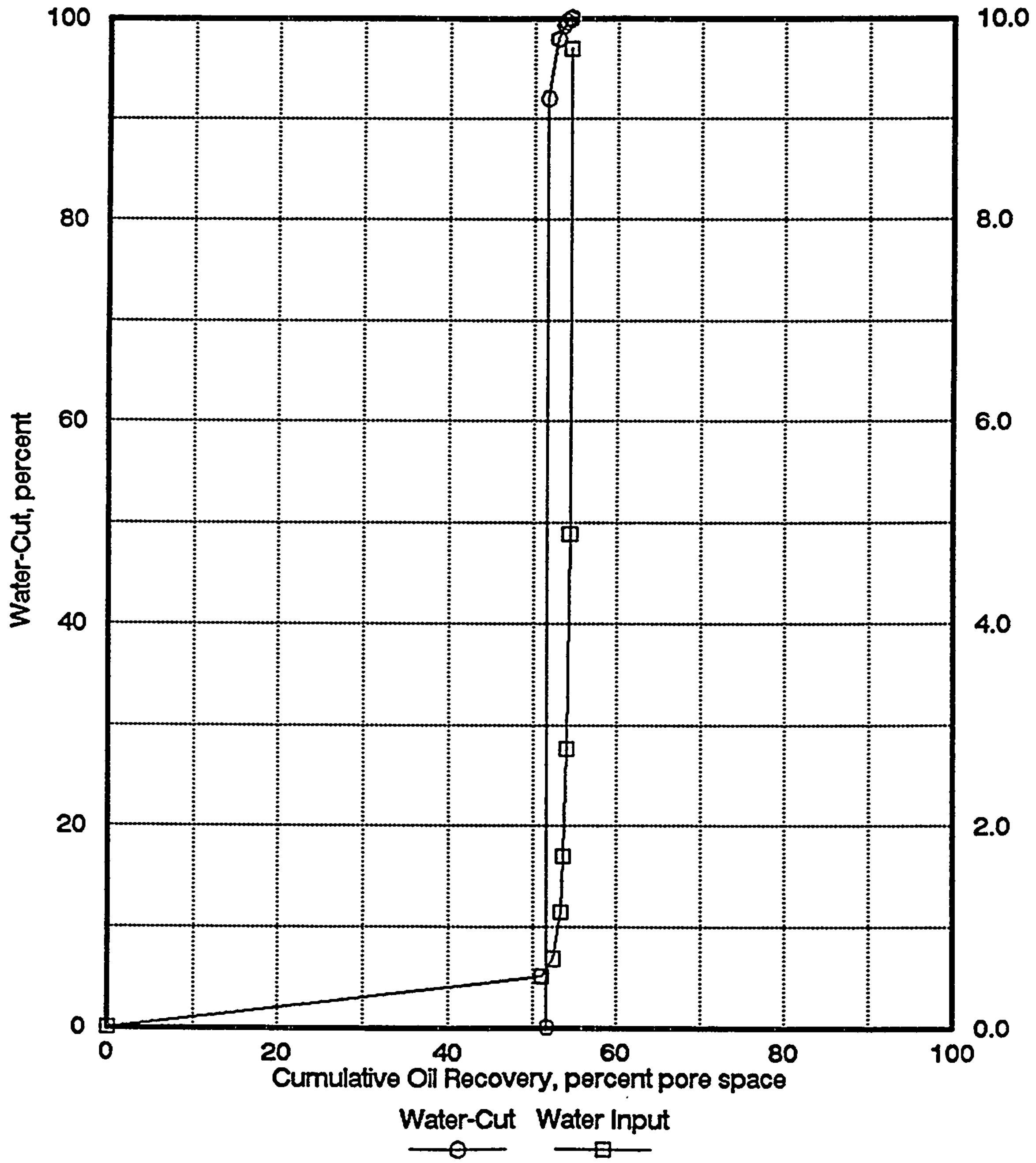
* Calculated for mid-point of incremental throughput
** Calculated from incremental throughput volumes
*** Breakthrough recovery

WATERFLOOD SUSCEPTIBILITY

Unsteady-State Clean Sample

Texaco, Inc.
Stark "B" No. 10 Well
Port Neches Field
Orange County, Texas

Sample I.D.:	23
Depth, feet:	5982.8
Permeability to Air, md:	3380
Porosity, percent:	30.1
Initial Water Saturation, percent:	10.9
Effective Permeability to Oil at Swi, md:	2550



Core Laboratories

WATERFLOOD SUSCEPTIBILITY TEST RESULTS

Temperature: 71°F

Texaco, Inc.
Stark "B" No. 10 Well
Port Neches Field
Orange County, Texas

Sample I.D.:	24
Depth:	5983.8 feet
Permeability to Air:	3730 md
Porosity:	31.4 percent
Initial Water Saturation:	7.5 percent
Effective Permeability to Oil at Initial Water Saturation:	2800 md

Water Input, pore volumes	Cumulative Oil Recovery, percent pore space	Average Oil Recovery*, percent pore space	Average Water Cut**, percent
0.539	53.6	53.6	-
0.749	54.3	53.9	96.6
1.15	54.8	54.6	98.7
2.12	55.4	55.1	99.4
4.02	55.8	55.6	99.8
8.52	55.9	55.8	99.97
17.1	55.9	55.9	99.996

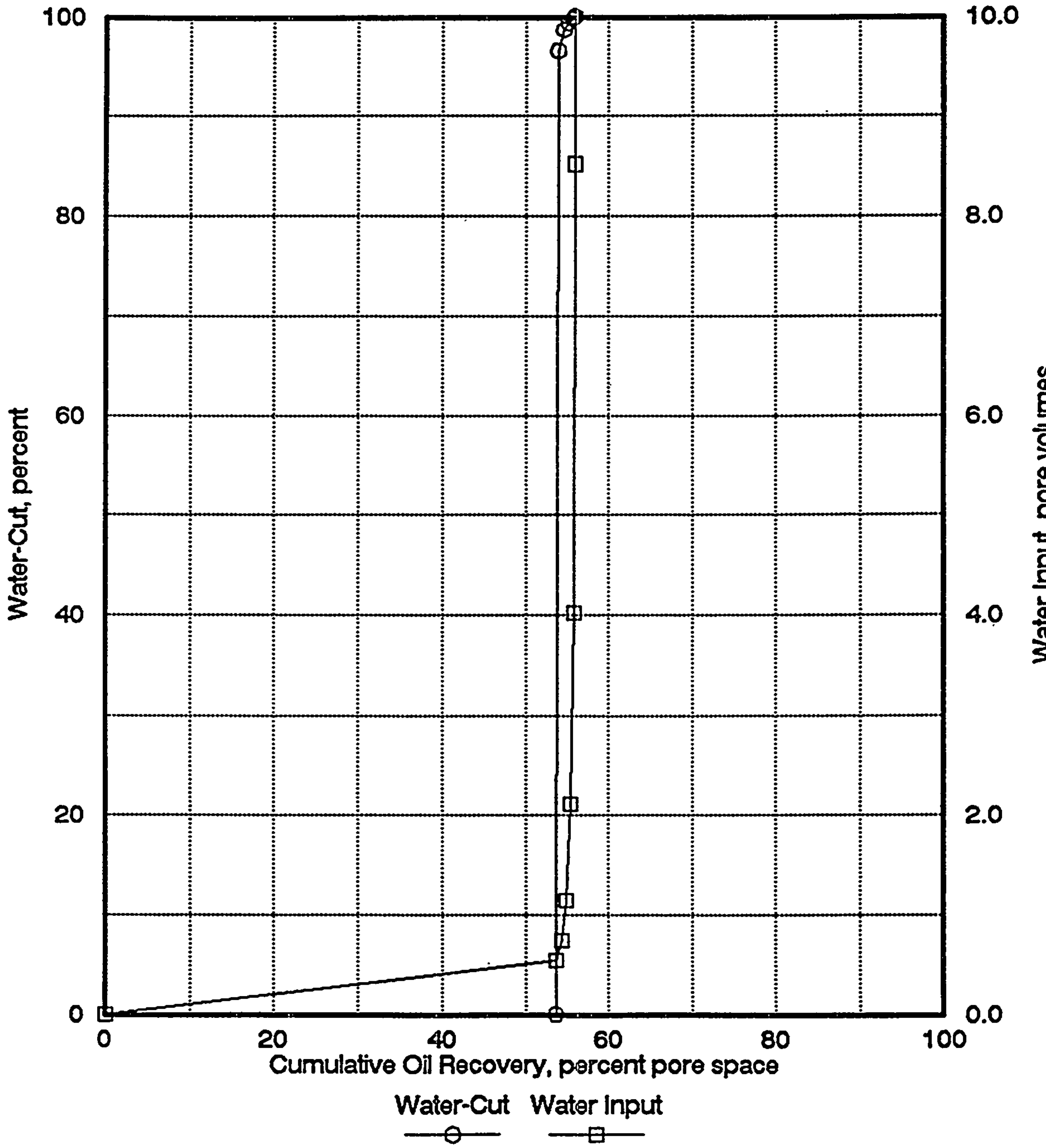
* Calculated for mid-point of incremental throughput
** Calculated from incremental throughput volumes
*** Breakthrough recovery

WATERFLOOD SUSCEPTIBILITY

Unsteady-State Clean Sample

Texaco, Inc.
Stark "B" No. 10 Well
Port Neches Field
Orange County, Texas

Sample I.D.:	24
Depth, feet:	5983.8
Permeability to Air, md:	3730
Porosity, percent:	31.4
Initial Water Saturation, percent:	7.5
Effective Permeability to Oil at Swi, md:	2800



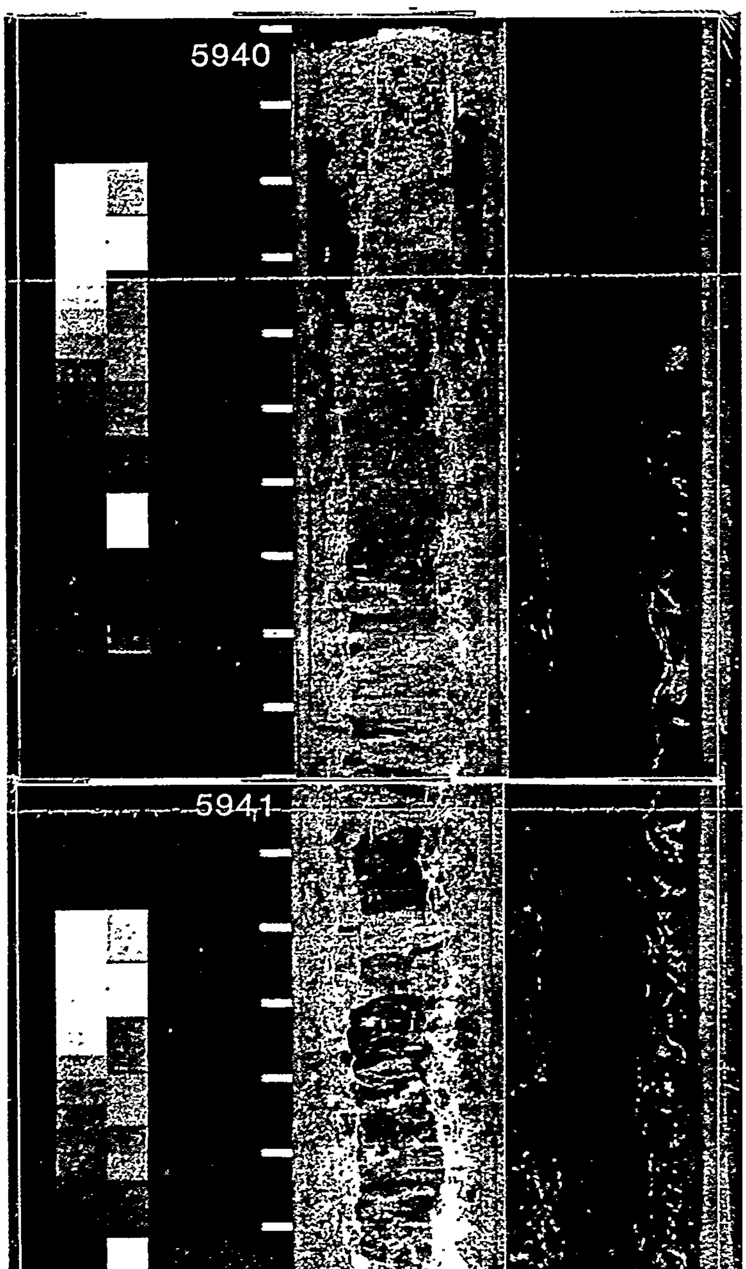
Core Laboratories

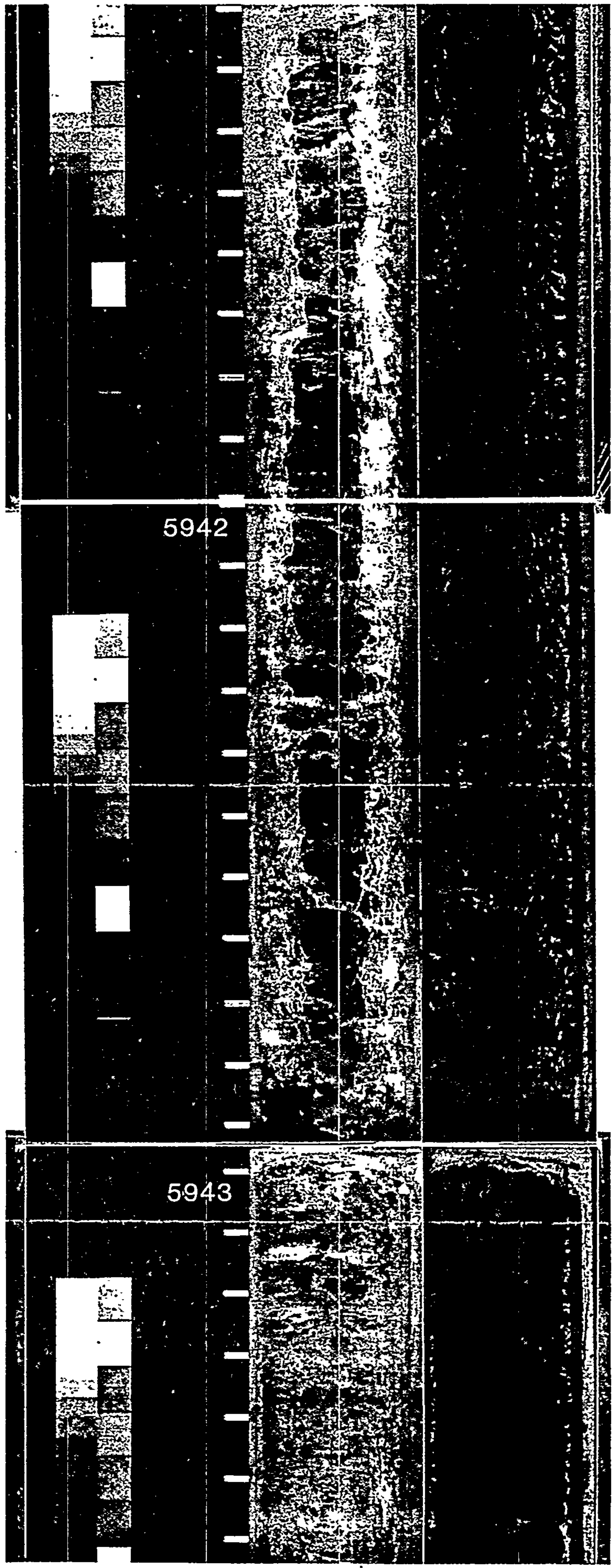
TEXACO, INC.

Stark "B" No. 10
Port Neches Field
Orange County, Texas
CL File No. 57161-11236

Core No. 1
Depth: 5940 - 5950

CorePhoto™

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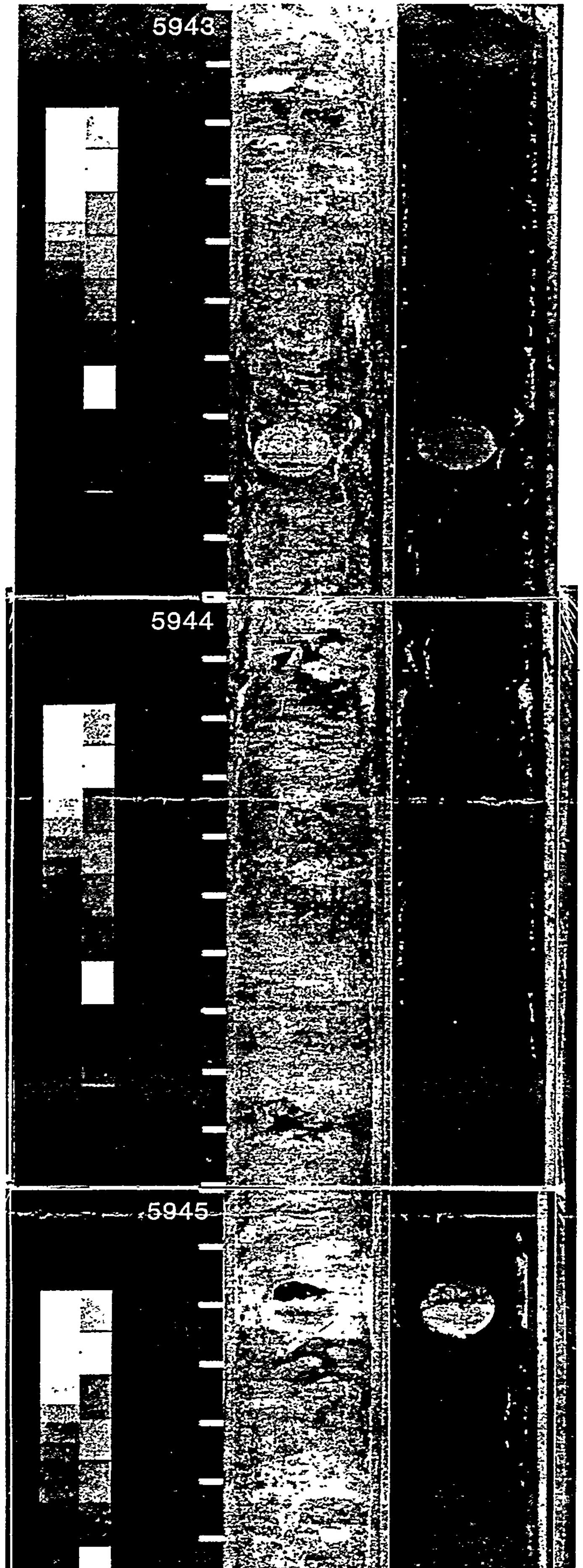
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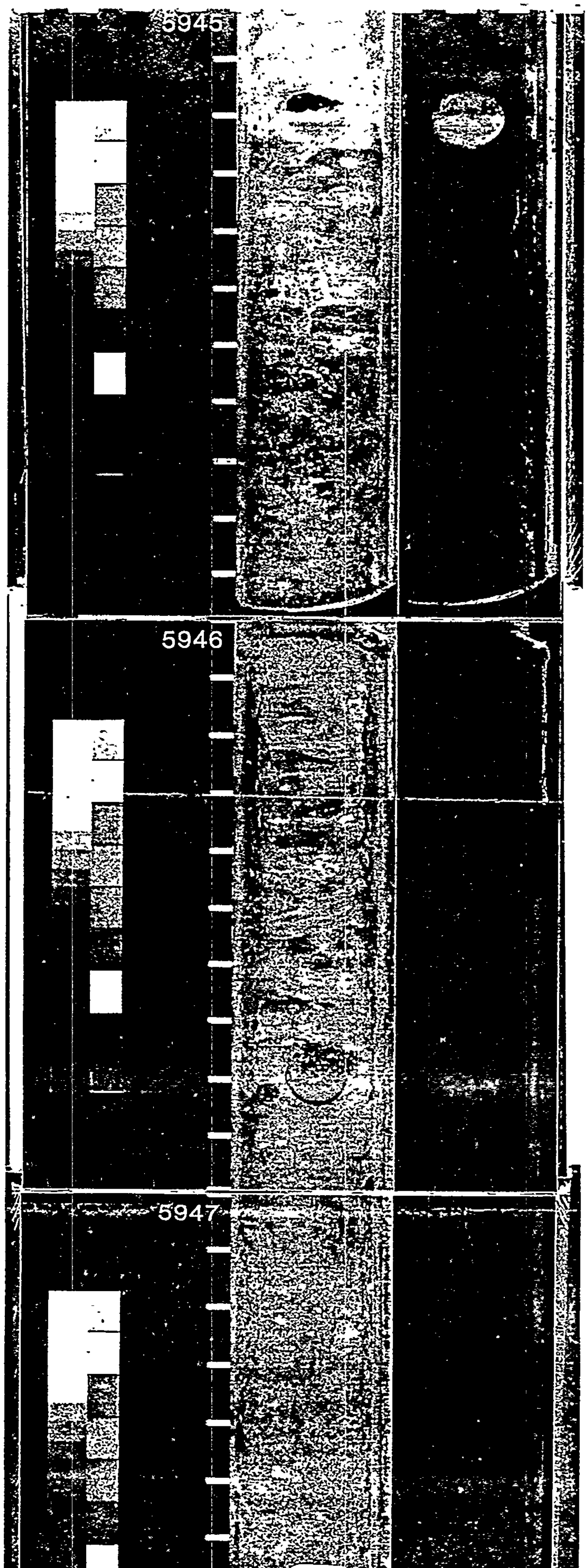
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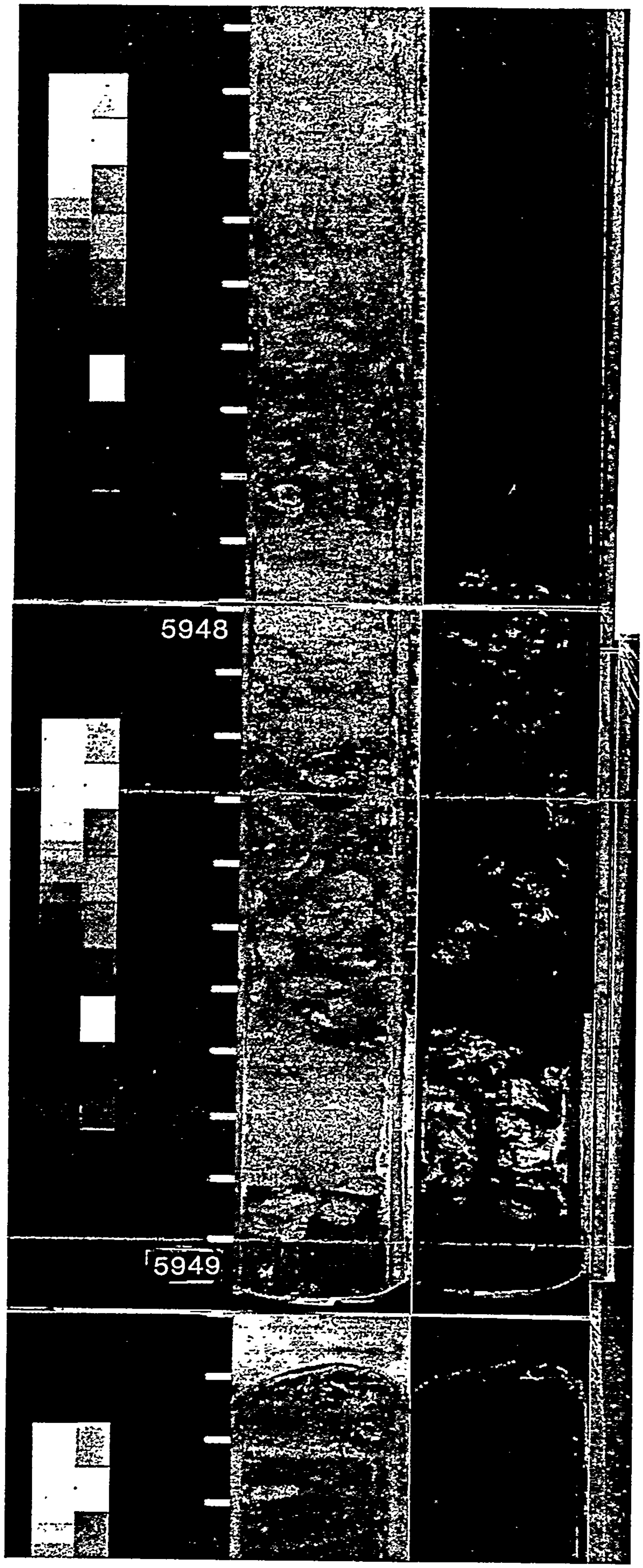
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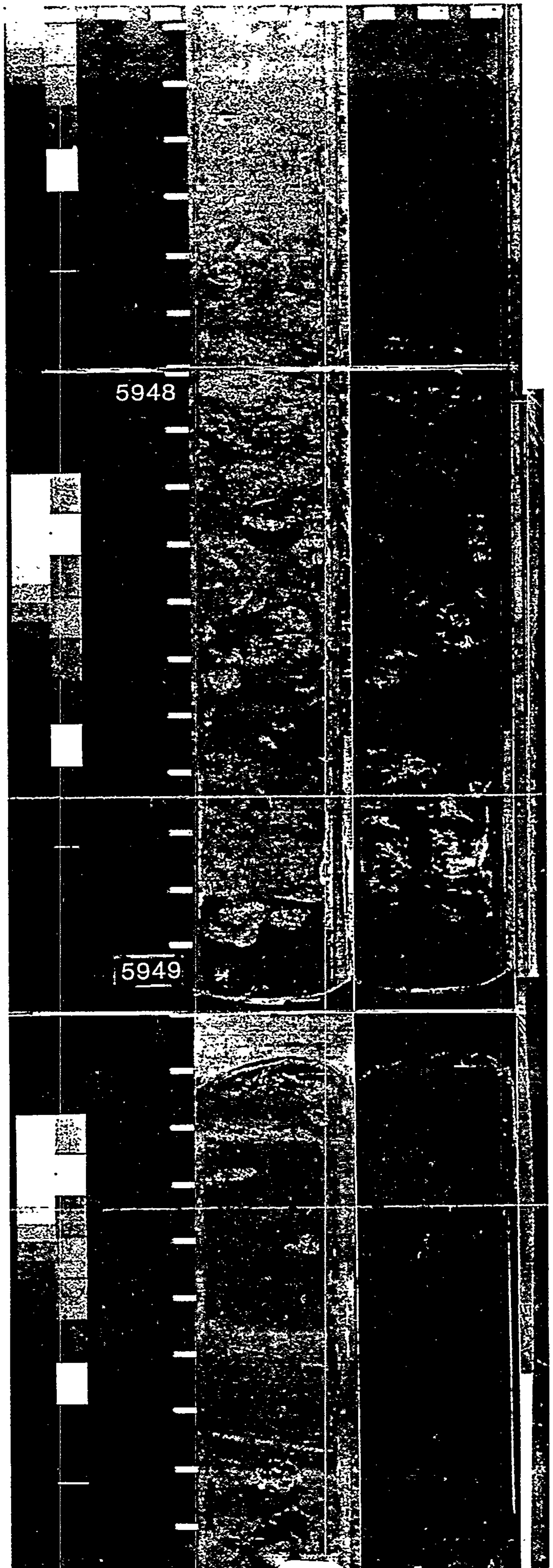
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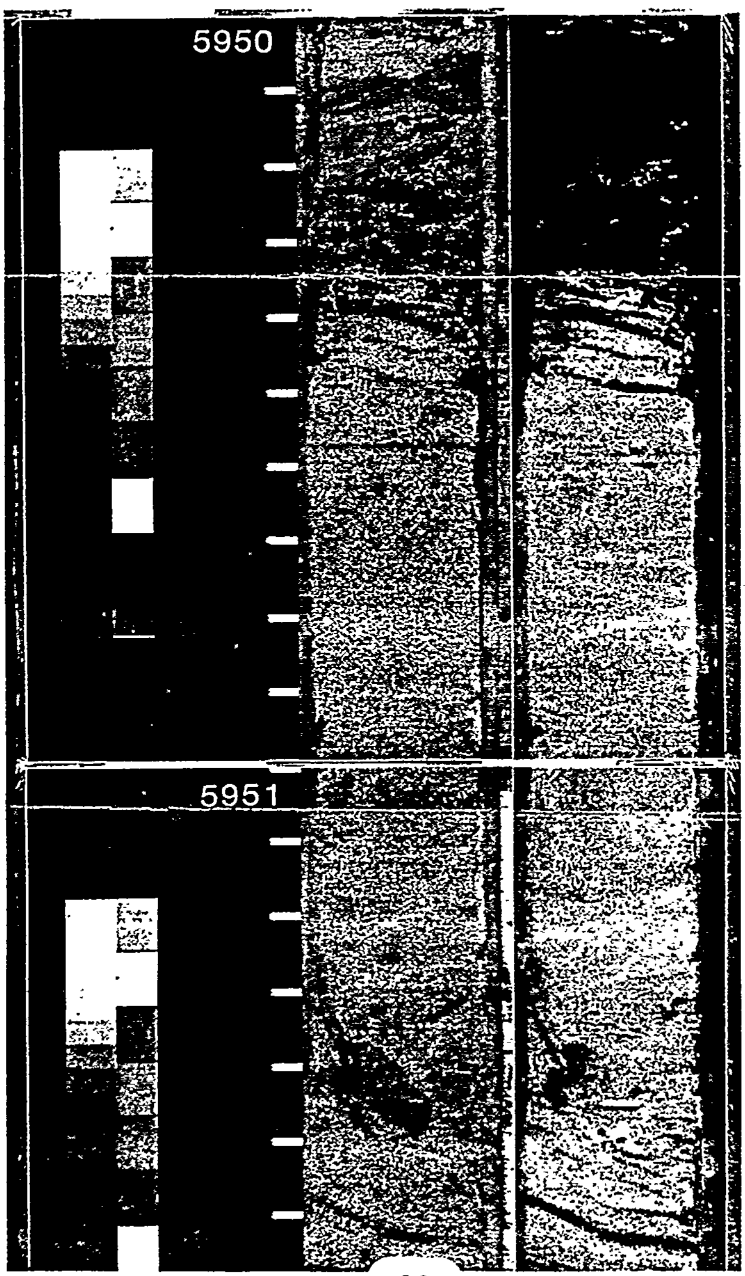
5949

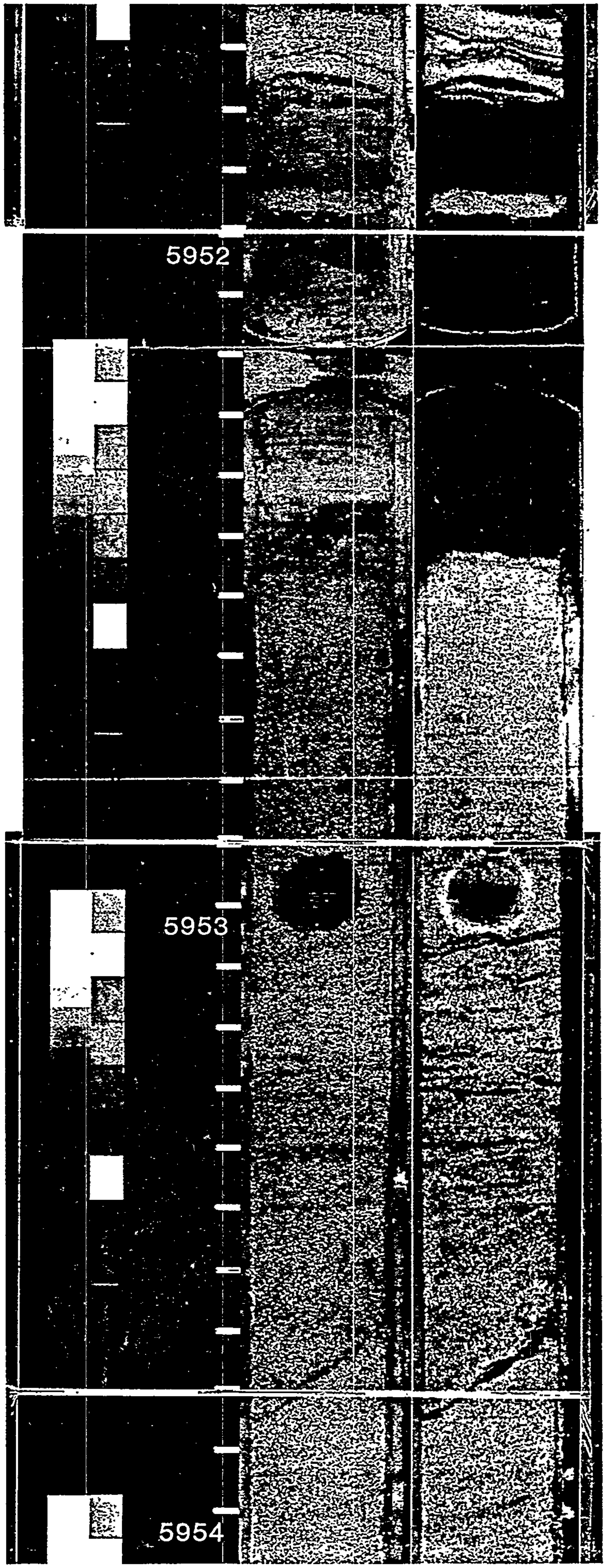
TEXACO, INC.

Stark "B" No. 10
Port Neches Field
Orange County, Texas
CL File No. 57161-11236

Core No. 1
Depth: 5950 - 5961.2

CorePhoto™

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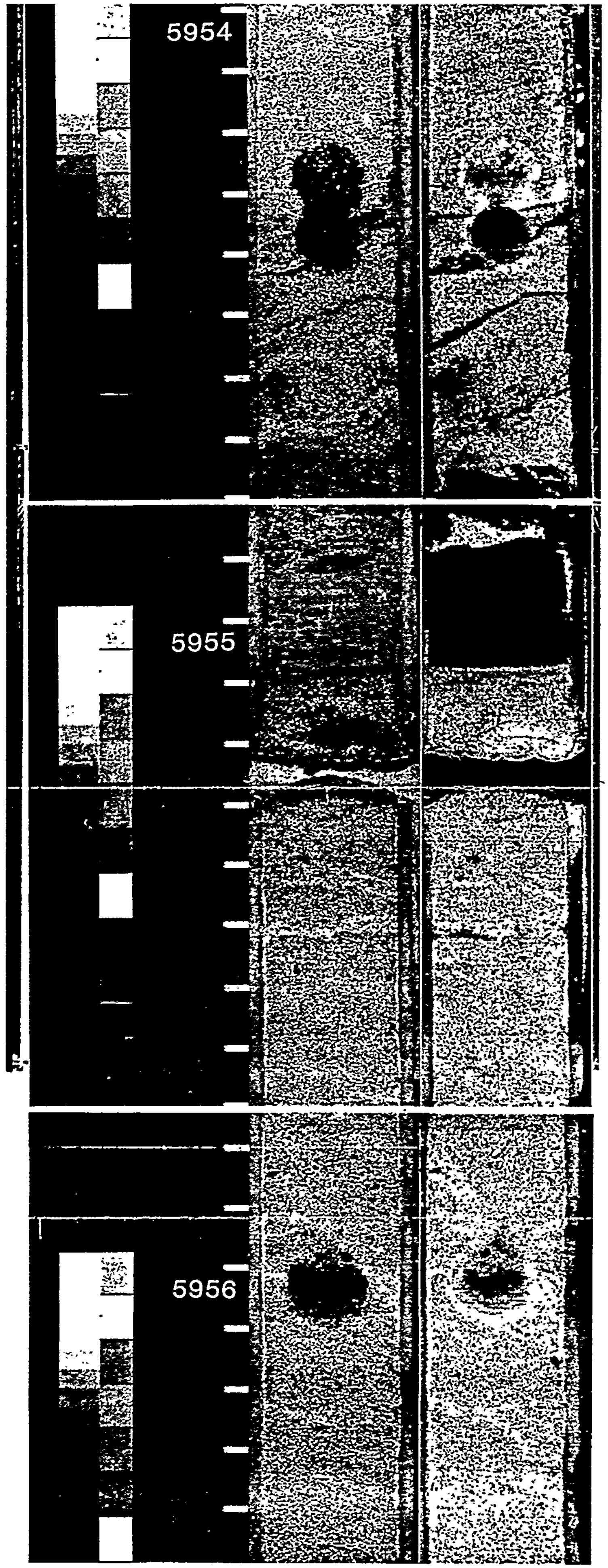
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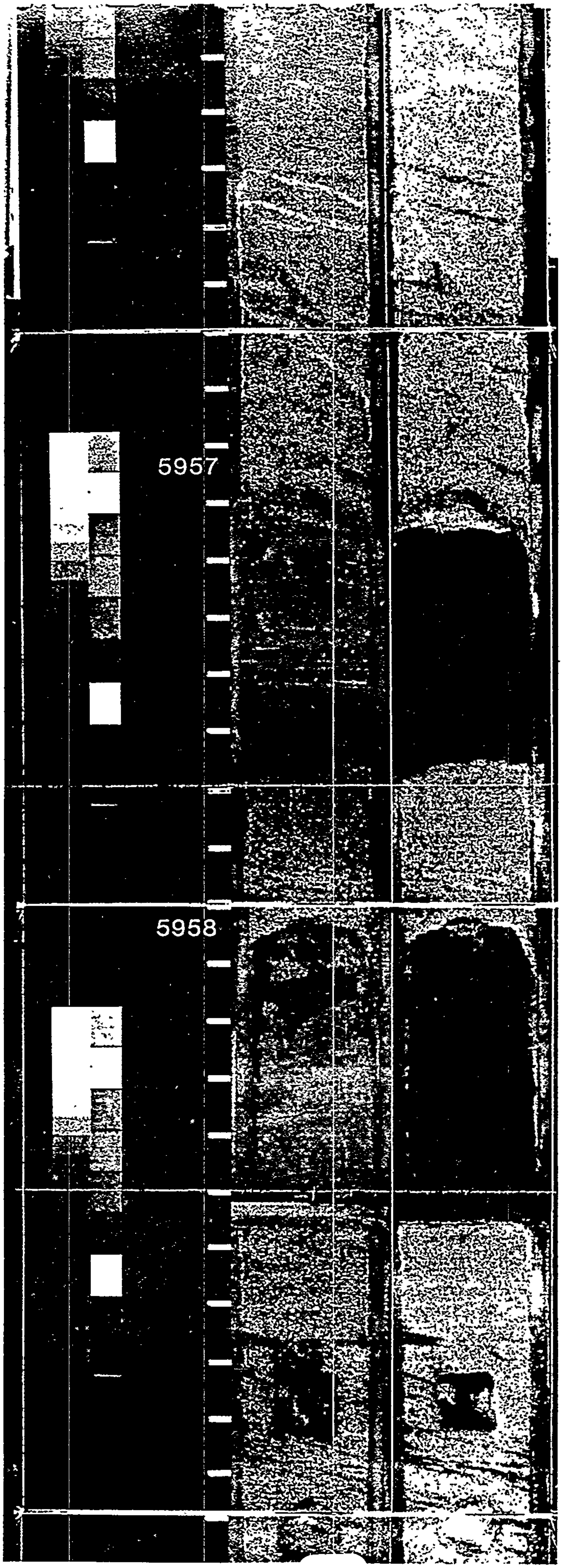
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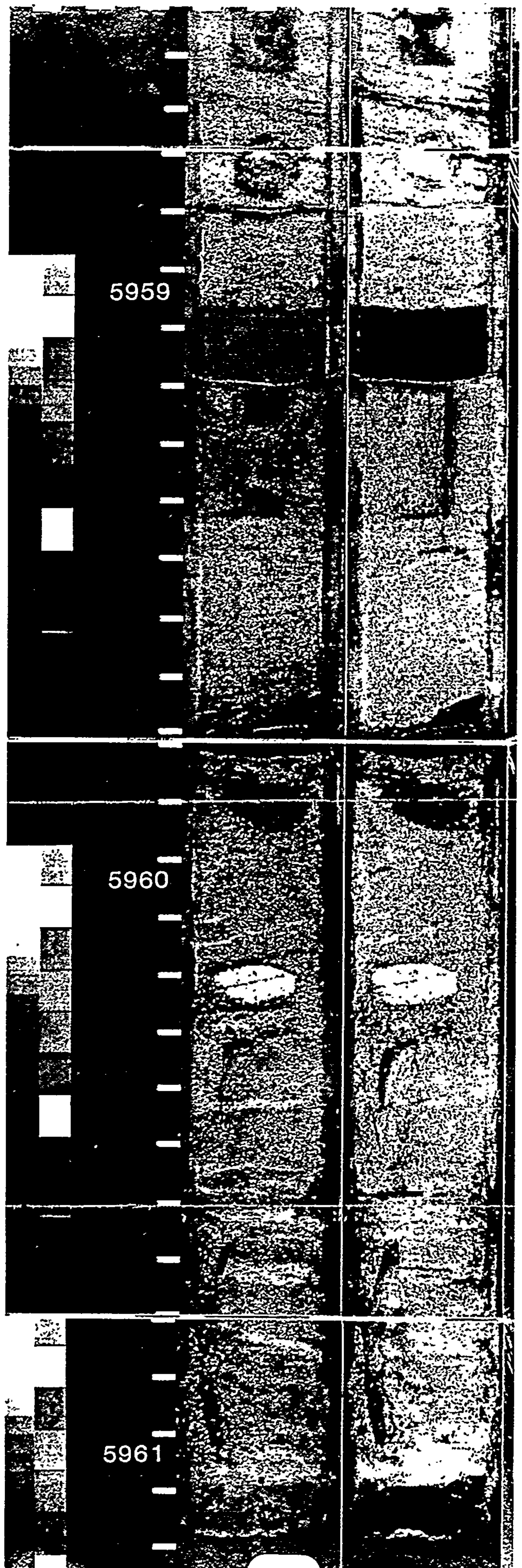
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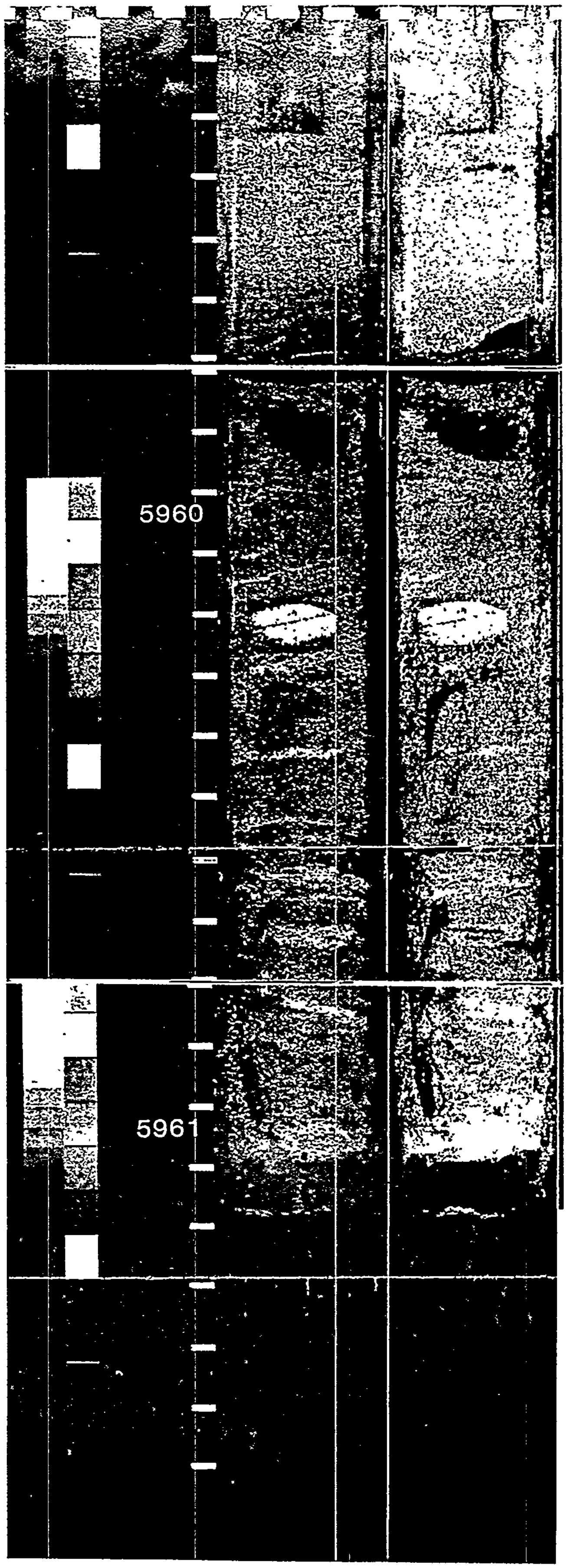
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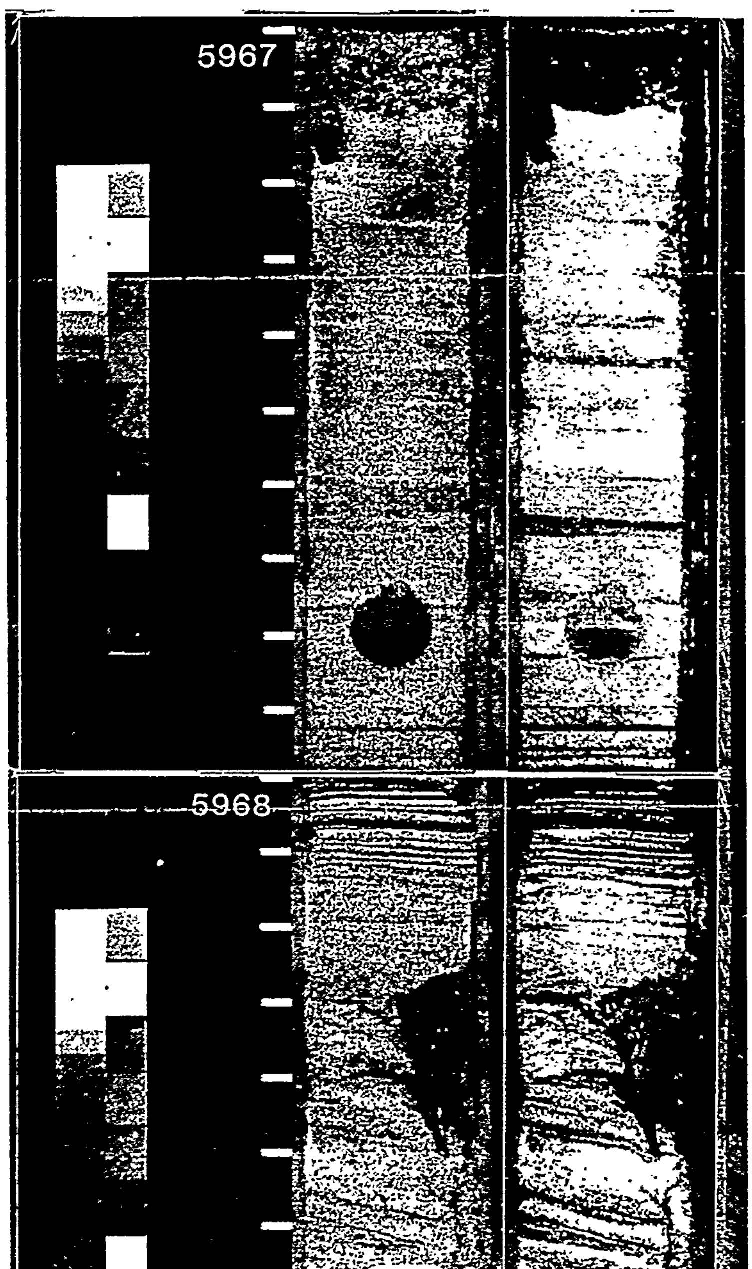
CORE LABORATORIES

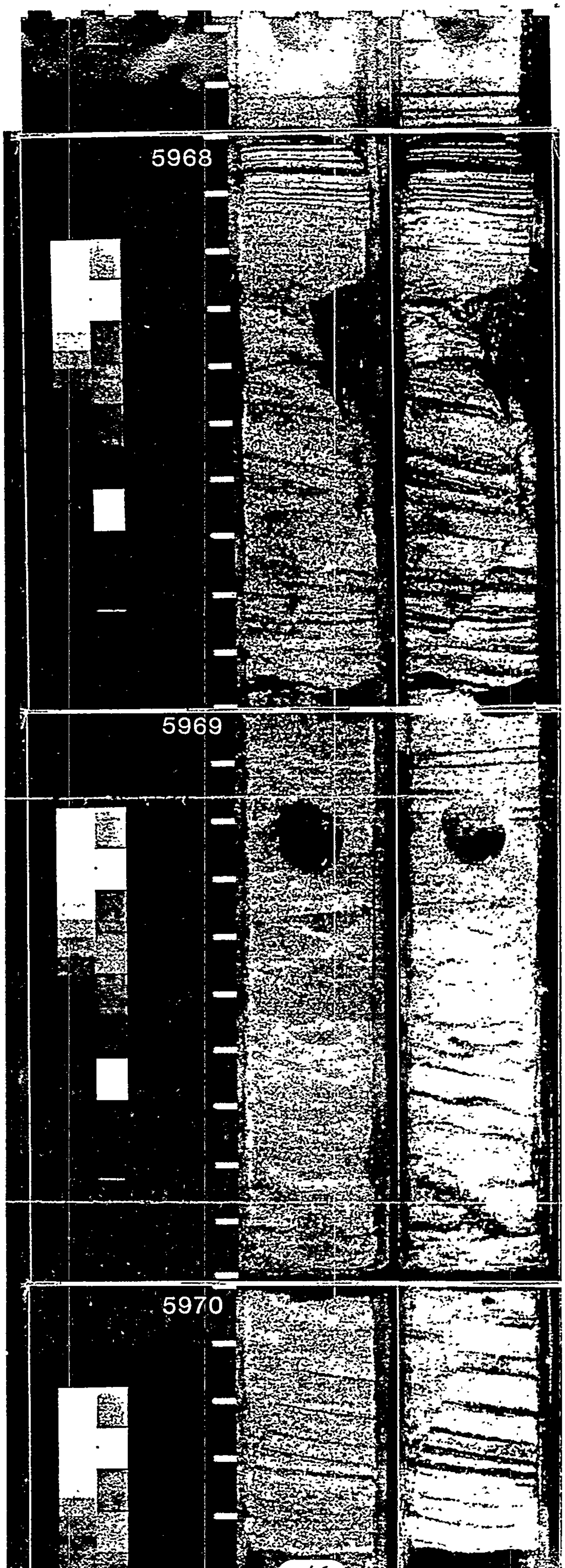
TEXACO, INC.

Stark "B" No. 10
Port Neches Field
Orange County, Texas
CL File No. 57161-11236

Core No. 2
Depth: 5967 - 5977

CorePhoto™

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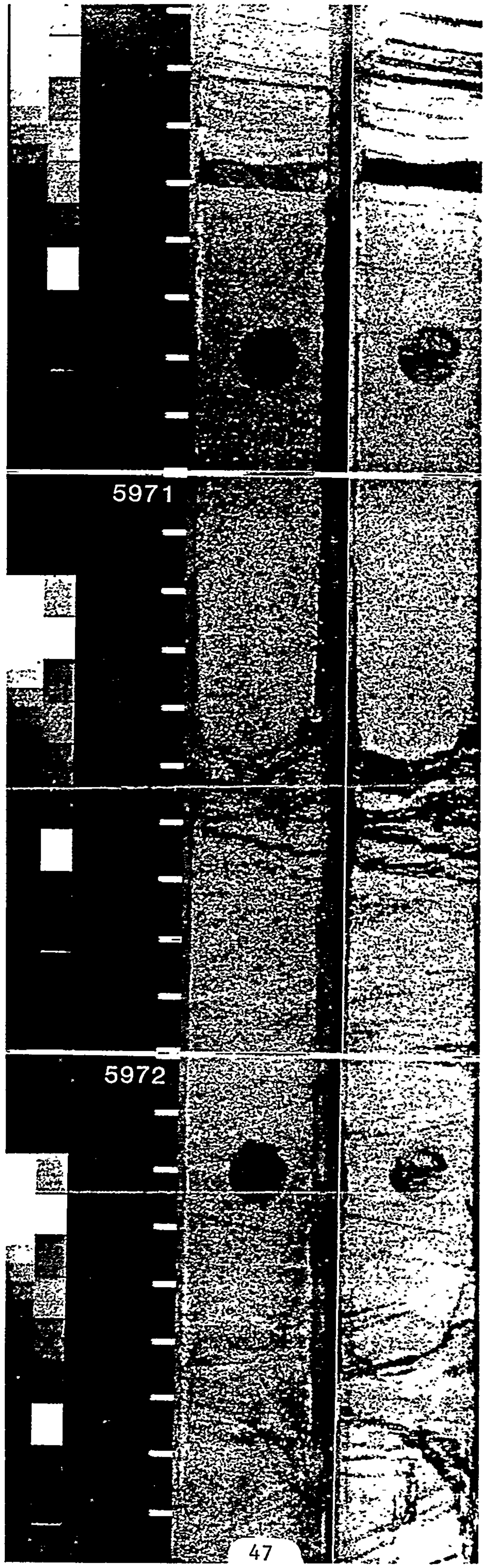
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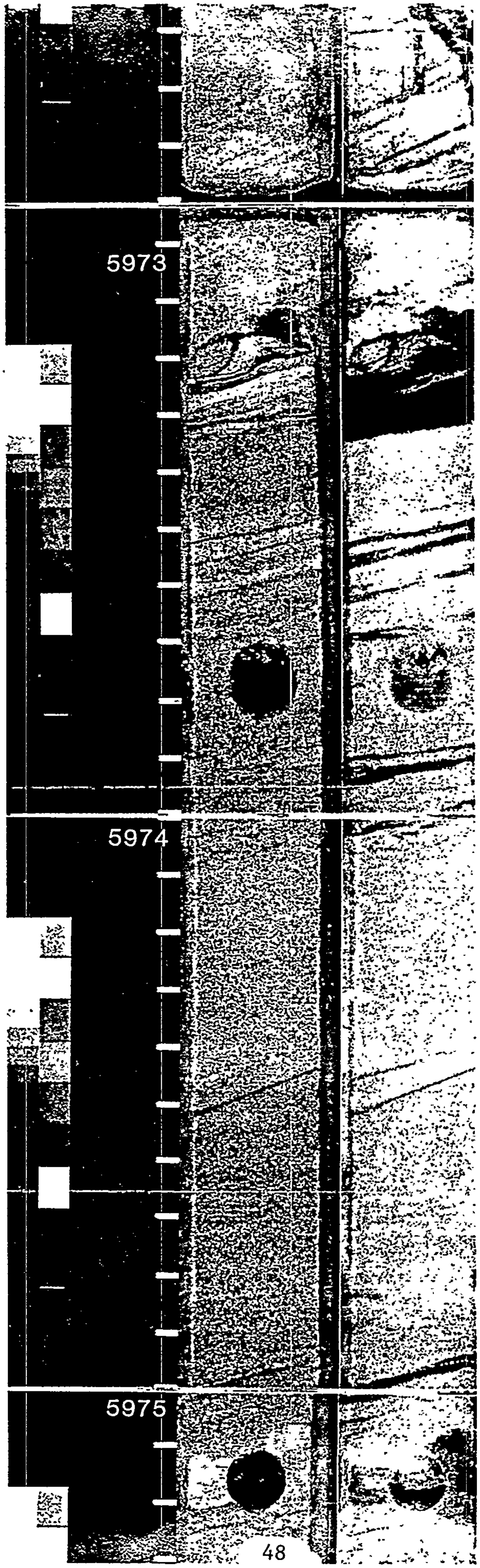
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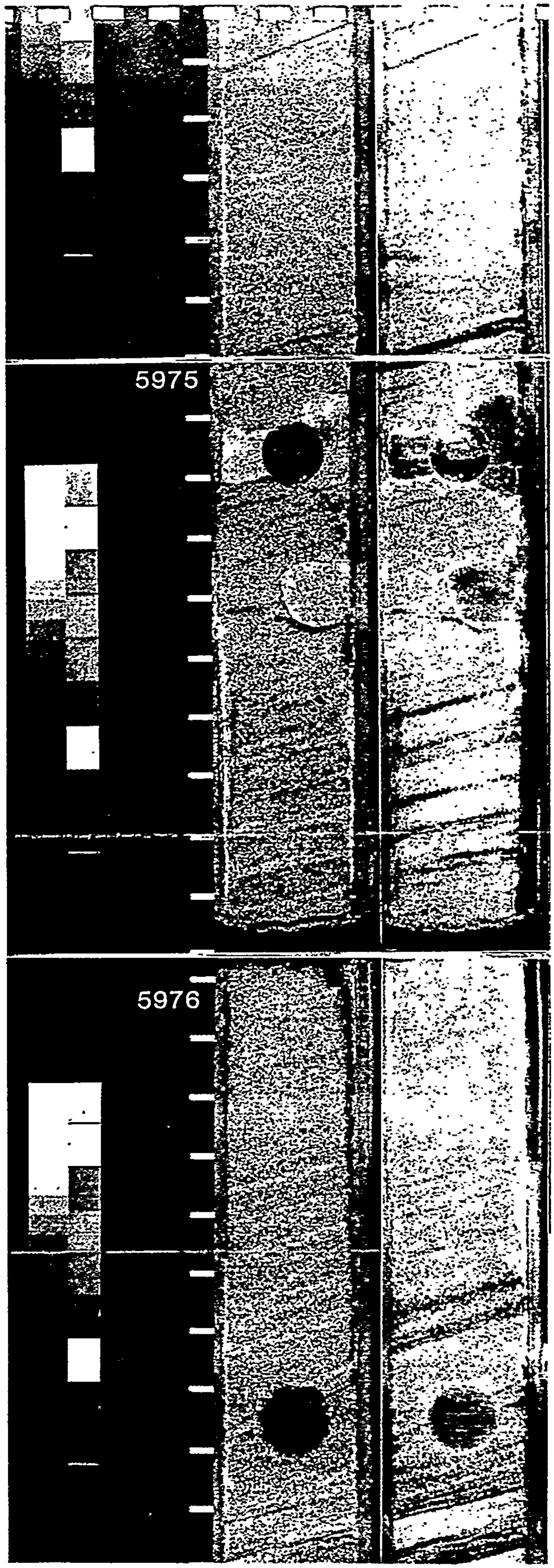
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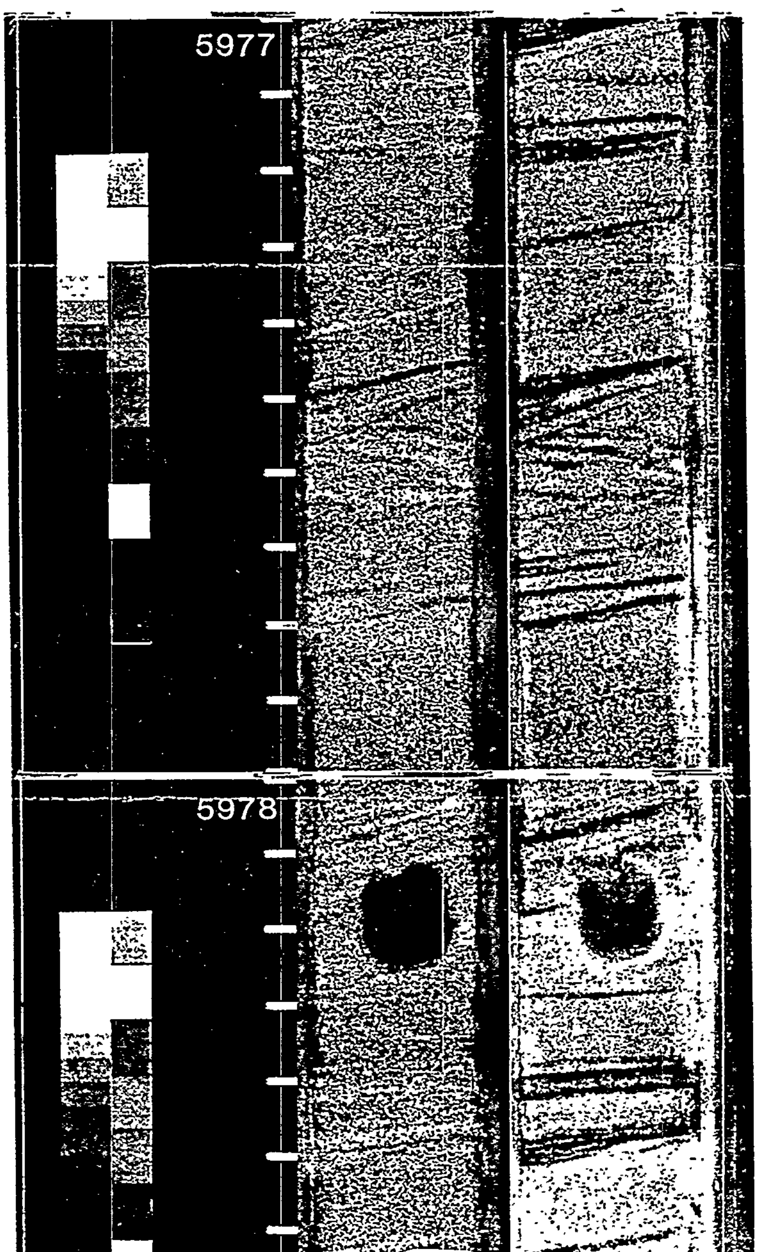
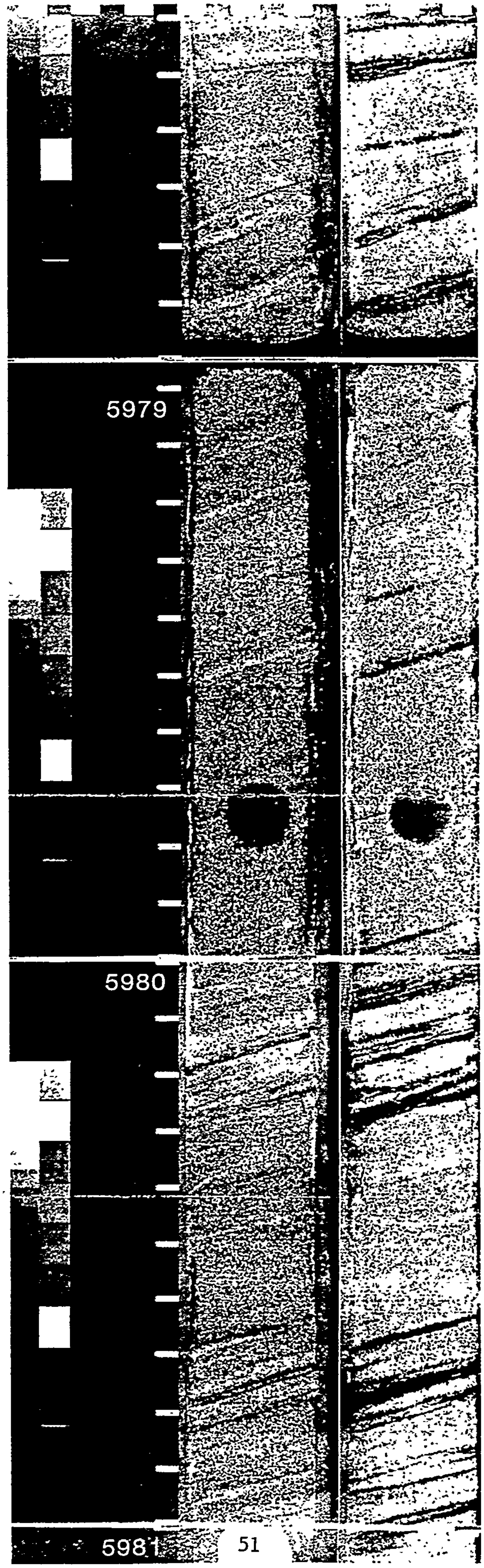
TEXACO, INC.

Stark "B" No. 10
Port Neches Field
Orange County, Texas
CL File No. 57161-11236

Core No. 2
Depth: 5977 - 5985.6

CorePhoto™

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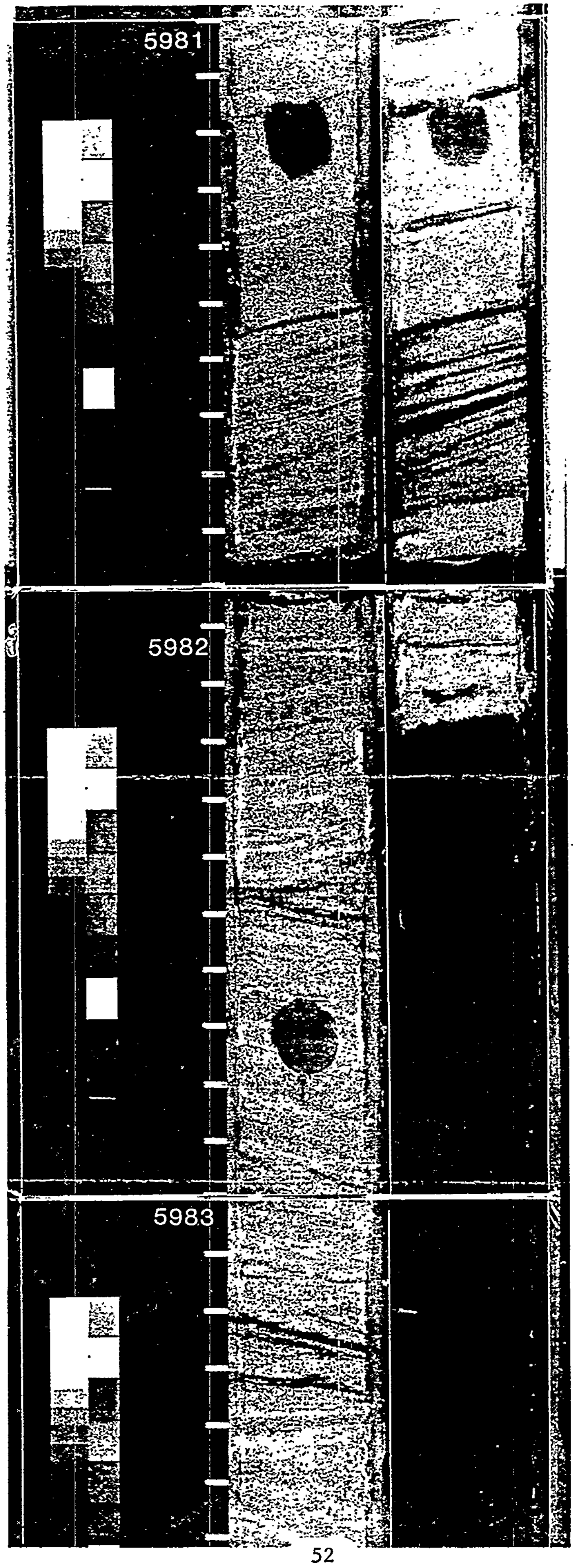
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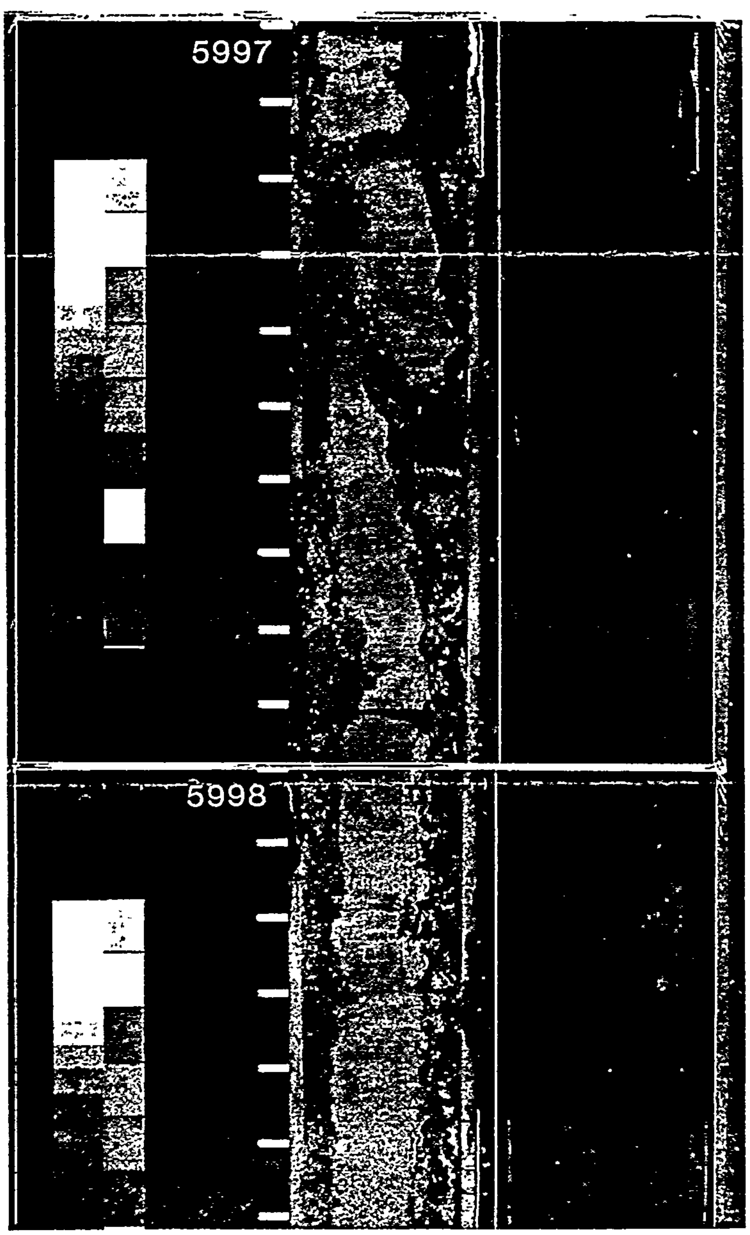
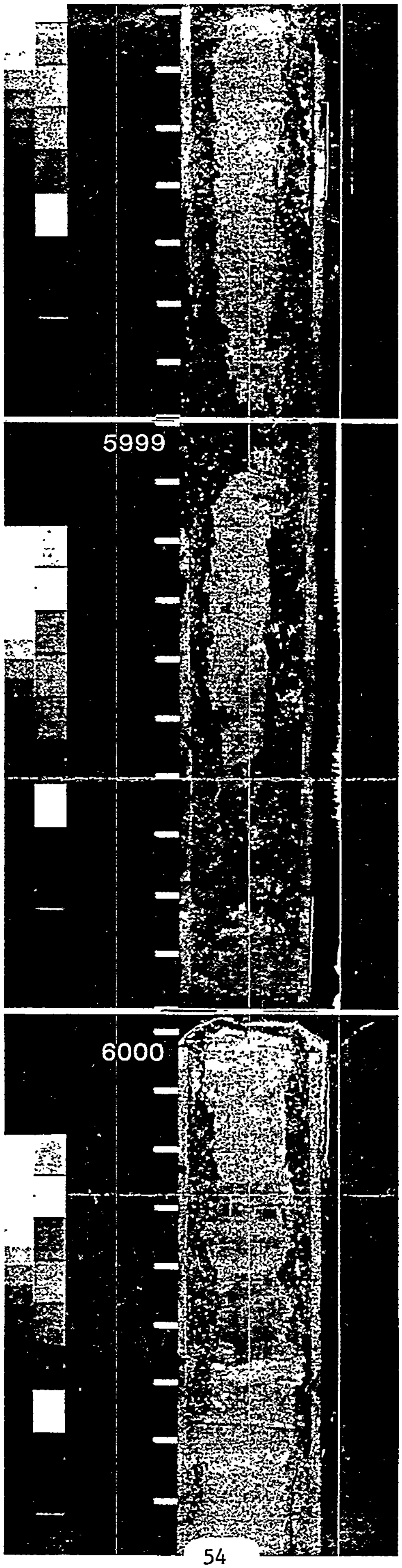
TEXACO, INC.

Stark "B" No. 10
Port Neches Field
Orange County, Texas
CL File No. 57161-11236

Core No. 3
Depth: 5997 - 6005.2

CorePhoto™

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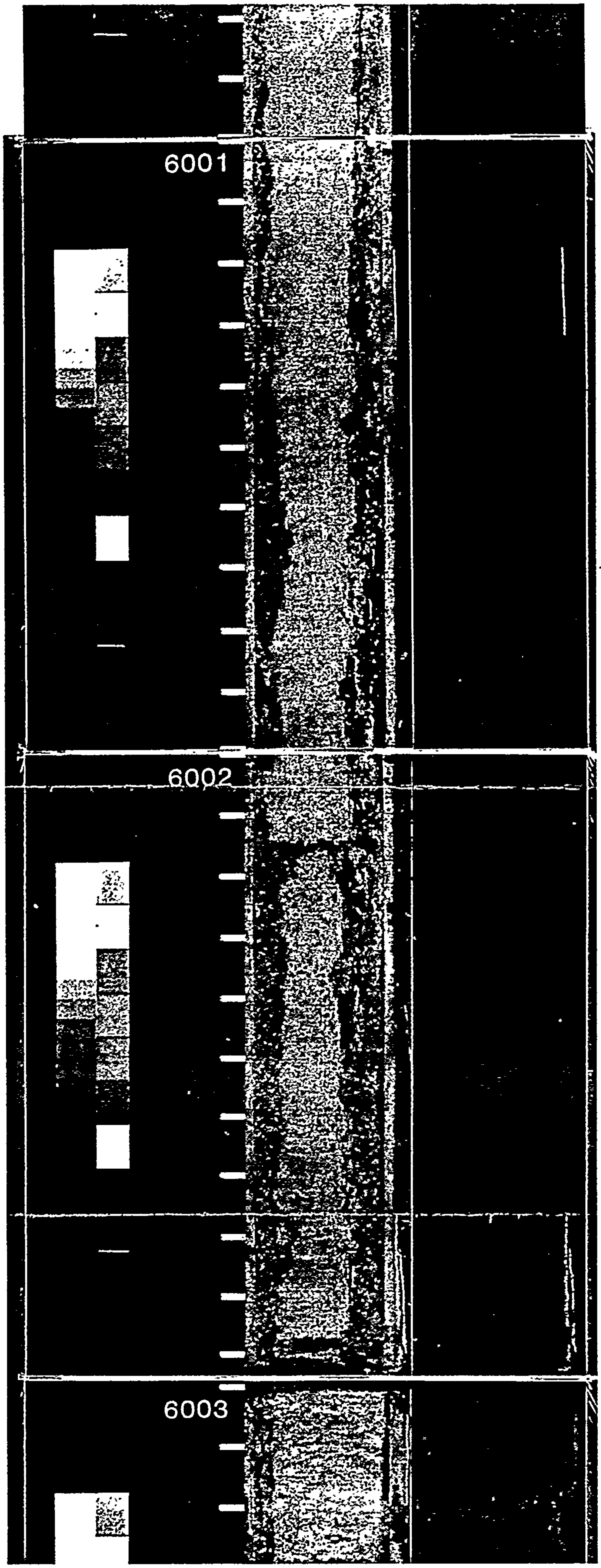
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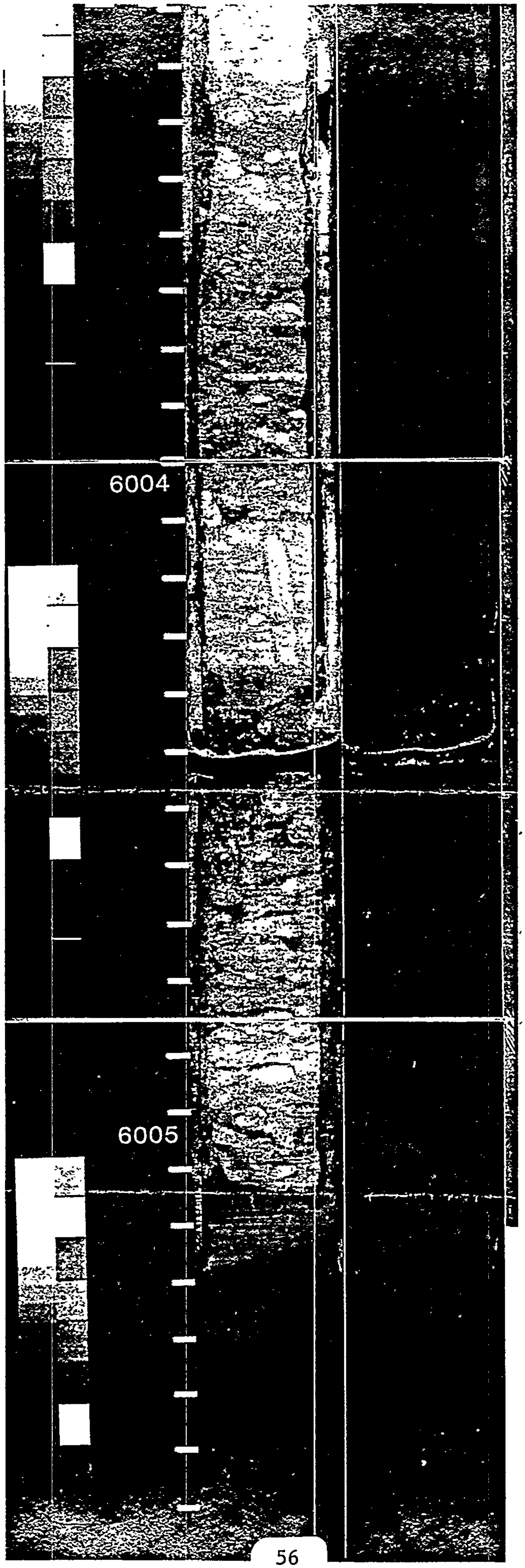

6004
6005

Texaco

DATE: May 17, 1993

TO: Mr. Joseph Babineaux, Jr.

FROM: M. D. Hogg

SUBJECT: **PRO** - Lithologic Description of Conventional Core, Port Neches Field
Analysis of *Marginulina* sand to Prepare for Horizontal Drilling

In 1993 the East Region Sour Lake Asset Management Team will drill a horizontal CO_2 injection well within the *Marginulina* sand (Oligocene) reservoir at Port Neches Field. Horizontal displacement through the *Marginulina* sand will be approximately 1500 feet. Net sand ranges from 20 to 35 feet along the proposed horizontal well bore course, which approximates the trend of the original oil-water contact. Since the well will serve as a CO_2 injector for a miscible EOR project, it is important to maintain vertical control during drilling through the productive interval to insure the well bore remains in-zone to maximize injection sweep efficiency.

Stratigraphic control at the wellsite will be based largely on bit cuttings collected during horizontal drilling. The primary purpose of this study is to establish lithologic characteristics of the Marginulina sand, the intervals immediately above and below the reservoir, and describe the vertical succession within the reservoir and confining beds. The vertical succession will be used to provide stratigraphic control within the proposed horizontal well. Well log curves and profile permeameter data (measured at Core Labs) is included as Attachment 2. The profile permeameter data is intended to assist Schlumberger in modeling MWD resistivity anomalies associated with out-of-zone wellbore excursions.

Lithologic characterization of overlying and underlying intervals was made using bit cuttings from the Texaco Stark "B" No. 10. Examination of these cuttings indicates that intervals enclosing the reservoir are similar and, therefore, have no diagnostic vertical patterns of lithology. Consequently, it is not possible to differentiate the shales and very fine-grained sandstones occurring above the reservoir from those below. Conventional cores of the reservoir recovered from the Stark "B" No. 10 were described to obtain representative and continuous sampling of the objective interval.

Sixty-seven feet of conventional core were cut in the Stark "B" No. 10 with 48 feet of recovery incorporating the *Marginulina* sand and overlying and underlying units. Analyses performed include core description, binocular microscope examination of core plugs, and micropaleontolgy (Total Biostratigraphic Services, Inc.). Attachment 1 is lithologic descriptions of the cored intervals including porosity and permeability data, micropaleontology sample points, and interpreted depositional environments. To assist wellsite personnel, sets of cuttings comparators from overlying and underlying intervals (from Stark "B" No. 10 samples) have been prepared for microscopic examination of bit cuttings while drilling. In addition, photographs of reservoir core plugs have been mounted adjacent to SP-gamma ray logs annotated with core plug location. The cuttings and core plug photographs should be used for real-time comparison with bit cuttings obtained during horizontal drilling.

Core examination indicates that three lithologies should be identifiable with drill cuttings. These key lithologies are: 1) unconsolidated medium-grained sand within the *Marginulina* sand proper, 2) homogeneous dark gray lignitic shales within the upper portions of the sand, and 3) calcareous and fossiliferous bioturbated shale and shaly very fine-grained sand above and below the *Marginulina* sand. Micropaleontology confirms the marginal marine depositional environments of confining units interpreted from core examination.

The only clearly distinctive zone within the reservoir consists of dolomite-cemented nodules at 5975.5 feet (see Attachment 1). It is unknown whether this nodular zone is widespread and confined to a specific stratigraphic position. However, cuttings of this material can be differentiated from the calcite-cemented sand of confining zones by slower effervescence of dolomite in dilute HCl compared to calcite and/or not taking a stain when immersed in a standard solution of alizarin red-S[1]. In addition, shale beds in the upper portion of the reservoir are only slightly calcareous with minor effervescence in dilute HCl whereas the calcareous shales in confining beds effervesce vigorously.

In summary, salient features of beds penetrated in the proposed horizontal CO_2 injection well are:

OVERLYING BEDS: (cuttings comparator)

- gray calcareous shale and mottled shaly bioturbated very fine-grained glauconitic sand; vigorous effervescence in dilute HCl
- pyrite
- marine fossils; forams, molluscs, echinoid fragments
- extremely finely interlaminated sand and shale

MARGINULINA SAND: (core plug photographs)

- nearly all unconsolidated medium-grained sand
- local tight dolomitic zone(s); slow effervescence in dilute HCl
- dark gray slightly calcareous shale beds near top of reservoir
- no fossils, calcite, or pyrite

(continued)

[1]In contrast to dolomite, calcite takes on a pink to light red stain when treated with alizarin red-S. Iron-rich dolomite may develop a mottled royal blue stain.

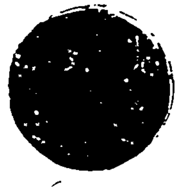
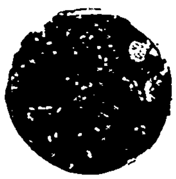
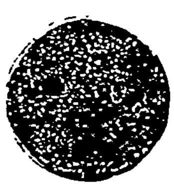
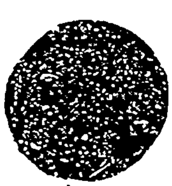
UNDERLYING BEDS: (cuttings comparator)

- gray calcareous shale and mottled shaly bioturbated very fine-grained glauconitic sand; vigorous effervescence in dilute HCl
- pyrite
- marine fossils; forams, molluscs, echinoid fragments
- extremely finely interlaminated sand and shale

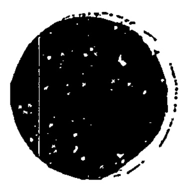
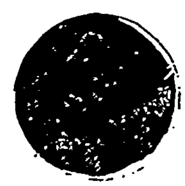
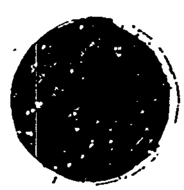
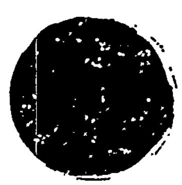
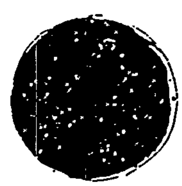
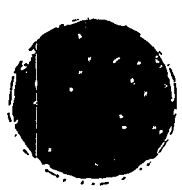
Michael D. Hogg

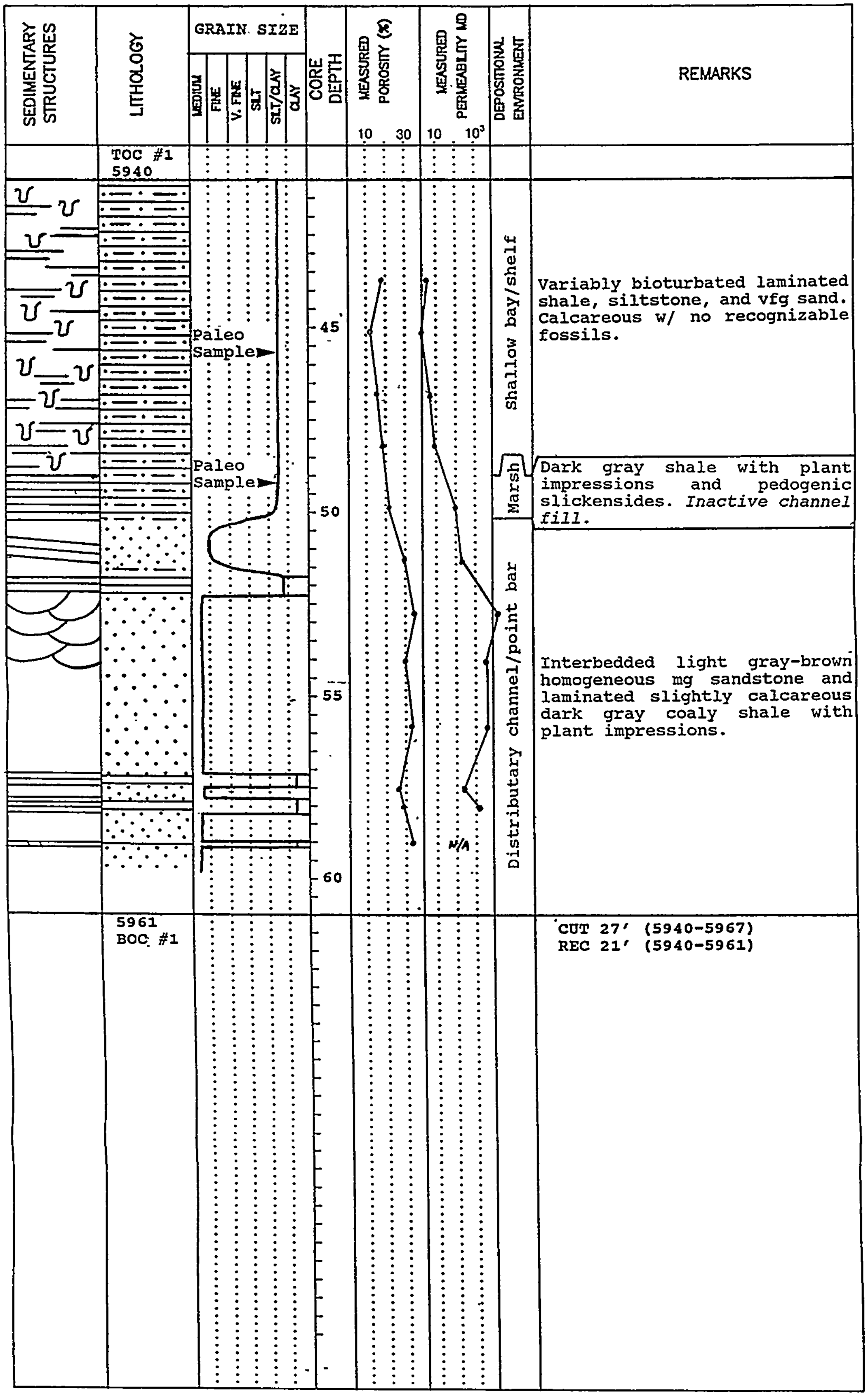
cc: Darrell Davis
Dennis Kuhfal

STARK "B" No. 10 COMPARATOR CHART - BELOW MARGINULINA SAND

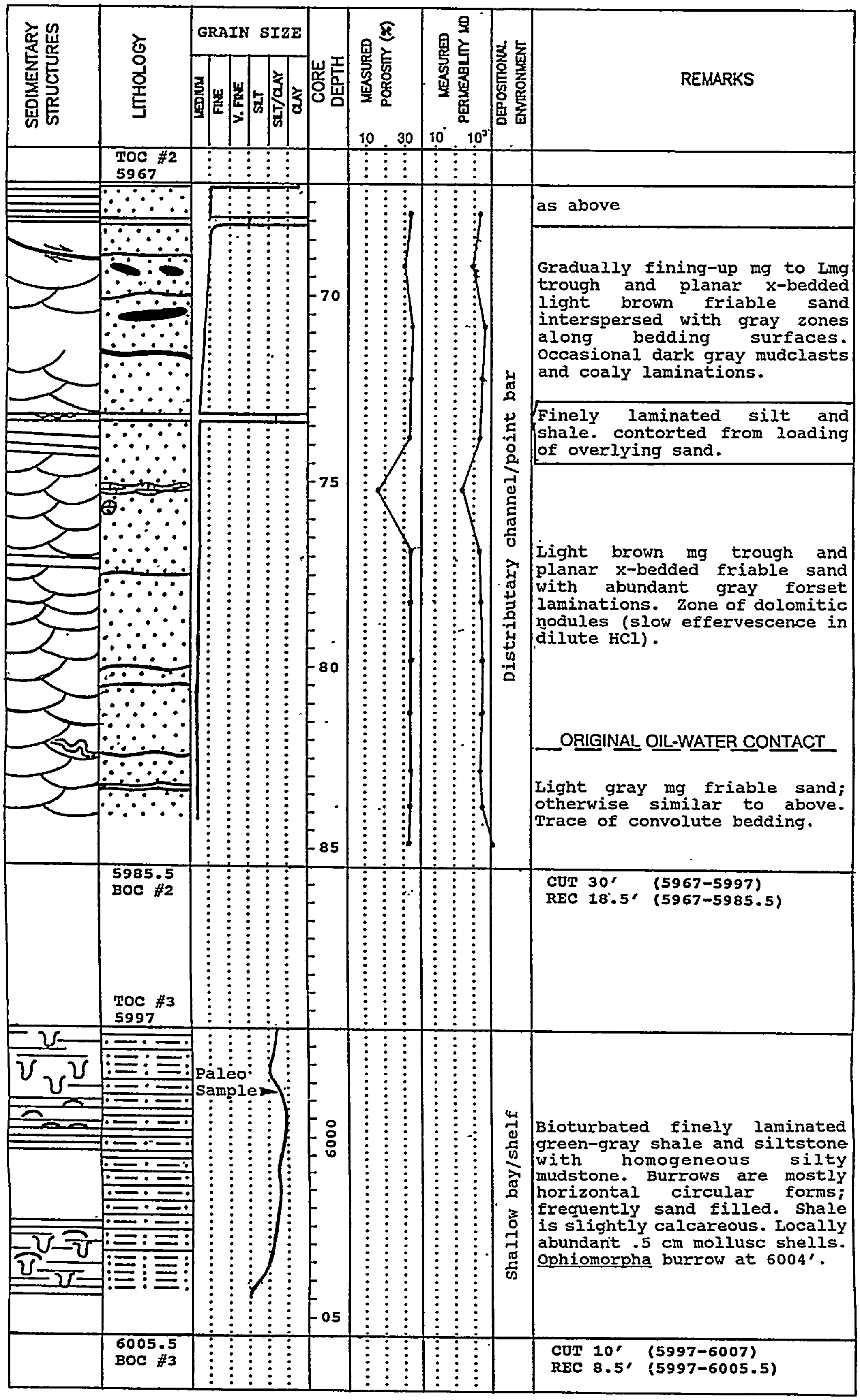
DEPTH	BULK	COARSE	COMMENTS	SAMPLE
5980/990			Tr.* glauconitic sand, pyrite-cemented sand, lignite, forams, very finely interlaminated silt and shale, fine lignitic plant debris. Mottled sand/shale. CALCAREOUS	
5990/000			Tr. * glauconitic sand, quartz-cemented sand, lignite, forams, mollusc fragments, fine lignitic plant debris on bedding surfaces. Mottled sand/shale. CALCAREOUS	
6000/010			Tr. * glauconitic sand, pyrite-cemented sand, very finely interlaminated silt and shale, lignite, forams, mollusc fragments. Mottled sand/shale. CALCAREOUS	
6010/020			Tr. * glauconitic sand, pyrite-cemented sand, mollusc fragments. Mottled sand/shale. CALCAREOUS	
6028/BU			Tr. * glauconitic sand, pyrite-cemented sand. Mottled sand/shale. CALCAREOUS	

STARK "B" No. 10 COMPARATOR CHART - ABOVE MARGINULINA SAND

DEPTH	BULK	COARSE	COMMENTS	SAMPLE
5890/900			Tr. * glauconitic sand, forams, echinoid spines, limestone, lignite, pyrite-cemented sand, very finely interlaminated shale and silt. CALCAREOUS	
5900/910			Tr. * glauconitic sand, pyrite-cemented sand, very finely interlaminated shale and silt, limestone, mottled sand/shale. CALCAREOUS	
5910/920			Tr. * glauconitic sand, pyrite-cemented sand, formams, mollusc fragments, lignite, mottled sand/shale. CALCAREOUS	
5920/930			Tr. * glauconitic sand, pyrite-cemented sand, mottled sand/shale. CALCAREOUS	
5930/940			Tr. * glauconitic sand, pyrite-cemented sand, lignite, mollusc fragments, very finely interlaminated silt and shale, mottled sand/shale. CALCAREOUS	

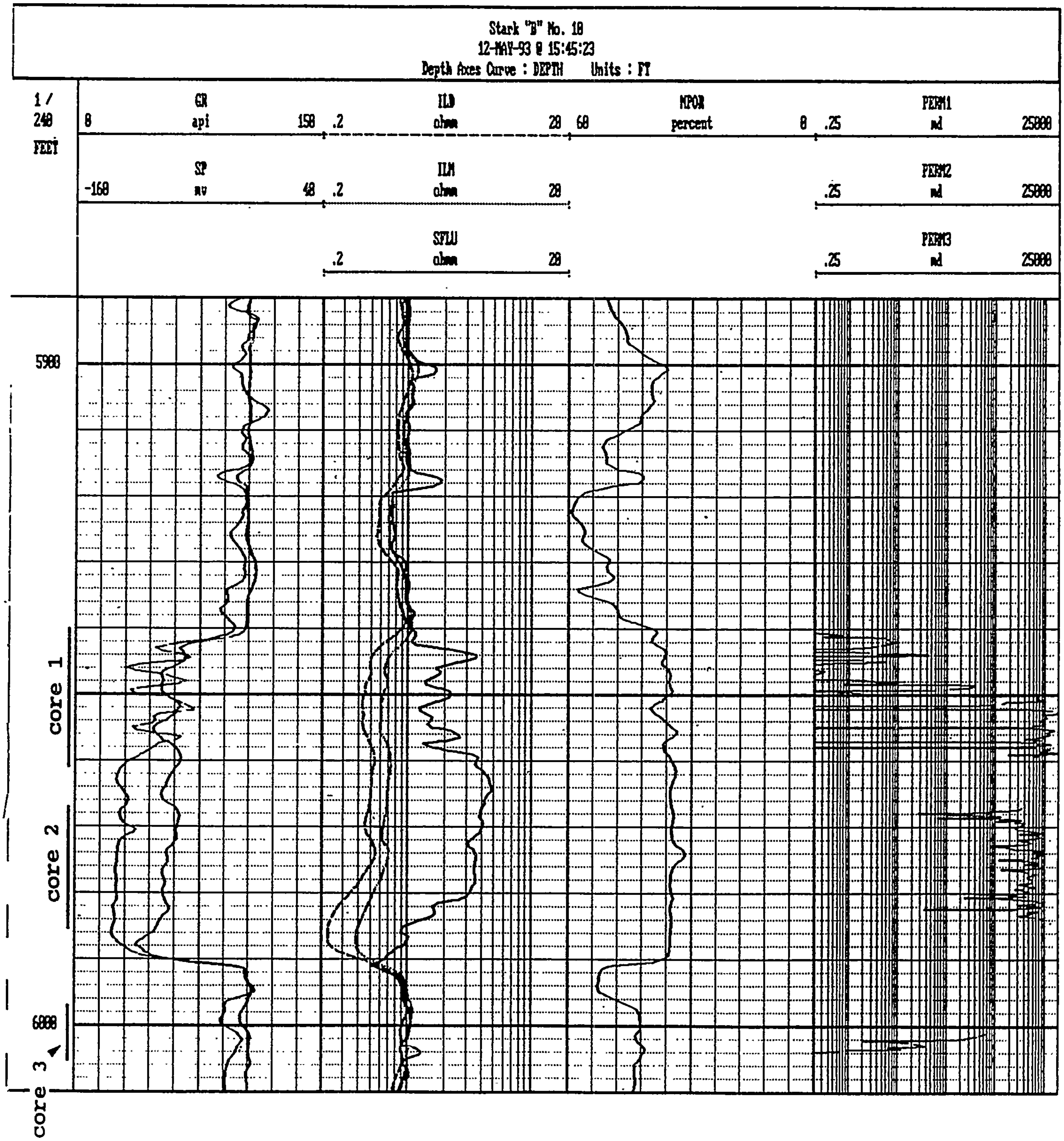


ATTACHMENT 1



ATTACHMENT 1 (continued)

ATTACHMENT 2



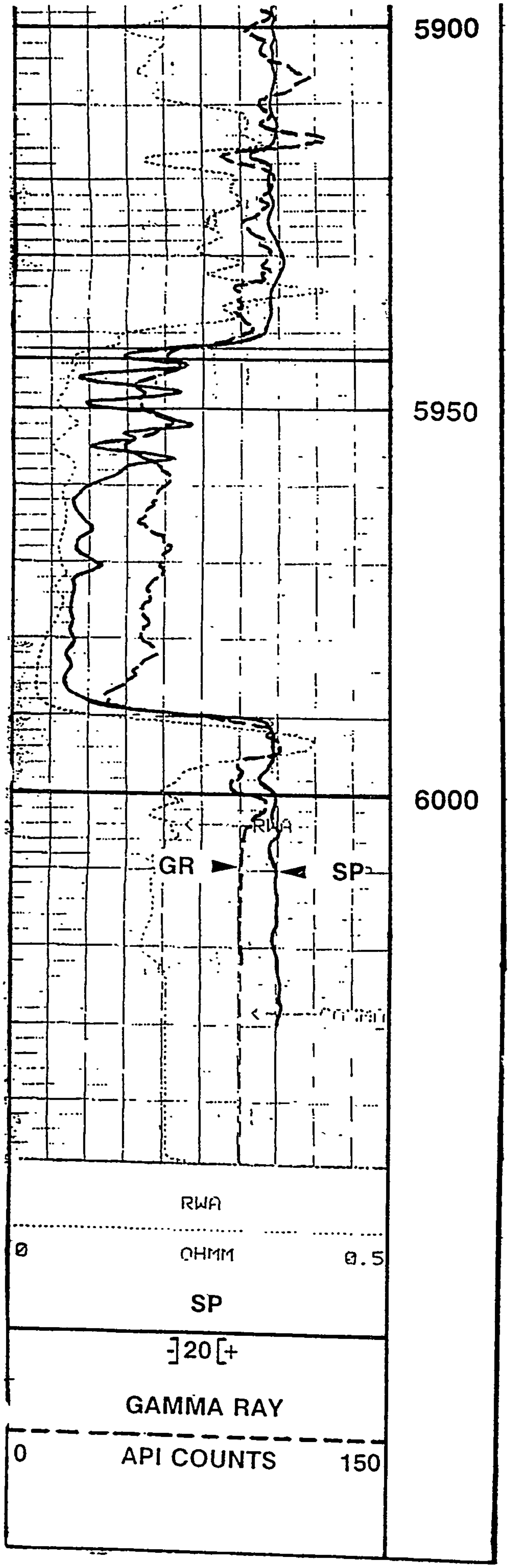
Core Photography

for

TEXACO, INC.

Stark "B" No. 10
Port Neches Field
Orange County, Texas
CL File No. 57161-11236

929 Howard Avenue, New Orleans Louisiana 70113, (504) 581-5222 Fax (504) 586-9476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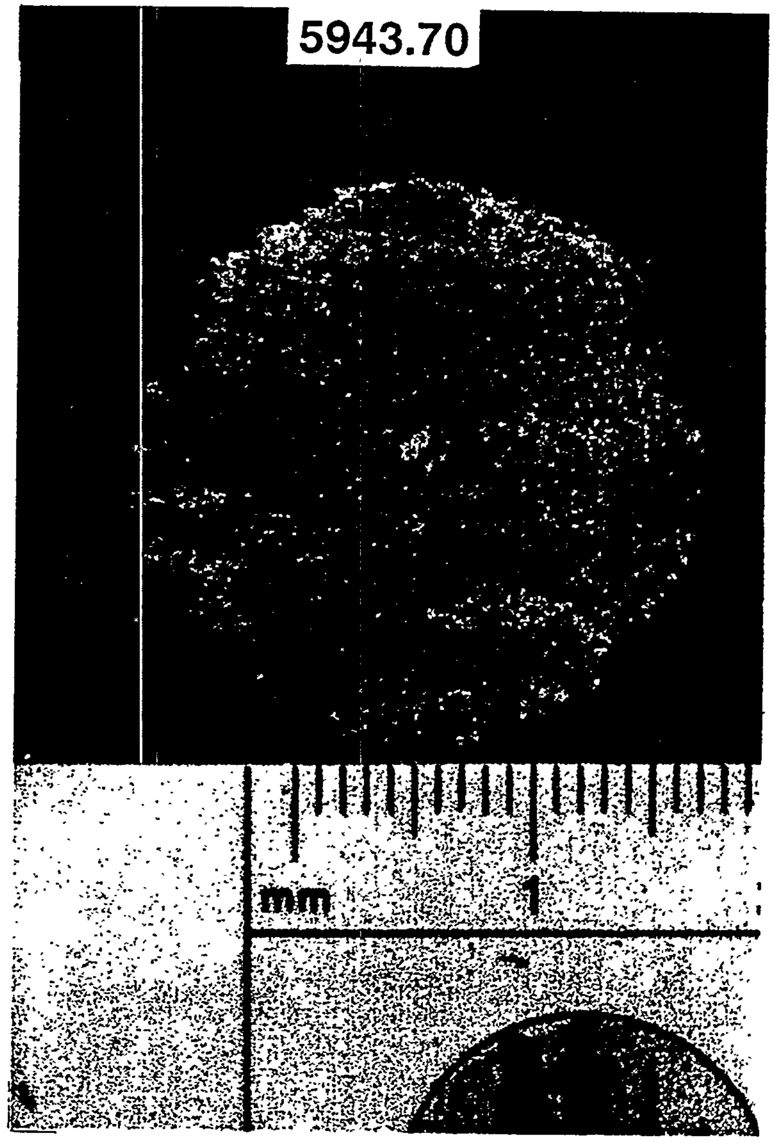
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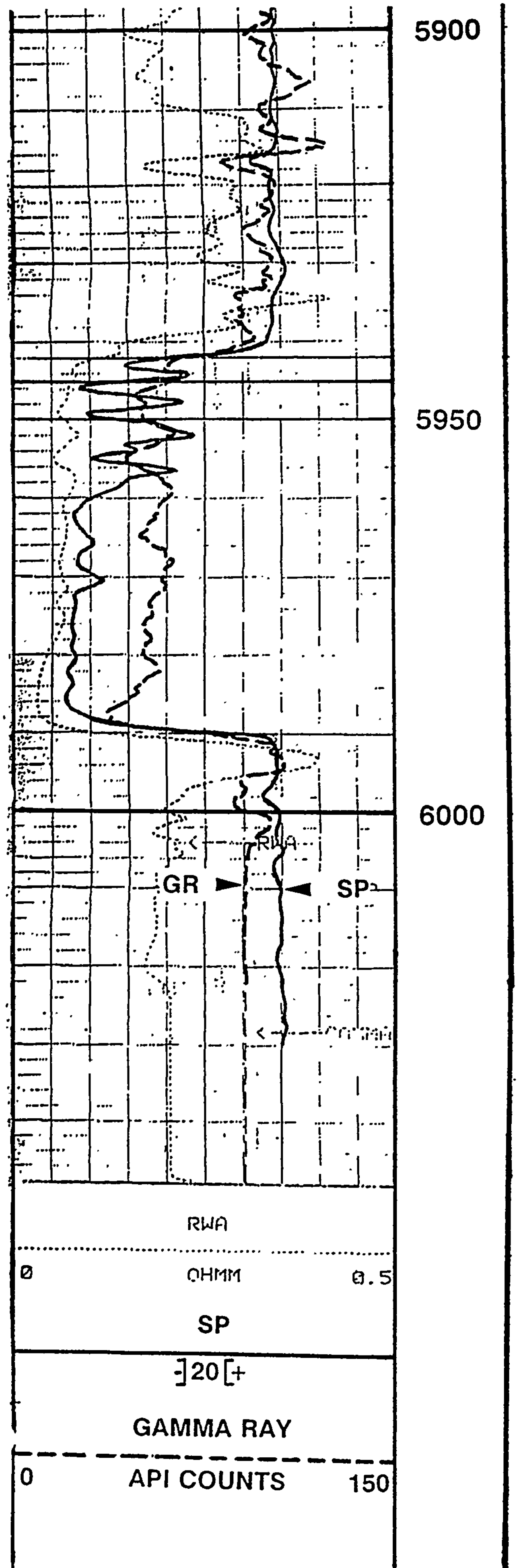

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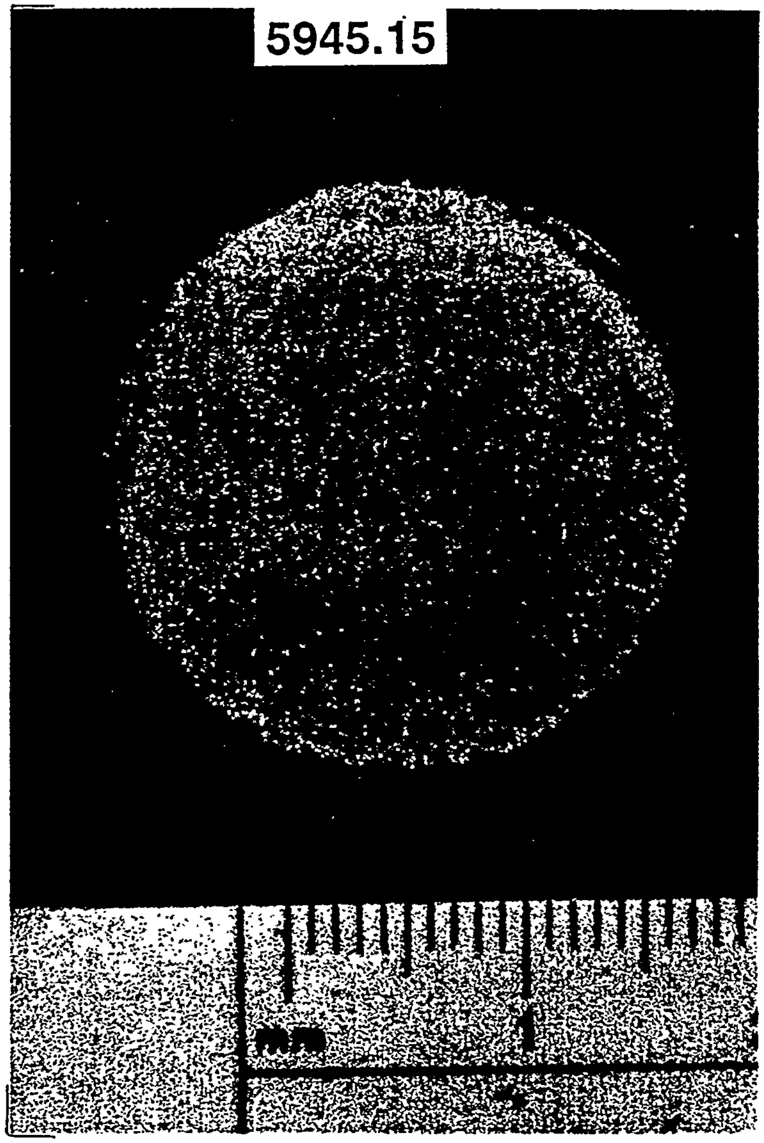

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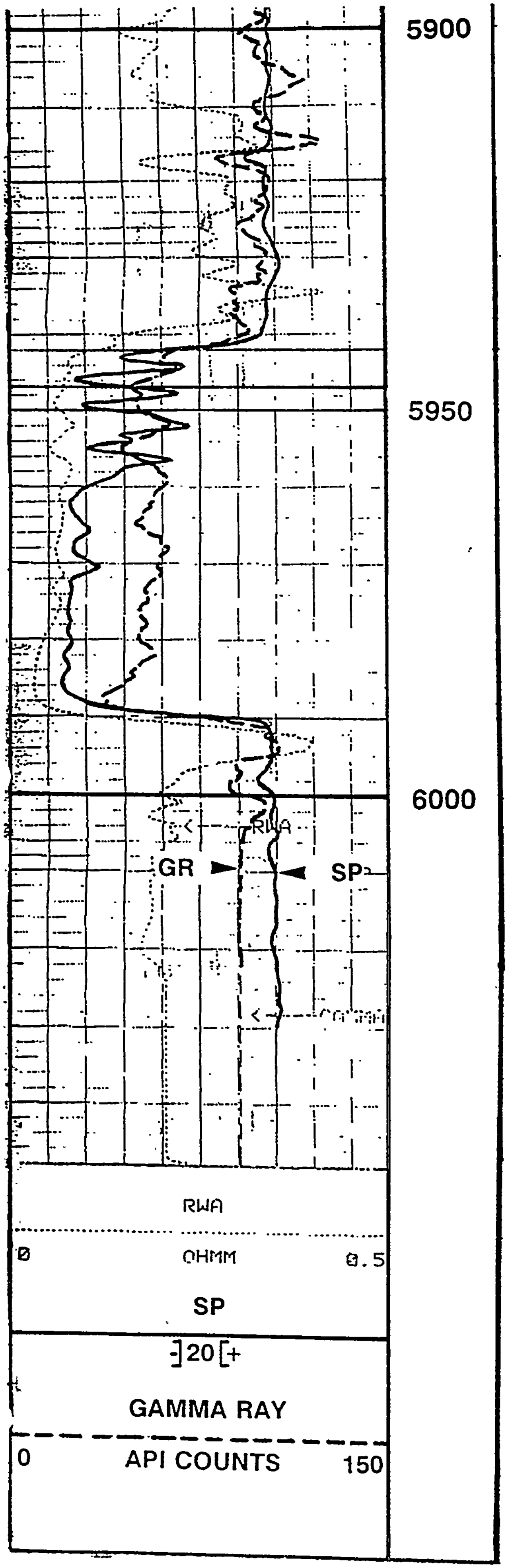

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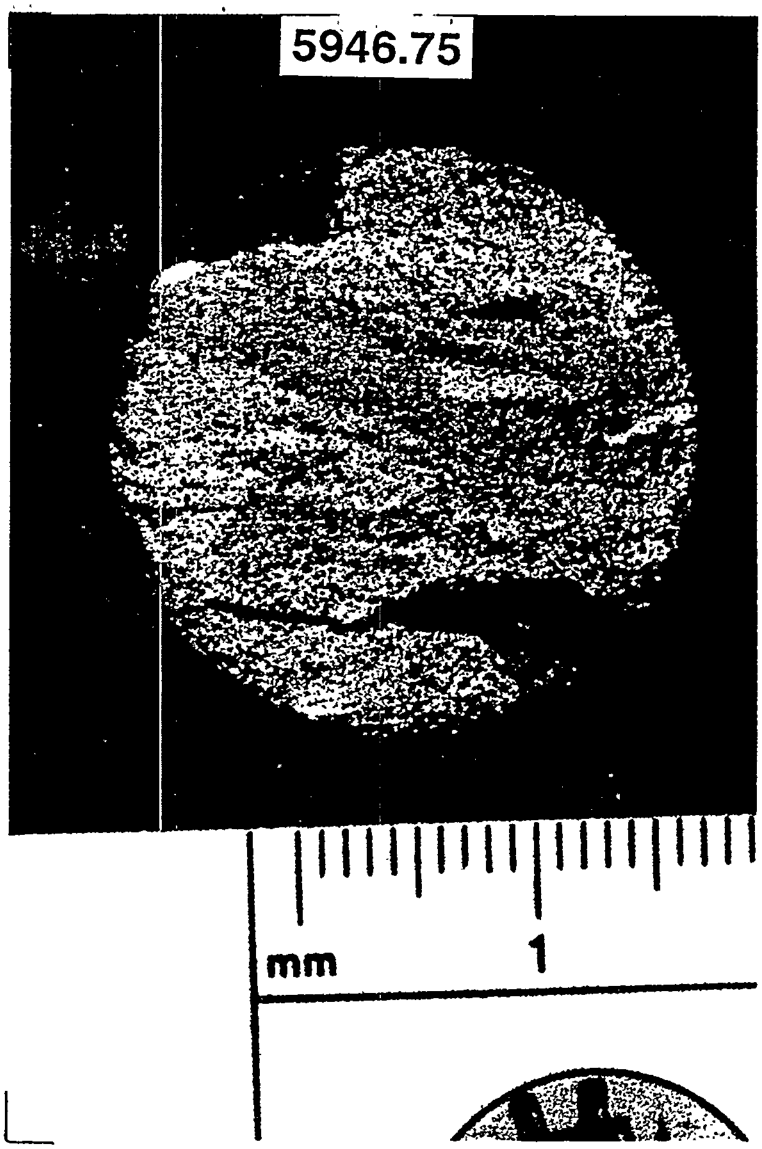

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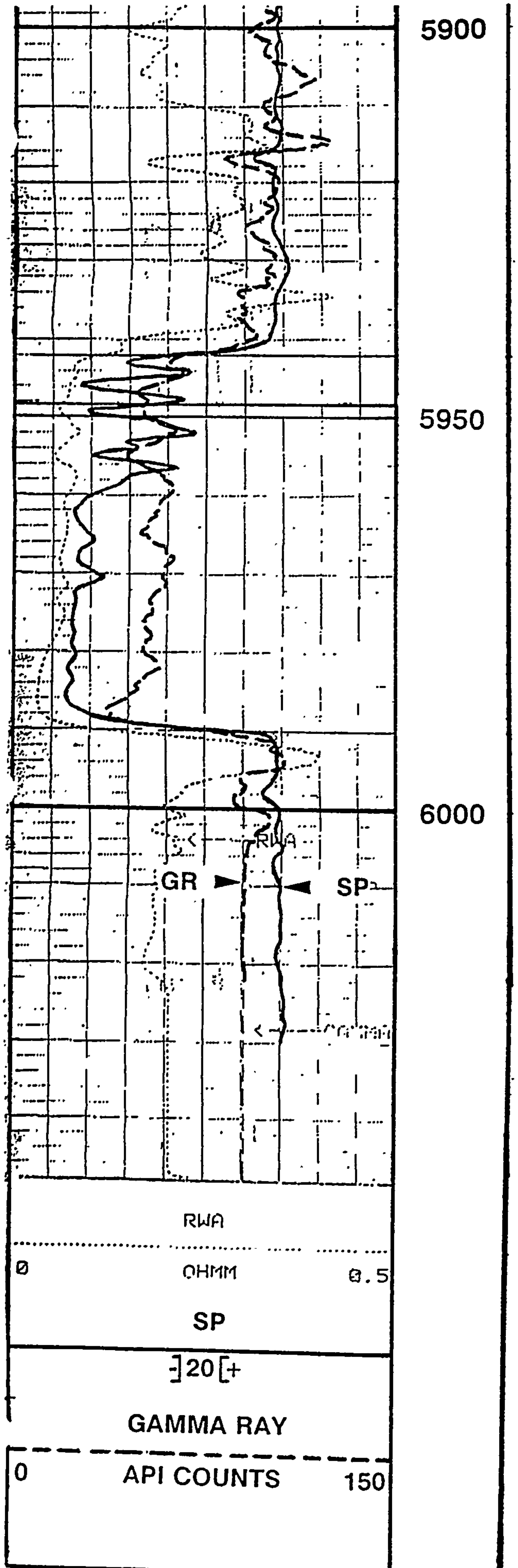
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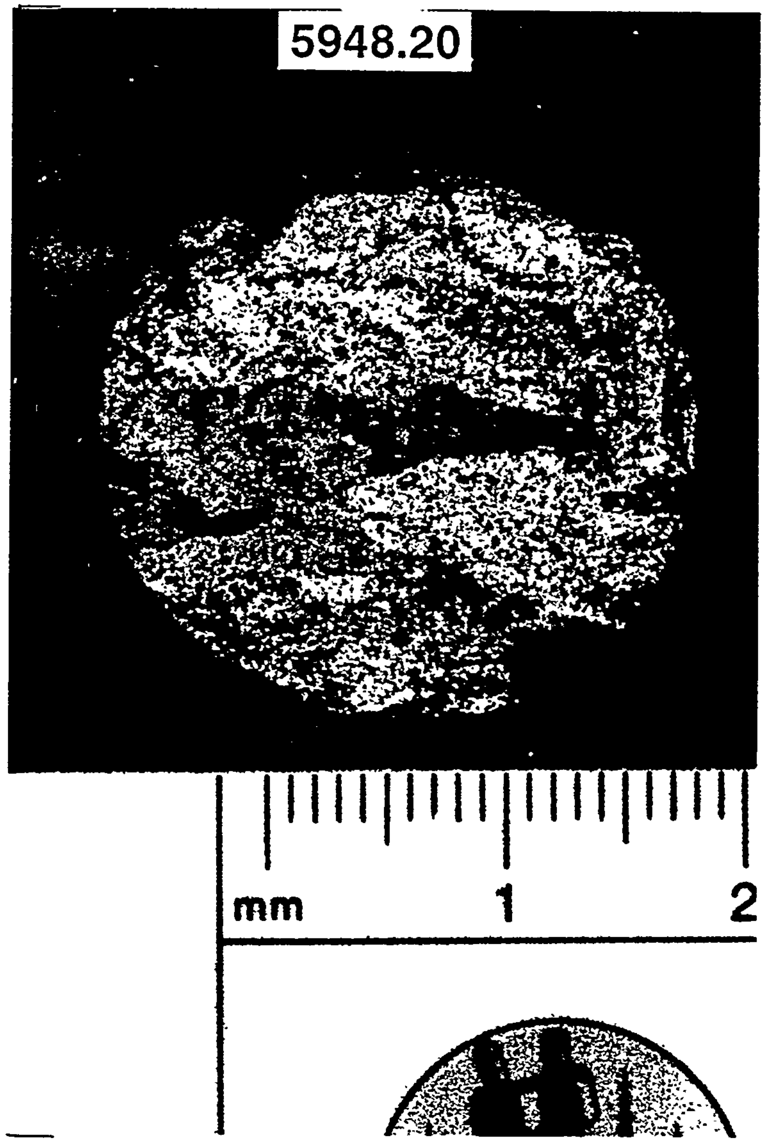
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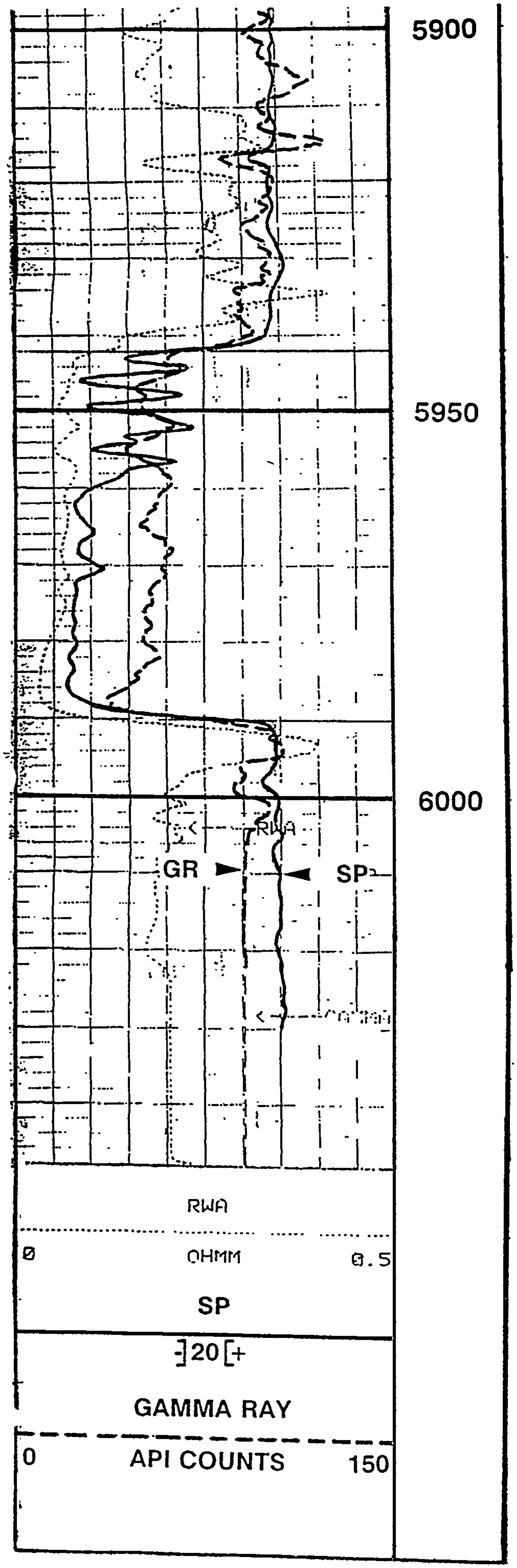
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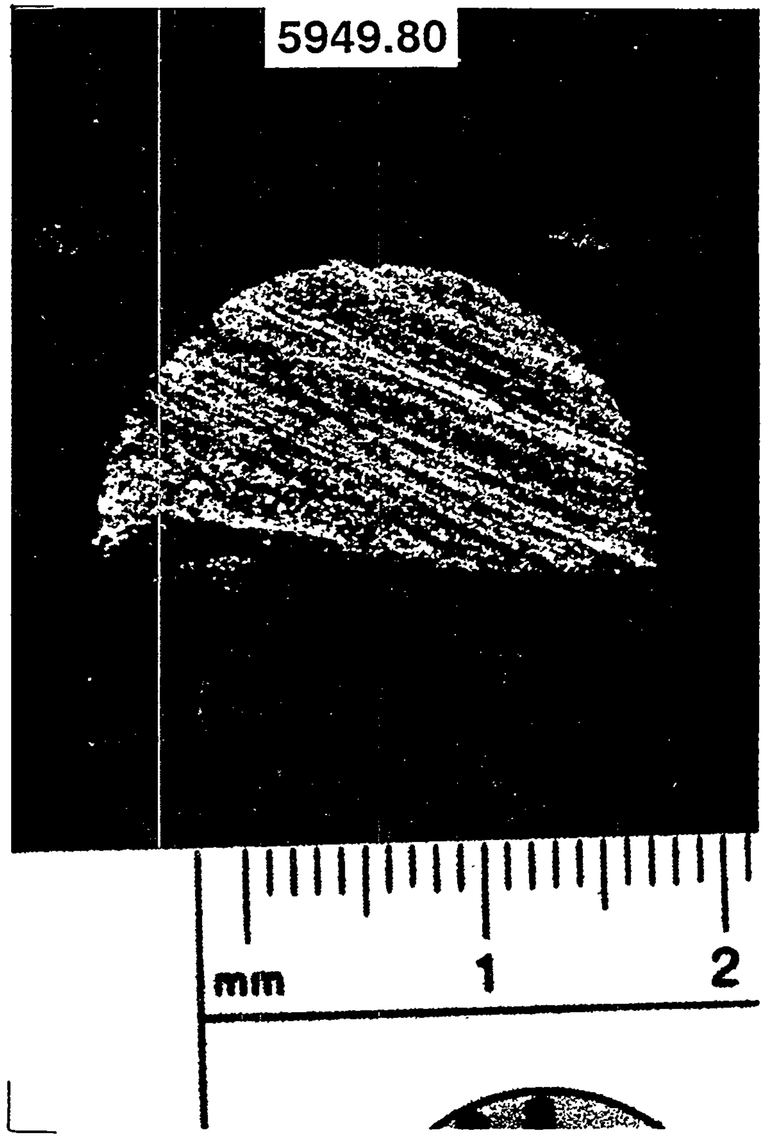
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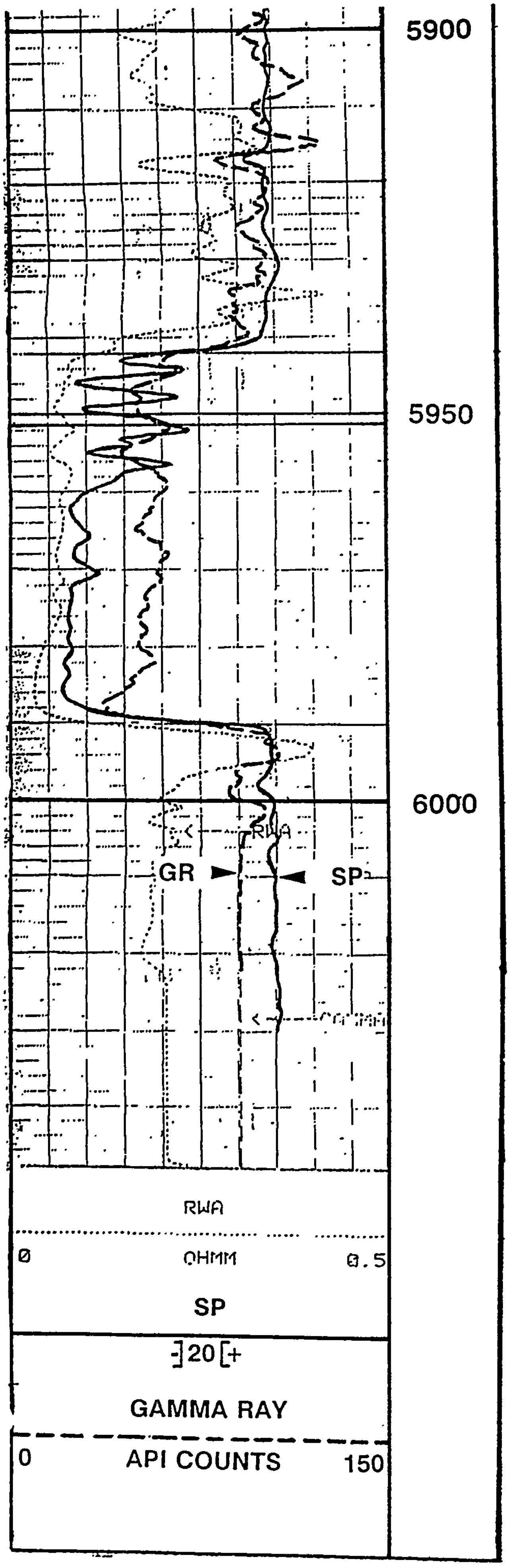

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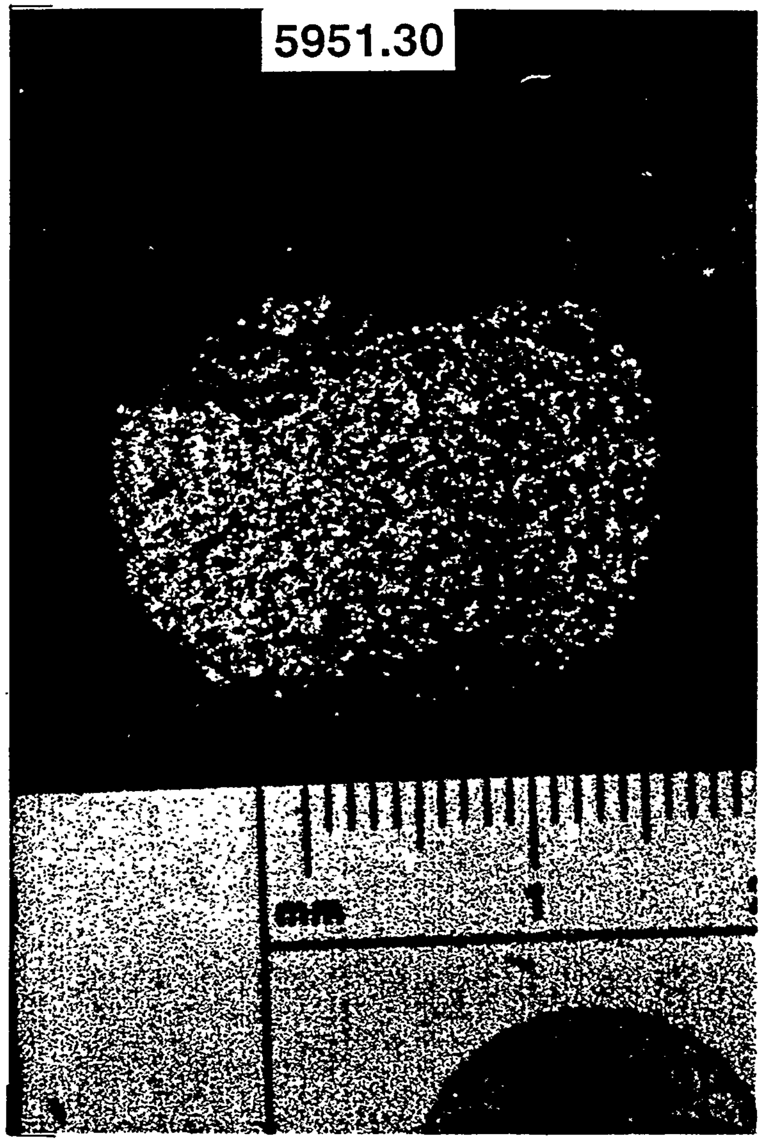

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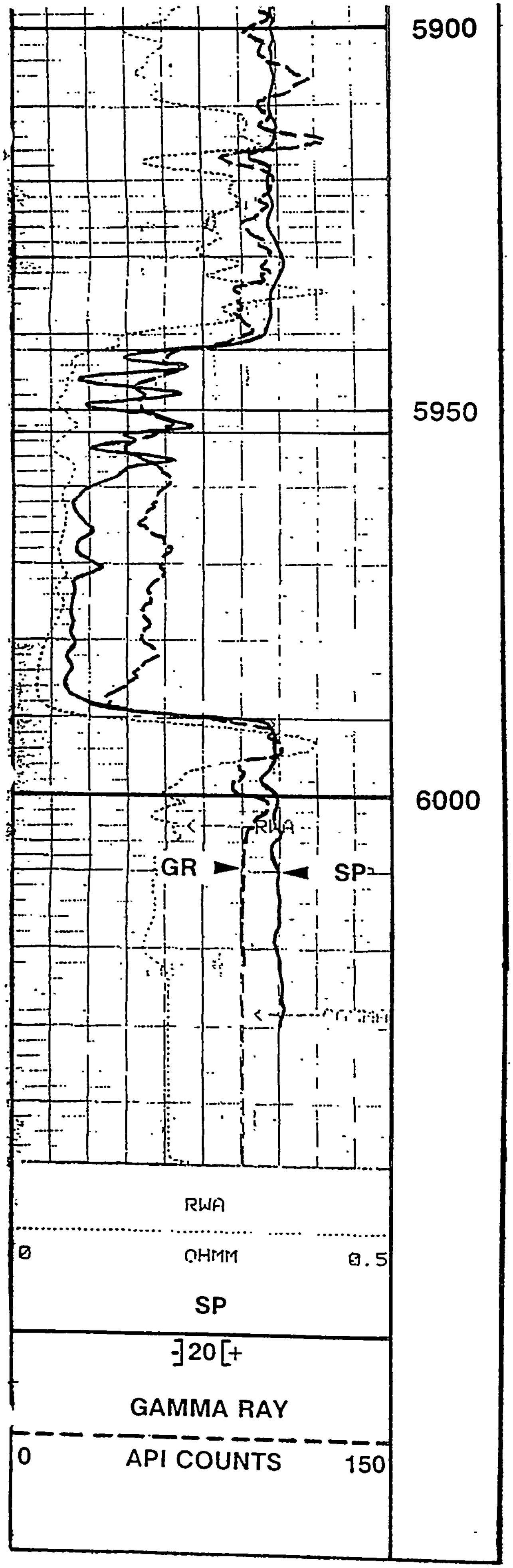
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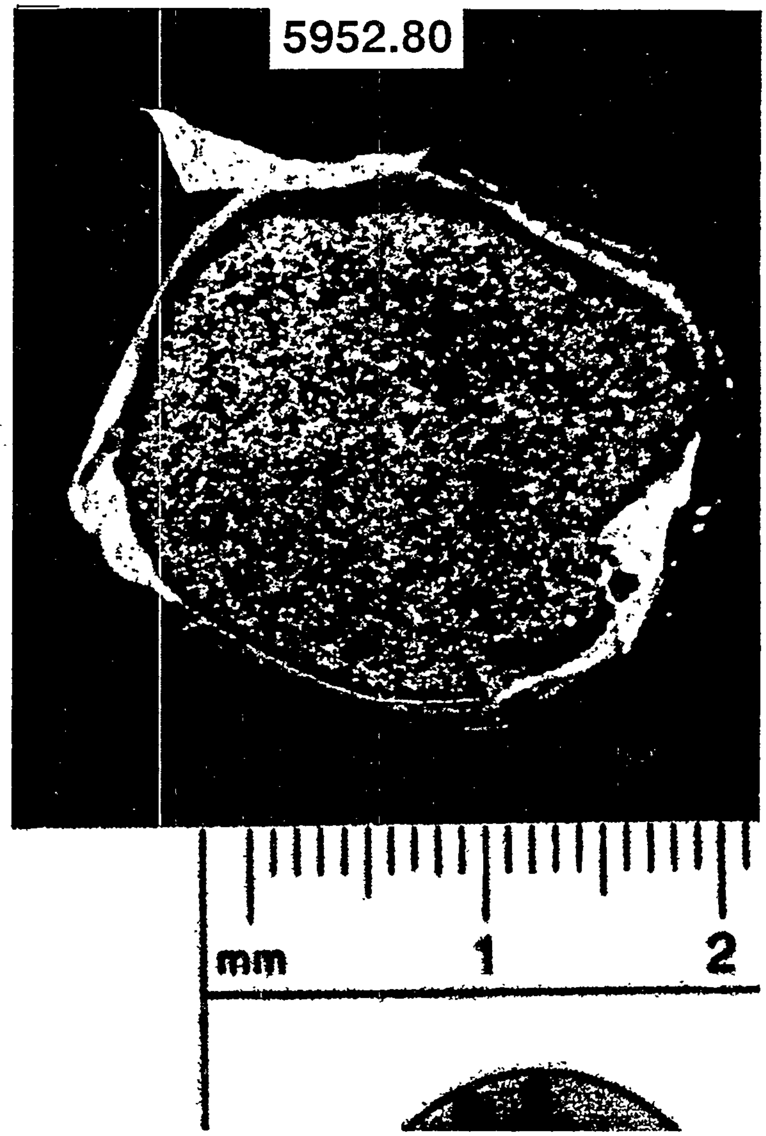
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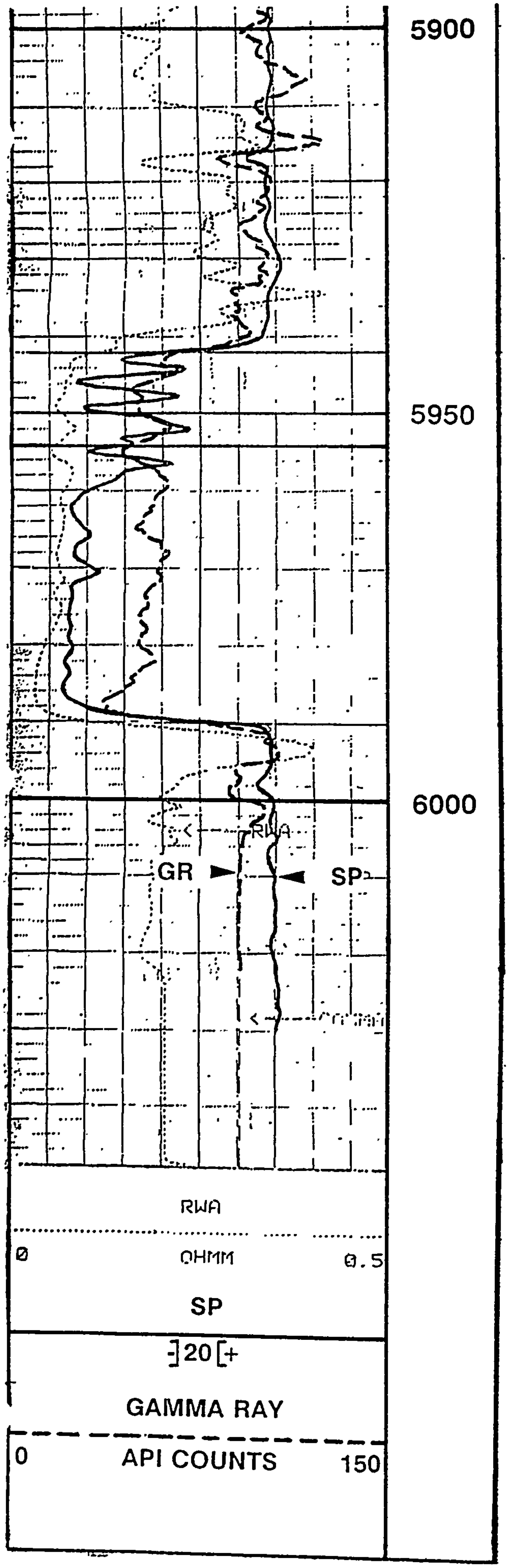

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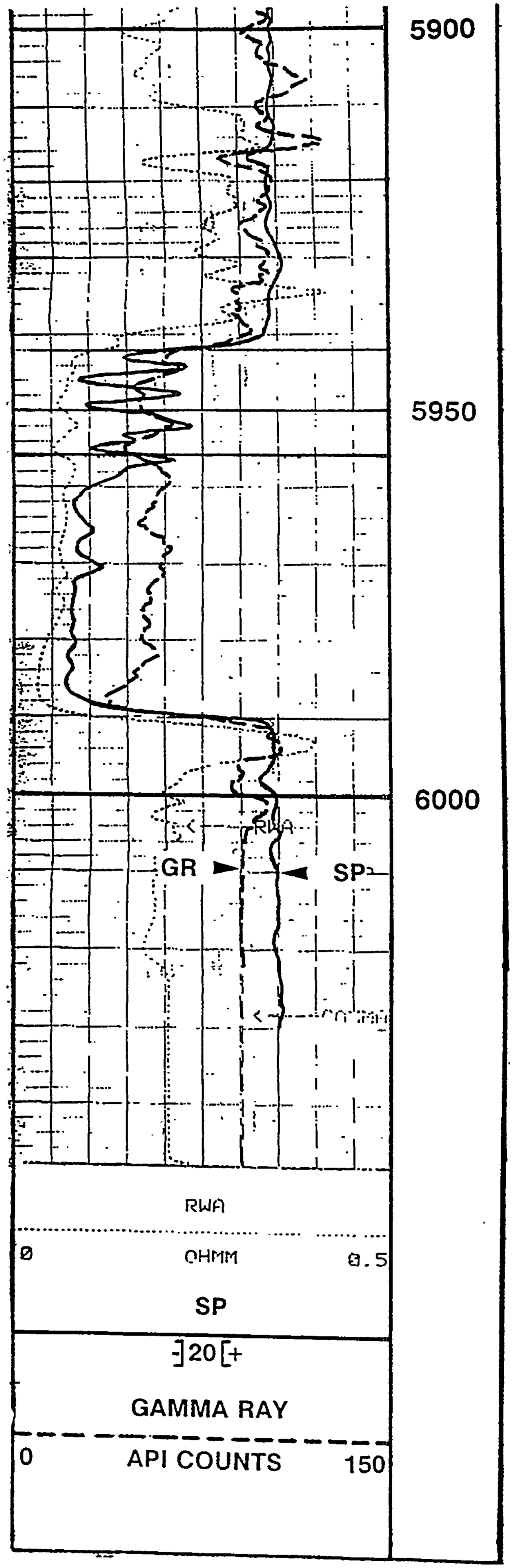

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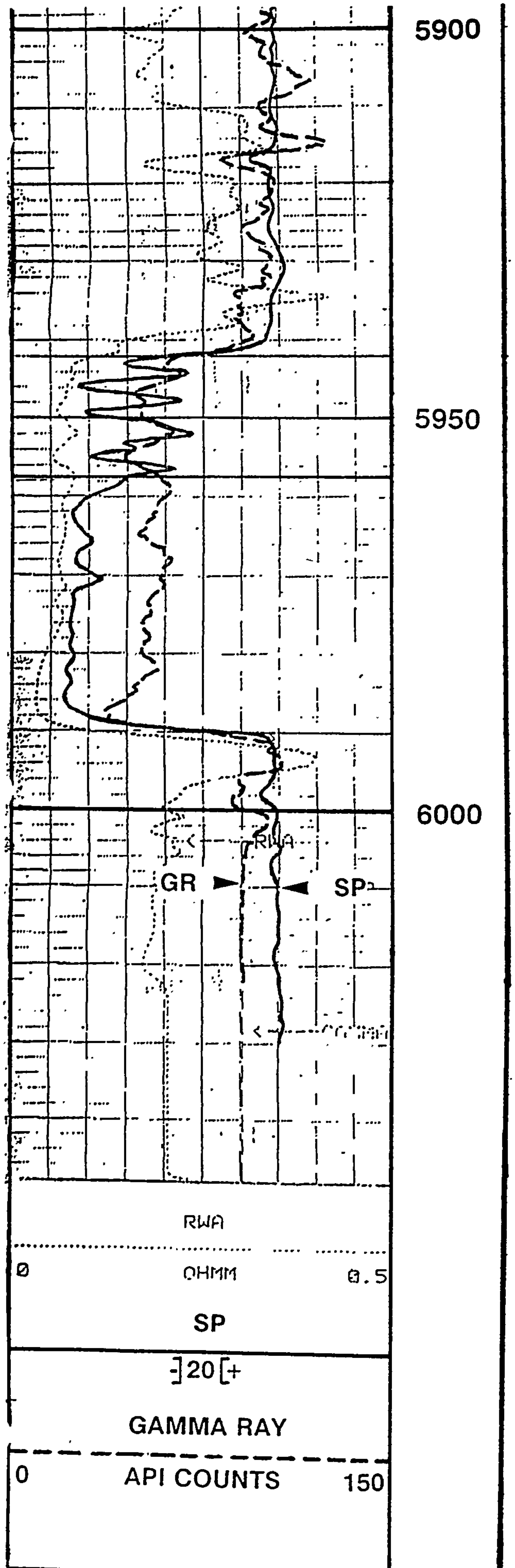

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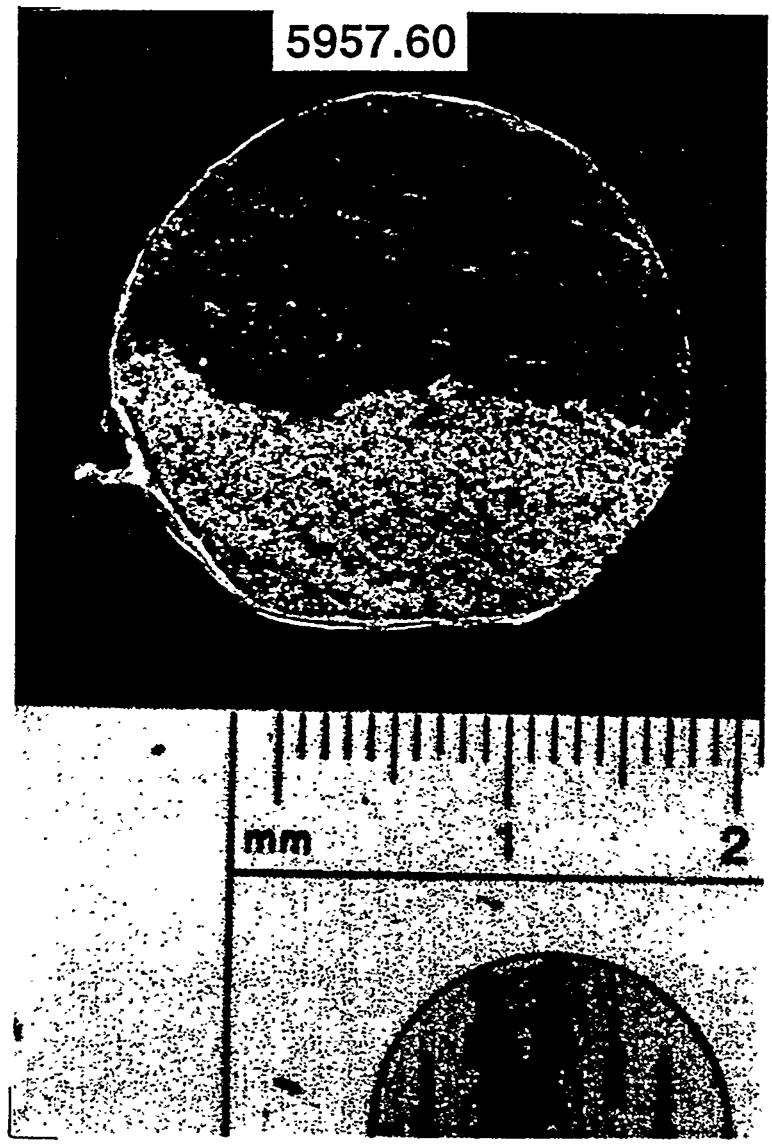

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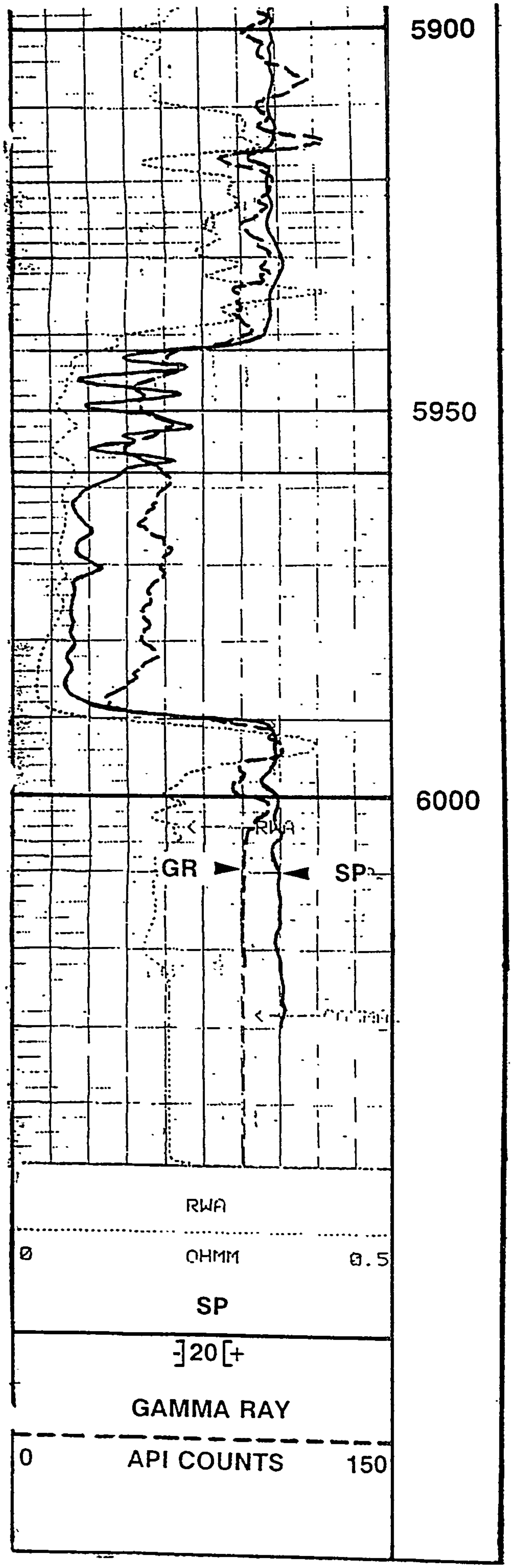

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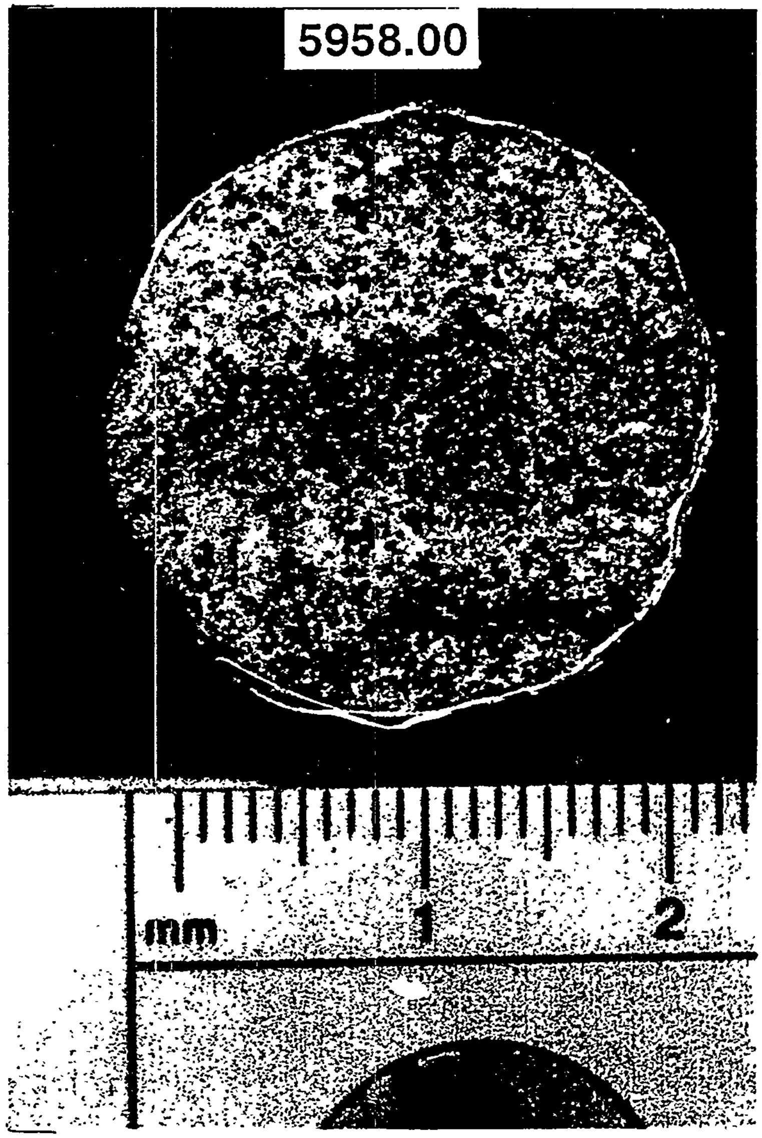

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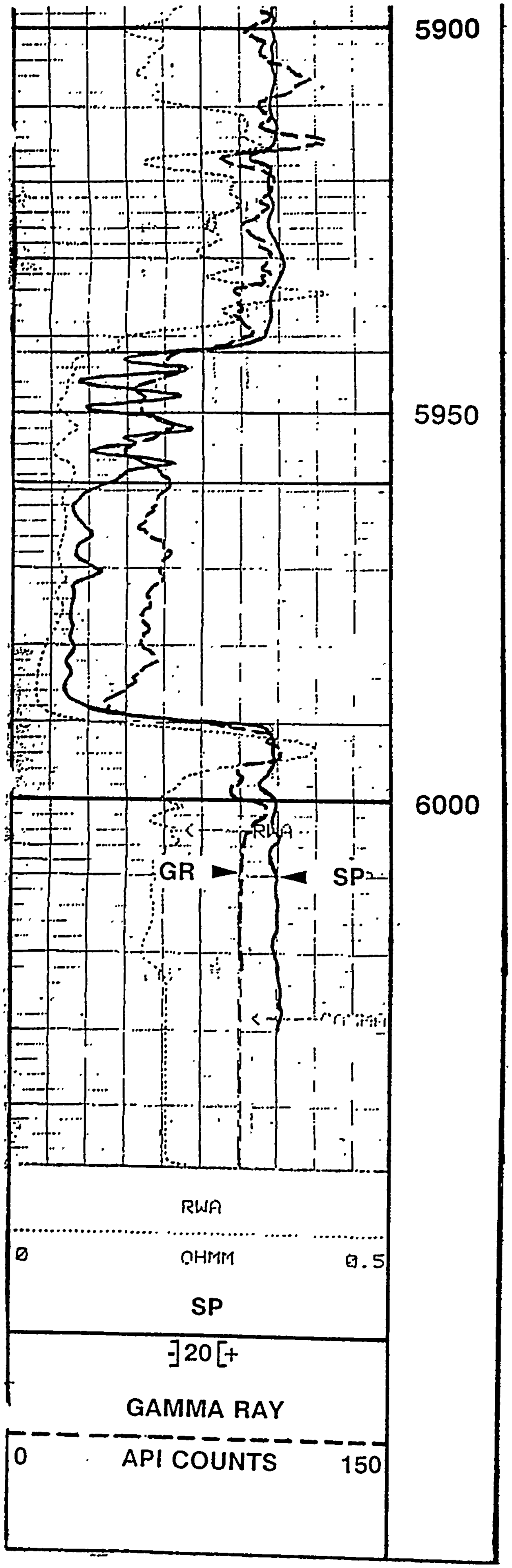
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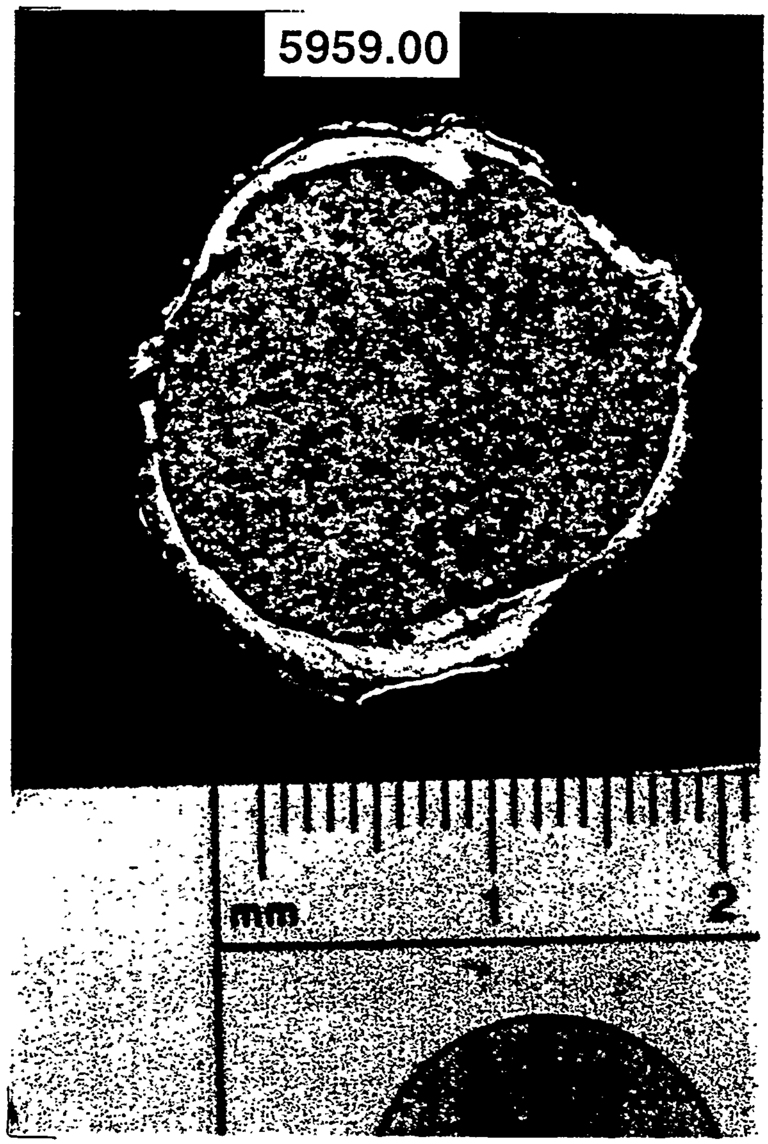
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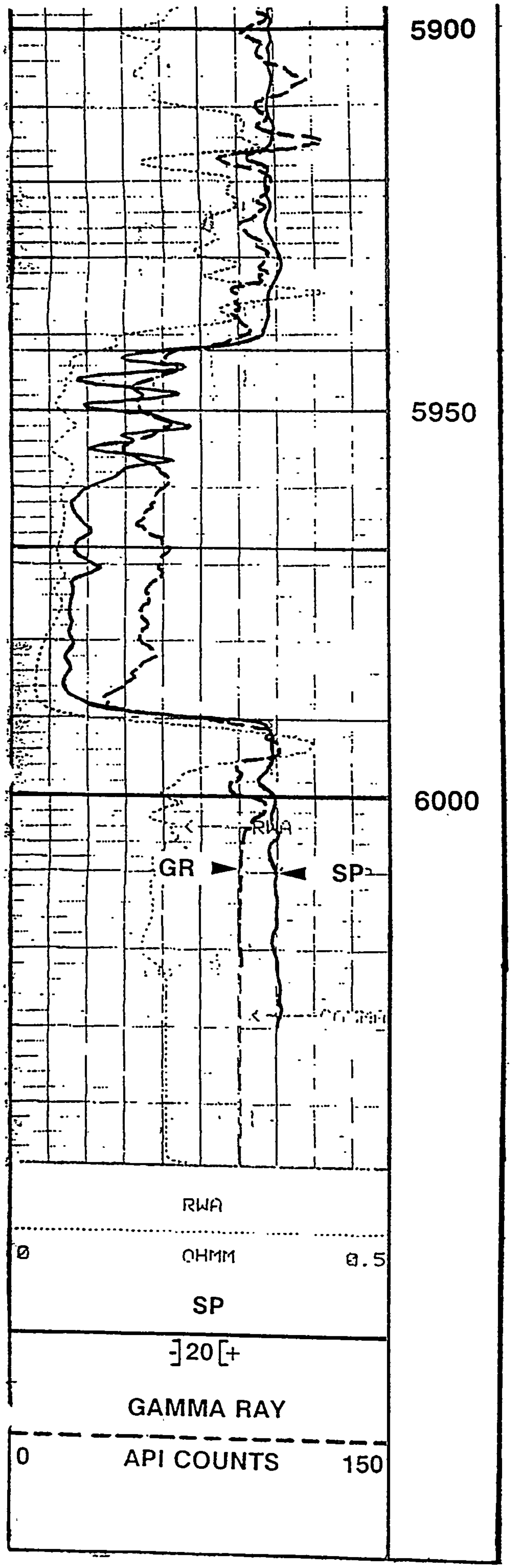
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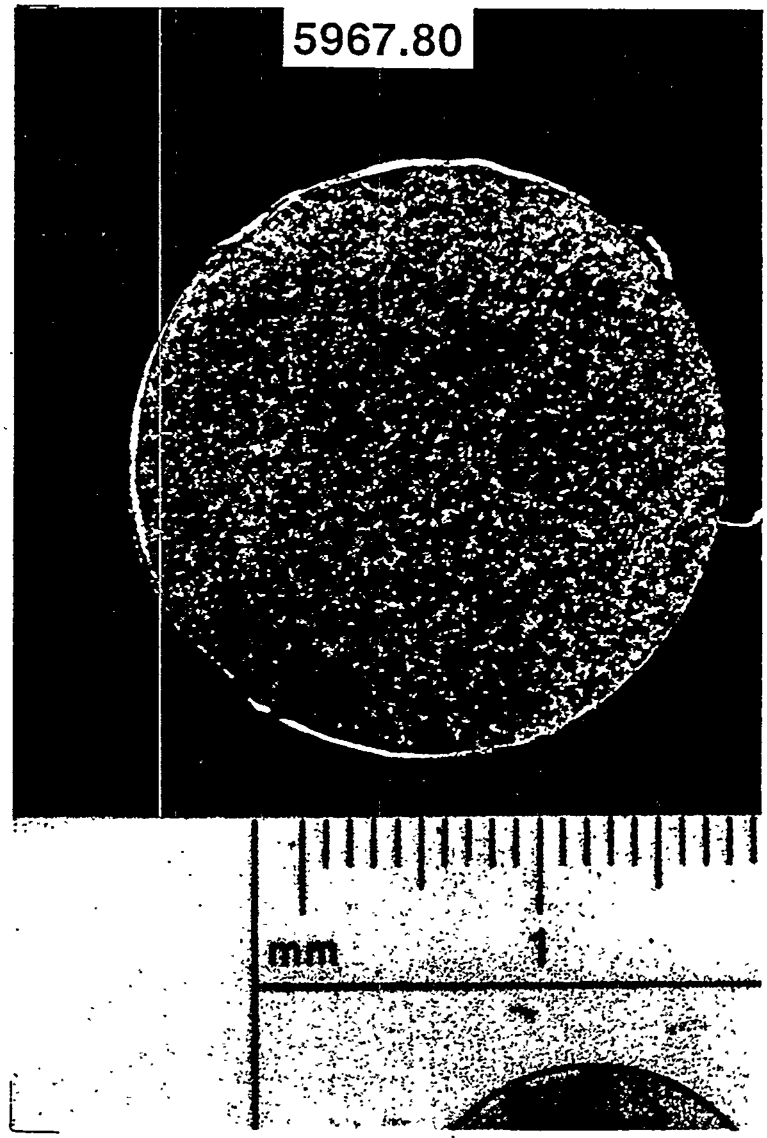
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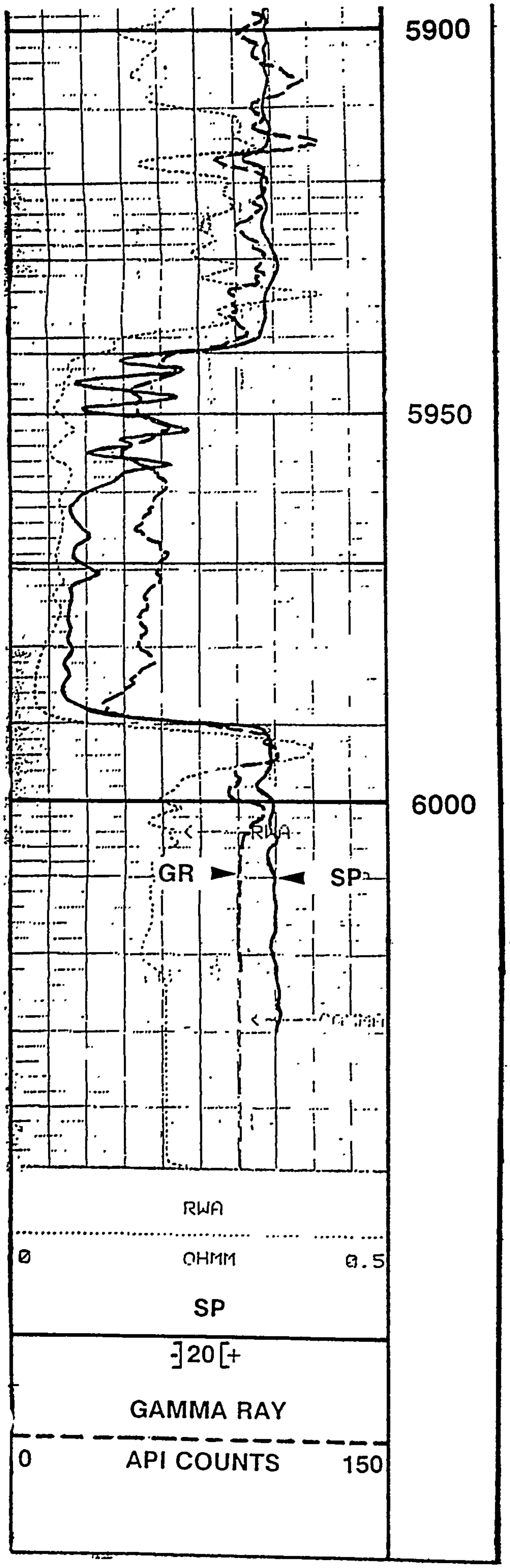
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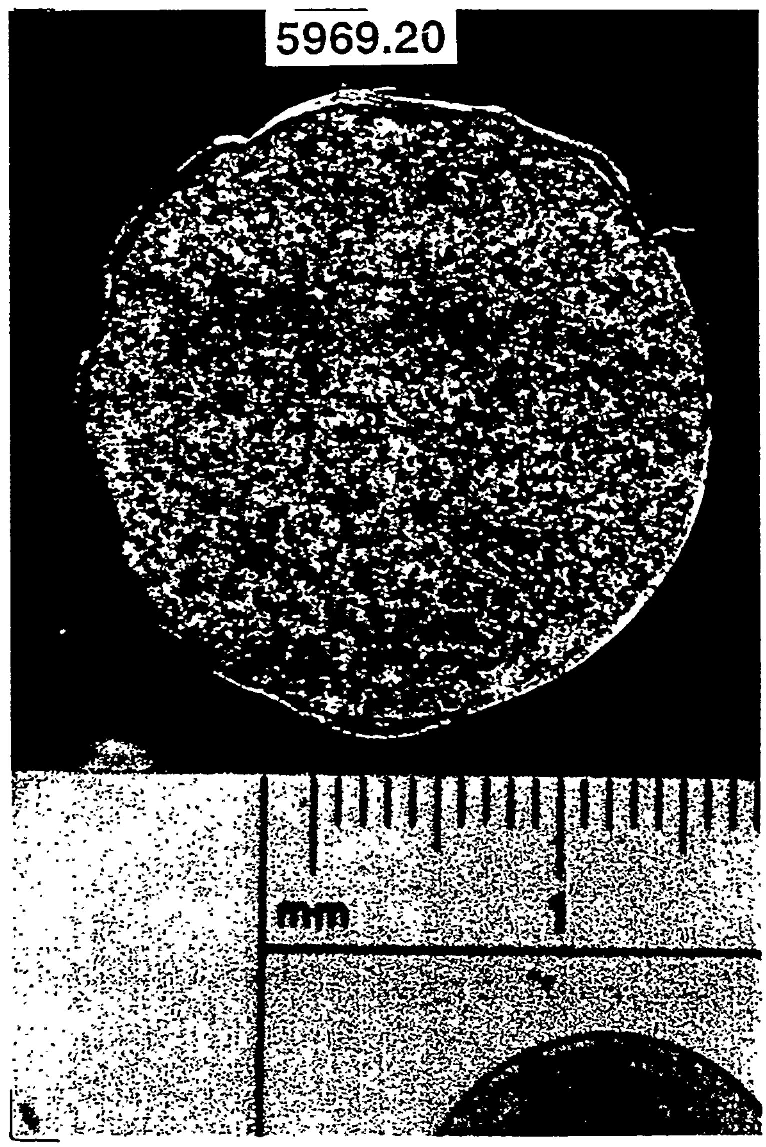
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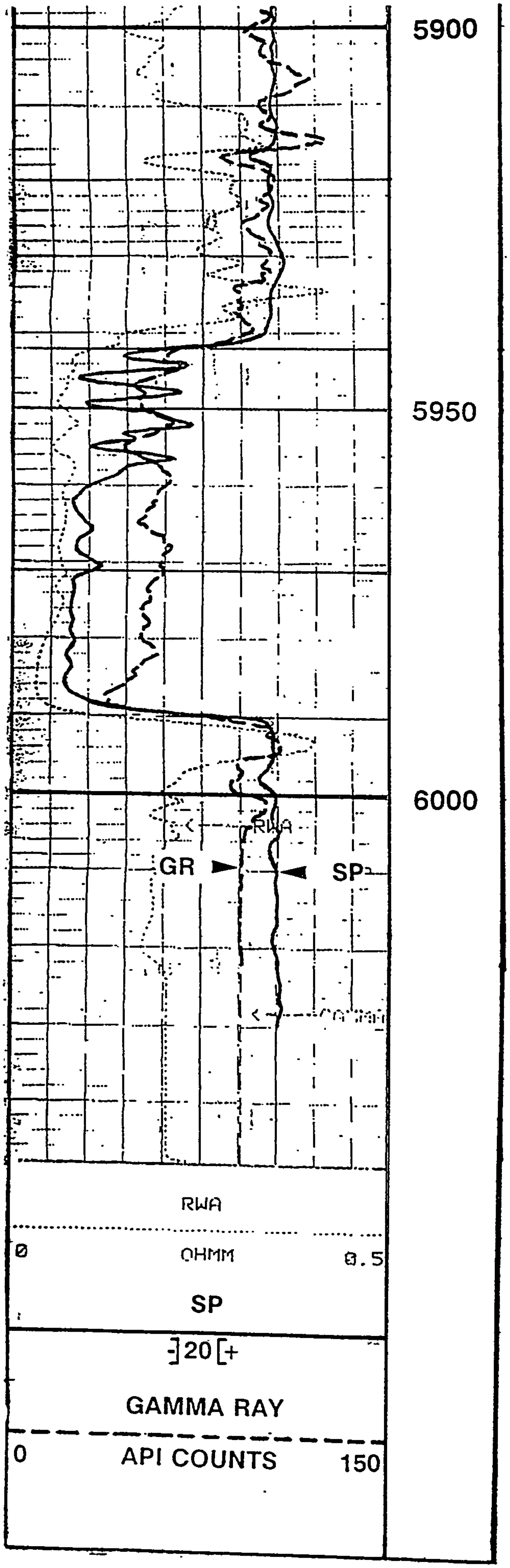
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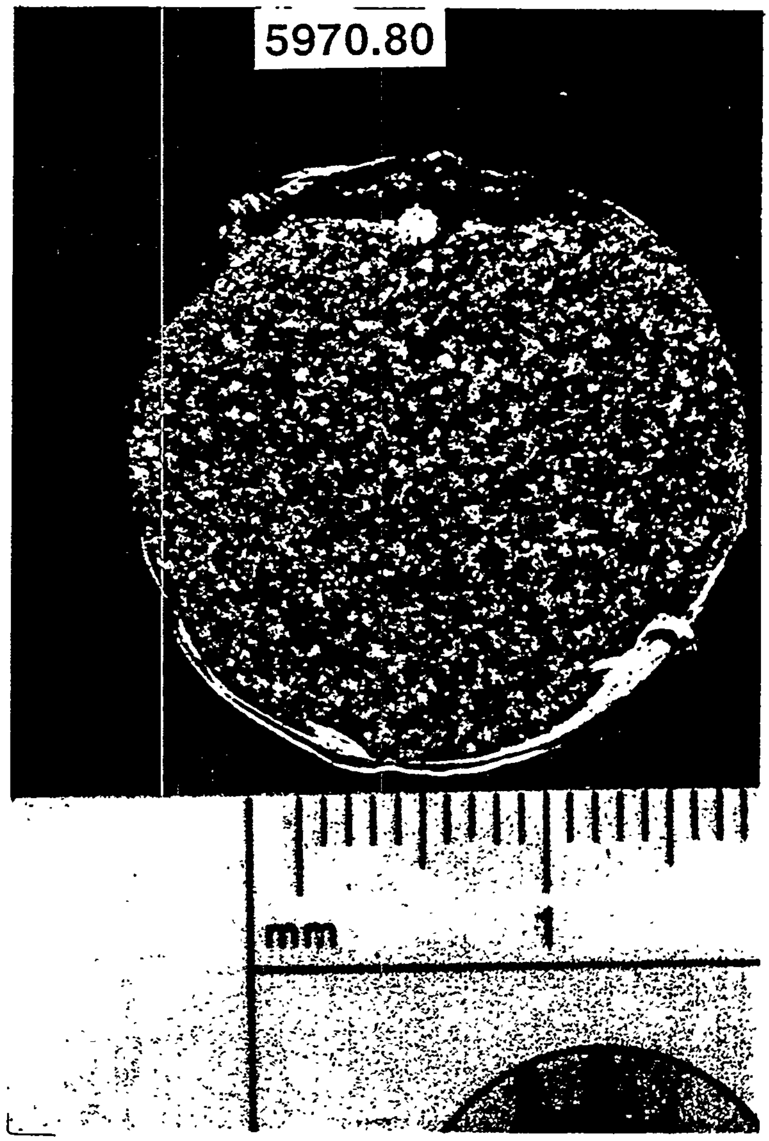
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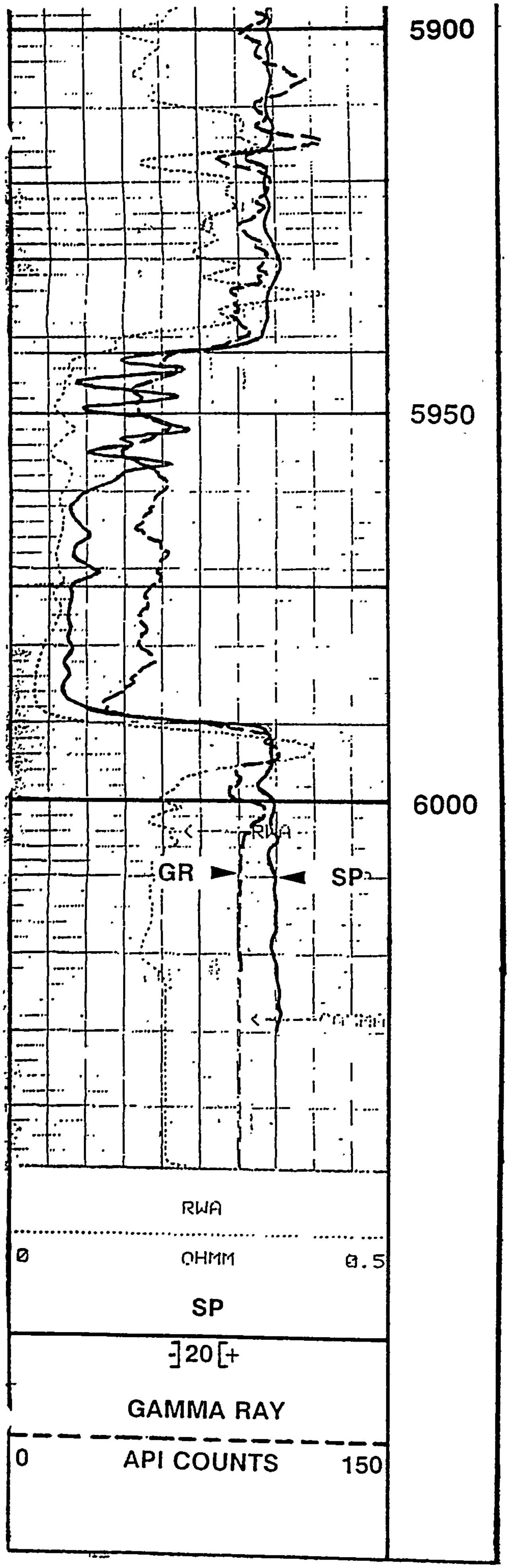

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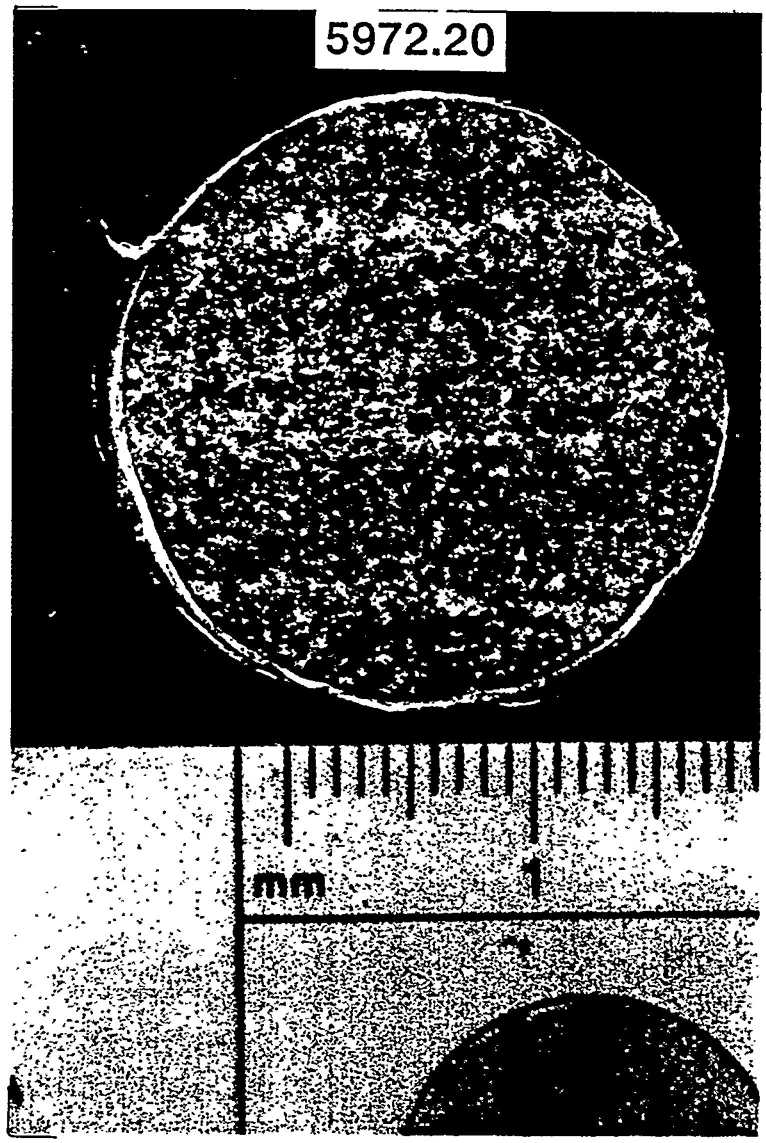

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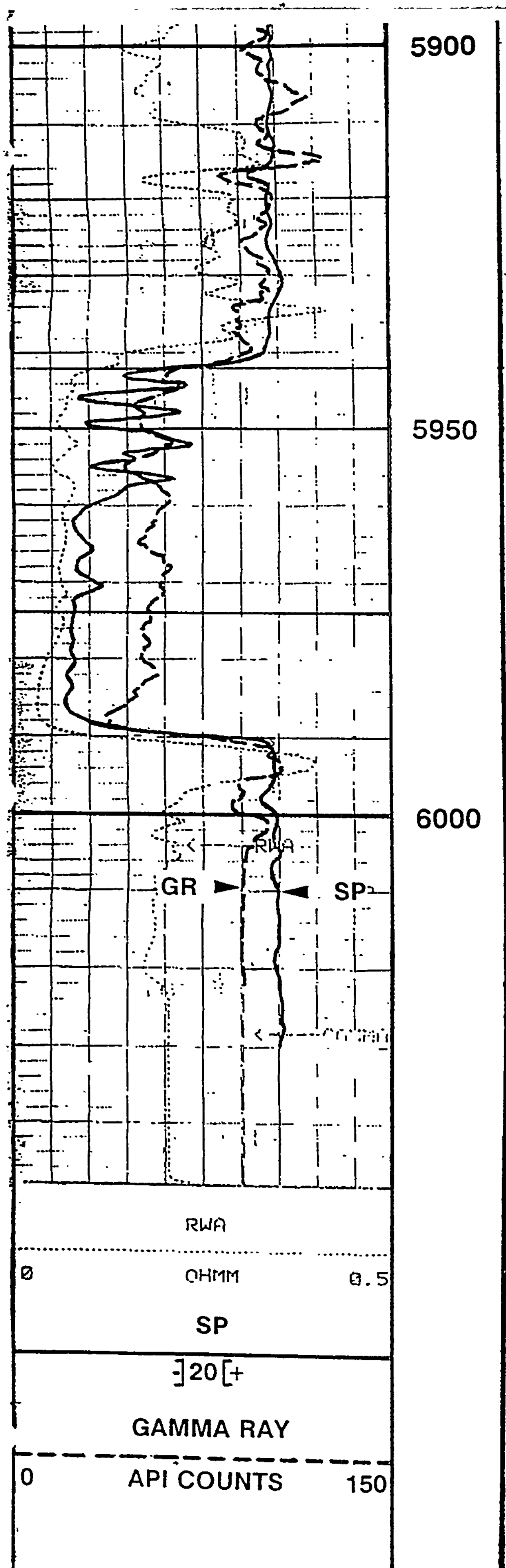
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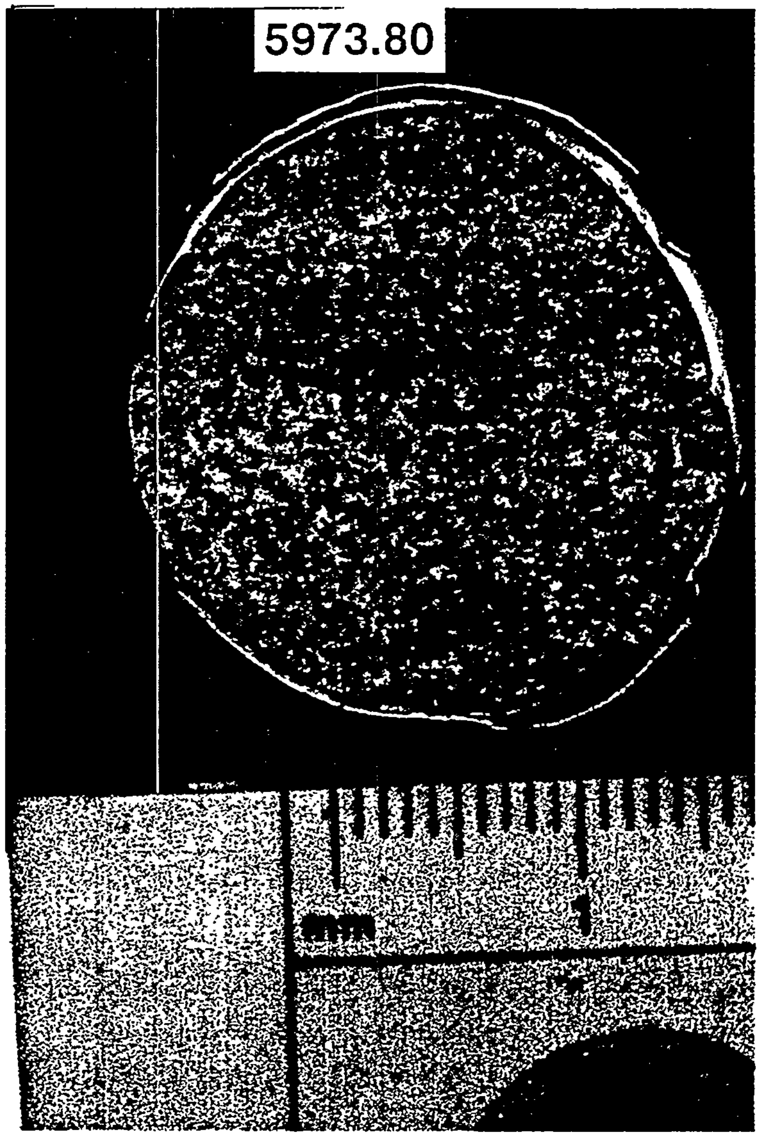
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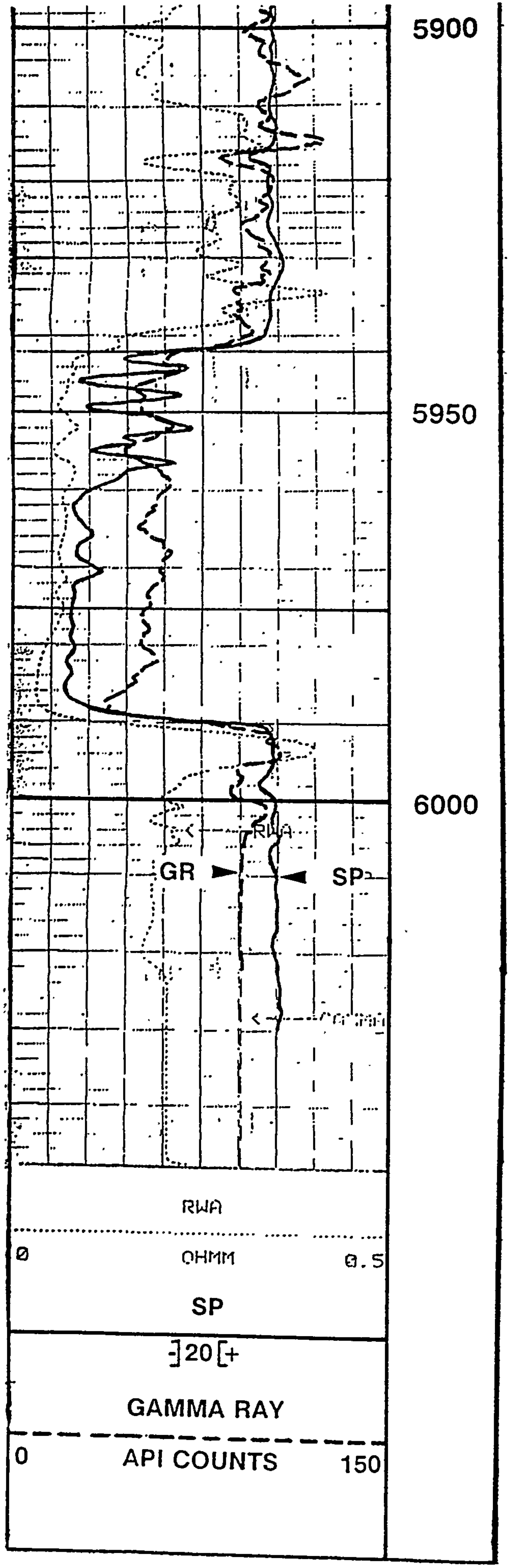
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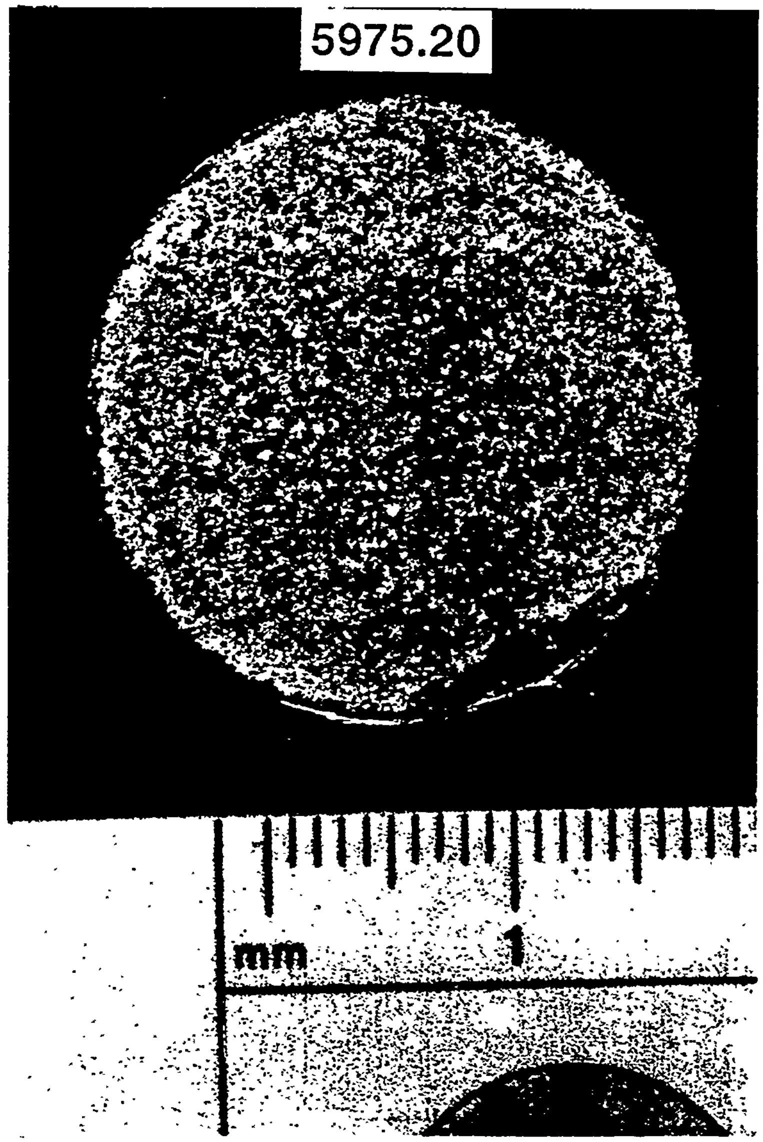
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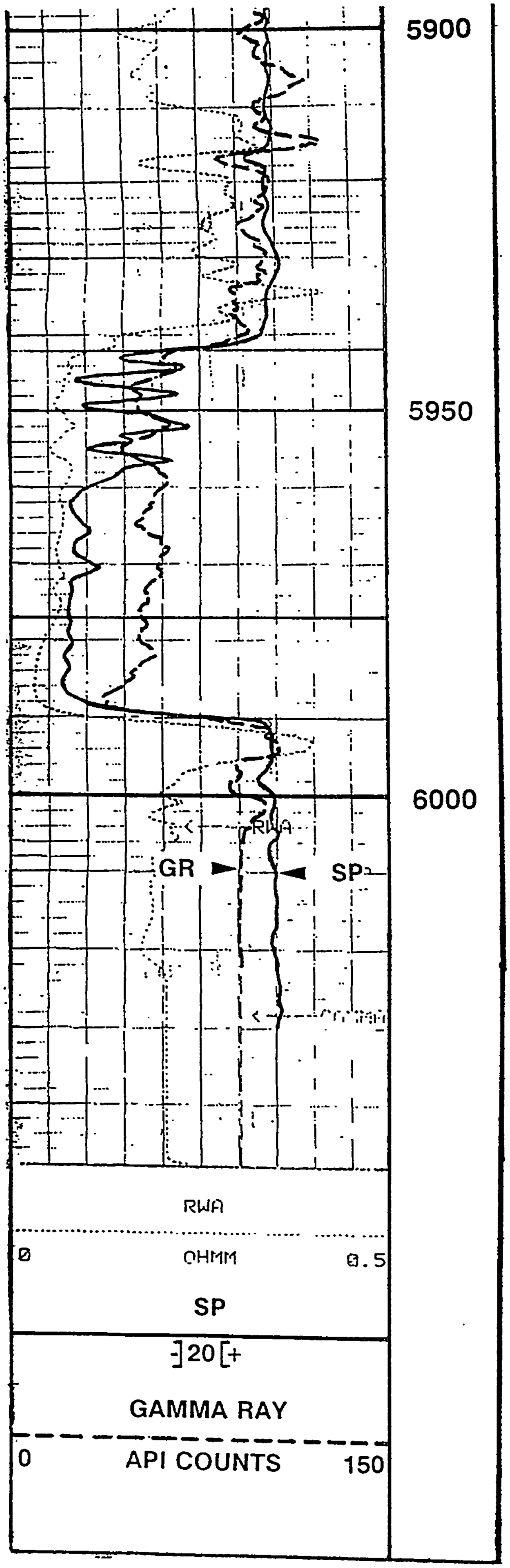

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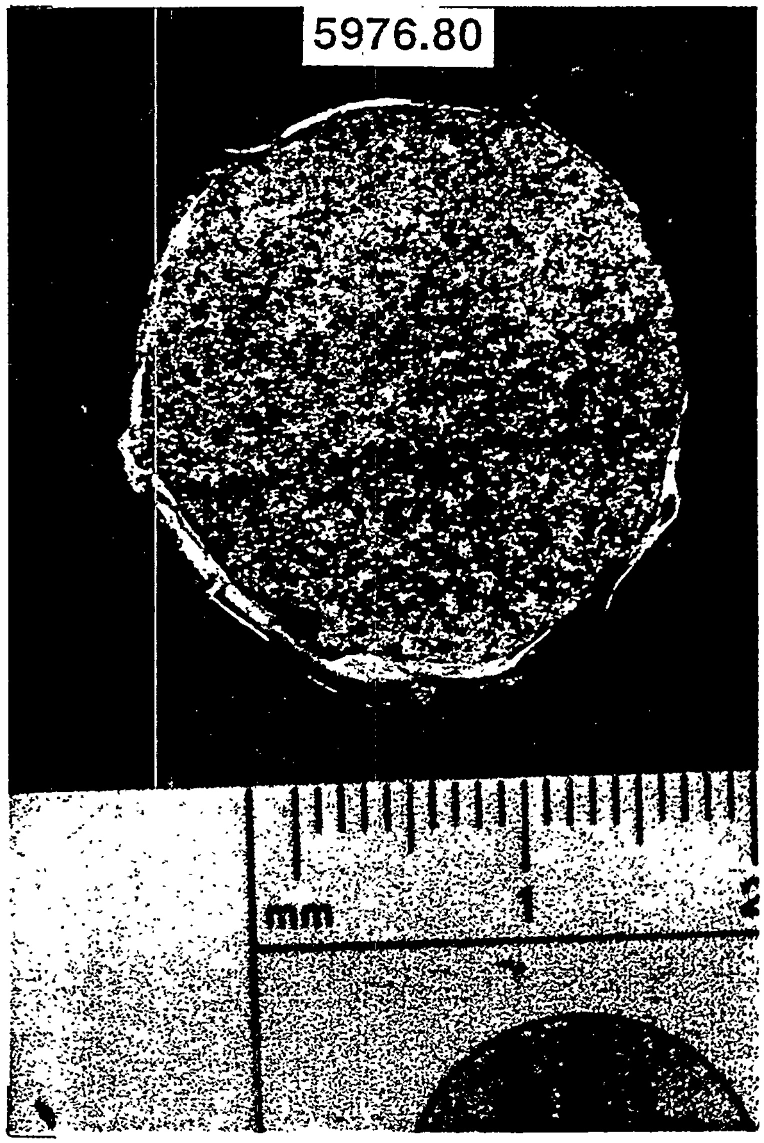

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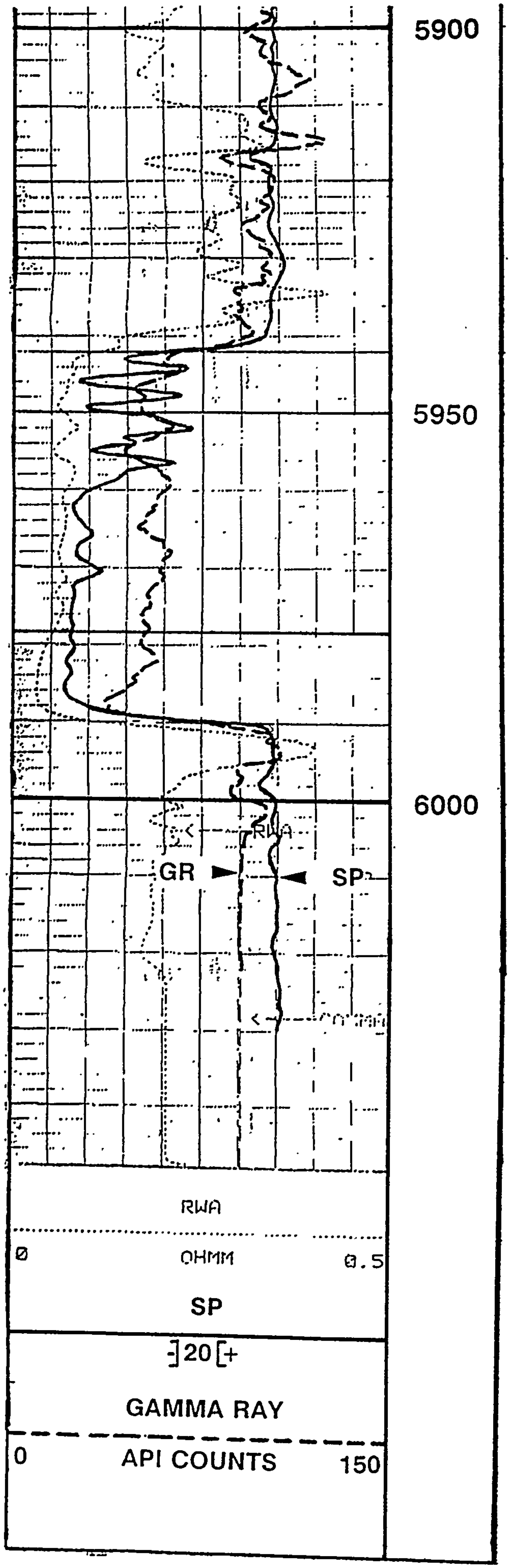

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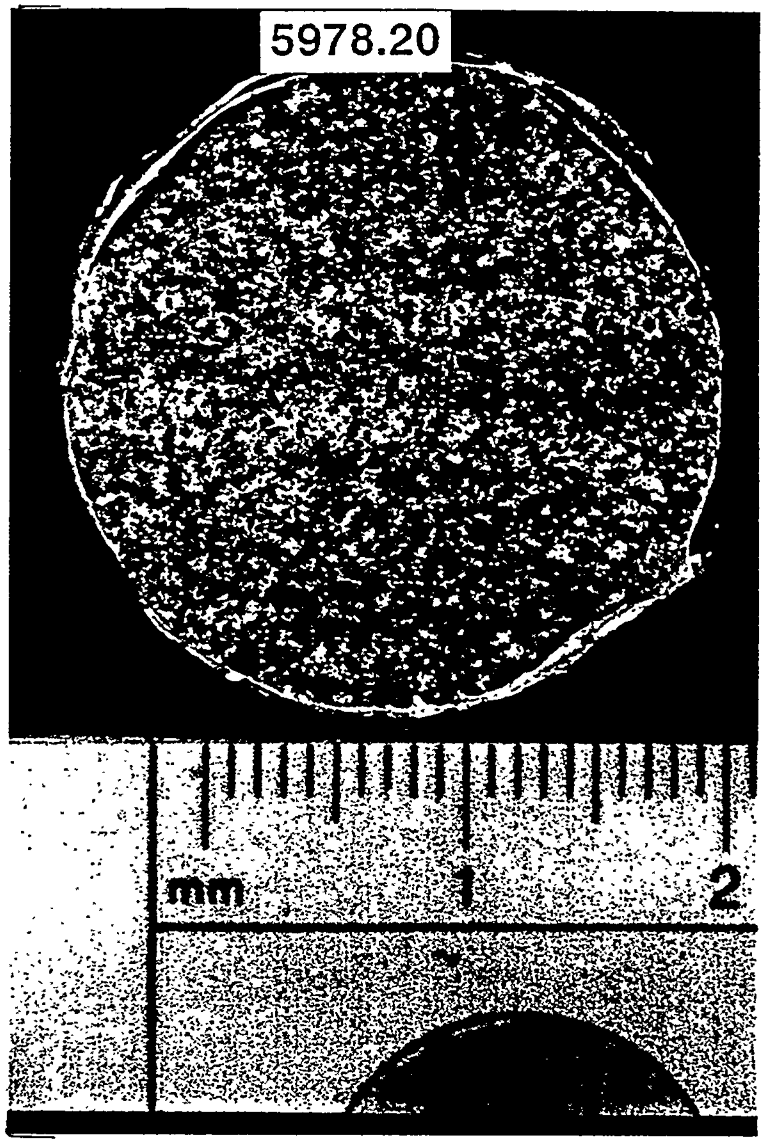

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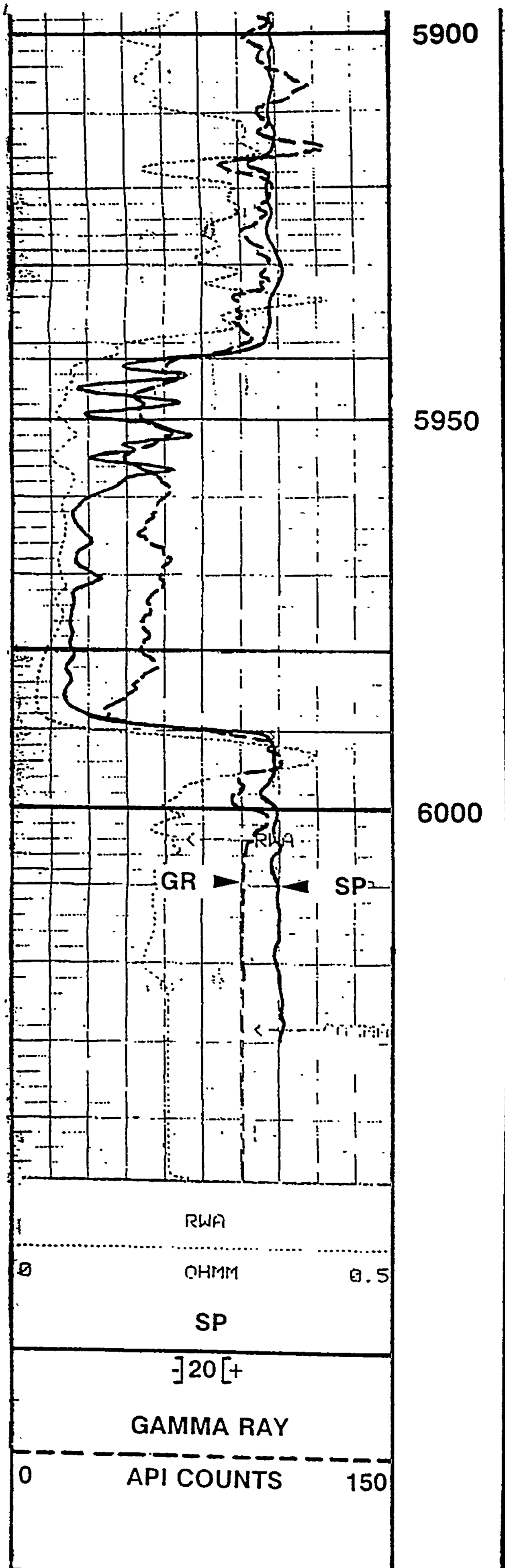

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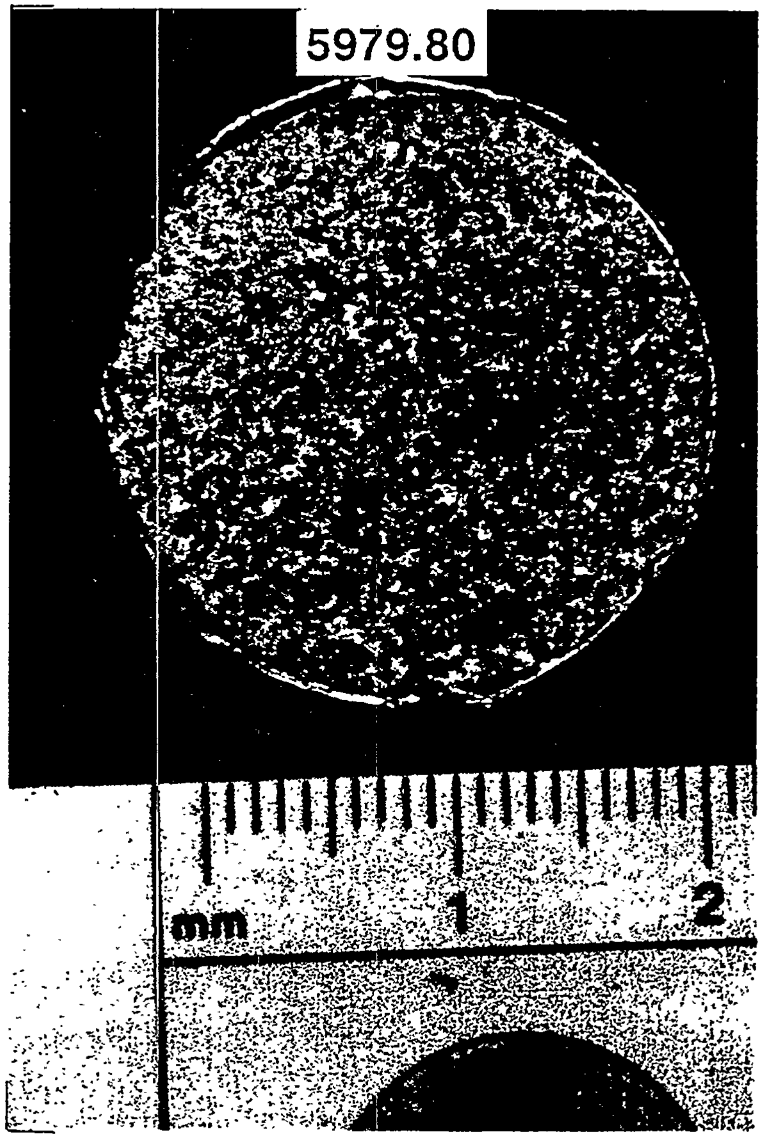

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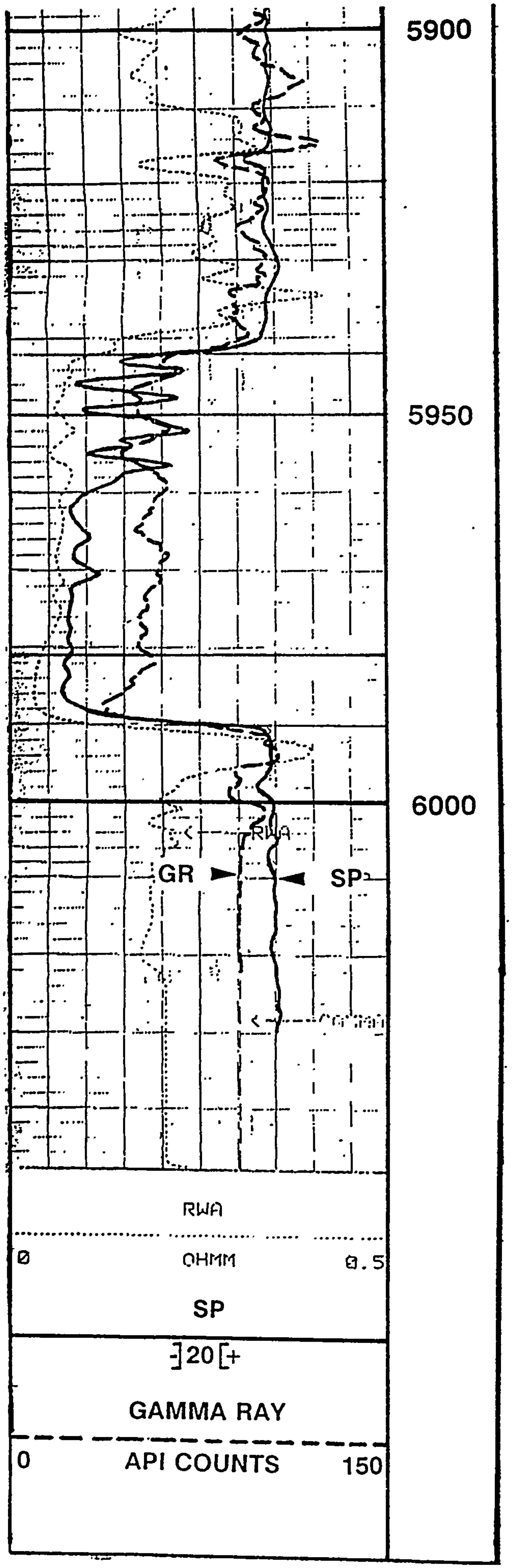

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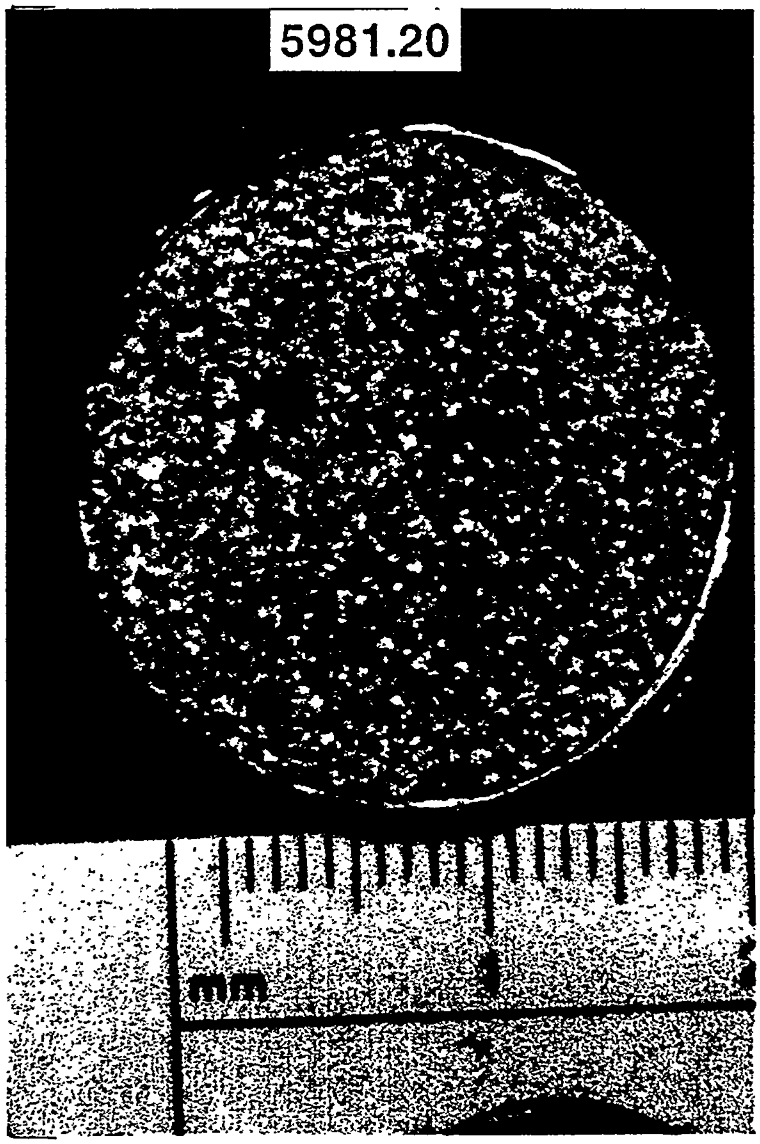

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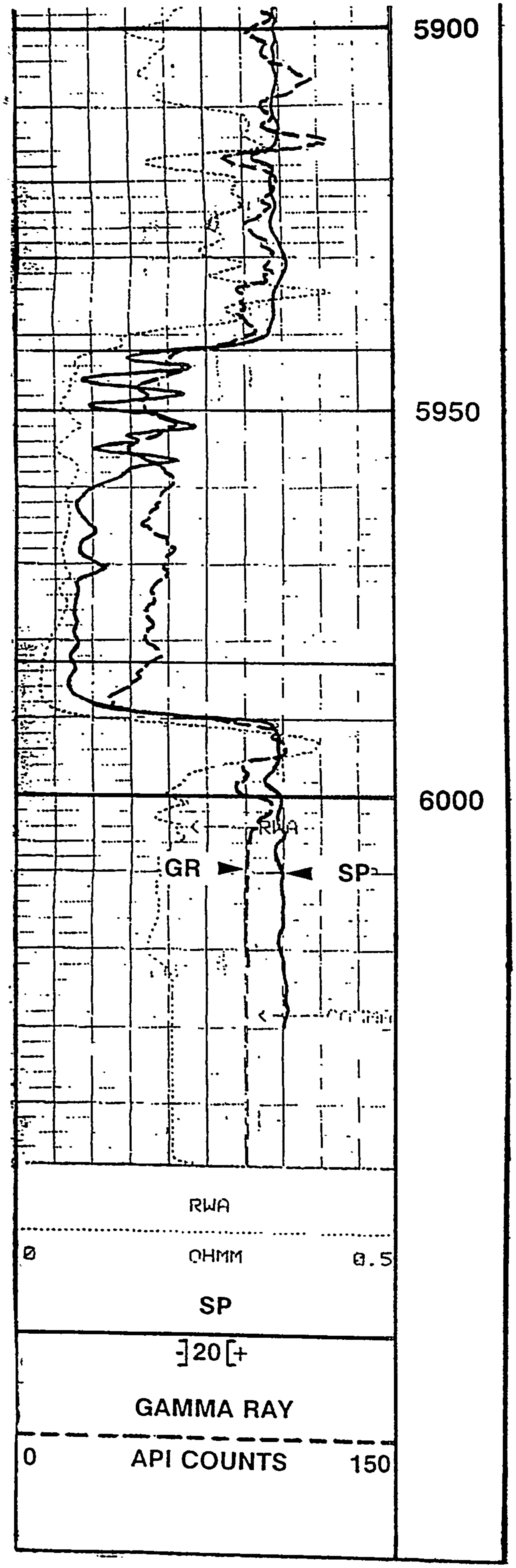

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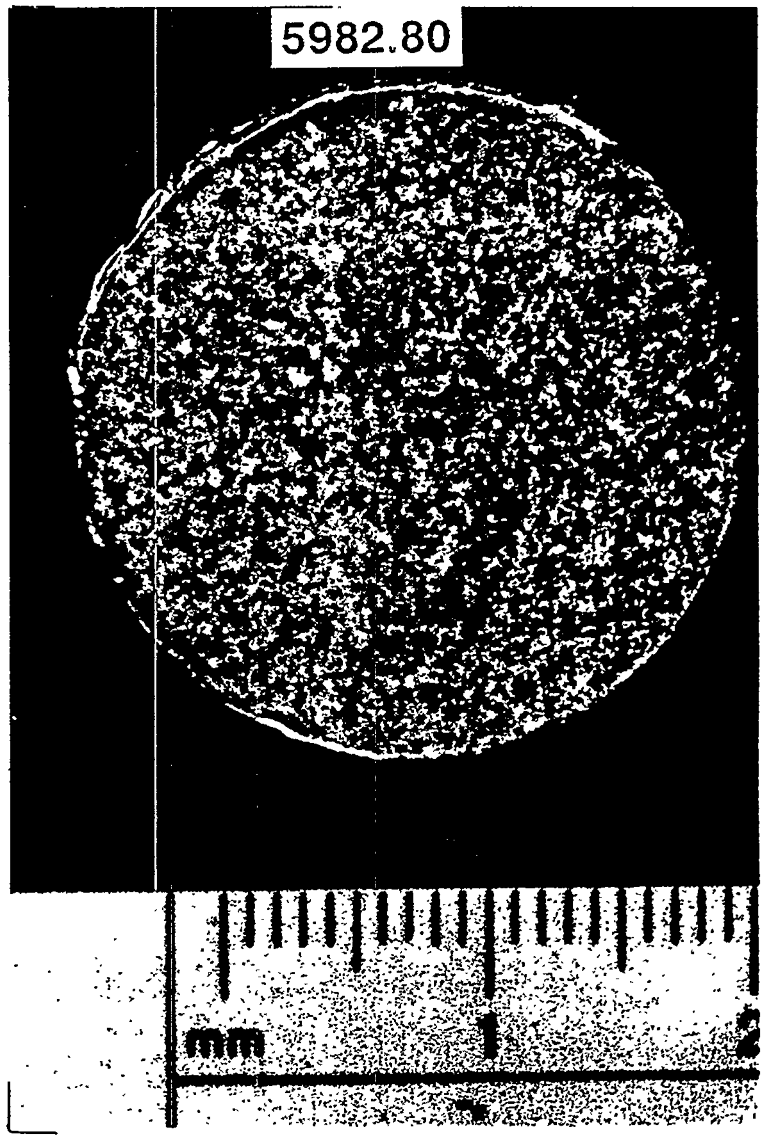

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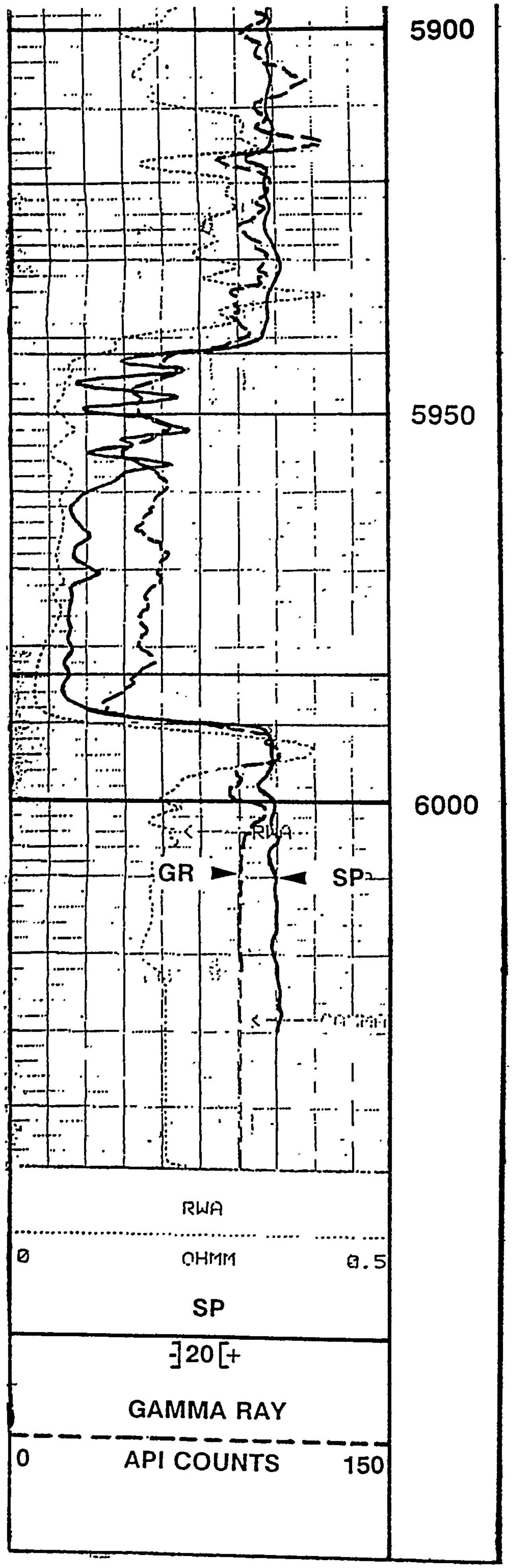
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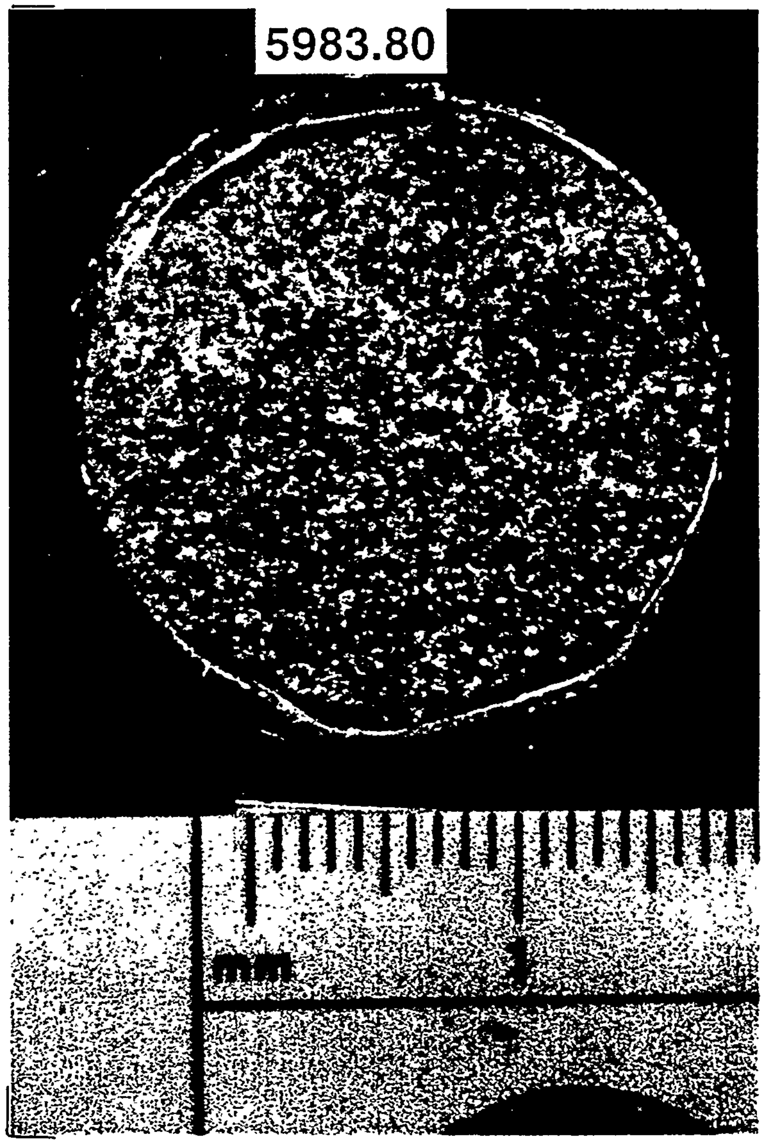
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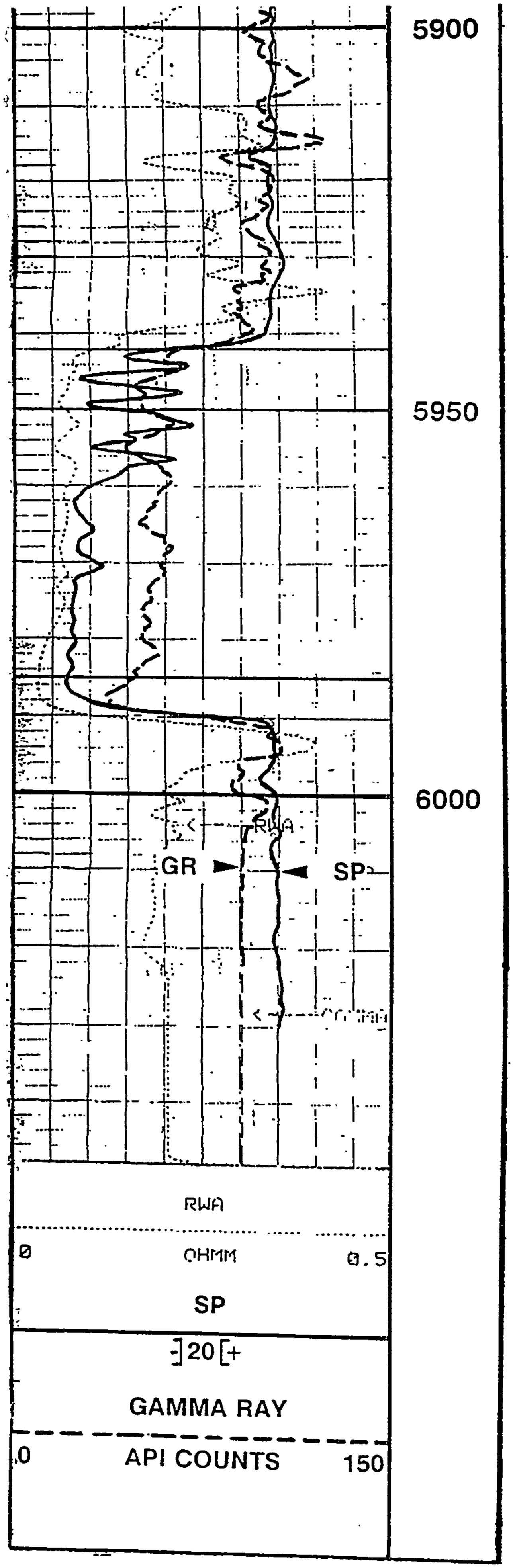
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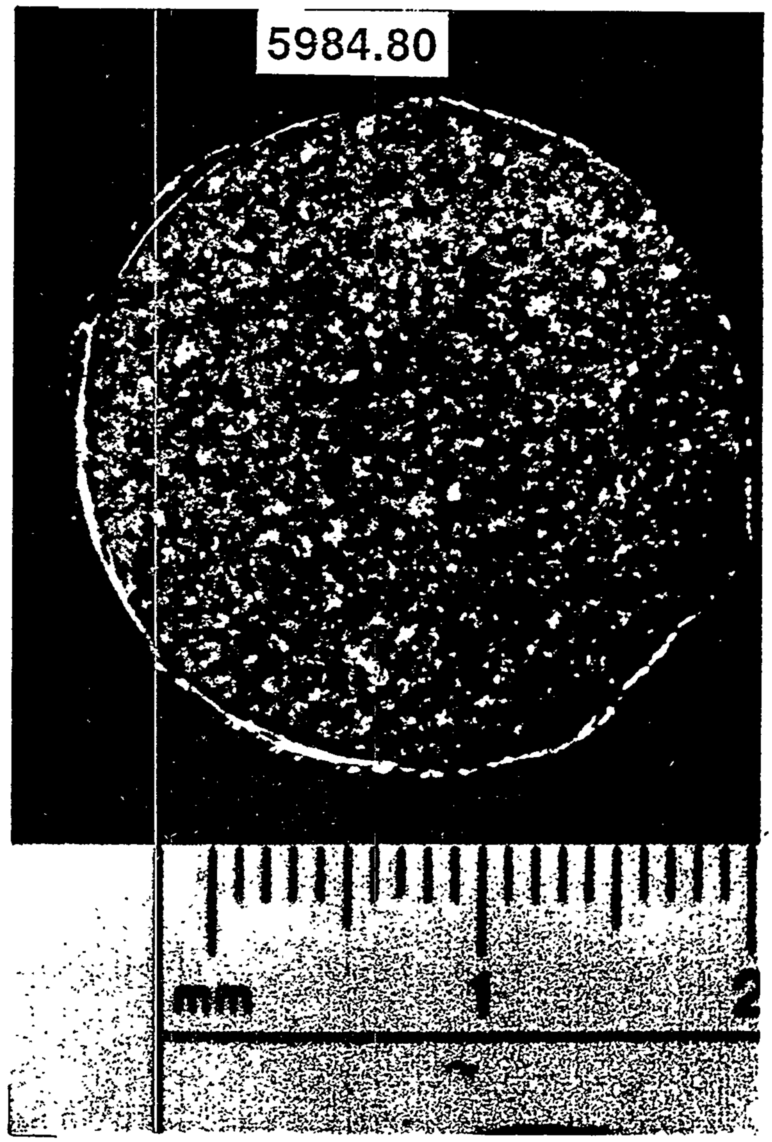
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2

Field Implementation

The horizontal well will be drilled in November along the original oil-water contact of the waterflooded fault block. The well will have 1500' of horizontal displacement and will have prepacked screens run within the section to control sand. The drilling of this well will be controlled by Schlumberger Anadrill's GeoSteering tool which will provide a resistivity measurement at the bit. An additional resistivity reading will be taken by the MWD tool 60' above the bit. This will allow for drilling to be maintained within the 30' sand.

Photographs are included in this section to show the work which was performed during the 1993 fiscal year. A description of photographs is as follows:

Photograph	Description
3-A	This is the producing well Kuhn #14. Notice the actuated wing valve used to control flow in case a downstream failure occurs.
3-B	This is the injection well Kuhn #36. This well is equipped with a hookup for both CO_2 and water injection. All wellheads are stainless steel trimmed to handle the corrosive CO_2 service.
3-C	Construction of the tank battery platform required pile driving and marsh work.
3-D	After the foundation of the tank battery was completed, new water and oil storage tanks were constructed.
3-E	Steel line pipe was cut and welded to hookup the various production equipment items.
3-F	Fiberglass flowlines were hooked to the production platform.
3-G	At a shop in Harvey, Louisiana an on-hand compressor barge was stripped clean and the new equipment was installed. Notice that the upper deck of the barge was removed to allow for clearance while piping was installed.
3-H	A production manifold was constructed which allowed for all wells to be hooked to the low pressure test and working separators and the intermediate pressure test and working separators.

3-I After completing all work on both decks of the compressor barge, the upper deck was lowered onto the lower deck.

3-J The compressor barge was then complete and ready to be floated over to the Port Neches Field.

3-K A total of three compressors were overhauled and equipped with corrosion resistant parts.

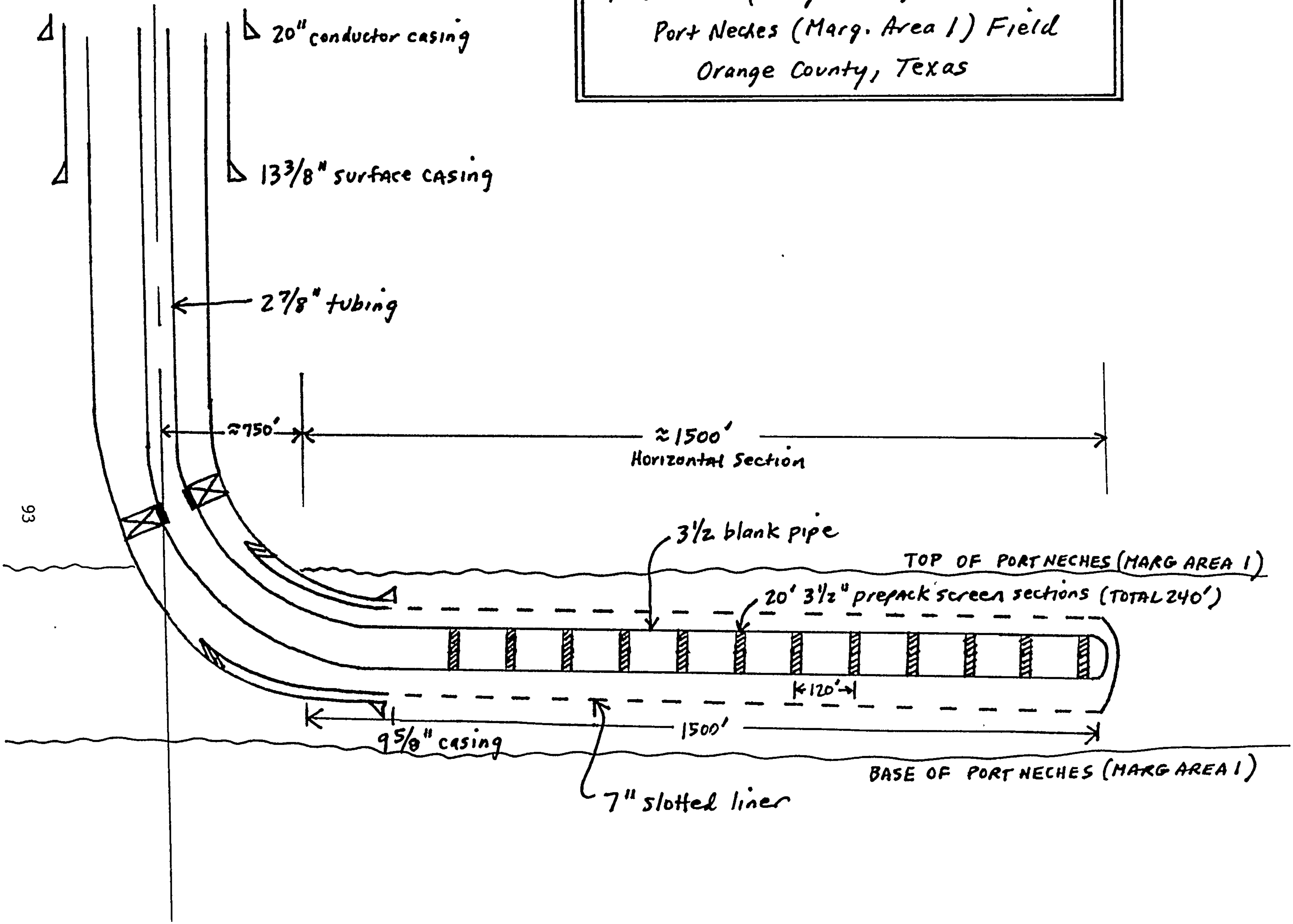
3-L A glycol dehydration tower was installed to removed free water from the CO_2 stream being produced from the wells.

3-M A CO_2 injection pump capable of handling 250 tons per day (4.3 MMCFPD) of CO_2 purchased from Cardox was installed on the upper deck of the compressor barge.

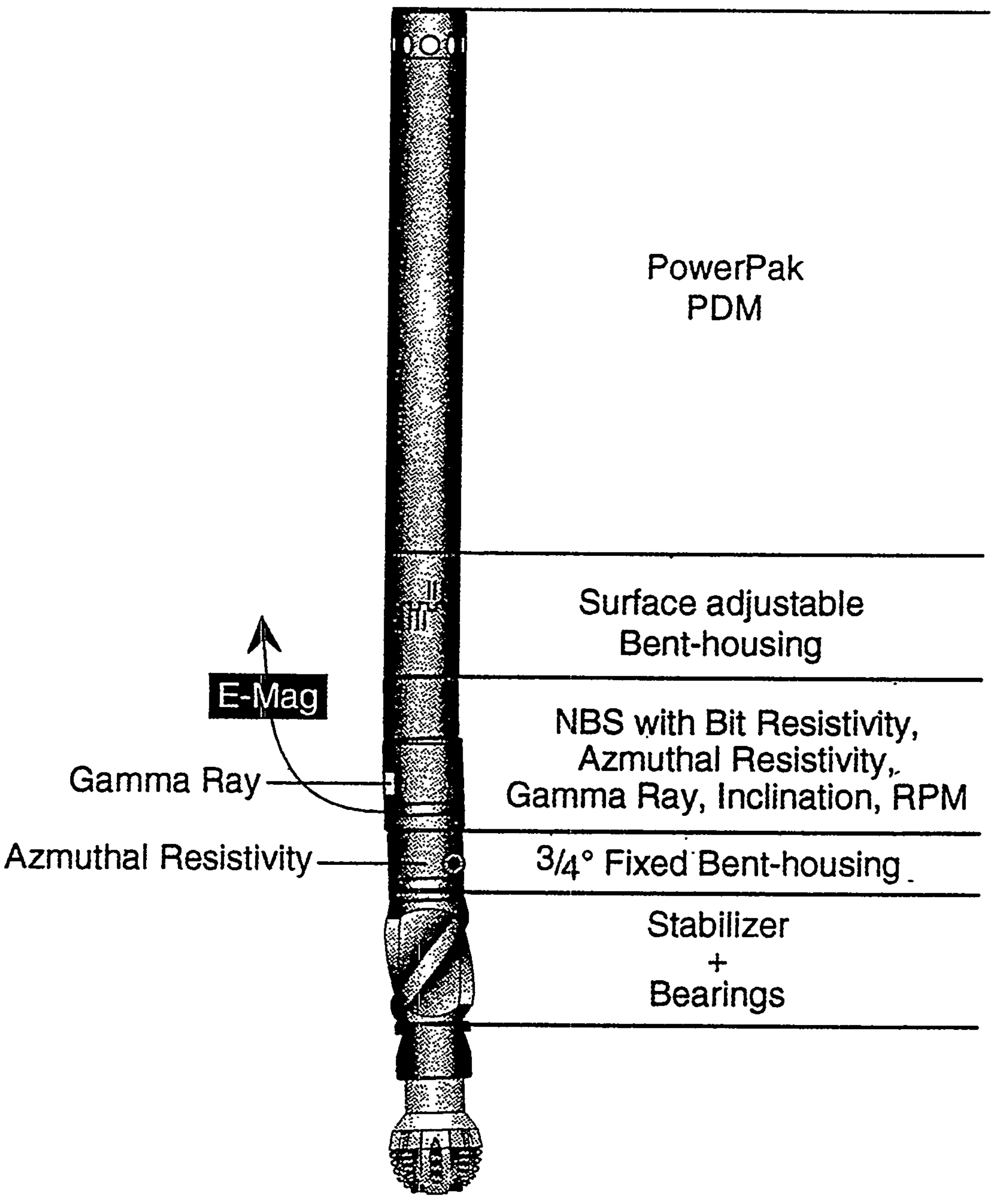
3-N The completed barge and tank battery facility is in place at Port Neches. An additional barge will be floated in next to the CO_2 compressor barge to handle other field production. On this barge will be an additional CO_2 injection compressor.

3-O Oil and water production gathered on the compressor barge is piped to the gunbarrel, oil, and water tanks.

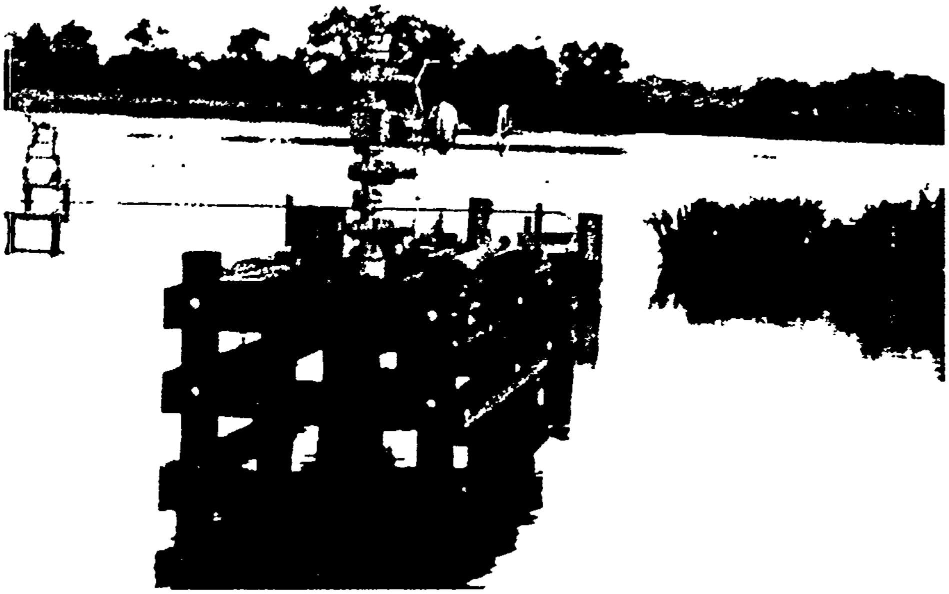
Port Neches (Marg. Area 1) Field
Orange County, Texas



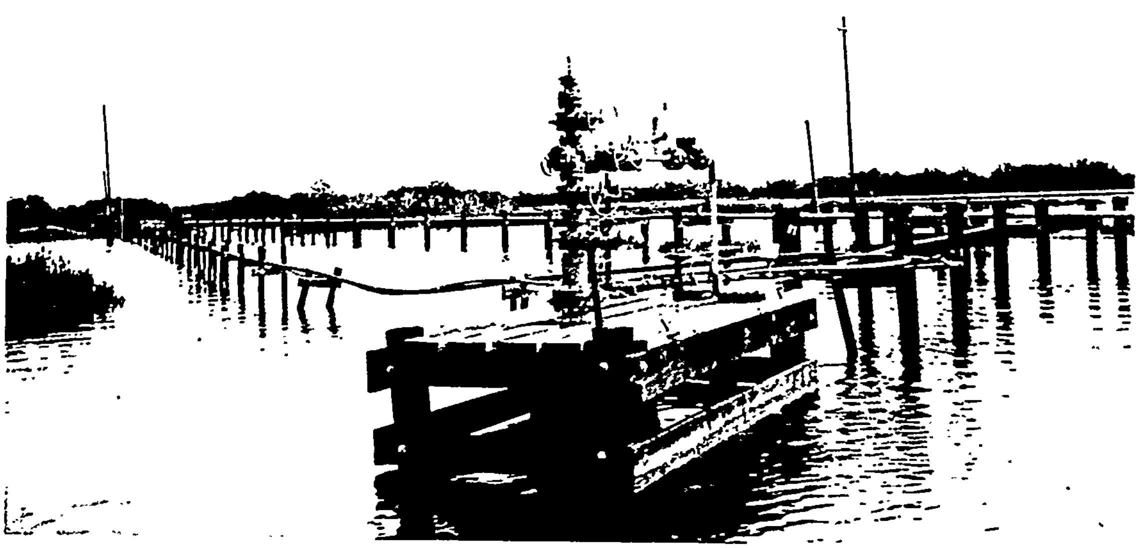
GeoSteering Tool



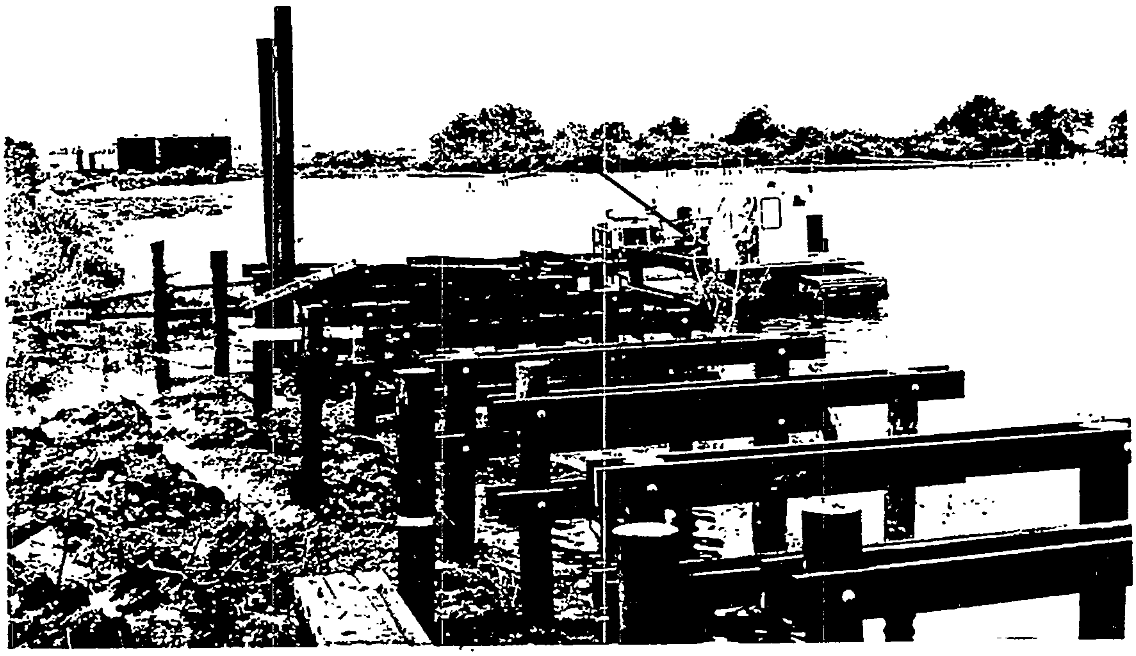
Photograph 3–A



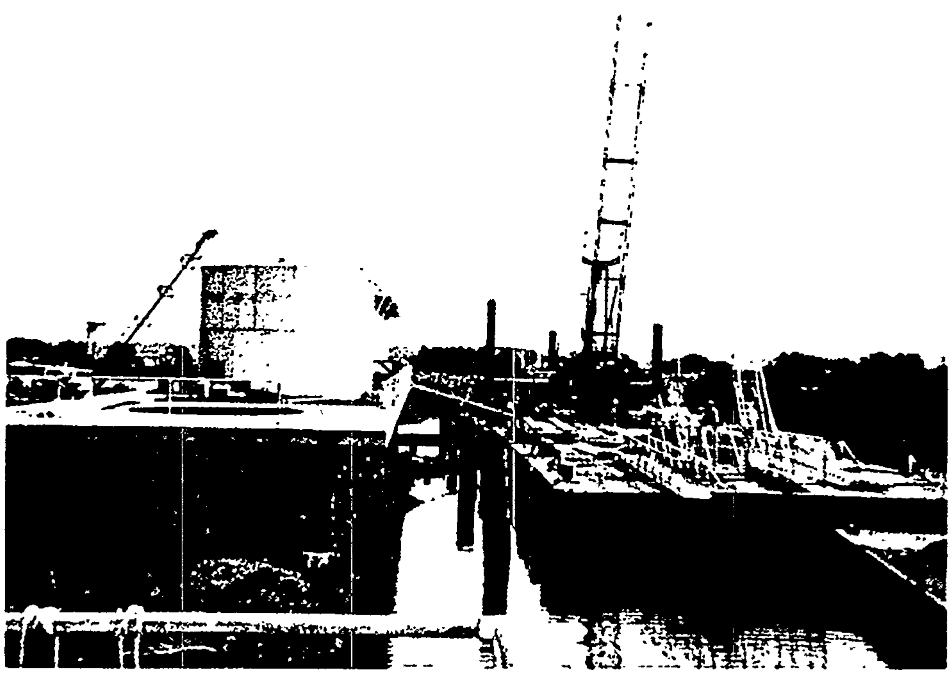
Photograph 3–B



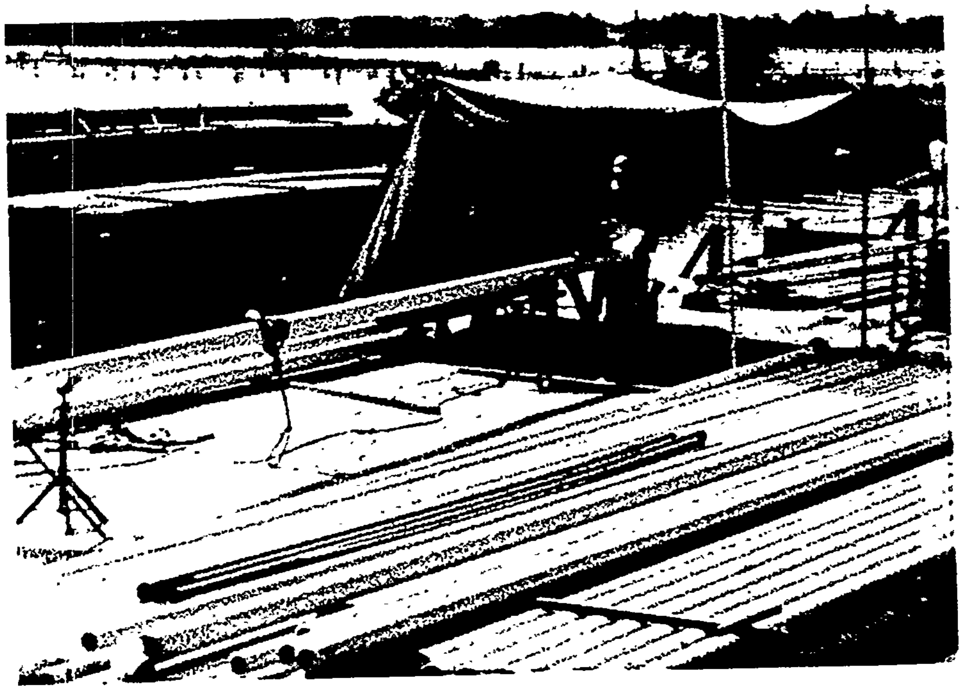
Photograph 3–C



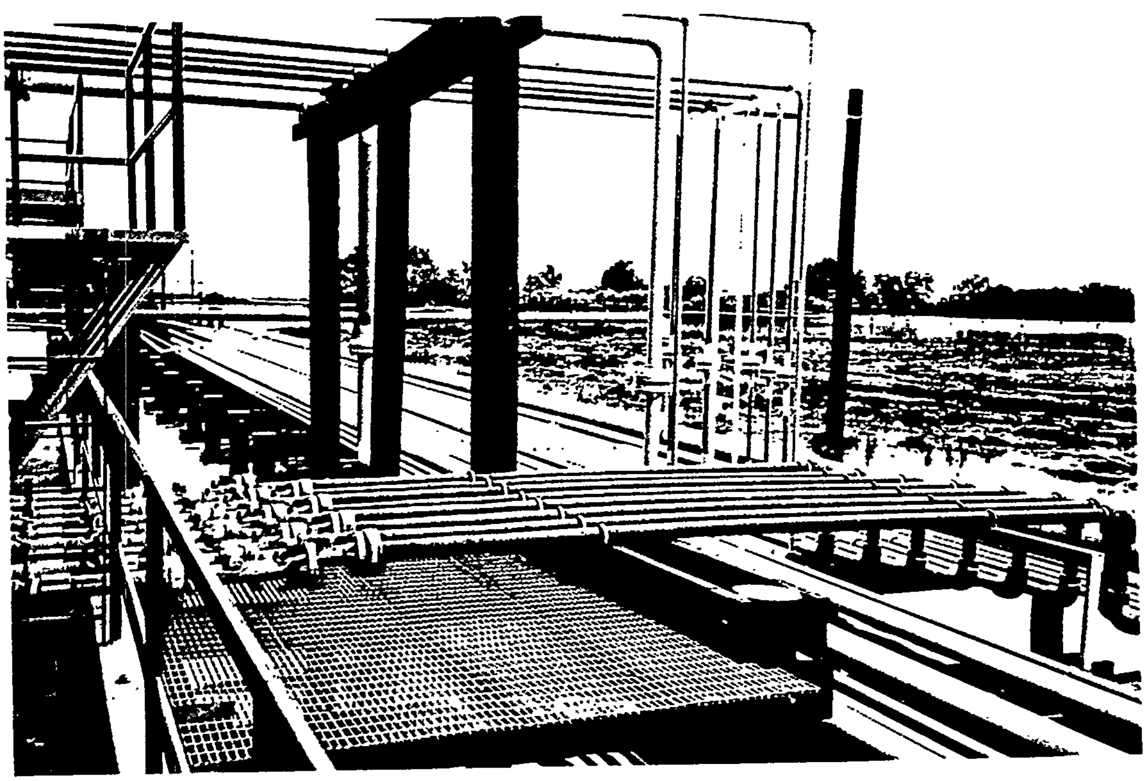
Photograph 3–D



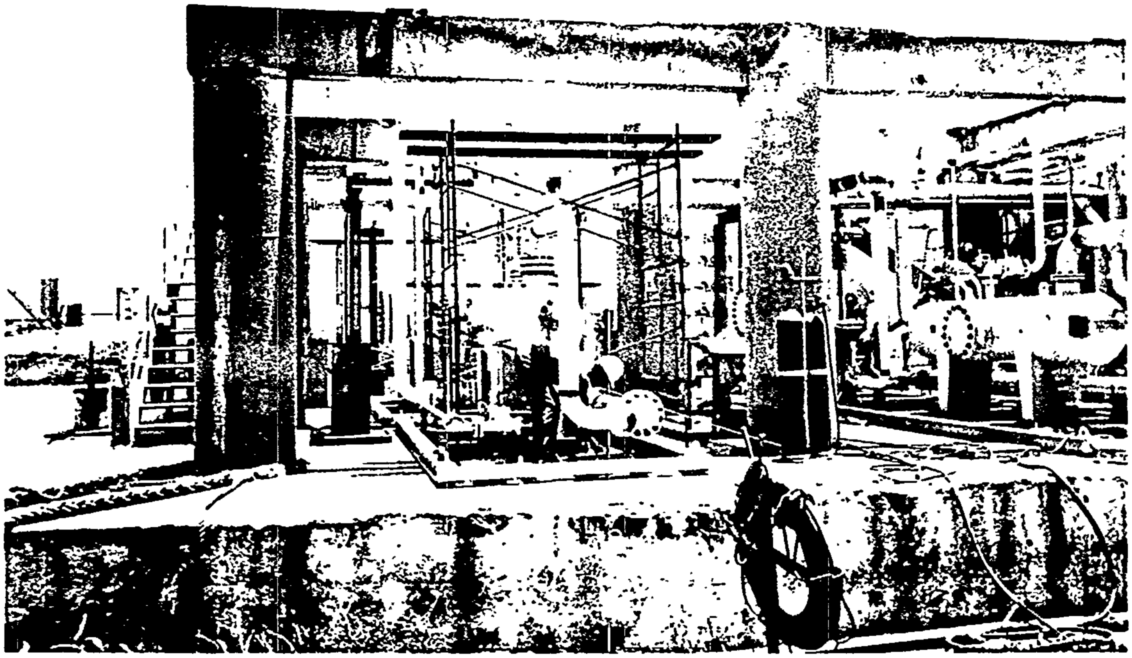
Photograph 3-E



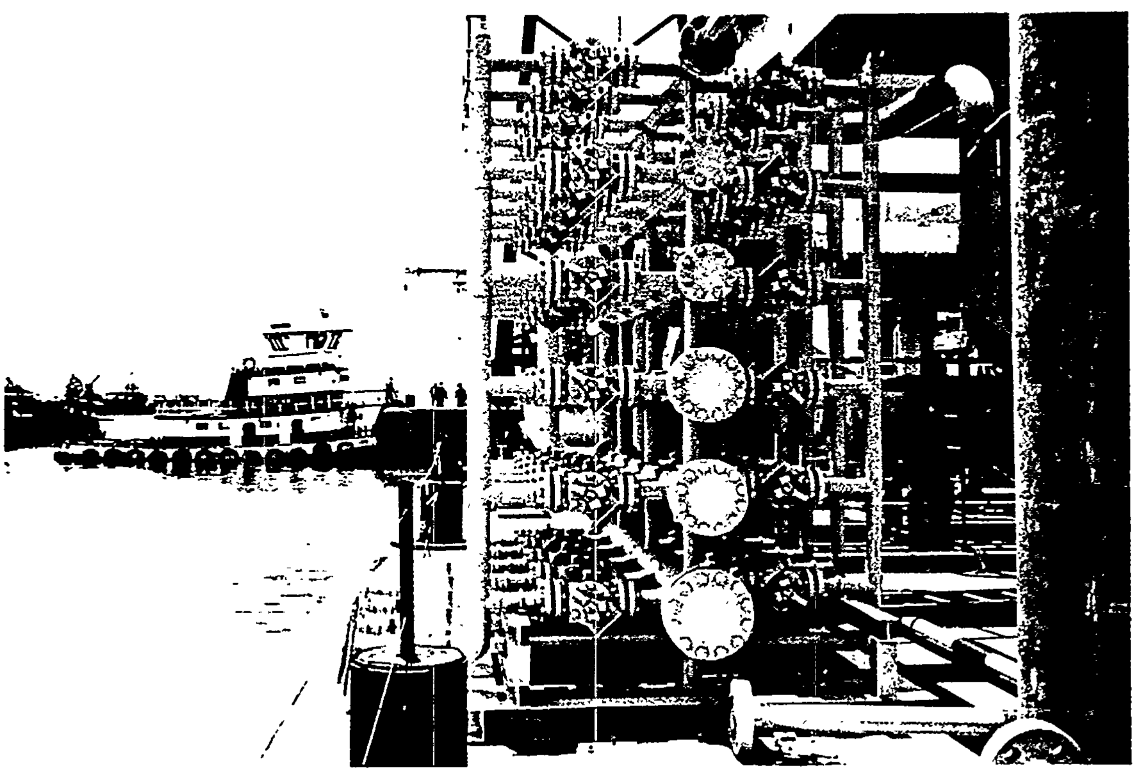
Photograph 3-F



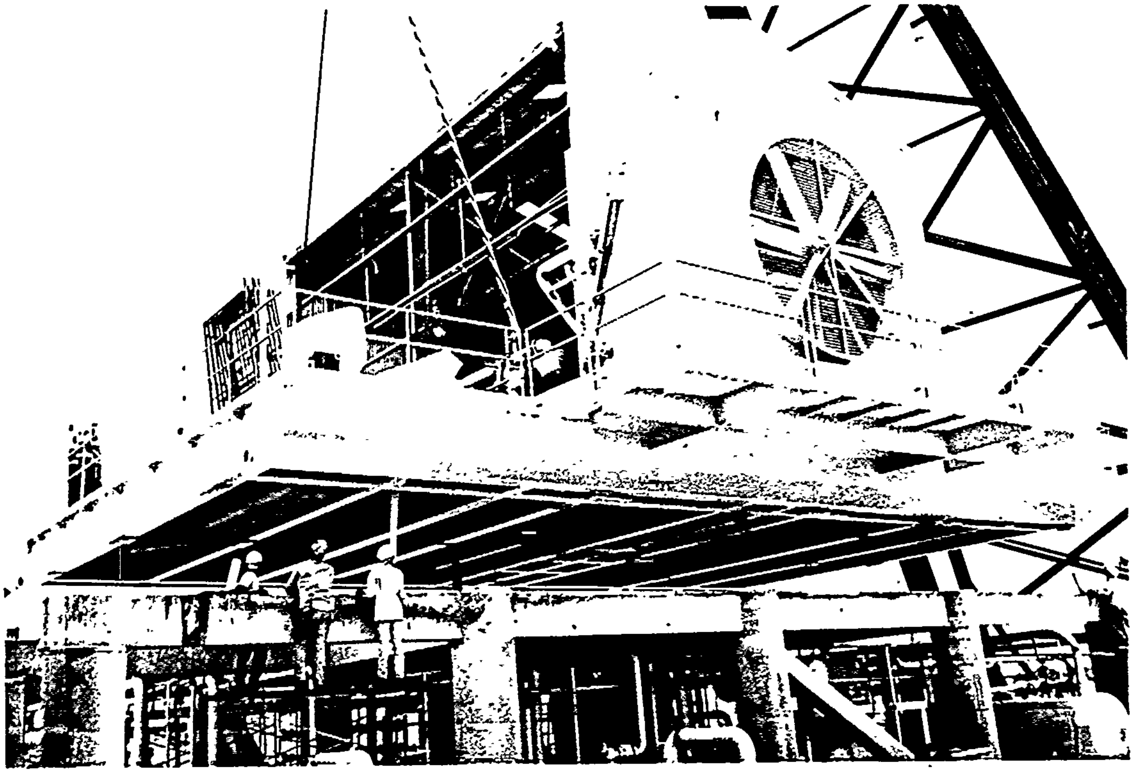
Photograph 3–G



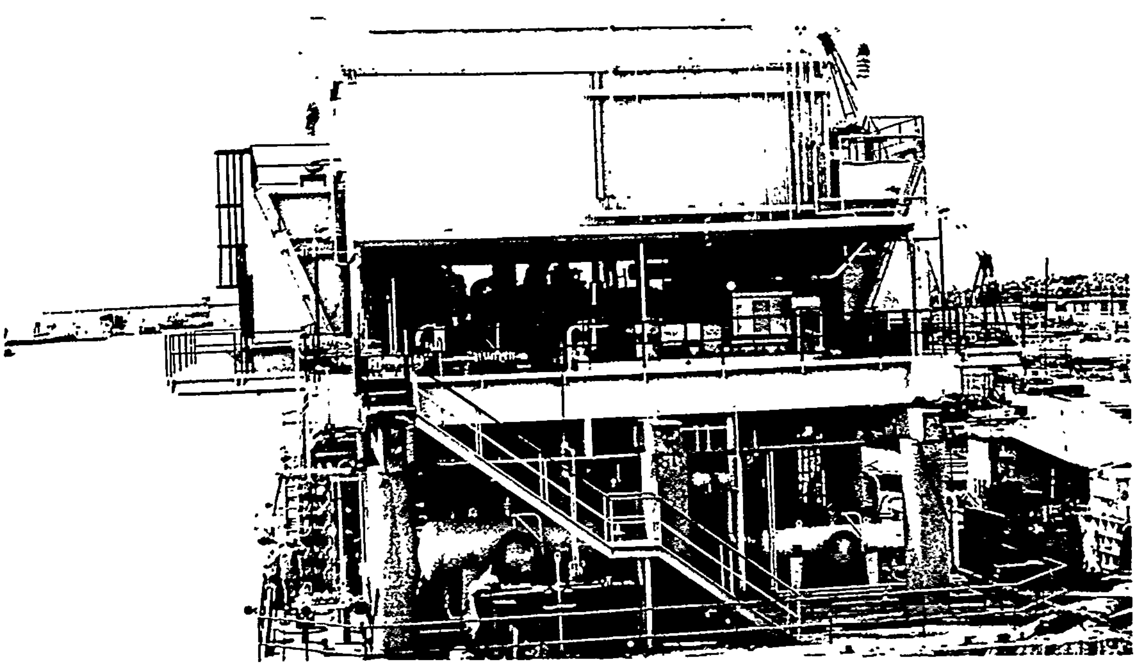
Photograph 3–H



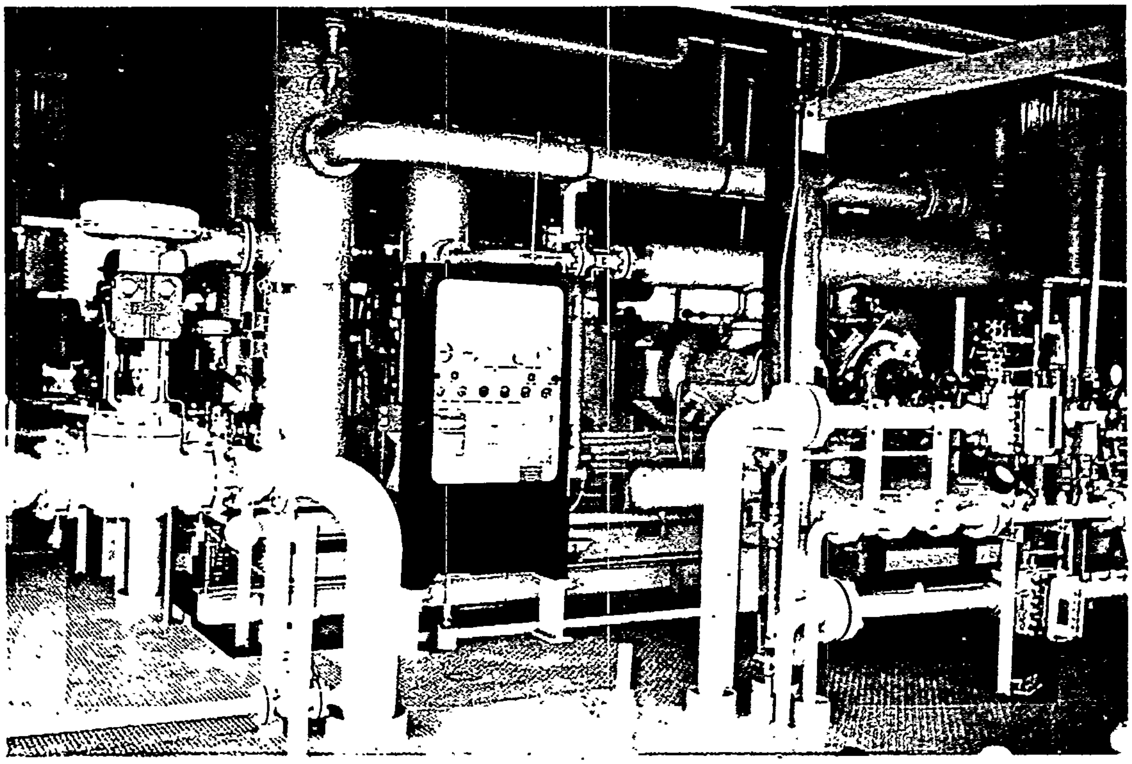
Photograph 3–I



Photograph 3–J

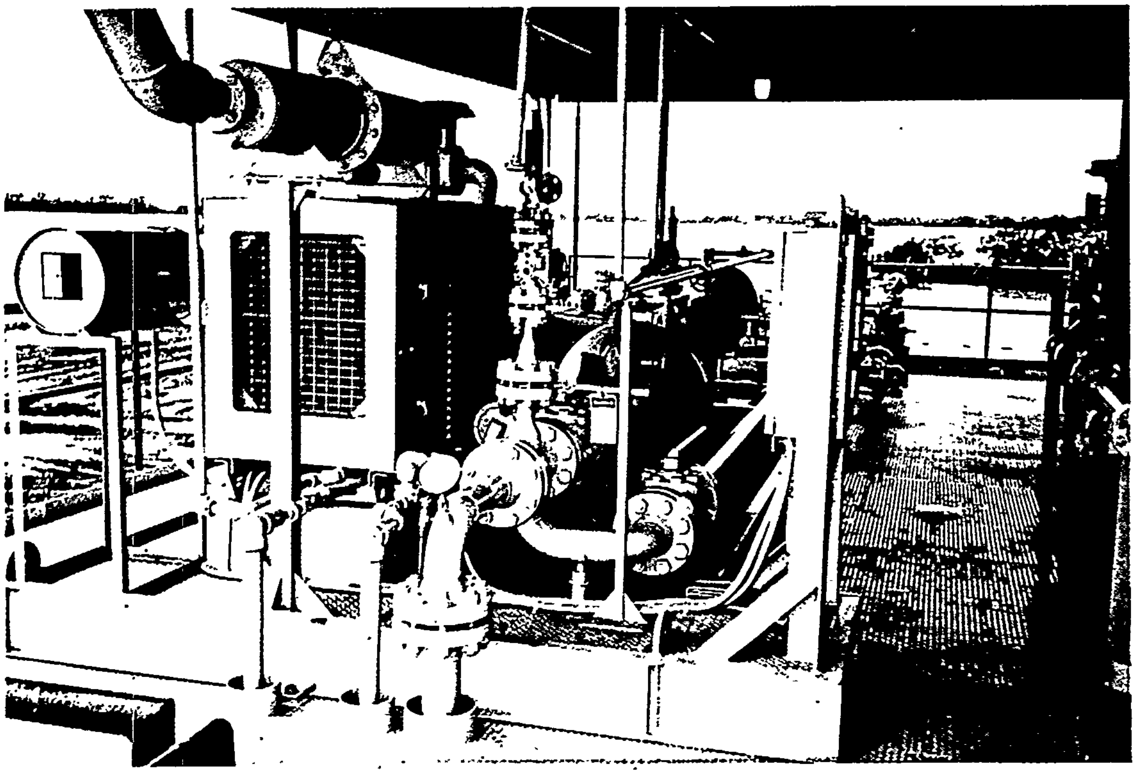


Photograph 3-K

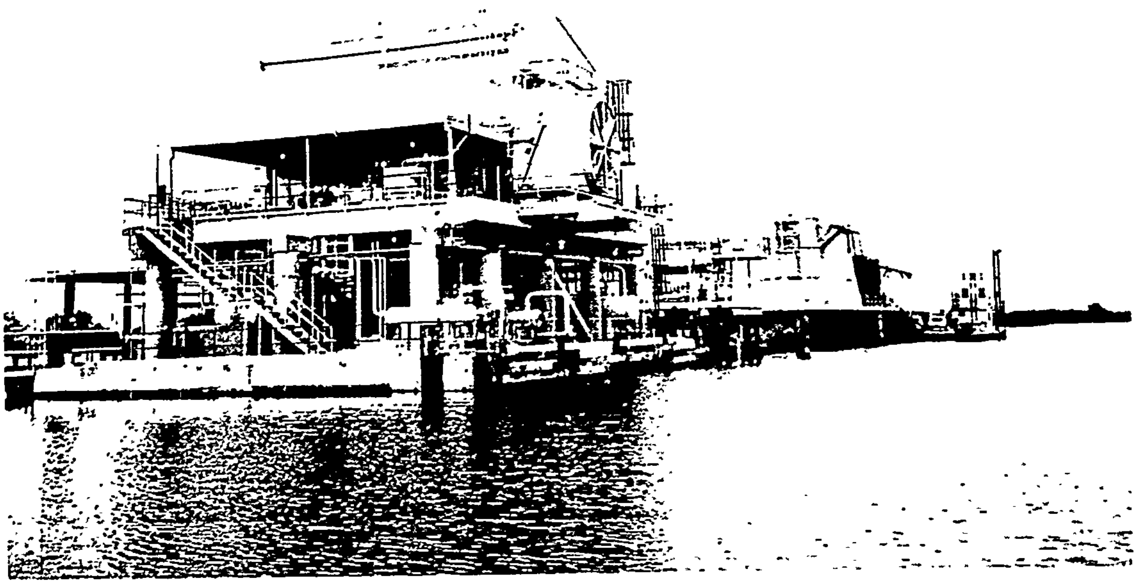


Photograph 3-L

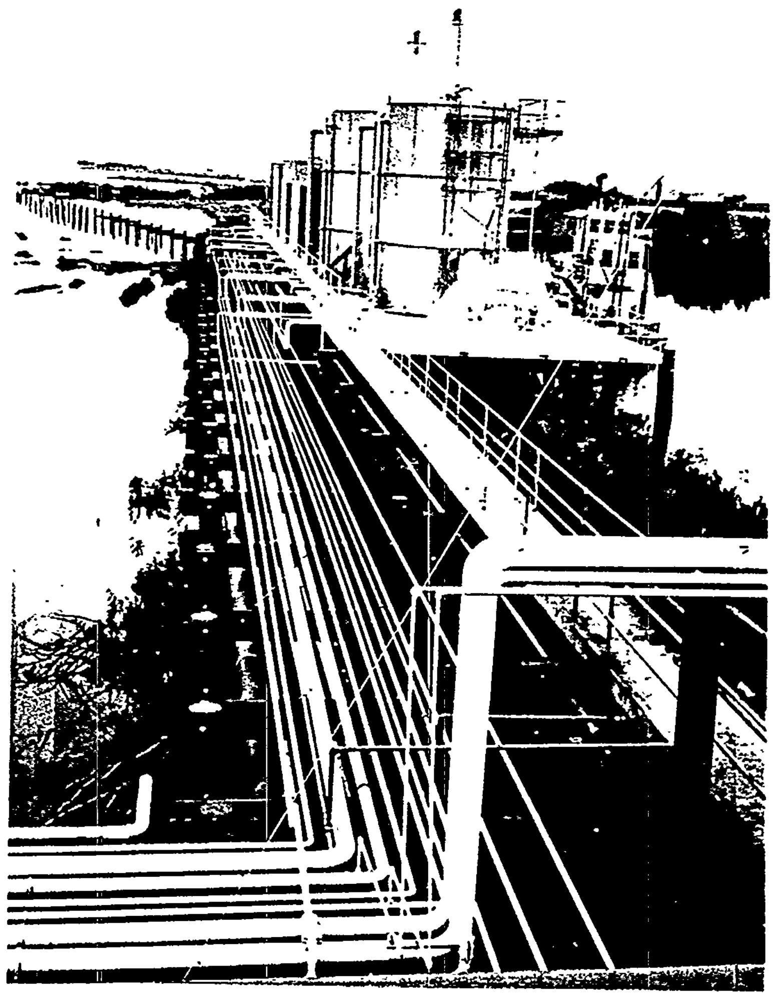
Photograph 3-M



Photograph 3-N



Photograph 3–O



CO_2/CO_2 Pipeline

A 4-1/2 mile 4" (I.D.) pipeline was installed from a Cardox CO_2 pipeline tie-in point to the Port Neches Field. Purchases began on September 22, 1993 at a rate of approximately 4 MMCFPD.

The attached photographs indicate the complexity of some of the work. After burying the pipe along the high elevation levels of the right-of way, the pipe was jetted in place in the marsh area after being welded on ground. Unfortunately there are no pictures of this operation, as it took only 1-1/2 days to pull the pipe into the jetted area of the marsh.

Photographs included are:

Photographs	Description
4-A	4" steel pipe is delivered to locations set up along the CO_2 pipeline right-of-way.
4-B	After offloading the pipe, it is layed along the right-of-way and made ready for welding.
4-C	The pipe is welded and buried a minimum of 3'.
4-D	Certified welders hand weld the pipe and then x-ray it for signs of any defective welds.
4-E	While the pipeline was parallel to many other pipelines, some major pipeline crossings were performed.
4-F	Most all crossings required that the pipe be placed beneath the other pipelines.

Photograph 4–A

Photograph 4–B

Photograph 4–C

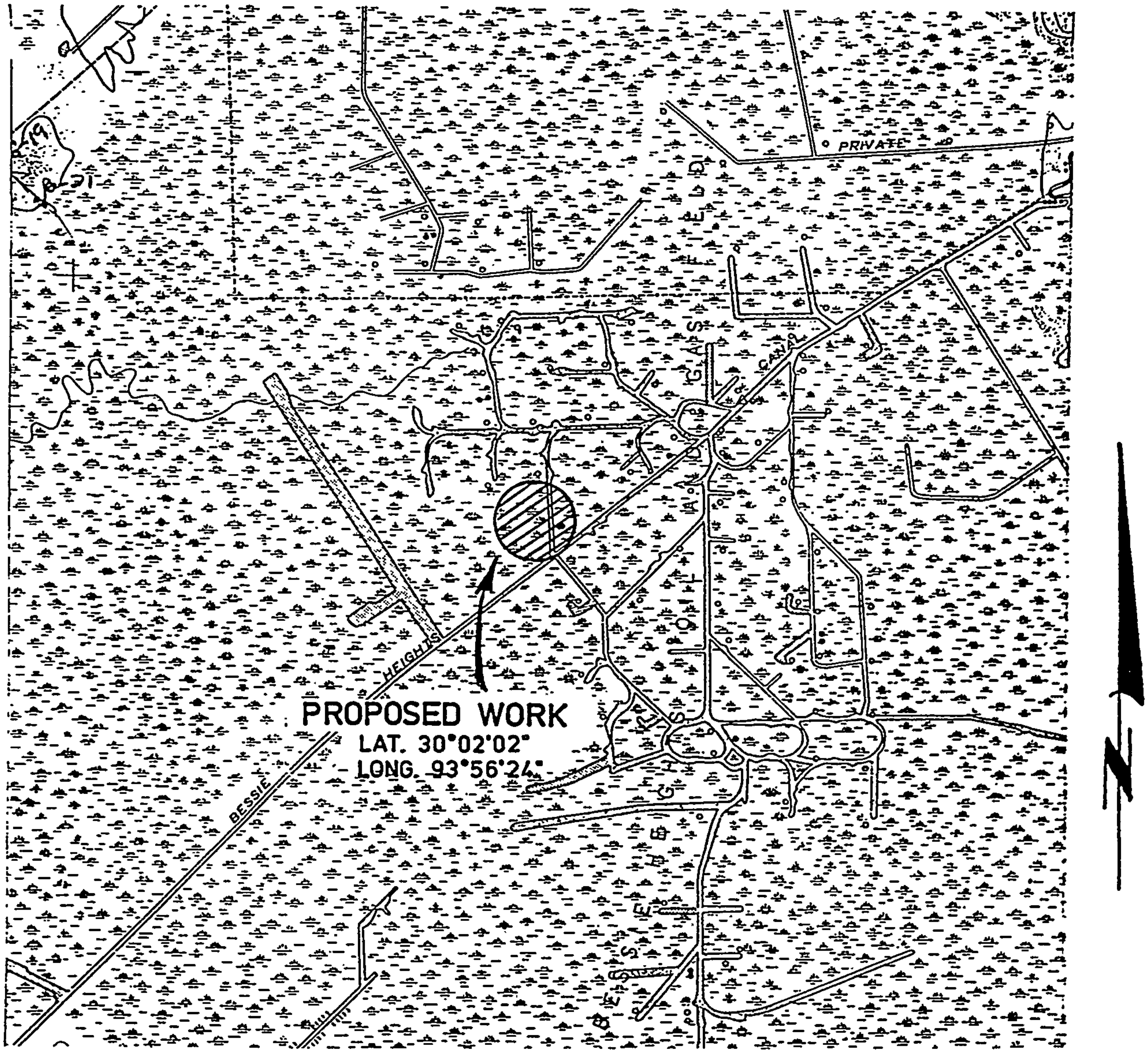
Photograph 4–D

Photograph 4-E

Photograph 4-F

Environmental

One the major items which was addressed from an environmental standpoint was that of the environmental liability of the CO_2 pipeline. An Army Corps of Engineers permit was received after Texaco met all reporting requirements. A public notice was issued by the Army Corps of Engineers and several meetings with the Texas Parks and Wildlife and the U. S. Fish and Wildlife Service were held. DOE also handled all necessary paperwork to allow for a categorical exclusion to N.E.P.A. regulations. Attached is a copy of the pipeline route.



VICINITY MAP

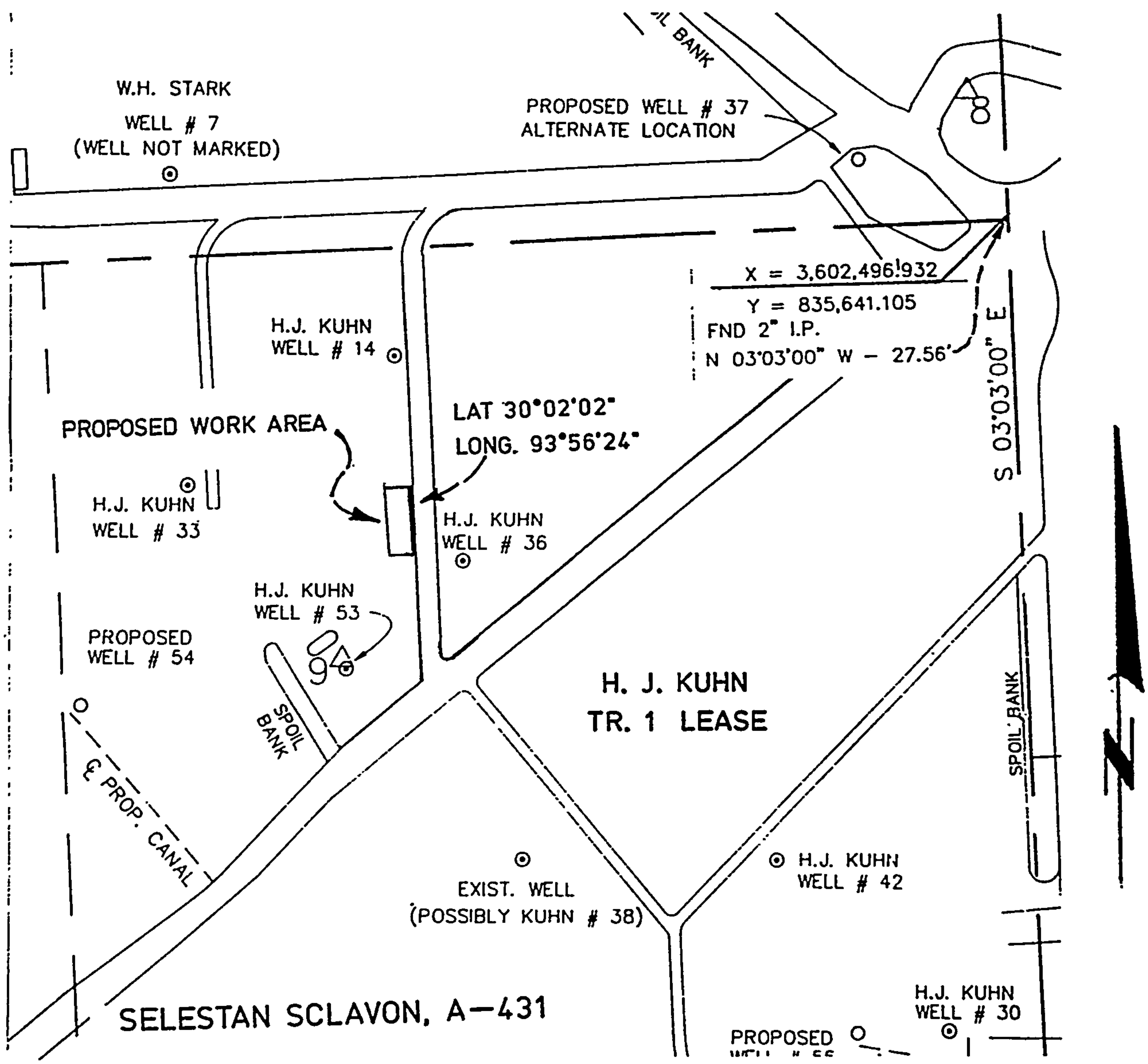
1000' 0 2000'

SCALE: 1"= 2000'

TEXACO USA
EASTERN E & P REGION
ONSHORE PRODUCING DIVISION OPERATIONS EAST

PORT NECHES FIELD
PROPOSED DREDGING & LIMESTONE MAT
FOR CO2 PRODUCTION FACILITY
SELESTAN SCLAVON, A-431
ORANGE COUNTY, TEXAS

FILE NAME: – PN–DRG.DWG		
Drawn by: SJI	Date: 1–25–93	Sheet 1 Of 4



PLAN

250' 0 500'

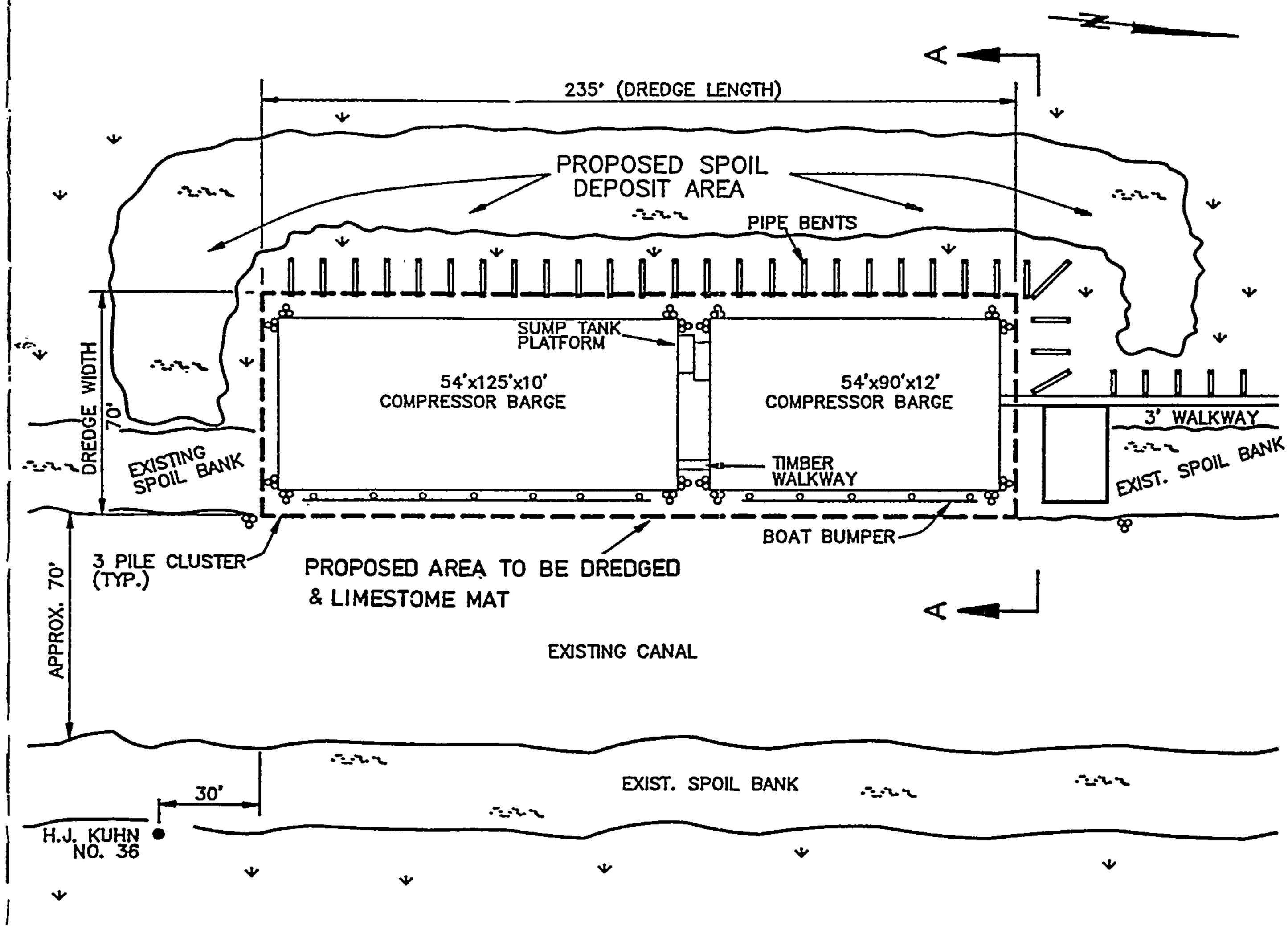
SCALE: 1"= 500'

TEXACO USA
EASTERN E & P REGION
ONSHORE PRODUCING DIVISION OPERATIONS EAST

PORT NECHES FIELD
PROPOSED DREDGING & LIMESTONE MAT
FOR CO2 PRODUCTION FACILITY
SELESTAN SCLAVON, A–431
ORANGE COUNTY, TEXAS

FILE NAME: – PN-DRG.DWG

Drawn by:	Date:	Sheet	Of
SJI	1–25–93	2	4



NOTE:
APPROX. 9,000 CU. YDS. OF SPOIL WILL BE DREDGED AND PLACED IN AREAS AS SHOWN.

PLAN DETAIL

25' 0 50'

SCALE: 1"= 50'

TEXACO USA
EASTERN E & P REGION
ONSHORE PRODUCING DIVISION OPERATIONS EAST

PORT NECHES FIELD
PROPOSED DREDGING & LIMESTONE MAT
FOR CO2 PRODUCTION FACILITY
SELESTAN SCLAVON, A-431
ORANGE COUNTY, TEXAS

FILE NAME: – PN-DRG.DWG

Drawn by:	Date:	Sheet	Of
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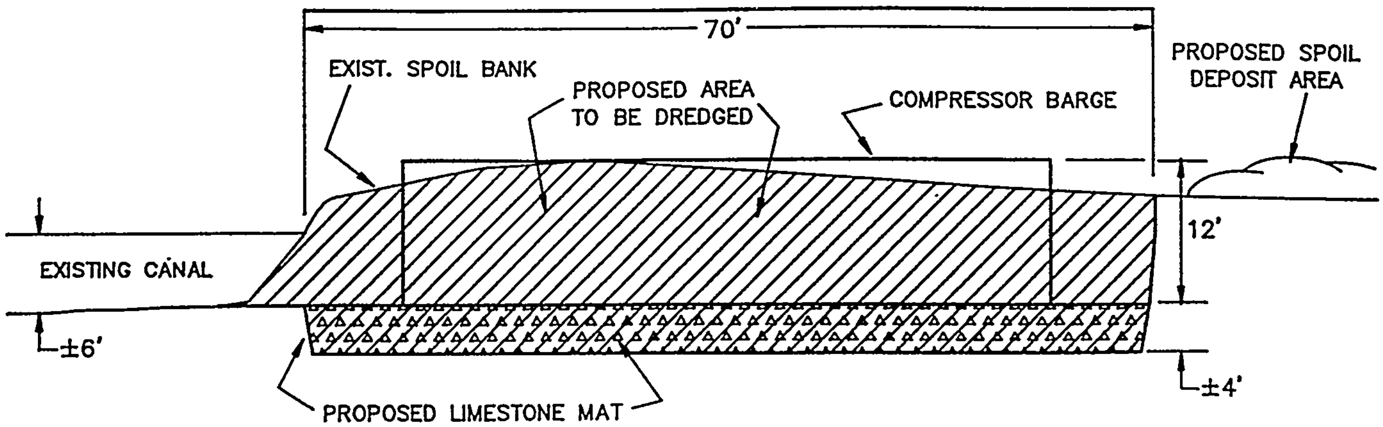


CROSS SECTION A–A

— PROPOSED AREA TO BE DREDGED (APPROX. 9000 CU. YDS. OF SPOIL TO BE DREDGED)

— PROPOSED LIMESTONE MAT (APPROX. 2450 CU. YDS. OF LIMESTONE TO BE USED)

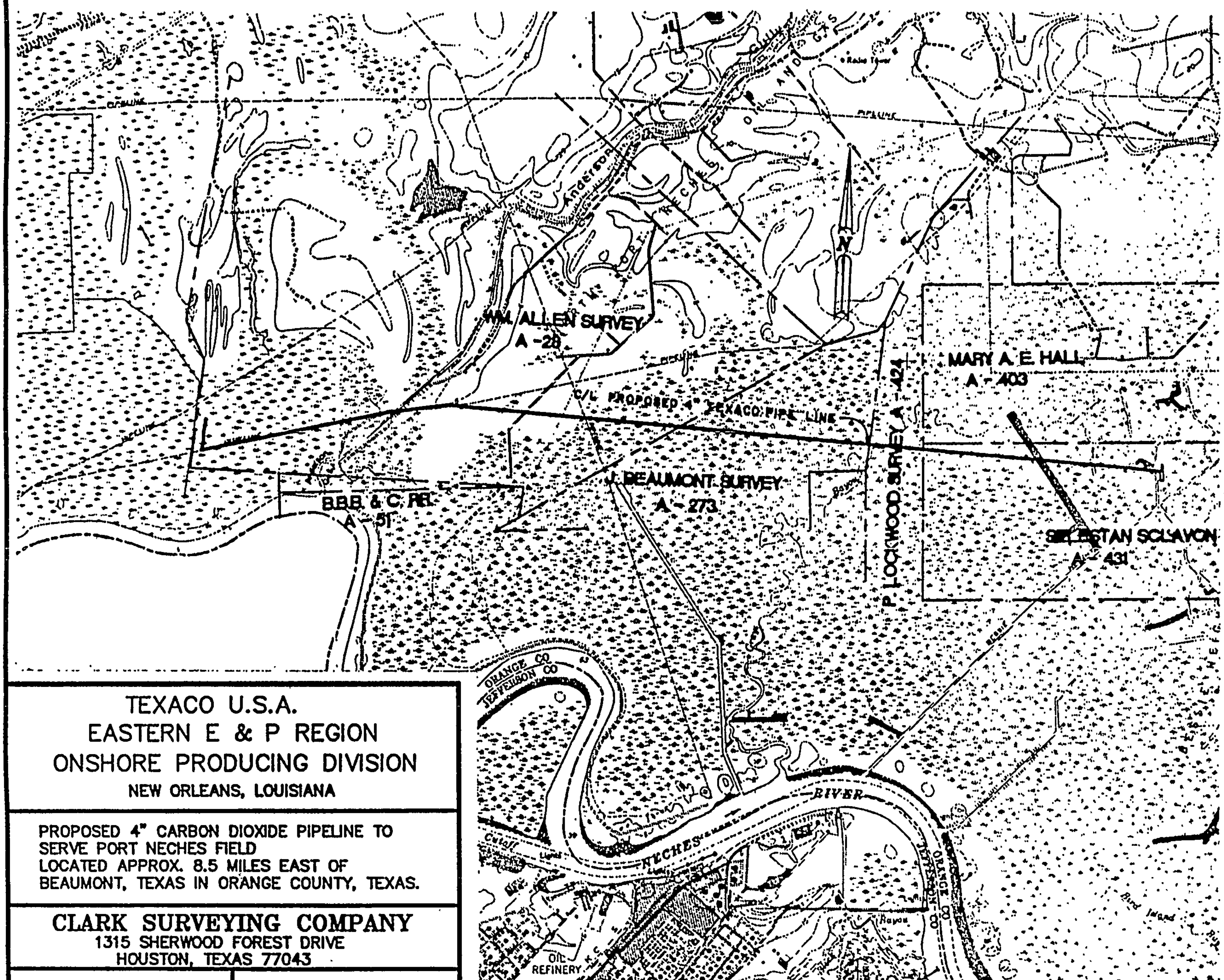
VERTICAL SCALE: 1"= 15'
7.5' 0 15'
7.5' 0 15'
HORIZONTAL SCALE: 1"= 15'

TEXACO USA
EASTERN E & P REGION
ONSHORE PRODUCING DIVISION OPERATIONS EAST

PORT NECHES FIELD
PROPOSED DREDGING & LIMESTONE MAT
FOR CO2 PRODUCTION FACILITY
SELESTAN SCLAVON, A–431
ORANGE COUNTY, TEXAS

FILE NAME: – PN–DRG.DWG

Drawn by:	Date:	Sheet	Of
SJI	1–25–93	4	4

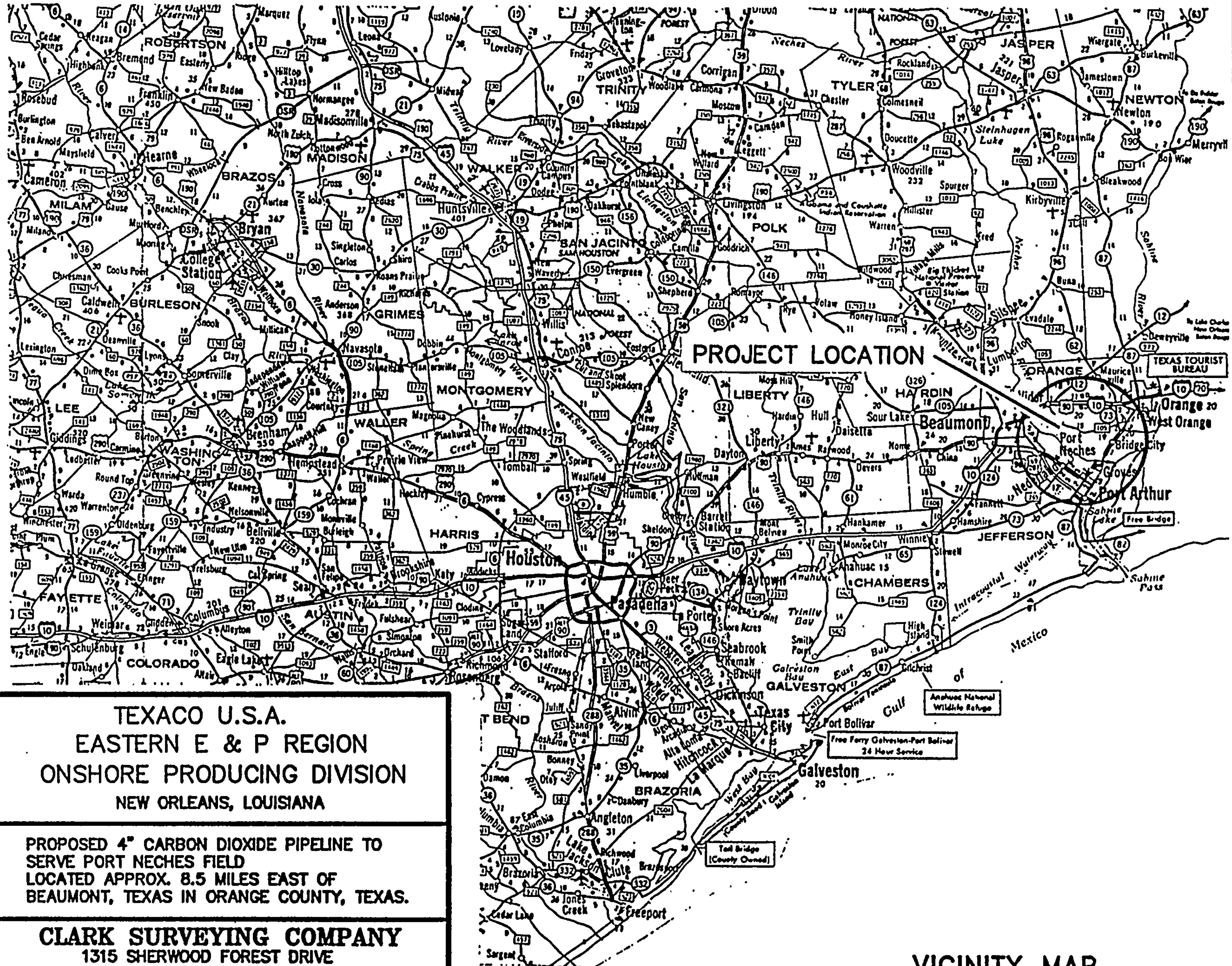


TEXACO U.S.A.
EASTERN E & P REGION
ONSHORE PRODUCING DIVISION
NEW ORLEANS, LOUISIANA

PROPOSED 4" CARBON DIOXIDE PIPELINE TO
SERVE PORT NECHES FIELD
LOCATED APPROX. 8.5 MILES EAST OF
BEAUMONT, TEXAS IN ORANGE COUNTY, TEXAS.

CLARK SURVEYING COMPANY
1315 SHERWOOD FOREST DRIVE
HOUSTON, TEXAS 77043

DATE: 2/11/93	SHEET 1 of 8



VICINITY MAP

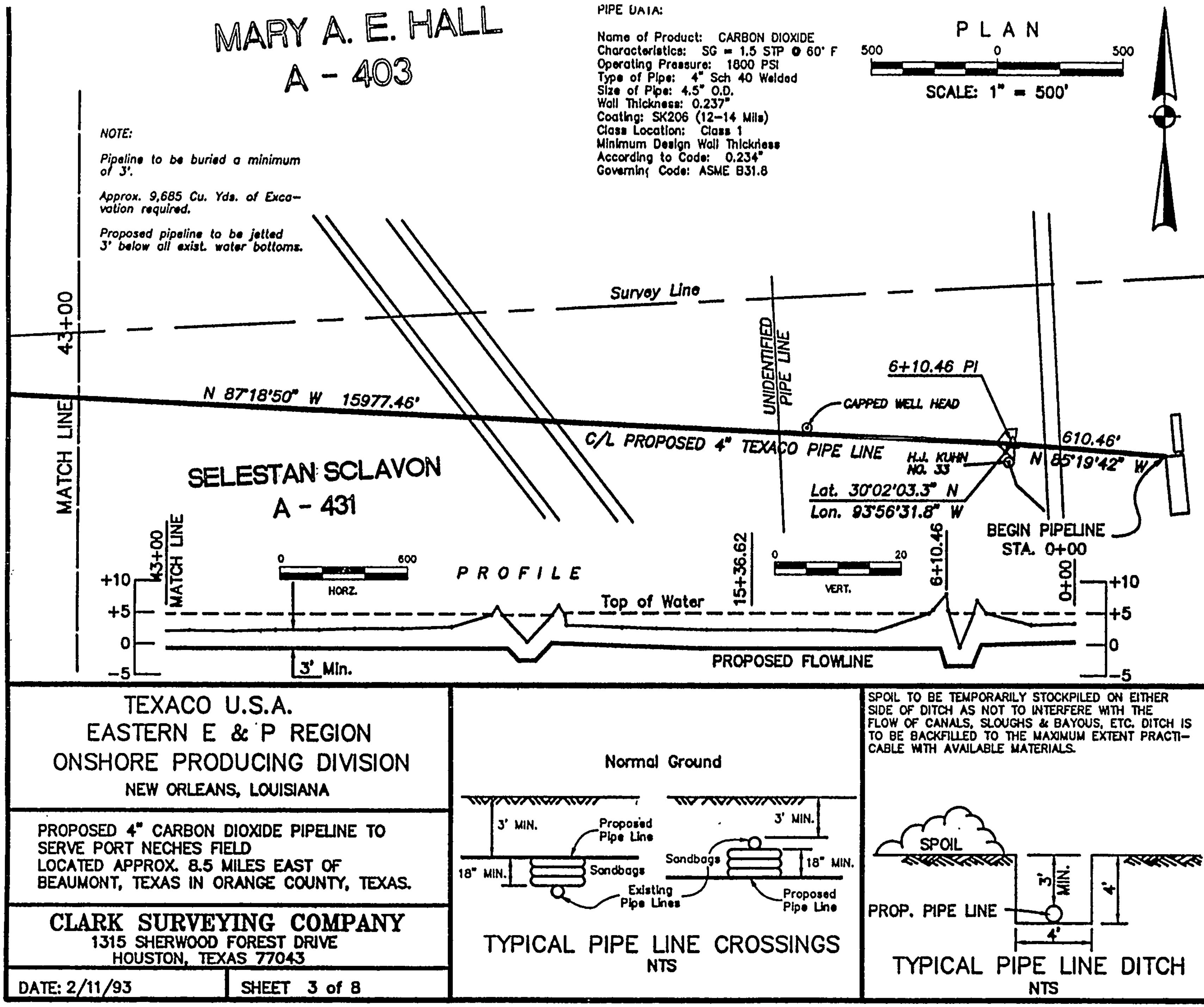
SCALE: 1" = APPROX. 23 MILES

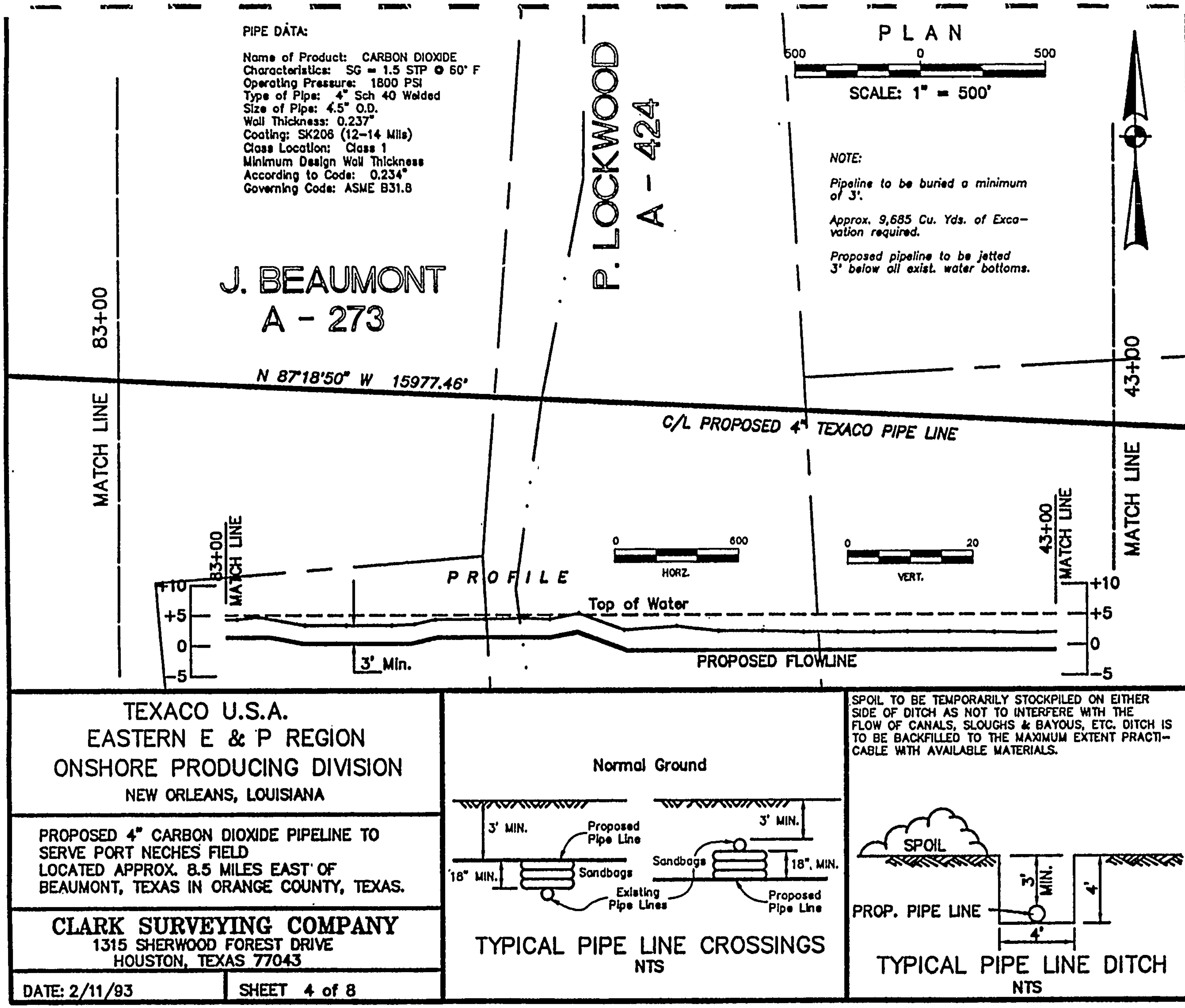
TEXACO U.S.A.
EASTERN E & P REGION
ONSHORE PRODUCING DIVISION
NEW ORLEANS, LOUISIANA

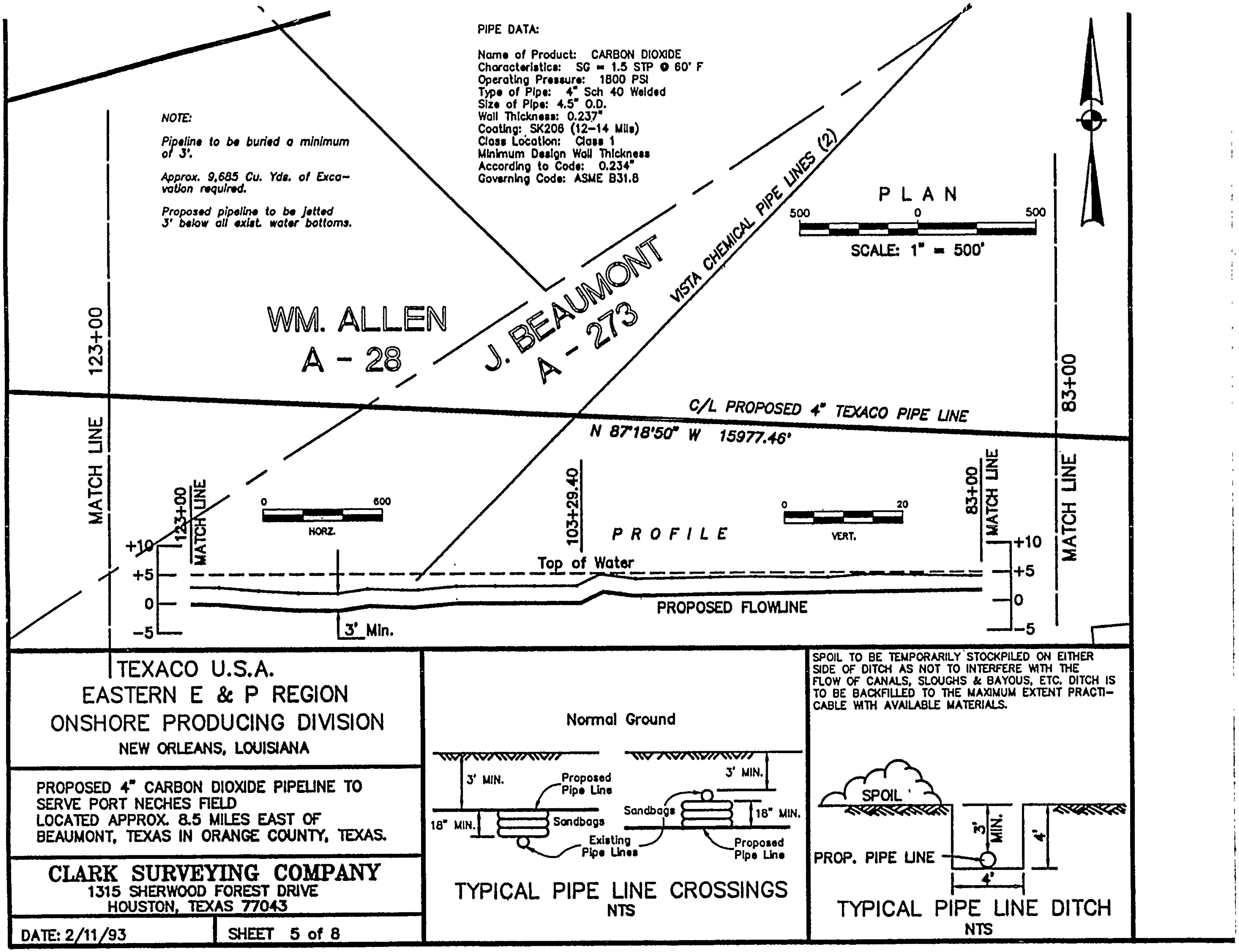
PROPOSED 4" CARBON DIOXIDE PIPELINE TO SERVE PORT NECHES FIELD LOCATED APPROX. 8.5 MILES EAST OF BEAUMONT, TEXAS IN ORANGE COUNTY, TEXAS.

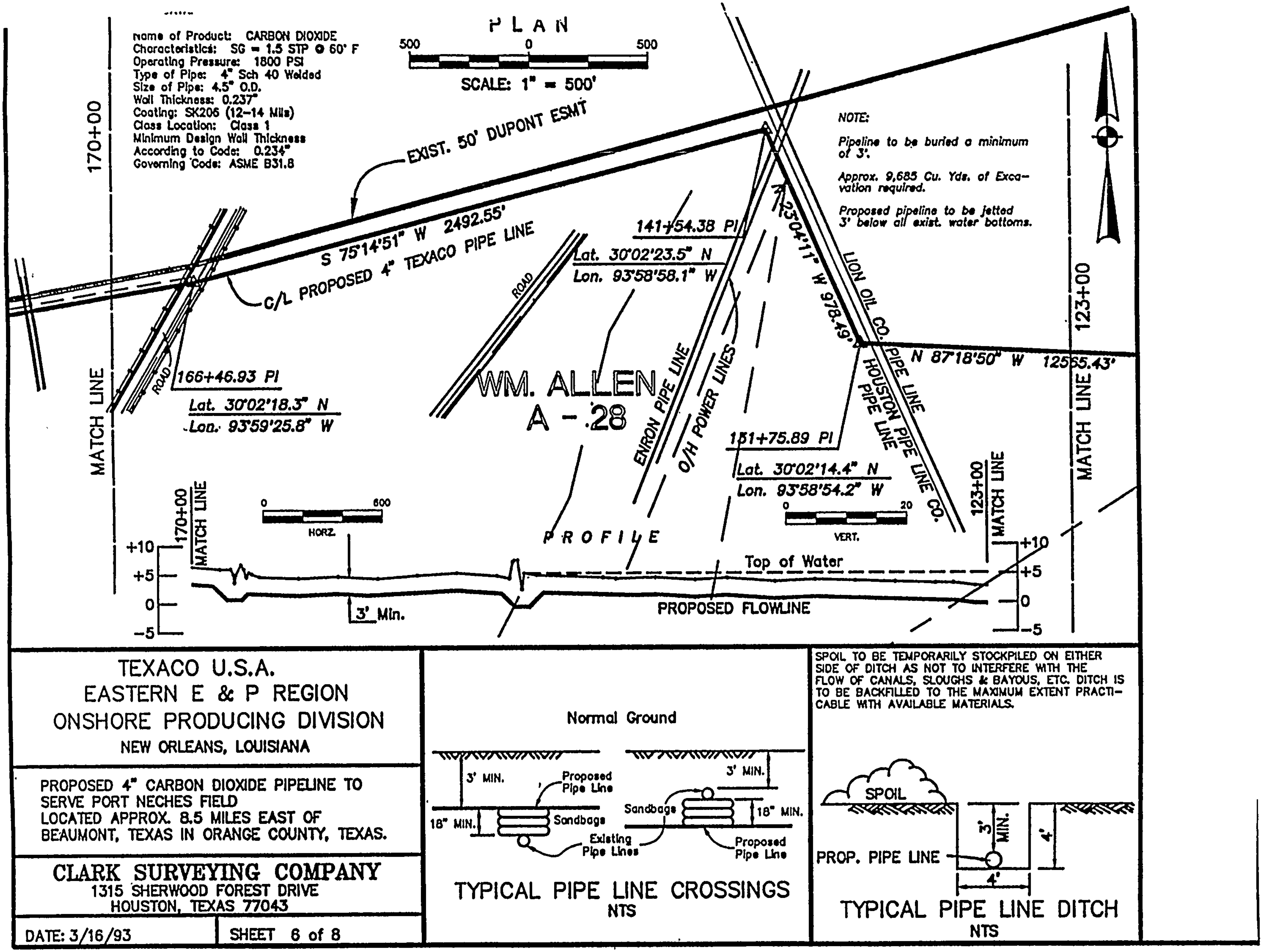
CLARK SURVEYING COMPANY
1315 SHERWOOD FOREST DRIVE
HOUSTON, TEXAS 77043

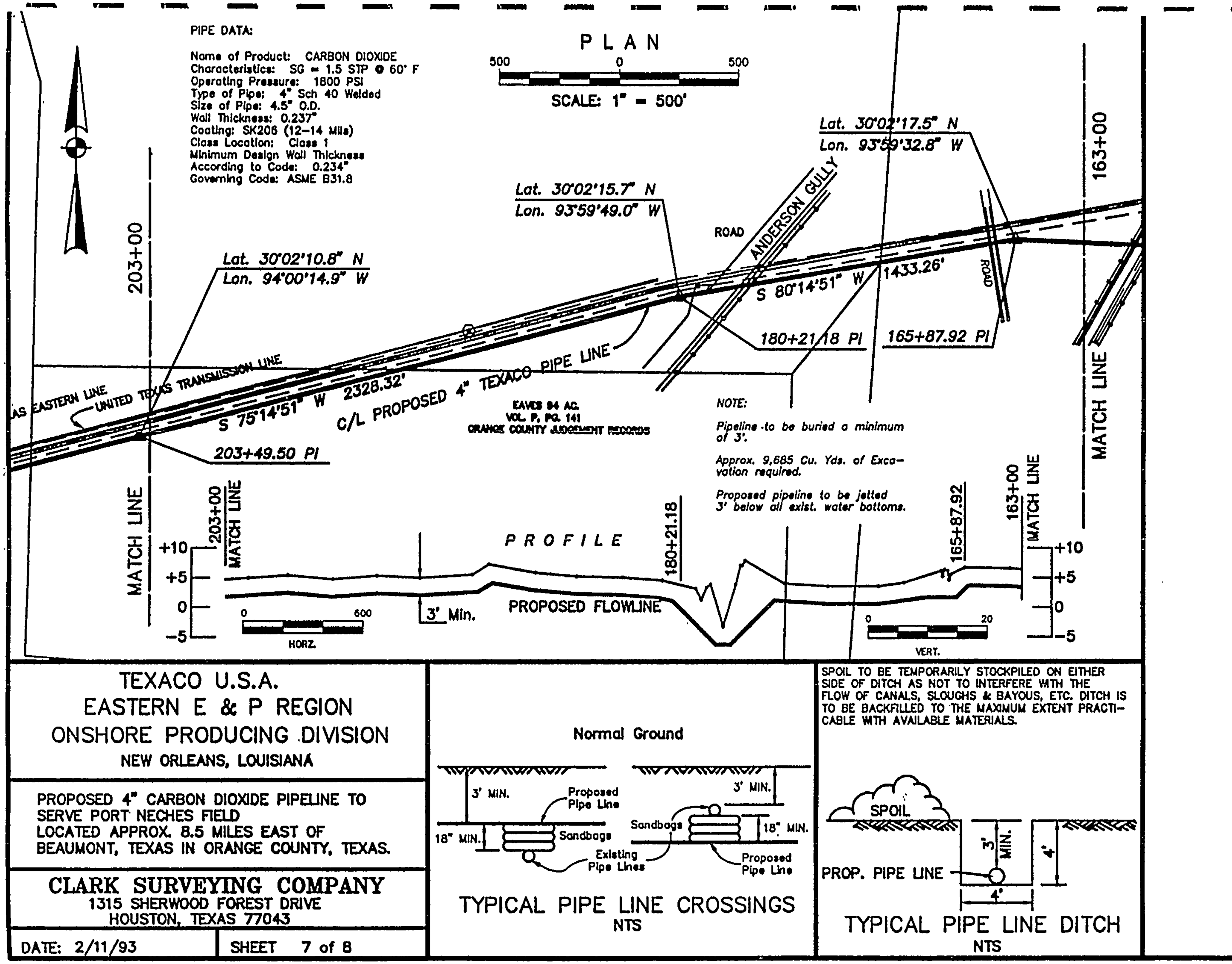
DATE: 2/11/93	SHEET 2 of 8

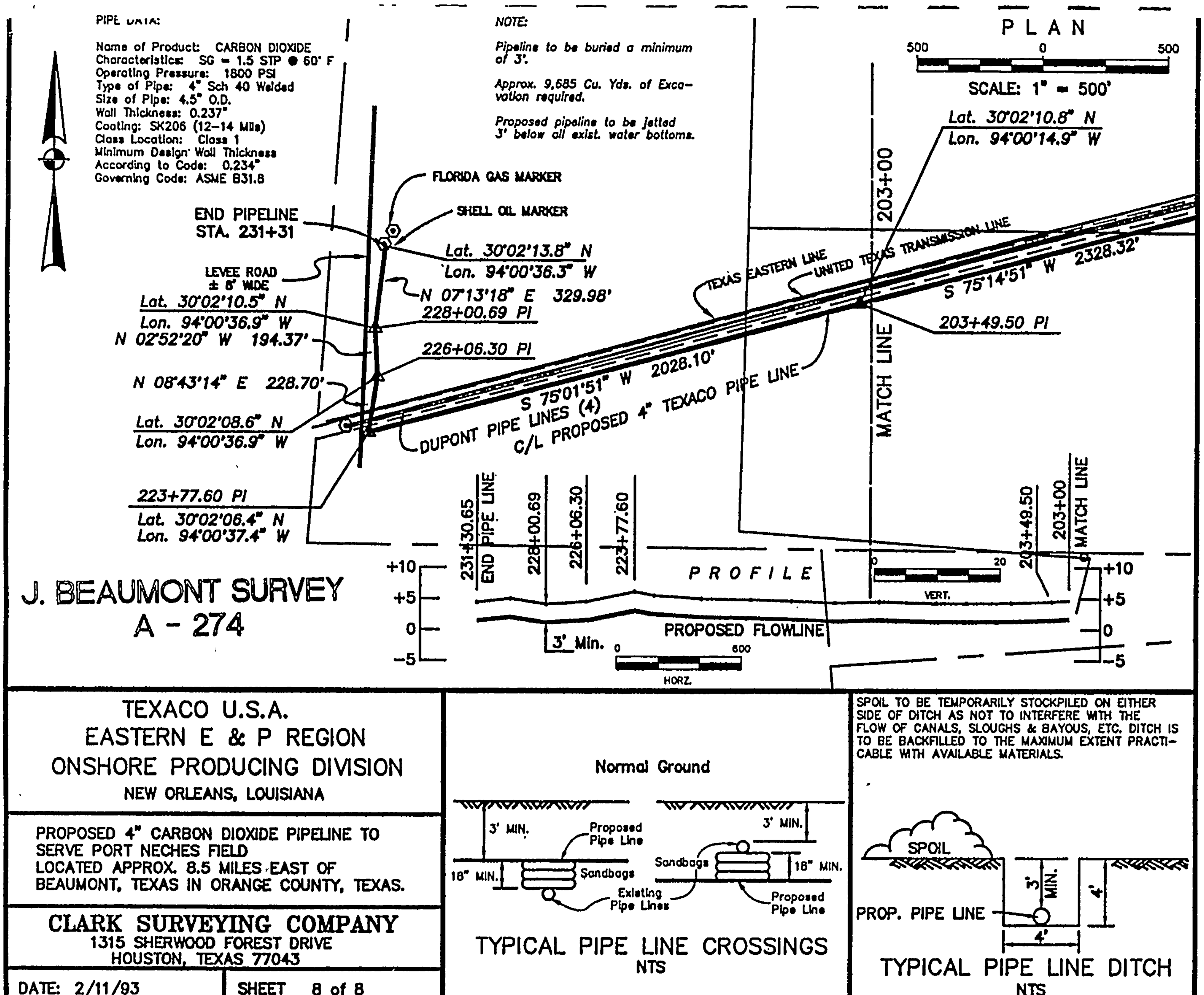

MARY A. E. HALL
A - 403
NOTE:
Pipeline to be buried a minimum of 3'.
Approx. 9,685 Cu. Yds. of Excavation required.
Proposed pipeline to be jetted 3' below all exist. water bottoms.
PIPE DATA:
Name of Product: CARBON DIOXIDE
Characteristics: SG = 1.5 STP @ 60° F
Operating Pressure: 1800 PSI
Type of Pipe: 4" Sch 40 Welded
Size of Pipe: 4.5" O.D.
Wall Thickness: 0.237"
Coating: SK206 (12-14 Mils)
Class Location: Class 1
Minimum Design Wall Thickness According to Code: 0.234"
Governing Code: ASME B31.8
PLAN
500 0 500
SCALE: 1" = 500'
Survey Line
43+00
MATCH LINE
N 87°18'50" W 15977.46'
UNIDENTIFIED PIPE LINE
CAPPED WELL HEAD
6+10.46 PI
610.46'
N 85°19'42" W
C/L PROPOSED 4" TEXACO PIPE LINE
H.J. KUHN NO. 33
Lat. 30°02'03.3" N
Lon. 93°56'31.8" W
BEGIN PIPELINE STA. 0+00
SELESTAN SCLAVON
A - 431
PROFILE
0 600
HORZ.
0 20
VERT.
+10
+5
0
-5
43+00 MATCH LINE
15+36.62
6+10.46
0+00
Top of Water
PROPOSED FLOWLINE
3' Min.
TEXACO U.S.A.
EASTERN E & P REGION
ONSHORE PRODUCING DIVISION
NEW ORLEANS, LOUISIANA
PROPOSED 4" CARBON DIOXIDE PIPELINE TO SERVE PORT NECHES FIELD LOCATED APPROX. 8.5 MILES EAST OF BEAUMONT, TEXAS IN ORANGE COUNTY, TEXAS.
CLARK SURVEYING COMPANY
1315 SHERWOOD FOREST DRIVE
HOUSTON, TEXAS 77043
DATE: 2/11/93
SHEET 3 of 8
Normal Ground
3' MIN.
18" MIN.
Proposed Pipe Line
Sandbags
Existing Pipe Lines
TYPICAL PIPE LINE CROSSINGS
NTS
SPOIL TO BE TEMPORARILY STOCKPILED ON EITHER SIDE OF DITCH AS NOT TO INTERFERE WITH THE FLOW OF CANALS, SLOUGHS & BAYOUS, ETC. DITCH IS TO BE BACKFILLED TO THE MAXIMUM EXTENT PRACTICABLE WITH AVAILABLE MATERIALS.
SPOIL
3' MIN.
4'
PROP. PIPE LINE
TYPICAL PIPE LINE DITCH
NTS


PIPE DATA:
Name of Product: CARBON DIOXIDE
Characteristics: SG = 1.5 STP @ 60° F
Operating Pressure: 1800 PSI
Type of Pipe: 4" Sch 40 Welded
Size of Pipe: 4.5" O.D.
Wall Thickness: 0.237"
Coating: SK206 (12-14 Mils)
Class Location: Class 1
Minimum Design Wall Thickness
According to Code: 0.234"
Governing Code: ASME B31.8
P L A N
500 0 500
SCALE: 1" = 500'
NOTE:
Pipeline to be buried a minimum of 3'.
Approx. 9,685 Cu. Yds. of Excavation required.
Proposed pipeline to be jetted 3' below all exist. water bottoms.
J. BEAUMONT
A - 273
P. LOCKWOOD
A - 424
MATCH LINE 83+00
MATCH LINE 43+00
N 87°18'50" W 15977.46'
C/L PROPOSED 4" TEXACO PIPE LINE
PROFILE
0 600
HORZ.
0 20
VERT.
83+00 MATCH LINE
43+00 MATCH LINE
+10
+5
0
-5
Top of Water
3' Min.
PROPOSED FLOWLINE
TEXACO U.S.A.
EASTERN E & P REGION
ONSHORE PRODUCING DIVISION
NEW ORLEANS, LOUISIANA
PROPOSED 4" CARBON DIOXIDE PIPELINE TO SERVE PORT NECHES FIELD
LOCATED APPROX. 8.5 MILES EAST OF BEAUMONT, TEXAS IN ORANGE COUNTY, TEXAS.
CLARK SURVEYING COMPANY
1315 SHERWOOD FOREST DRIVE
HOUSTON, TEXAS 77043
DATE: 2/11/93
SHEET 4 of 8
Normal Ground
3' MIN.
18" MIN.
Proposed Pipe Line
Sandbags
Existing Pipe Lines
3' MIN.
18". MIN.
Sandbags
Proposed Pipe Line
TYPICAL PIPE LINE CROSSINGS
NTS
SPOIL TO BE TEMPORARILY STOCKPILED ON EITHER SIDE OF DITCH AS NOT TO INTERFERE WITH THE FLOW OF CANALS, SLOUGHS & BAYOUS, ETC. DITCH IS TO BE BACKFILLED TO THE MAXIMUM EXTENT PRACTICABLE WITH AVAILABLE MATERIALS.
SPOIL
3' MIN.
4'
PROP. PIPE LINE
4'
TYPICAL PIPE LINE DITCH
NTS


PIPE DATA:
Name of Product: CARBON DIOXIDE
Characteristics: SG = 1.5 STP @ 60° F
Operating Pressure: 1800 PSI
Type of Pipe: 4" Sch 40 Welded
Size of Pipe: 4.5" O.D.
Wall Thickness: 0.237"
Coating: SK206 (12-14 Mils)
Class Location: Class 1
Minimum Design Wall Thickness
According to Code: 0.234"
Governing Code: ASME B31.8
NOTE:
Pipeline to be buried a minimum of 3'.
Approx. 9,685 Cu. Yds. of Excavation required.
Proposed pipeline to be jetted 3' below all exist. water bottoms.
PLAN
500
0
500
SCALE: 1" = 500'
WM. ALLEN
A - 28
J. BEAUMONT
A - 273
VISTA CHEMICAL PIPE LINES (2)
C/L PROPOSED 4" TEXACO PIPE LINE
N 87°18'50" W 15977.46'
MATCH LINE
123+00
MATCH LINE
83+00
PROFILE
0
600
HORZ.
0
20
VERT.
123+00
MATCH LINE
103+29.40
83+00
MATCH LINE
+10
+5
0
-5
Top of Water
PROPOSED FLOWLINE
3' Min.
TEXACO U.S.A.
EASTERN E & P REGION
ONSHORE PRODUCING DIVISION
NEW ORLEANS, LOUISIANA
PROPOSED 4" CARBON DIOXIDE PIPELINE TO SERVE PORT NECHES FIELD
LOCATED APPROX. 8.5 MILES EAST OF BEAUMONT, TEXAS IN ORANGE COUNTY, TEXAS.
CLARK SURVEYING COMPANY
1315 SHERWOOD FOREST DRIVE
HOUSTON, TEXAS 77043
DATE: 2/11/93
SHEET 5 of 8
Normal Ground
3' MIN.
18" MIN.
Proposed Pipe Line
Sandbags
Existing Pipe Lines
TYPICAL PIPE LINE CROSSINGS
NTS
SPOIL TO BE TEMPORARILY STOCKPILED ON EITHER SIDE OF DITCH AS NOT TO INTERFERE WITH THE FLOW OF CANALS, SLOUGHS & BAYOUS, ETC. DITCH IS TO BE BACKFILLED TO THE MAXIMUM EXTENT PRACTICABLE WITH AVAILABLE MATERIALS.
SPOIL
3' MIN.
4'
PROP. PIPE LINE
TYPICAL PIPE LINE DITCH
NTS


PLAN
500 0 500
SCALE: 1" = 500'
Name of Product: CARBON DIOXIDE
Characteristics: SG = 1.5 STP @ 60° F
Operating Pressure: 1800 PSI
Type of Pipe: 4" Sch 40 Welded
Size of Pipe: 4.5" O.D.
Wall Thickness: 0.237"
Coating: SK206 (12-14 Mils)
Class Location: Class 1
Minimum Design Wall Thickness
According to Code: 0.234"
Governing Code: ASME B31.8
170+00
MATCH LINE
EXIST. 50' DUPONT ESMT
S 75°14'51" W 2492.55'
C/L PROPOSED 4" TEXACO PIPE LINE
ROAD
166+46.93 PI
Lat. 30°02'18.3" N
Lon. 93°59'25.8" W
ROAD
WM. ALLEN
A - 28
141+54.38 PI
Lat. 30°02'23.5" N
Lon. 93°58'58.1" W
ENRON PIPE LINE
O/H POWER LINES
N 23°04'11" W 978.49'
LION OIL CO. PIPE LINE
HOUSTON PIPE LINE CO. PIPE LINE
131+75.89 PI
Lat. 30°02'14.4" N
Lon. 93°58'54.2" W
N 87°18'50" W 12555.43'
123+00
MATCH LINE
NOTE:
Pipeline to be buried a minimum of 3'.
Approx. 9,685 Cu. Yds. of Excavation required.
Proposed pipeline to be jetted 3' below all exist. water bottoms.
0 600
HORZ.
0 20
VERT.
PROFILE
170+00
MATCH LINE
+10
+5
0
-5
Top of Water
3' Min.
PROPOSED FLOWLINE
123+00
MATCH LINE
TEXACO U.S.A.
EASTERN E & P REGION
ONSHORE PRODUCING DIVISION
NEW ORLEANS, LOUISIANA
PROPOSED 4" CARBON DIOXIDE PIPELINE TO SERVE PORT NECHES FIELD
LOCATED APPROX. 8.5 MILES EAST OF BEAUMONT, TEXAS IN ORANGE COUNTY, TEXAS.
CLARK SURVEYING COMPANY
1315 SHERWOOD FOREST DRIVE
HOUSTON, TEXAS 77043
DATE: 3/16/93
SHEET 6 of 8
Normal Ground
3' MIN.
Proposed Pipe Line
18" MIN.
Sandbags
Existing Pipe Lines
Sandbags
3' MIN.
18" MIN.
Proposed Pipe Line
TYPICAL PIPE LINE CROSSINGS
NTS
SPOIL TO BE TEMPORARILY STOCKPILED ON EITHER SIDE OF DITCH AS NOT TO INTERFERE WITH THE FLOW OF CANALS, SLOUGHS & BAYOUS, ETC. DITCH IS TO BE BACKFILLED TO THE MAXIMUM EXTENT PRACTICABLE WITH AVAILABLE MATERIALS.
SPOIL
3' MIN.
4'
PROP. PIPE LINE
4'
TYPICAL PIPE LINE DITCH
NTS


PIPE DATA:
Name of Product: CARBON DIOXIDE
Characteristics: SG = 1.5 STP @ 60° F
Operating Pressure: 1800 PSI
Type of Pipe: 4" Sch 40 Welded
Size of Pipe: 4.5" O.D.
Wall Thickness: 0.237"
Coating: SK206 (12–14 Mils)
Class Location: Class 1
Minimum Design Wall Thickness
According to Code: 0.234"
Governing Code: ASME B31.8
PLAN
500 0 500
SCALE: 1" = 500'
Lat. 30°02'17.5" N
Lon. 93°59'32.8" W
Lat. 30°02'15.7" N
Lon. 93°59'49.0" W
Lat. 30°02'10.8" N
Lon. 94°00'14.9" W
203+00
163+00
ROAD
ANDERSON GULLY
ROAD
S 80°14'51" W 1433.26'
180+21.18 PI
165+87.92 PI
MATCH LINE
UNITED TEXAS TRANSMISSION LINE
AS EASTERN LINE
S 75°14'51" W 2328.32'
C/L PROPOSED 4" TEXACO PIPE LINE
EAVES 94 AC.
VOL. P, PG. 141
ORANGE COUNTY JUDGEMENT RECORDS
203+49.50 PI
NOTE:
Pipeline to be buried a minimum of 3'.
Approx. 9,685 Cu. Yds. of Excavation required.
Proposed pipeline to be jetted 3' below all exist. water bottoms.
MATCH LINE
203+00 MATCH LINE
180+21.18
165+87.92
163+00 MATCH LINE
PROFILE
+10
+5
0
−5
3' Min.
PROPOSED FLOWLINE
0 600
HORZ.
0 20
VERT.
TEXACO U.S.A.
EASTERN E & P REGION
ONSHORE PRODUCING DIVISION
NEW ORLEANS, LOUISIANA
PROPOSED 4" CARBON DIOXIDE PIPELINE TO SERVE PORT NECHES FIELD
LOCATED APPROX. 8.5 MILES EAST OF BEAUMONT, TEXAS IN ORANGE COUNTY, TEXAS.
CLARK SURVEYING COMPANY
1315 SHERWOOD FOREST DRIVE
HOUSTON, TEXAS 77043
DATE: 2/11/93
SHEET 7 of 8
Normal Ground
3' MIN.
18" MIN.
Proposed Pipe Line
Sandbags
Existing Pipe Lines
Sandbags
3' MIN.
18" MIN.
Proposed Pipe Line
TYPICAL PIPE LINE CROSSINGS
NTS
SPOIL TO BE TEMPORARILY STOCKPILED ON EITHER SIDE OF DITCH AS NOT TO INTERFERE WITH THE FLOW OF CANALS, SLOUGHS & BAYOUS, ETC. DITCH IS TO BE BACKFILLED TO THE MAXIMUM EXTENT PRACTICABLE WITH AVAILABLE MATERIALS.
SPOIL
3' MIN.
4'
PROP. PIPE LINE
4'
TYPICAL PIPE LINE DITCH
NTS


PIPE DATA:
Name of Product: CARBON DIOXIDE
Characteristics: SG = 1.5 STP @ 60° F
Operating Pressure: 1800 PSI
Type of Pipe: 4" Sch 40 Welded
Size of Pipe: 4.5" O.D.
Wall Thickness: 0.237"
Coating: SK206 (12–14 Mils)
Class Location: Class 1
Minimum Design Wall Thickness According to Code: 0.234"
Governing Code: ASME B31.8
NOTE:
Pipeline to be buried a minimum of 3'.
Approx. 9,685 Cu. Yds. of Excavation required.
Proposed pipeline to be jetted 3' below all exist. water bottoms.
PLAN
500
0
500
SCALE: 1" = 500'
Lat. 30°02'10.8" N
Lon. 94°00'14.9" W
FLORIDA GAS MARKER
SHELL OIL MARKER
END PIPELINE
STA. 231+31
Lat. 30°02'13.8" N
Lon. 94°00'36.3" W
LEVEE ROAD
± 8' WIDE
N 07°13'18" E 329.98'
228+00.69 PI
Lat. 30°02'10.5" N
Lon. 94°00'36.9" W
N 02°52'20" W 194.37'
226+06.30 PI
N 08°43'14" E 228.70'
Lat. 30°02'08.6" N
Lon. 94°00'36.9" W
223+77.60 PI
Lat. 30°02'06.4" N
Lon. 94°00'37.4" W
TEXAS EASTERN LINE
UNITED TEXAS TRANSMISSION LINE
S 75°14'51" W 2328.32'
203+49.50 PI
203+00
MATCH LINE
S 75°01'51" W 2028.10'
DUPONT PIPE LINES (4)
C/L PROPOSED 4" TEXACO PIPE LINE
J. BEAUMONT SURVEY
A - 274
231+30.65
END PIPE LINE
228+00.69
226+06.30
223+77.60
203+49.50
203+00
MATCH LINE
+10
+5
0
-5
PROFILE
0
20
VERT.
3' Min.
0
600
HORZ.
PROPOSED FLOWLINE
TEXACO U.S.A.
EASTERN E & P REGION
ONSHORE PRODUCING DIVISION
NEW ORLEANS, LOUISIANA
PROPOSED 4" CARBON DIOXIDE PIPELINE TO SERVE PORT NECHES FIELD
LOCATED APPROX. 8.5 MILES EAST OF BEAUMONT, TEXAS IN ORANGE COUNTY, TEXAS.
CLARK SURVEYING COMPANY
1315 SHERWOOD FOREST DRIVE
HOUSTON, TEXAS 77043
DATE: 2/11/93
SHEET 8 of 8
Normal Ground
3' MIN.
18" MIN.
Proposed Pipe Line
Sandbags
Existing Pipe Lines
TYPICAL PIPE LINE CROSSINGS
NTS
SPOIL TO BE TEMPORARILY STOCKPILED ON EITHER SIDE OF DITCH AS NOT TO INTERFERE WITH THE FLOW OF CANALS, SLOUGHS & BAYOUS, ETC. DITCH IS TO BE BACKFILLED TO THE MAXIMUM EXTENT PRACTICABLE WITH AVAILABLE MATERIALS.
SPOIL
3' MIN.
4'
4'
PROP. PIPE LINE
TYPICAL PIPE LINE DITCH
NTS

Technology Transfer

The PC-based model developed by Texaco's research lab in Houston for this project has been tested against other compositional simulators and is found to be very reliable. A draft by our research center documents these results and will be presented at the Improved Oil Recovery Symposium in Tulsa during April, 1994.

An SPE paper documenting the theory behind the model was also recently presented at the Annual SPE meeting in Houston.

DRAFT

INTRODUCTION

This report compares the CO_2 flood performance predicted by PC-Prophet with the predictions of COMP III and VIP-EXEC(COMP). The objective is to provide users of PC-Prophet with information on how the predictions of PC-Prophet compare to those of the compositional simulators which are now used within Texaco.

An additional issue discussed is what option for the solvent phase relative permeability in PC-Prophet gives results closest to those of the compositional simulators.

Three variations of the CO_2 flooding process were compared:

Tertiary with a waterflood, CO_2/WAG flood, and chase water
Tertiary with a waterflood, single continuous CO_2 slug, and chase water
Secondary with immobile water

The comparative cases which were simulated were based on a five-spot pattern using Roberts Unit data.

CONCLUSIONS

The following conclusions result from the comparative study of PC-Prophet and the compositional simulators.

1. The predictions of PC-Prophet for waterflood and CO_2 flood performance in a five spot were found to be very close to those of COMP III and VIP-EXEC(COMP) for oil recovery. The predictions during WAG were especially close.

2. The similarity is expected to hold for other cases with simple reservoir descriptions (homogeneous layers without crossflow).

3. For most cases, the saturation weighted average method of calculating relative permeability for the miscible phase in PC-Prophet produced results closest to those of VIP-EXEC(COMP) and COMP III. Under some circumstances, the option in which the miscible phase relative permeability is set equal to that of the oil produced results closer to a compositional simulator.

PC-Prophet predicted much too high an oil recovery during the chase water drive period under some special circumstances. This problem has been corrected. The runs in this report were done with the corrected version. The correction will be included in the next general revision. Users who want a version of PC-Prophet now which includes this correction can contact John Prieditis (Texnet 659-6168) or John Dobitz (Texnet 659-6080).

FUTURE WORK

There are no additional comparative studies of PC-Prophet planned at this time.

DISCUSSION

This study compares the predictions of PC-Prophet, COMP III, and VIP-EXEC(COMP). First, some background information on the comparison cases is provided, and then results of the comparisons are discussed.

Background

Model Background

COMP III and VIP-EXEC(COMP) are both grid-based finite difference compositional simulators which model the miscibility of CO_2 and oil by using equation-of-state flash calculations.

PC-Prophet is a simulator which does finite difference calculations along streamtubes. The miscibility of CO_2 and oil is modeled by using a modified Todd and Longstaff mixing parameter approach. Miscibility is modeled by the calculation of effective fluid viscosities and effective relative permeabilities.

> The effective fluid viscosities are adjusted with the mixing parameter, omega. The mixing parameter can be set between 0.0 and 1.0. As the parameter is set closer to 1.0, the effective CO_2 and oil viscosities are made closer at the CO_2-oil contact.
>
>> For all the PC-Prophet runs, the mixing parameter, omega, was set to 0.666. This can be considered a standard value. The results of PC-Prophet were close to those of the compositional simulators with omega set to 0.666. Adjustment of the mixing parameter was not needed.
>
> Effective miscible phase relative permeabilities are calculated to model the miscibility between CO_2 and oil. PC-Prophet can do this in three different ways. The ways are discussed in detail in Appendix A. The miscible phase relative permeability can be calculated as
>
>> a saturation weighted average of the solvent and oil relative permeabilities (This method is unique to PC-Prophet.)
>>
>> a simple average of the oil and gas relative permeabilities (This method corresponds to the documentation for COMP III)

equal to the oil relative permeability (This is the standard method for mixing parameter models.)

One objective of this study was to investigate which of these methods gave results closest to those of the compositional simulators.

Basic Approach

The approach was to create the same input data for PC-Prophet and the compositional simulators, run the simulators, and compare the results. There was no attempt to adjust parameters within PC-Prophet to match the results of the compositional simulators.

The comparative simulations were based on a five spot pattern using data from an earlier Roberts Unit simulation[1].

First, the pattern characteristics and input data are outlined. Then, the results of the simulations are discussed.

Input Data

Reservoir description - Four homogeneous layers with no vertical permeability or cross-flow. No difference between the X and Y direction permeabilities in each layer. Fairly high permeability variation among the layers with a Dykstra-Parsons coefficient of 0.75.

Pattern - Five-spot

Fluid properties - Same fluid viscosities in PC-Prophet and the compositional simulators.

Relative permeabilities - Same relative permeabilities in PC-Prophet and the compositional simulators. No miscible residual oil saturation for PC-Prophet (i.e., Sorm = 0.0).

The vertical permeability in the compositional models was set to zero to eliminate cross-flow between the layers.

A typical input data set (i.e., an INDATA file) is provided in Appendix B.

Recovery Processes and Injection Sequences

Three types of recovery process were compared, including a tertiary WAG, a tertiary single CO_2 slug, and a secondary process.

Tertiary WAG. The stages in the flooding process for the tertiary WAG were:

Waterflood - starting with 11.8% OOIP already recovered
CO_2-WAG - 0.31 HCPV CO_2 with 1.17:1 WAG ratio (water:CO_2)
Water chase

The 0.31 HCPV CO_2 is computed based on the original oil in place prior to the primary period. The WAG period ends at 0.67 total (CO_2+water) HCPV injected.

Tertiary Continuous CO_2 Slug. The stages in the flooding process for the tertiary CO_2 slug were:

Waterflood - starting with 11.8% OOIP already recovered
CO_2 slug - 0.31 HCPV CO_2 with no water
Water chase

Secondary. The secondary injection sequence was the injection of CO_2 into an oil-filled pattern starting at the connate water saturation. The water was immobile in this case; only the CO_2 and oil were flowing.

Gas Relative Permeability Variations

A strong test of how closely PC-Prophet compares with the compositional simulators, is to run comparative cases over as broad a range of gas permeabilities as might be expected. This is a much more thorough test than a comparison in which the gas and oil relative permeabilities are the same.

When the gas relative permeability is changed in compositional simulators, there is a difference in the predicted CO_2 flood performance, both for oil recovery and for CO_2 production. This is because, to a large degree, the CO_2 follows the gas relative permeability curve.

PC-Prophet can use different gas relative permeability curves, unlike most mixing parameter models. This is done by using the saturation weighted method in PC-Prophet and treating the solvent relative permeability curve as if it were the gas relative permeability curve. In contrast, most mixing parameter models cannot match predicted CO_2 flood performance differences that are the result of differences in the gas relative permeability. This is because they do not even use the gas relative permeability curve. They instead define the miscible phase relative permeability as equal to the oil relative permeability.

The predictions of PC-Prophet were compared with those of the compositional simulators for three values of the gas relative permeability. Three levels of the endpoint gas (or CO_2) to oil relative permeability ratio were investigated. The ratios were 3.4, 0.34, and 0.034.

For example, the 0.034 ratio represents an endpoint CO_2 relative permeability which is only 3.4 percent of that for the oil.

The following shows the relationship between the gas relative permeability endpoints (krgcw) and the gas to oil endpoint relative permeability ratios that were used:

Endpoint gas rel perm krgcw	Endpoint gas rel perm / Endpoint oil rel perm
1.0	3.4
0.1	0.34
0.01	0.034

The oil endpoint relative permeability was 0.295.

Adjusting the gas relative permeability curve is one of the few ways of trying to match CO_2 flooding performance without affecting the waterflood history match.

Simulation Results

CO_2 flood predictions using PC-Prophet, VIP-EXEC(COMP), and COMP III were compared. The format of the results is discussed first followed by conclusions about the PC-Prophet options. The comparison of the results is divided into discussions of the waterflood, the CO_2-WAG process, the single CO_2 slug followed by chase water, and secondary recovery.

Table and Figure Format of Results

The results presented in the figures and table show tertiary recovery after the end of the initial waterflood as a function of HCPV. These are not incremental tertiary recoveries as usually defined, because they do not exclude the oil which would have been recovered just by the continued waterflood. Instead, these values are additional amounts recovered after the end of the waterflood (i.e., the recovery at the end of the waterflood has been subtracted). The injected HCPV (hydrocarbon pore volume) is the HCPV injected after the end of the waterflood (i.e, the water injected during the waterflood has been subtracted). The injected HCPV includes both the injected water and CO_2.

Miscible Phase Relative Permeability Option in PC-Prophet

The three options available for the miscible phase relative permeability were listed previously and are discussed in more detail in Appendix A. In short, these options are the saturation weighted method, the simple average method, and the equal to oil method.

Saturation Weighted. Except under special circumstances, the saturation weighted method in PC-Prophet produced predictions closer to the compositional simulators than the other two options. This was especially true for the cases in which the gas relative permeability was smaller than that of the oil. This method is unique to PC-Prophet, but it is similar to Amoco's solvent relative permeability (SRP) model.[2]

Equal to Oil. The standard formulation, in which the miscible phase relative permeability is set equal to the oil relative permeability k_{row}, gives only a single result for all values of the gas relative permeability. CO_2 or gas relative permeabilities are not included in any calculation. This method, however, gave results closest to those of a compositional simulator under some conditions. There were two conditions that had to be met:

the process had to be a CO_2 slug (followed by water) or secondary recovery

the CO_2 relative permeability had to be greater than that of the oil

Simple Average. The simple averaging method was taken from the documentation for COMP III. However, it did not produce results closer to those of COMP III than the other two methods. Instead, it produced results very close to those of the method in which the miscible phase relative permeability is set equal to that of the oil. For cases of very small gas relative permeability, the oil recovery was actually slightly reduced. This is contrary to what should happen.

Situation in which option choice does not matter. All three methods of defining the miscible phase relative permeability in PC-Prophet produce essentially identical results when the gas and oil endpoint relative permeabilities are very similar. For many (perhaps even most) previous simulations, the gas and oil endpoint relative permeabilities have, in fact, been very similar. Consequently, all three options for the miscible phase relative permeability would have resulted in very similar predictions for these simulations.

In the absence of any information about the gas relative permeability, the standard method, in which the solvent relative permeability is set equal to that of the oil, is recommended.

Waterflood Results

All three simulators produced essentially identical results for the waterflood. As indicated previously, there was no special attempt to make PC-Prophet match the compositional simulators. The objective was to make the input data sets as similar as possible and then compare the results.

Figure 1 shows the waterflood comparisons.

Comparisons are also provided in Table 1. It should be noted that the primary recovery of 11.8% has been added to the end of waterflood recovery reported in the table. The waterflood was initiated with 11.8% HCPV already recovered.

CO_2-WAG

The predicted recoveries during the WAG period were remarkably close for all three simulators and for all three values of the gas relative permeability. The WAG period was from 0.0 to 0.67 HCPV and included 0.31 HCPV CO_2. There was as much difference between the two compositional simulators as there was between PC-Prophet and either of the two compositional simulators. PC-Prophet predicted somewhat higher recoveries during the subsequent chase water period for all values of the gas relative permeability.

A revised version of PC-Prophet was used for these cases. The revision has the following change:

> For cases in which the CO_2 mobility is greater than the brine mobility, the relative fluid injection ratios for each stream tube remain constant during the water chase period. These constant values are the values that occurred just at the end of the period during which CO_2 was injected.

Prior to this revision, PC-Prophet predicted an even higher recovery during the chase water period.

> Figures 2,3, and 4 show the cumulative HCPV oil recovery for the three values of the gas relative permeability. The saturation weighted method was used in PC-Prophet for these cases.
>
> Figure 5 includes the PC-Prophet result for the case in which the miscible phase relative permeability is set equal to the oil phase relative permeability. As might be expected, this method produced a result between that for the high and intermediate values of the gas relative permeability.
>
> Figures 6,7, and 8 show the predicted oil production rates. Again the results are very similar for all the simulators and cases.

For a WAG process, the saturation weighted method produces the best results for all values of the gas relative permeability.

Single Continuous CO_2 Slug Followed by Chase Water

For these comparisons, only COMP III and PC-Prophet were used. PC-Prophet again predicted recoveries very close to those of the COMP III compositional simulator. The qualification is that different PC-Prophet options for the miscible phase relative permeability must be used for different values of the gas relative permeability.

> <u>Gas Relative Permeability Higher than that for Oil</u>. For a case in which the gas relative permeability endpoint is higher than that for the oil, the PC-Prophet option which makes the miscible phase relative permeability equal to that for the oil gives results closest to those of COMP III. The example for this case is shown in Figure 9; the gas endpoint relative permeability, krgcw, is 1.0 while that for the oil is 0.295.

> <u>Gas Relative Permeability Smaller than that for Oil</u>. For cases in which the gas relative permeability endpoint is smaller than that for the oil, the saturation weighted option gives the closest results.

For the case in which the gas relative permeability is higher than that of the oil, it is not certain whether PC-Prophet with the saturation weighted method or COMP III is actually more accurate.

<u>Secondary Recovery</u>

The results for secondary recovery were analogous to those for the previous case of a continuous CO_2 slug followed by chase water. As before, only COMP III and PC-Prophet were used. PC-Prophet and COMP III had very similar predictions. As before, the qualification is that the PC-Prophet option which sets the miscible phase relative permeability equal to that for the oil must be used when the gas relative permeability is larger than that of the oil.

> <u>Figures 12, 13, and 14</u> show the predicted cumulative HCPV oil recoveries for the three different values of the gas relative permeability in the secondary CO_2 recovery process.

The results for secondary recovery are analogous to those of a continuous (tertiary) CO_2 slug followed by a chase water drive.

> <u>Gas Relative Permeability Higher than that for Oil</u>. The PC-Prophet option which makes the miscible phase relative permeability equal to that for the oil gives results closest to those of COMP III for a case in which the gas relative permeability endpoint is higher than that for the oil. The example for this case is shown in Figure 12.

> <u>Gas Relative Permeability Smaller than that for Oil</u>. For cases in which the gas relative permeability endpoint is smaller than that for the oil, the saturation weighted option gives the closest results.

Summary of Option Performance

The following is a summary of which PC-Prophet options produce results closet to the compositional simulators and under what circumstances.

CO_2-WAG - Saturated weighted in all cases

Tertiary Continuous CO_2 slug followed by Chase Water
or
Secondary Recovery

Gas endpoint relative permeability higher than that of oil - miscible phase equal to oil

Gas endpoint relative permeability smaller than that of oil - miscible phase equal to oil

Additional Observations

Hysteresis Effects. Water and oil hysteresis tend to occur in San Andres carbonates. The current commercial compositional simulators cannot effectively include the hysteresis effects. The typical effect of water hysteresis is an increased residual water saturation. An increased residual water saturation tends to make predicted CO_2 breakthrough earlier as well as increase the predicted early oil and CO_2 production.

The inability to include water and oil hysteresis may make it difficult for compositional simulators to effectively model CO_2 breakthrough.

Gas Relative Permeability Effects.. There are some important effects of the gas relative permeability shown in Table 1.

1. The predicted oil recoveries increased as the gas/oil endpoint relative permeability ratio was decreased. The oil recovery increase was greatest for VIP-EXEC(COMP) and least for COMP III. VIP Comp is thus the most sensitive to the gas relative permeability. PC-Prophet had an intermediate increase.

2. The predicted CO_2 production decreased more than the oil production increased when the gas relative permeability was decreased. Predicted CO_2 production is more sensitive to the gas relative permeability. Although not directly shown, the predicted CO_2 injectivity is also significantly reduced by large reductions in gas relative permeability.

REFERENCES

1. Wang, B., Cheng, C. T., and Tipton, T. L., "CO_2 Flood Simulation for East Sector of Roberts Unit," EPTD Report No. 90-045.

2. Chopra, A. K., Stein, M.H. and Dismuke, C. T., "Prediction of Performance of Miscible Gas Pilots," SPE Paper 18078, 1988 Fall Annual Meeting.

APPENDIX A

The miscible phase relative permeability, k_{rm}, can be represented as

a saturation weighted average of k_{row} and k_{rs}

$$k_{rm} = \frac{S_o - S_{orm}}{1 - S_w - S_{orm}} k_{row} + \frac{S_g}{1 - S_w - S_{orm}} k_{rs} \tag{1}$$

where k_{row} is the oil relative permeability and k_{rs} is the solvent relative permeability

an average of k_{row} and k_{rg}

$$k_{rm} = 0.5(k_{row} + k_{rg}) \tag{2}$$

where k_{rg} is the gas relative permeability

equal to k_{row}

$$k_{rm} = k_{row} \tag{3}$$

The first option, which makes k_{rm} a saturation weighted average, can incorporate a reduced CO_2 relative permeability. This method is unique to PC-Prophet. When the CO_2 saturation is at a maximum (with an immobile oil saturation at S_{orm}, the miscible residual oil saturation), the miscible phase relative permeability equals the endpoint CO_2 relative permeability.

The second option makes the miscible phase relative permeability a simple average of the gas and oil relative permeabilities. This method corresponds to COMP III documentation.

The third option, in which the miscible phase relative permeability is set equal to that of the oil, is the standard formulation which is used in mixing parameter models. However, it cannot incorporate a reduced CO_2 relative permeability.

The solvent and oil are tracked separately even though they are miscible. This is done by dividing the miscible phase relative permeability and assigning to the solvent and oil the correct fractions. The correct fractions are based on saturation. Under miscible conditions, the gas relative permeability is

$$\frac{S_g}{1-S_w-S_{orm}}k_{rm} \tag{4}$$

and the oil relative permeability is

$$\frac{S_o-S_{orm}}{1-S_w-S_{orm}}k_{rm} \tag{5}$$

In some formulations the miscible residual is left out of the denominator. However, when this is done, the non-aqueous phase permeability is not completely distributed between the CO_2 and oil.

APPENDIX B

```
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'NBNDPT'
5
'BOUNDX    BOUNDY'
0,  0
0,  1
1,  1
1,  0
0,  0
'************* PROGRAM CONTROLS ********'
'LWGEN    OUTTIM'
'N',    0.5
'**** RELATIVE PERMEABILITY PARAMETERS ***'
'SORW    SORG    SORM'
0.40,    0.25,    0.001
'SGR    SSR'
0.05,    0.05
'SWC    SWIR'
0.15,    0.15
'KROCW    KWRO    KRSMAX    KRGCW'
0.295,    0.27,    0.1,    0.1
'EXPOW    EXPW    EXPS    EXPG    EXPOG'
2.36,    2.10,    3.17,    3.17,    1.49
'KRMSEL    W'
0,    0.666
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'BO    RS    API    SALN    CSG'
1.22,    600,    32,    50000,    0.8
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'TRES    P    MMP'
114,    2000,    1500
'DPCOEF    PERMAV    THICK    POROS    NLAYERS'
```

```
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0.75,     0,     0.25
'AREA    XKVH'
1742400,     0.0
'********** INJECTION PARAMETERS *********'
'NTIMES    WAGTAG'
3,     'V'
'HCPVI    WTRRAT    SOLRAT    TMORVL'
0.58,     200.,     0,     1
0.31,     368,     0.688,     0.54
1.05,     360.0,     0,     1
```

TABLE 1

PROPHET

Process Oil Recovery, % OOIP	K_{rgcw}/K_{rocw} 3.4	0.34	0.034
Waterflood & Primary	32.6	32.6	32.6
CO_2 WAG	15.7	17.1	17.8
Chase Waterflood, 0.75 HCPV water	6.1	8.2	8.8
Maximum Oil Rate, BOPD	14	13	12
CO_2 Produced, End of WAG, %	51	34	21
Maximum GOR, SCF/STB	8590	5250	3260

VIP COMP

Process Oil Recovery, % OOIP	3.4	0.34	0.034
Waterflood & Primary	32.8	32.8	32.8
CO_2 WAG	15.3	17.4	18.8
Chase Waterflood, 0.75 HCPV water	4.7	4.6	5.7
Maximum Oil Rate, BOPD	15.3	15.7	14.3
Maximum GOR, SCF/STB	8487	6577	2966

COMP3

Process Oil Recovery, % OOIP	3.4	0.34	0.034
Waterflood & Primary	32.4	32.4	32.4
CO_2 WAG	15.4	16.5	16.9
Chase Waterflood, 0.75 HCPV water	5.6	6.2	7.1
Maximum Oil Rate, BOPD	18	16	13
CO_2 Produced, End of WAG, %	43	23	8.5
Maximum GOR, SCF/STB	8580	5500	2400

ROBERTS UNIT 5 SPOT PATTERN
WATERFLOOD

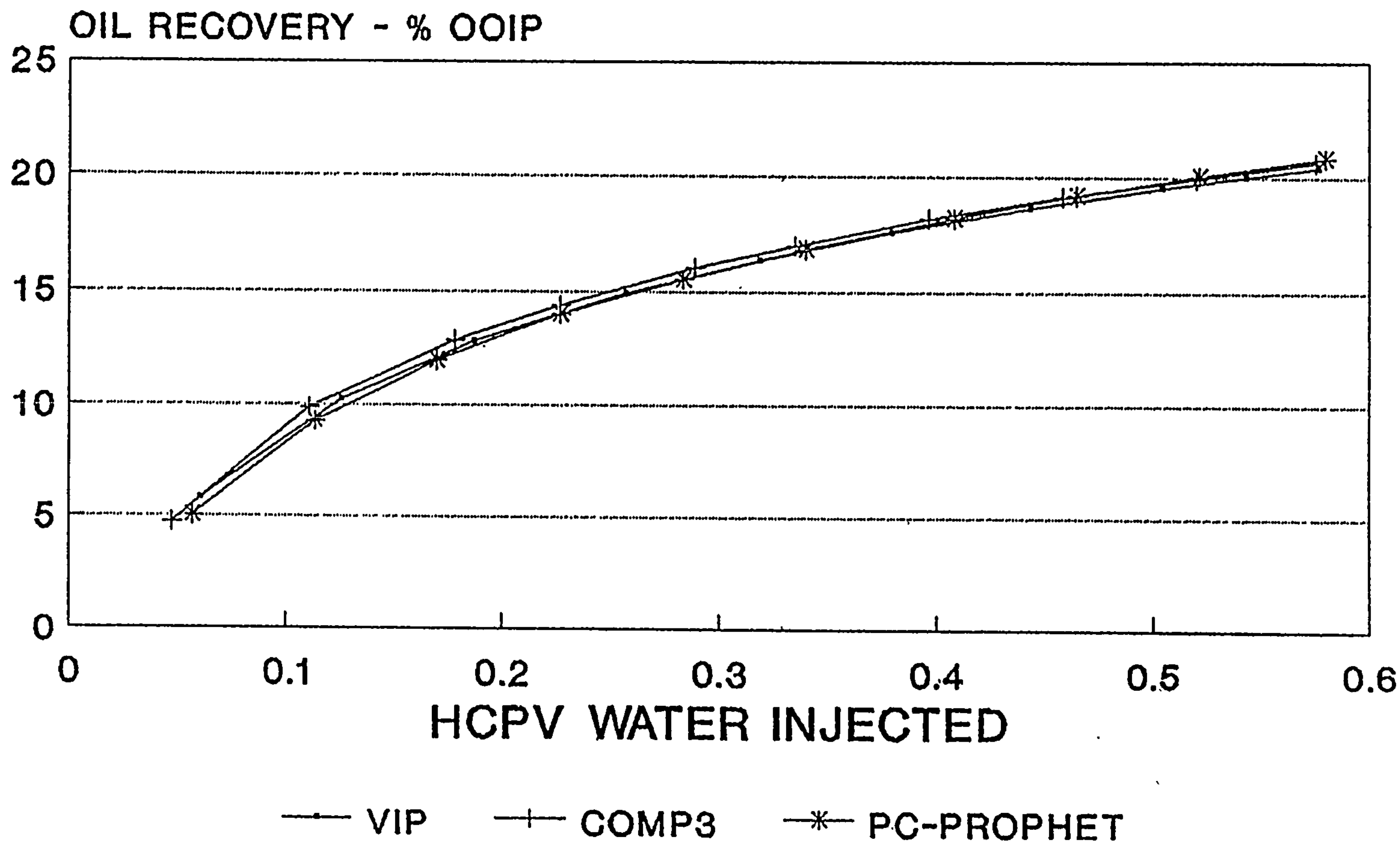


Figure 1

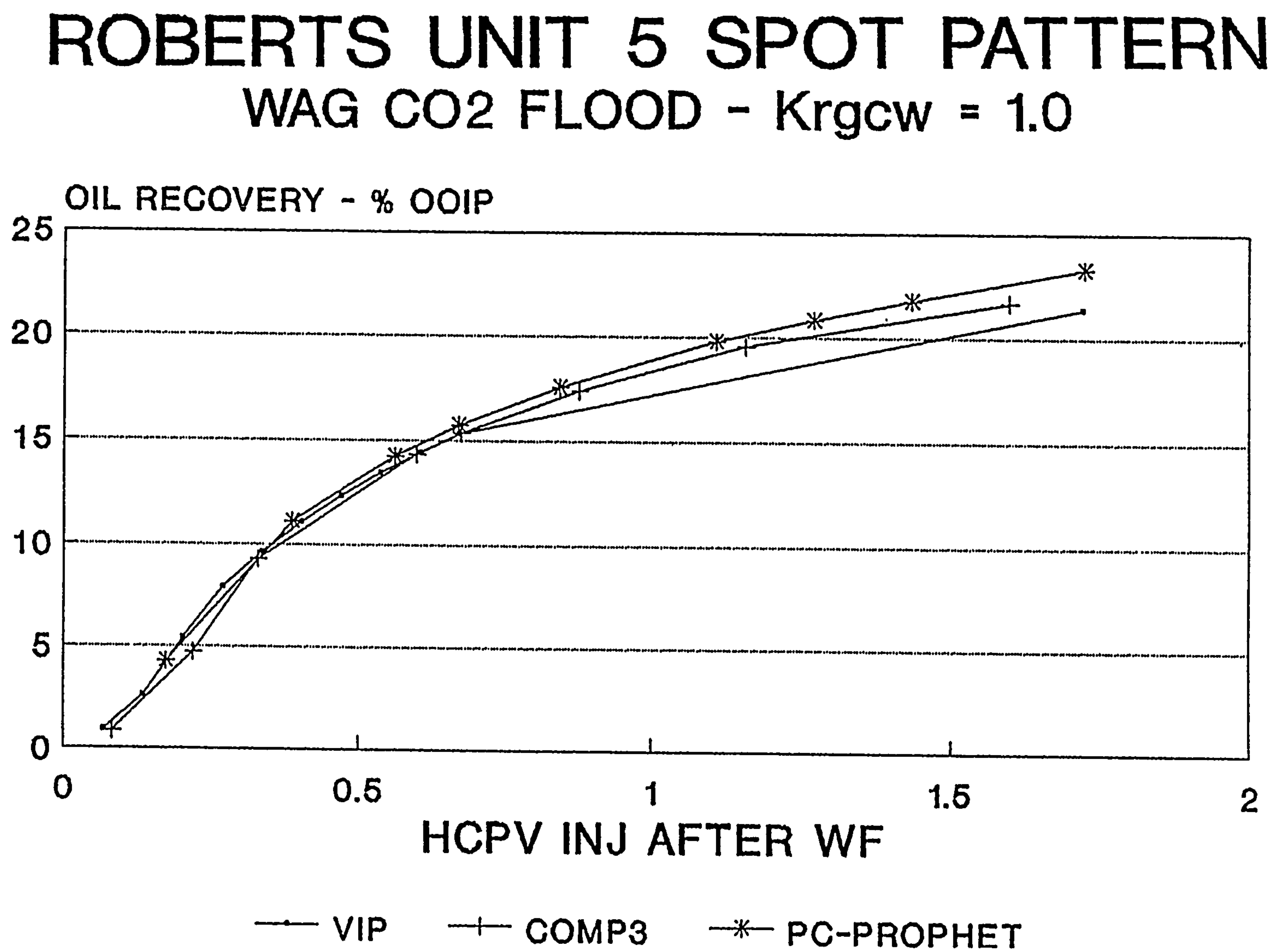

ROBERTS UNIT 5 SPOT PATTERN
WAG CO2 FLOOD - Krgcw = 1.0
OIL RECOVERY - % OOIP
25
20
15
10
5
0
0
0.5
1
1.5
2
HCPV INJ AFTER WF
VIP
COMP3
PC-PROPHET

Figure 2

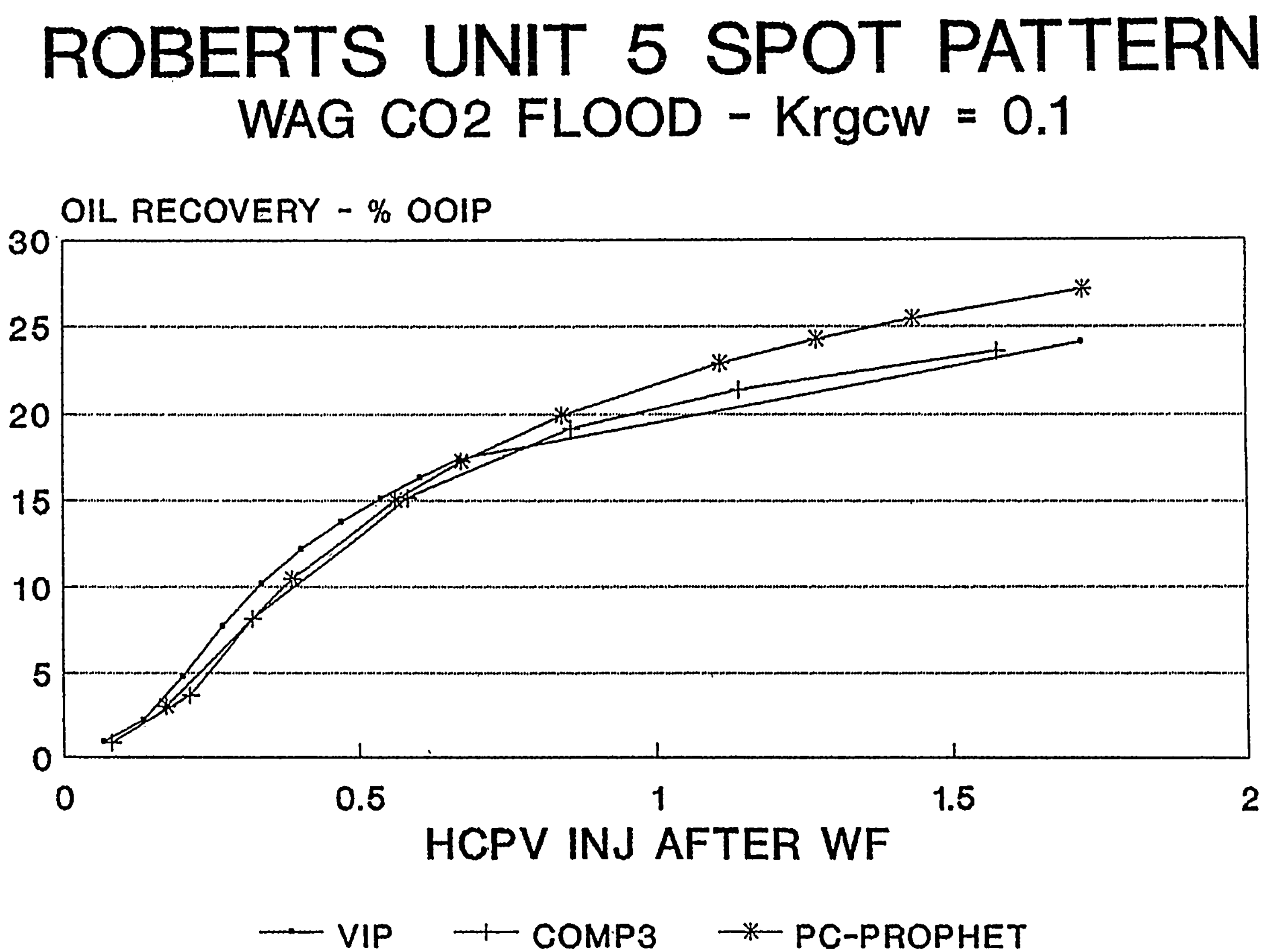

ROBERTS UNIT 5 SPOT PATTERN
WAG CO2 FLOOD - Krgcw = 0.1
OIL RECOVERY - % OOIP
30
25
20
15
10
5
0
0
0.5
1
1.5
2
HCPV INJ AFTER WF
VIP
COMP3
PC-PROPHET

Figure 3

ROBERTS UNIT 5 SPOT PATTERN

WAG CO2 FLOOD - Krgcw = 0.01

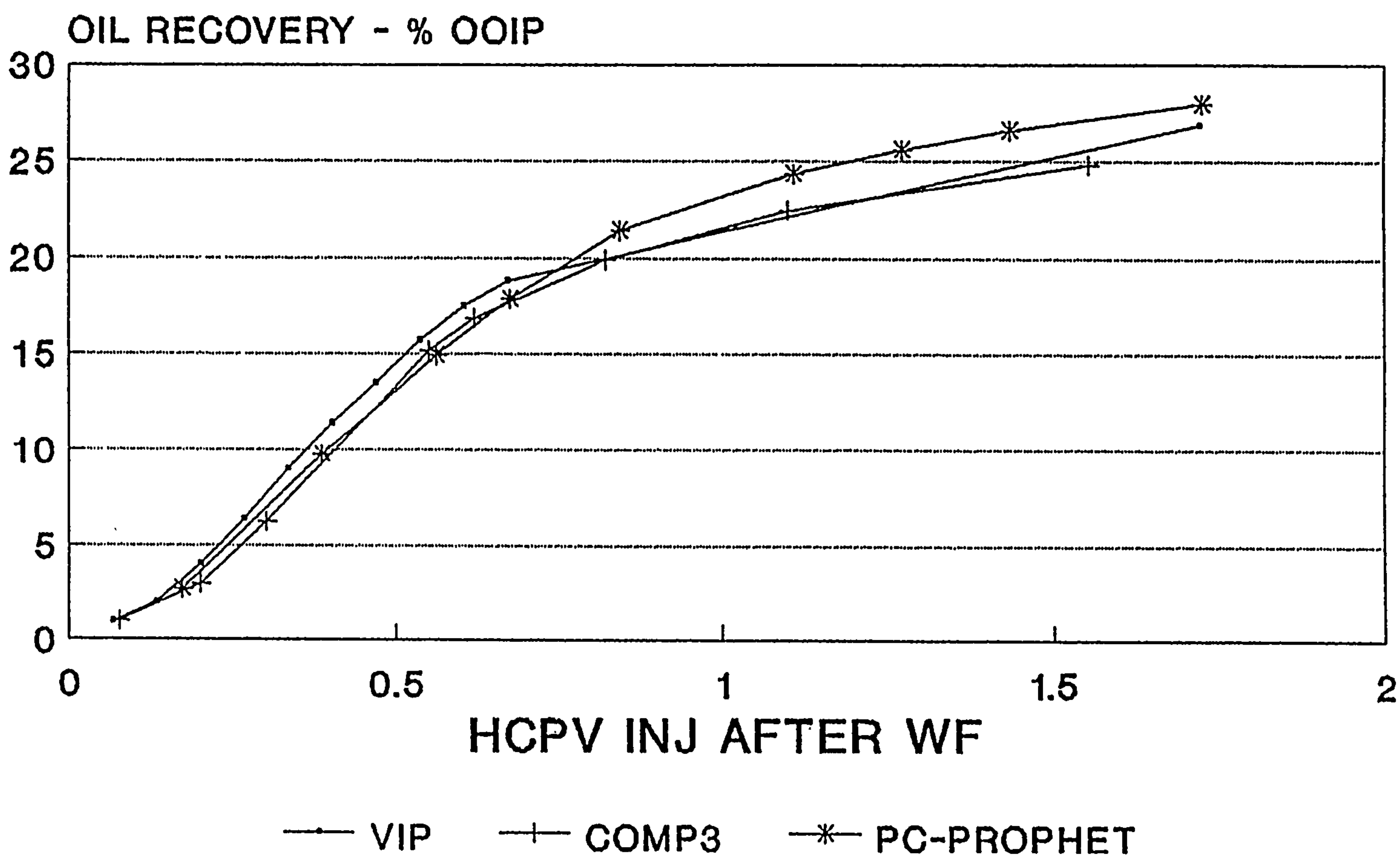


Figure 4

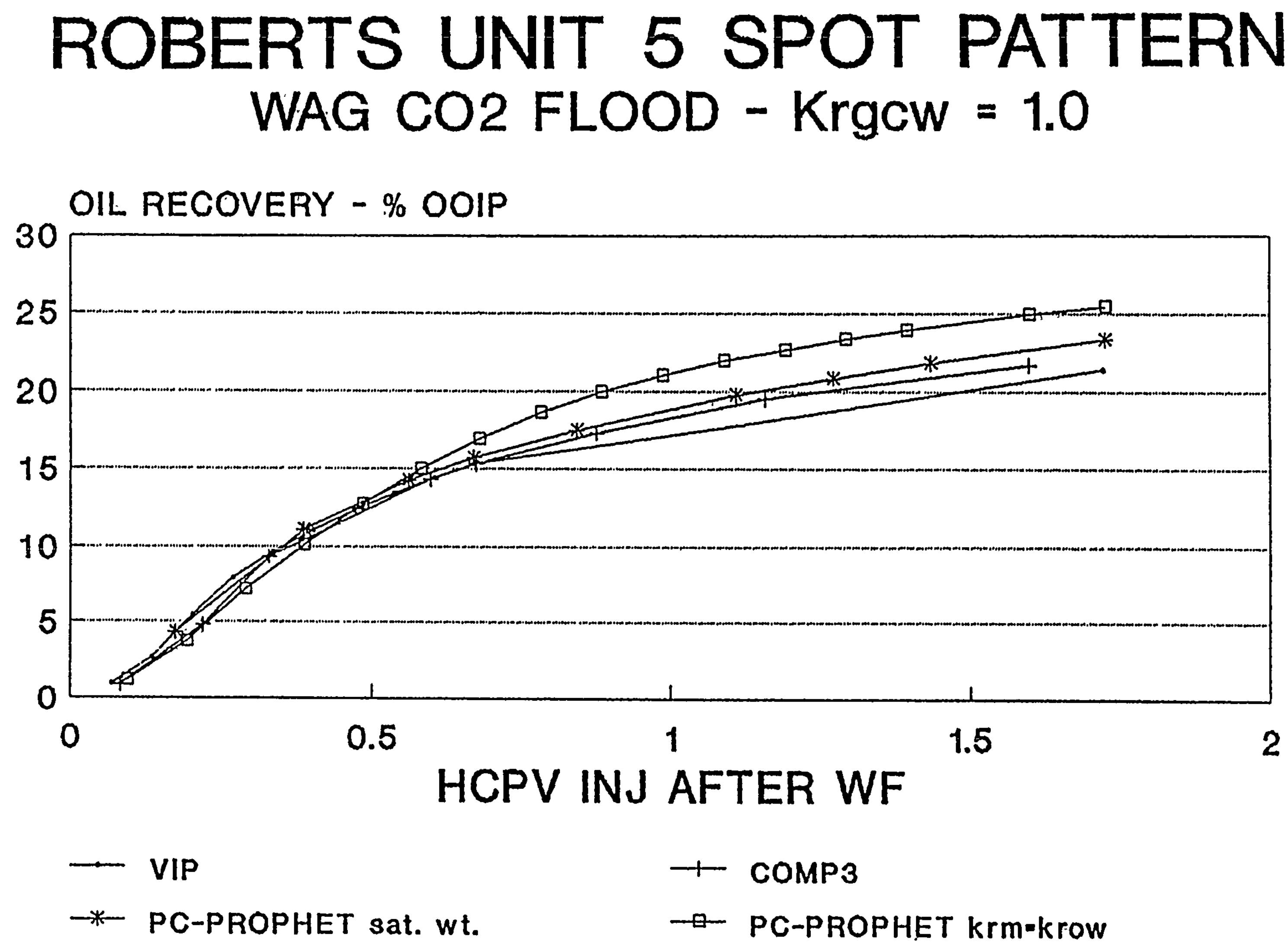
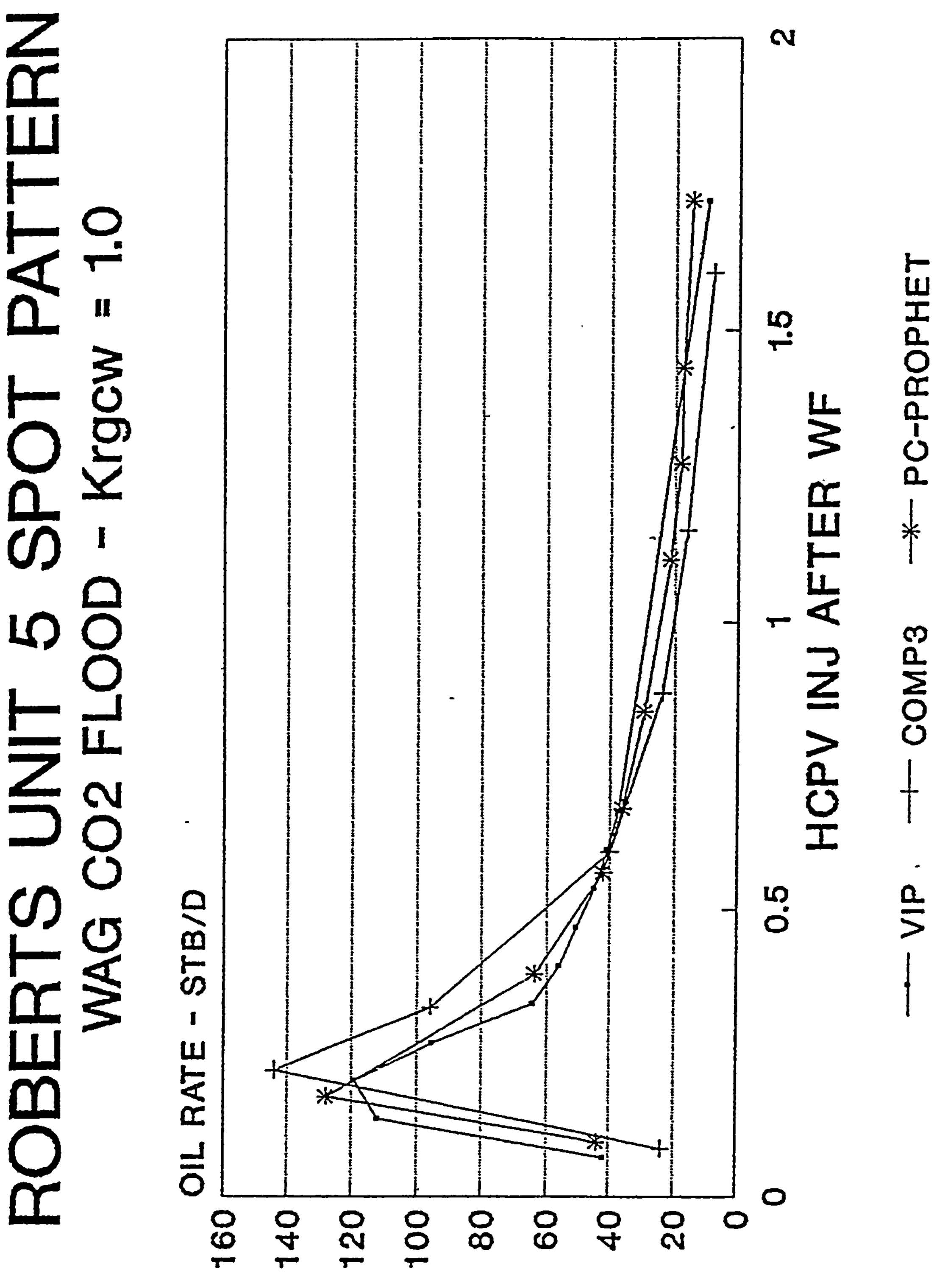
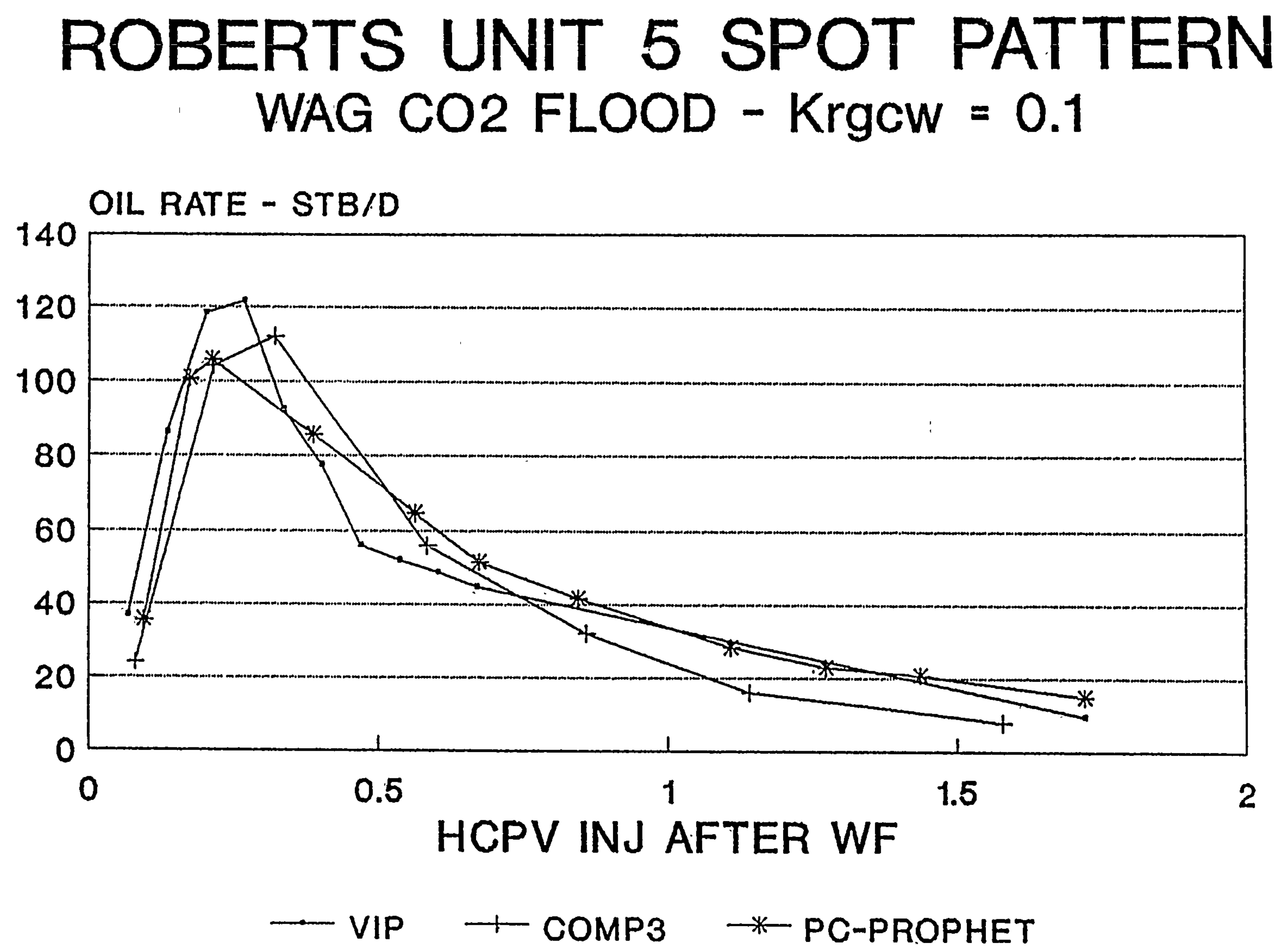

ROBERTS UNIT 5 SPOT PATTERN
WAG CO2 FLOOD - Krgcw = 1.0
OIL RECOVERY - % OOIP
30
25
20
15
10
5
0
0
0.5
1
1.5
2
HCPV INJ AFTER WF
VIP
COMP3
PC-PROPHET sat. wt.
PC-PROPHET krm=krow

Figure 5



ROBERTS UNIT 5 SPOT PATTERN
WAG CO2 FLOOD - Krgcw = 1.0
OIL RATE - STB/D
160
140
120
100
80
60
40
20
0
0
0.5
1
1.5
2
HCPV INJ AFTER WF
VIP
COMP3
PC-PROPHET

Figure 6



ROBERTS UNIT 5 SPOT PATTERN
WAG CO2 FLOOD - Krgcw = 0.1
OIL RATE - STB/D
140
120
100
80
60
40
20
0
0
0.5
1
1.5
2
HCPV INJ AFTER WF
VIP
COMP3
PC-PROPHET

Figure 7

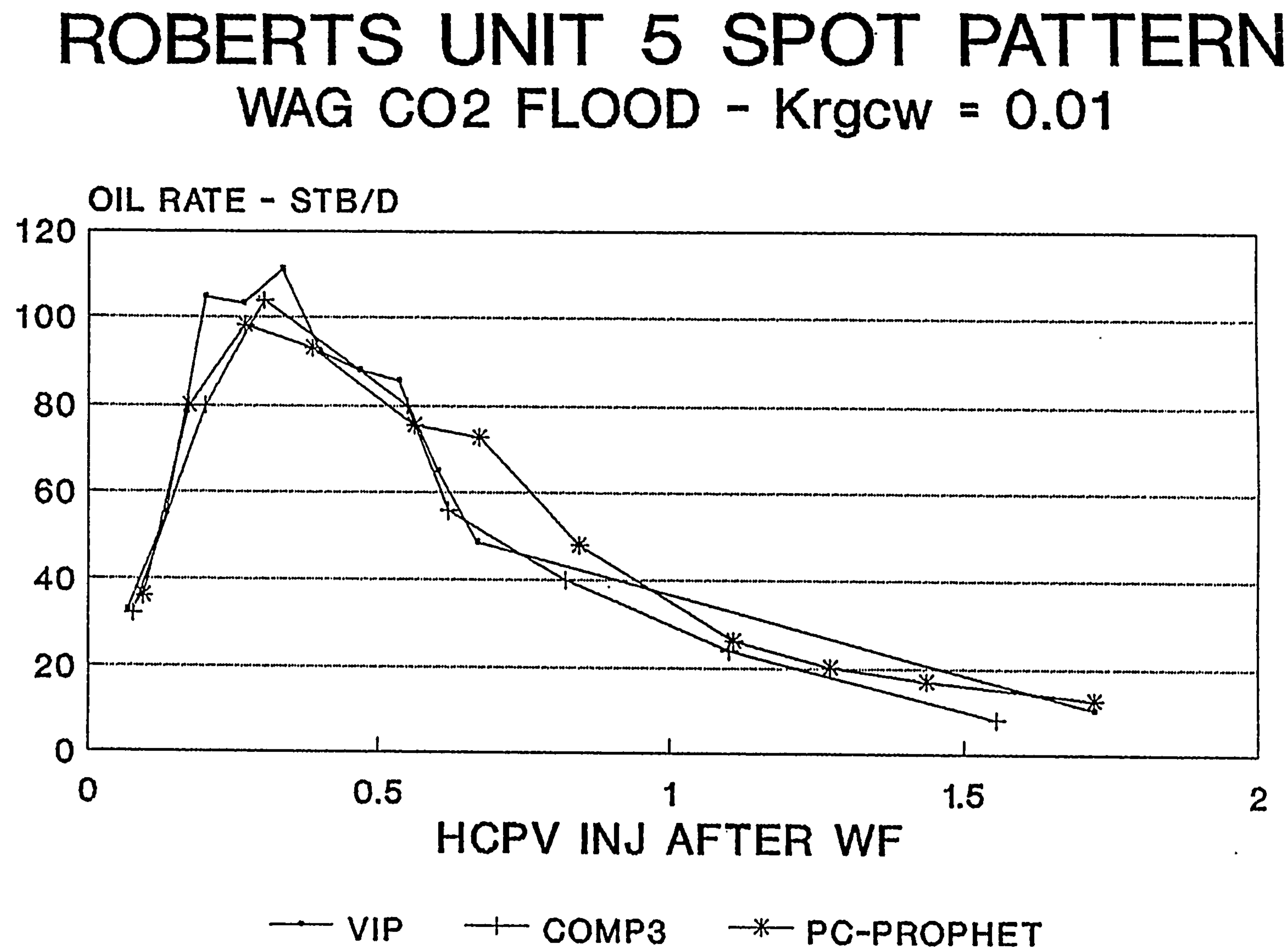

ROBERTS UNIT 5 SPOT PATTERN
WAG CO2 FLOOD - Krgcw = 0.01
OIL RATE - STB/D
120
100
80
60
40
20
0
0
0.5
1
1.5
2
HCPV INJ AFTER WF
VIP
COMP3
PC-PROPHET

Figure 8

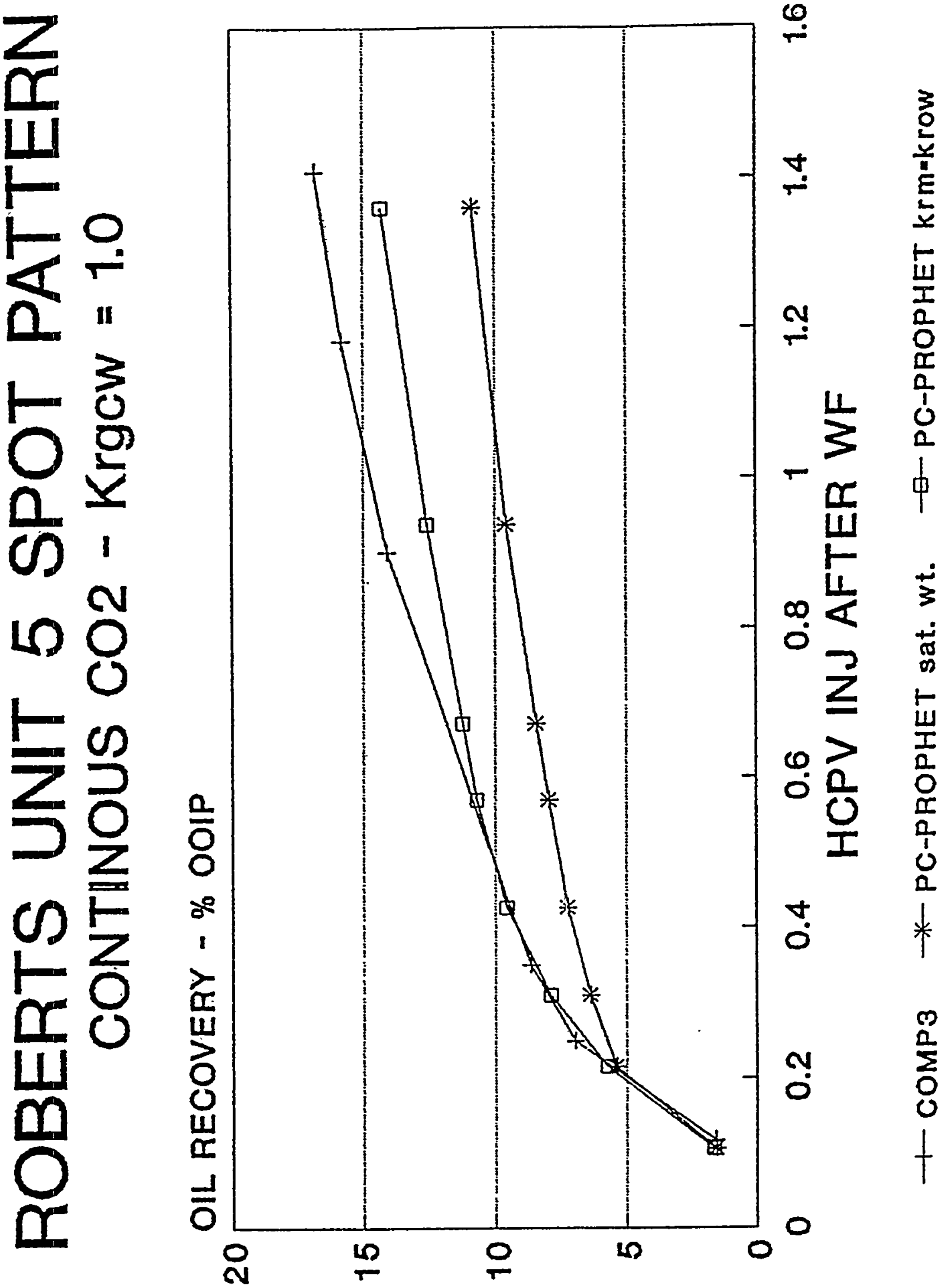

ROBERTS UNIT 5 SPOT PATTERN
CONTINOUS CO2 - Krgcw = 1.0
OIL RECOVERY - % OOIP
20
15
10
5
0
0
0.2
0.4
0.6
0.8
1
1.2
1.4
1.6
HCPV INJ AFTER WF
COMP3
PC-PROPHET sat. wt.
PC-PROPHET krm=krow

Figure 9

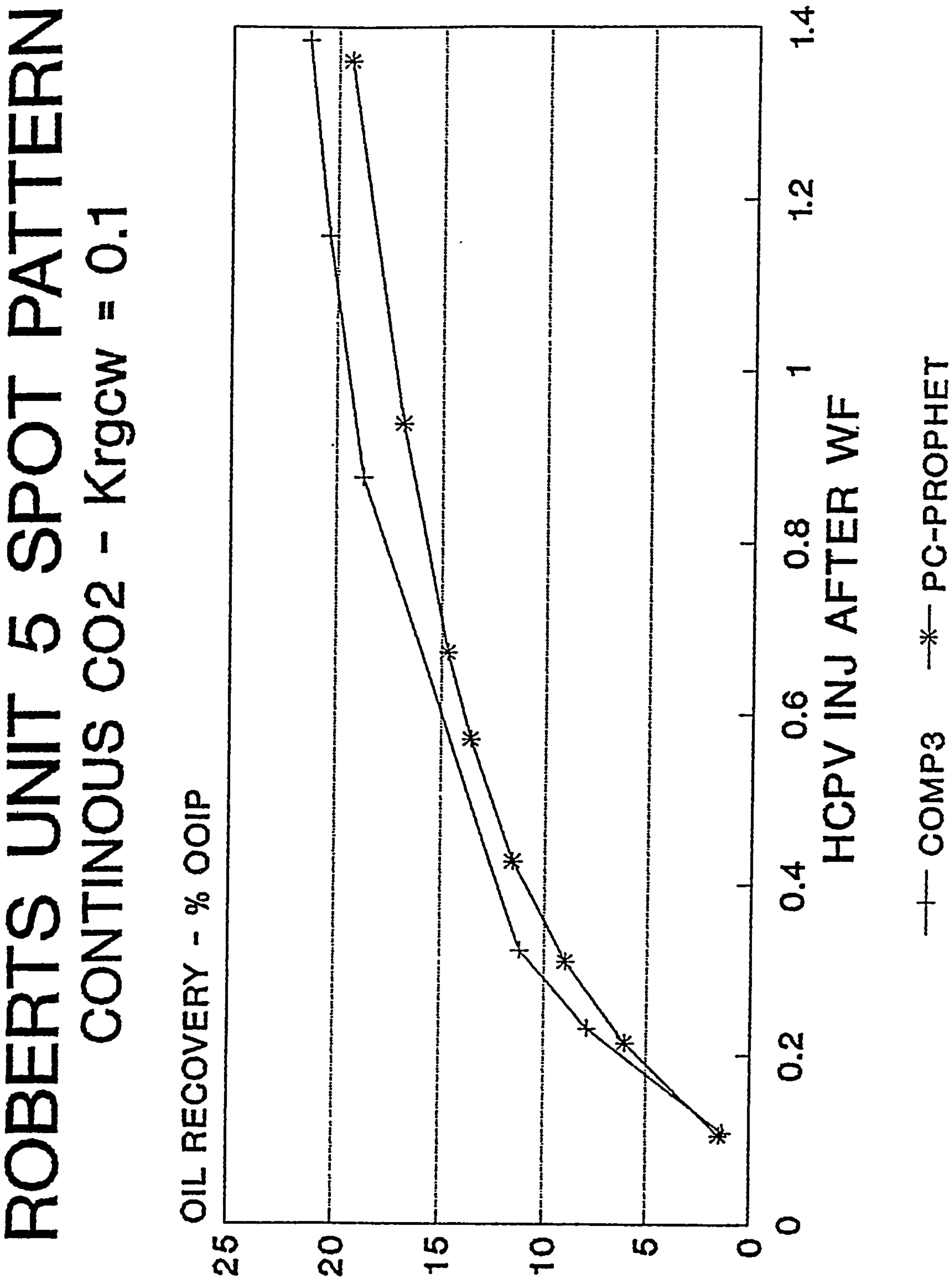

ROBERTS UNIT 5 SPOT PATTERN
CONTINOUS CO2 - Krgcw = 0.1
OIL RECOVERY - % OOIP
25
20
15
10
5
0
0
0.2
0.4
0.6
0.8
1
1.2
1.4
HCPV INJ AFTER WF
COMP3
PC-PROPHET

Figure 10

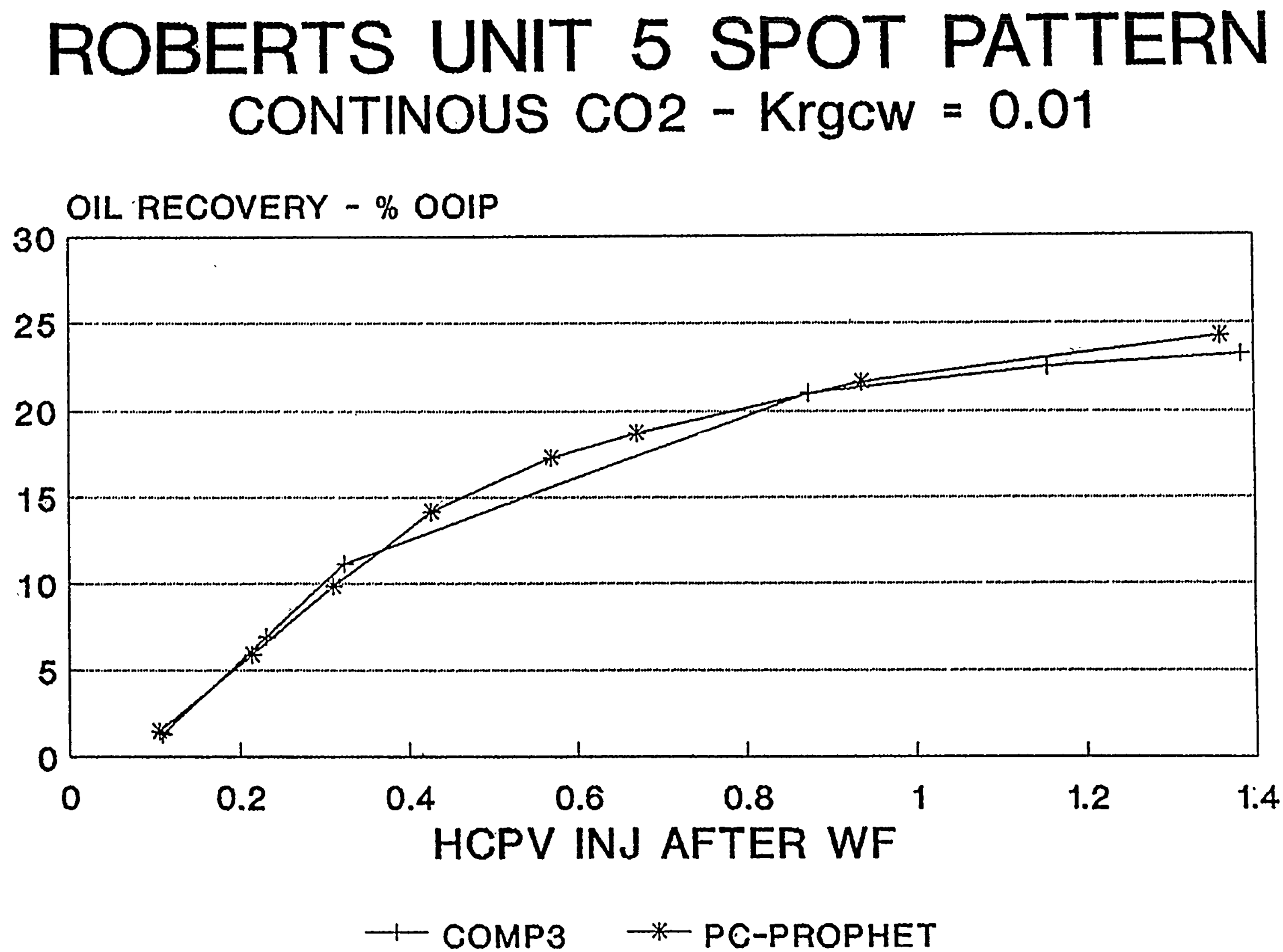

ROBERTS UNIT 5 SPOT PATTERN
CONTINOUS CO2 - Krgcw = 0.01
OIL RECOVERY - % OOIP
30
25
20
15
10
5
0
0
0.2
0.4
0.6
0.8
1
1.2
1.4
HCPV INJ AFTER WF
COMP3
PC-PROPHET

Figure 11

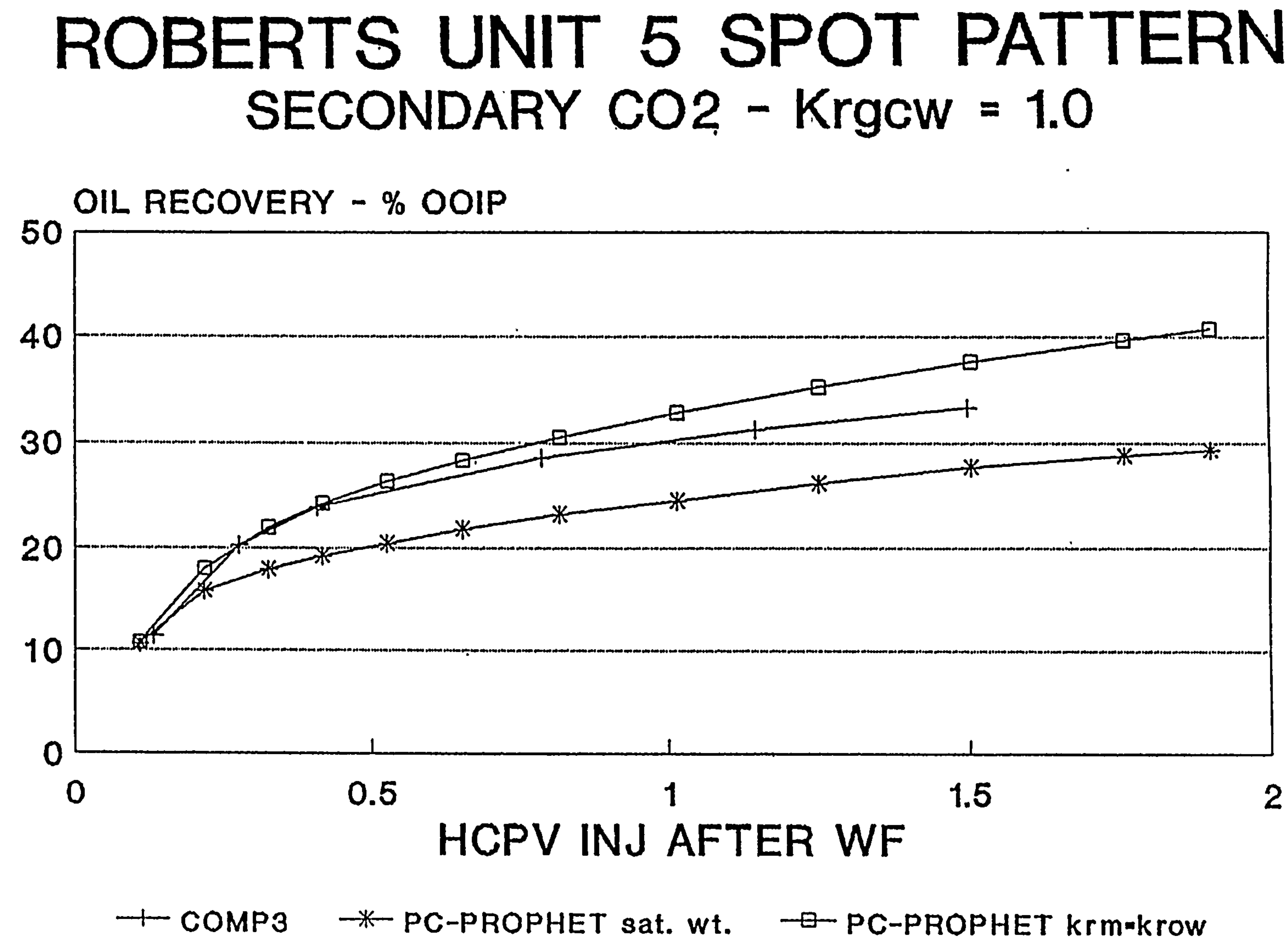

ROBERTS UNIT 5 SPOT PATTERN
SECONDARY CO2 - Krgcw = 1.0
OIL RECOVERY - % OOIP
50
40
30
20
10
0
0
0.5
1
1.5
2
HCPV INJ AFTER WF
COMP3
PC-PROPHET sat. wt.
PC-PROPHET krm=krow

Figure 12

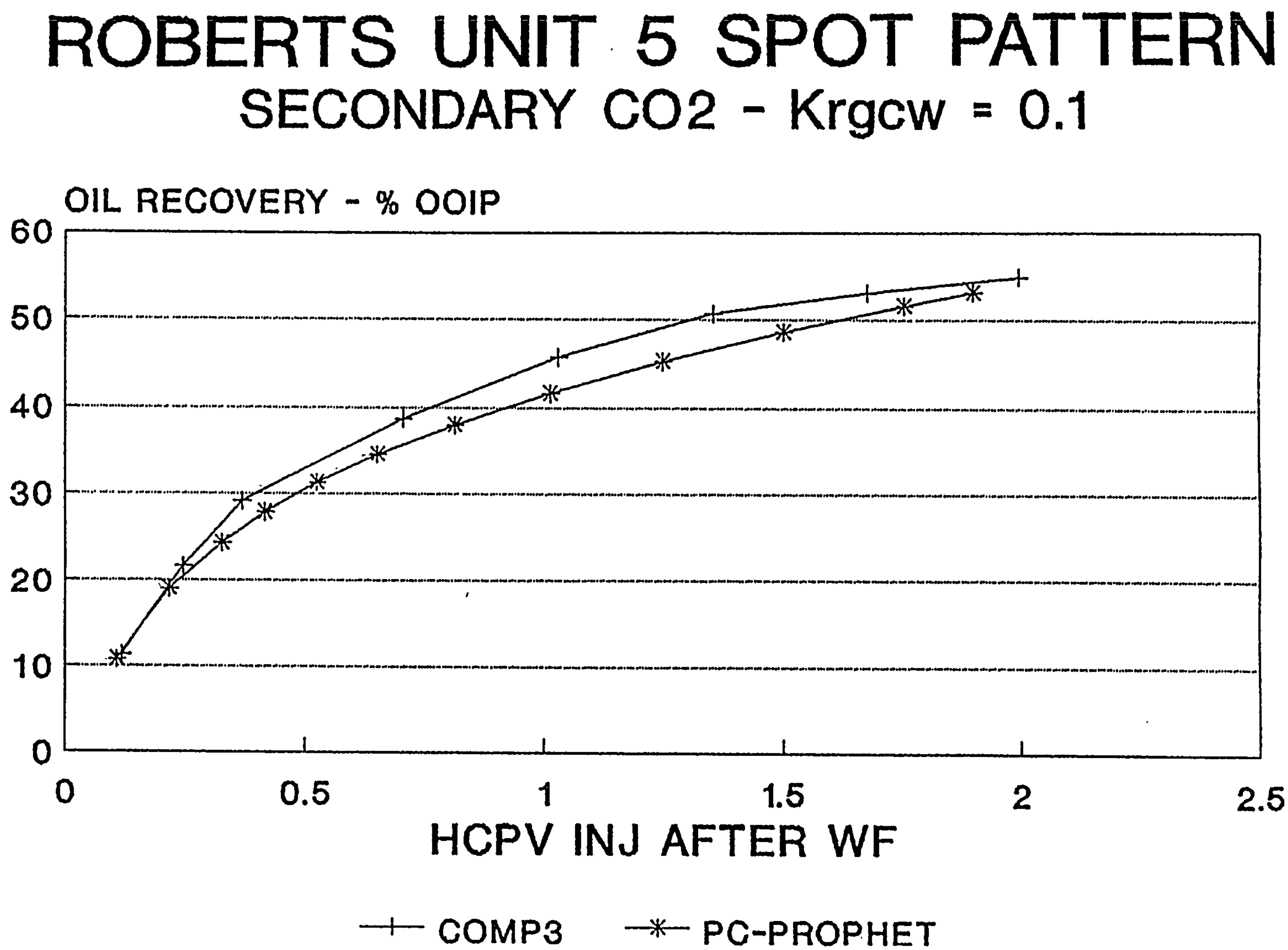

ROBERTS UNIT 5 SPOT PATTERN
SECONDARY CO2 - Krgcw = 0.1
OIL RECOVERY - % OOIP
60
50
40
30
20
10
0
0
0.5
1
1.5
2
2.5
HCPV INJ AFTER WF
COMP3
PC-PROPHET

Figure 13

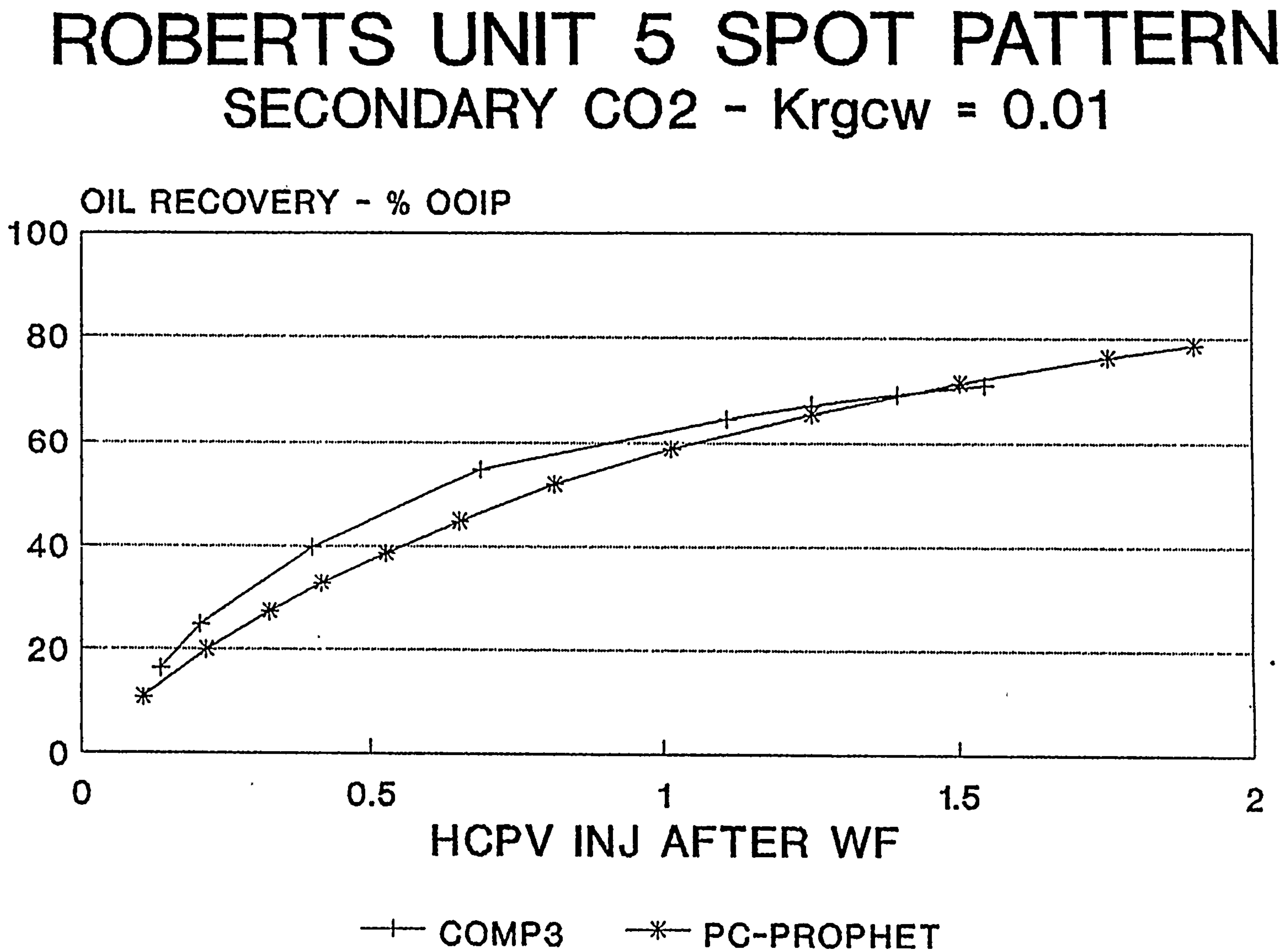

ROBERTS UNIT 5 SPOT PATTERN
SECONDARY CO2 - Krgcw = 0.01
OIL RECOVERY - % OOIP
100
80
60
40
20
0
0
0.5
1
1.5
2
HCPV INJ AFTER WF
COMP3
PC-PROPHET

Figure 14

SPE 26650

Effects of Recent Relative Permeability Data on CO_2 Flood Modeling

John Prieditis and R.J. Brugman, Texaco Inc.

SPE Members

Σ

ABSTRACT

Results from laboratory tertiary CO_2 flooding studies conducted at representative reservoir conditions are becoming available. Predicted CO_2 flood performance can be significantly changed by using this data in reservoir models. The laboratory data includes water and oil relative permeabilities when the water saturation is decreasing, residual oil saturations to a miscible flood, residual CO_2 saturations, and CO_2 relative permeabilities. Predicted oil recovery, CO_2 production, and breakthrough times are all influenced.

Unfortunately, much of this data cannot be used in most presently available commercial reservoir simulators. Additionally, there is uncertainty about the proper form for the relative permeability of the miscible (non-aqueous) phase. For example, should the miscible phase relative permeability be based on the gas, oil, or solvent relative permeability or some combination? Texaco has developed a mixing parameter based reservoir simulator that not only uses the new relative permeability data but also incorporates different forms for the miscible phase relative permeability.

This paper describes how the recently available laboratory data and the form of the miscible relative permeability formulation affect predicted CO2 flood performance. Results presented show the importance of using the laboratory data and show what changes in existing simulators may be advisable.

References and illustrations at end of paper

INTRODUCTION

The modeling and prediction of tertiary CO_2 flood performance can be improved if the results from recently reported laboratory CO_2 displacement tests at representative reservoir conditions are used.

Reported results from such tests are still somewhat rare, but some tertiary CO_2 flooding studies have recently been reported[1,2,3,4,5]. Data from these studies include water and oil relative permeabilities measured when the water saturation is decreasing (often called hysteresis curves), residual oil saturations to miscible CO_2 floods, CO_2 relative permeabilities, and residual CO_2 saturations.

Results from these studies have shown that CO_2 relative permeabilities can be very small in representative west Texas carbonates[1,2,3]. Work reported by Shyeh-Yung[3] and Stern[2] demonstrates that the endpoint relative permeabilities of CO_2 can be as much as 100 times smaller than the oil endpoint relative permeabilities in west Texas carbonates. Reduced CO_2 relative permeabilities would be expected to improve oil recovery while simultaneously reducing CO_2 production.

Residual oil saturations to miscible CO_2 floods have been measured. The presence of miscible residuals would be expected to reduce oil recovery by reducing the effectively available oil. Shyeh-Yung[3] and Stern[2] report miscible residuals as large as 15%. However, the presence of miscible residuals also reduces CO_2 relative permeability[2,3]. The largest reductions in CO_2

relative permeability occur for the largest residual oil saturations. Consequently, miscible residuals may increase sweep efficiency even though they reduce the effectively available oil.

An additional characteristic is the presence of a residual CO_2 saturation that is much larger than the typically very small critical gas saturation. The residual CO_2 saturation is typically about the magnitude of the residual oil saturation to a waterflood in representative west Texas rock material[1]. The presence of large residual CO_2 saturations affects both oil recovery and CO_2 production.

Hysteresis in the water and oil relative permeability curves has also been observed[1,5,10]. In particular, the water saturation may not be reduced to the original connate level following an oil flood or a CO_2 flood. Furthermore, the oil relative permeability curve may shift in a water drainage process. An increase in the residual water saturation has a large potential effect in the early part of a CO_2 flood because it influences how fast CO_2 and oil move through the reservoir.

OBJECTIVES

This study investigates the importance of several relative permeability parameters for predicting CO_2 flood performance and examines how they can be incorporated into simulation models.

Specifically, the following parameters are examined:

- reduced relative permeability of CO_2
- residual oil saturation to a miscible flood
- residual CO_2 saturation
- relative permeability curve hysteresis including an increase in the residual water saturation and a shift in the oil relative permeability

In addition, there is uncertainty about the proper formulation for the relative permeability of the miscible phase that is formed between the CO_2 and oil. For example, the formulation could be based on the gas, oil, or CO_2 relative permeability or some combination. Consequently, another issue that is investigated is how the predicted CO_2 flood performance changes for different formulations of the miscible phase relative permeability.

DESCRIPTION OF METHODS

The characteristics of the simulation model are outlined before the effects of the relative permeability parameters and formulations are discussed.

Description of the Simulator

Much of the recent CO_2 relative permeability data cannot be directly used in commercially available miscible flood simulators. Consequently, a Texaco developed CO_2 flood simulator was used for the present study. It incorporates the required relative permeability relationships.

A simplified miscible flood simulator has been developed at Texaco as an alternative to the U.S. Department of Energy's CO_2 miscible flood predictive model, CO2PM. The simulator was partially developed as part of the DOE's Class I cost share program. In particular, it was part of the project entitled "Post Waterflood; CO_2 Flood in a Light Oil, Flüvial Dominated Deltaic Reservoir."

Texaco's simulator generates streamlines for fluid flow between user specified injection and production wells and then does displacement and recovery calculations along the streamtubes. A finite difference routine is used for the displacement calculations along streamtubes. A special advantage of the streamtube method is the avoidance of grid orientation effects.

The mixing parameter approach proposed by Todd and Longstaff[6] is used for simulation of the miscible CO_2 process. The model can simulate both waterfloods and CO_2 floods.

Three-dimensional flow is modeled by displacement in areally homogenous layers. However, there is no crossflow between the layers, and the effect of gravity is not incorporated.

There are 3 components and 3 potential flowing phases in the model, solvent (gas), water, and oil. The solvent (i.e., CO_2) is treated as the gas. However, in fully miscible flow there are effectively only two flowing phases, the solvent-oil phase and water. All the phases are treated as incompressible.

Accuracy and Limitations of the Simulator

The simulator used in the present work was compared against available simulation results. It was found to give accurate results both for waterfloods and CO_2 floods under the assumptions of areal homogeneity and the absence of both gravity and crossflow. The results are presented in Appendix A.

The simulator used in the study is based on the mixing parameter approach, and there may be some differences with the way relative permeabilities influence results in the compositional simulators which are often used.

Relative Permeability Relationships

The analytical relative permeability relationships used in the simulator are presented in detail. The reason for doing this is to identify exactly how and where the relative permeability parameters investigated in the current study are used in the model.

k_{rw}

The equation for the two-phase water relative permeability, k_{rw}, is

$$k_{rw} = k_{wro}\left(\frac{S_w - S_{wir}}{1 - S_{wir} - S_{orw}}\right)^{n_w} \qquad (1)$$

where S_w is the water saturation, n_w is the water equation exponent, S_{wir} is the irreducible water saturation, S_{orw} is the residual oil to waterflood, and k_{wro} is the endpoint (maximum) relative permeability of water at the residual oil saturation.

A simplified form of water curve hysteresis is used in the model. Water hysteresis is represented by changes in the irreducible water saturation, S_{wir}. During the initial waterflood (i.e., before hysteresis), S_{wir} is set equal to the connate water saturation, S_{wc}. After the start of CO_2 injection (i.e., after hysteresis would occur), S_{wir} is reset, if desired, to a value greater than S_{wc} in locations where the water saturation is decreasing. Several increased values of S_{wir} are investigated.

k_{row}

The equation for the two-phase oil relative permeability in the presence of water, k_{row}, is

$$k_{row} = k_{rocw}\left(\frac{1 - S_w - S_{orw}}{1 - S_{wc} - S_{orw}}\right)^{n_{ow}} \qquad (2)$$

where S_w is the water saturation, n_{ow} is the oil equation exponent, S_{wc} is the connate water saturation, S_{orw} is the residual oil to waterflood, and k_{rocw} is the endpoint (maximum) relative permeability of oil at the irreducible water saturation.

The effects of shifts (i.e., hysteresis) in the oil relative permeability curve are also investigated with a simplified method. After the start of CO_2 injection (i.e., after hysteresis would occur), k_{rocw} is adjusted, if desired, for locations in which the water saturation is decreasing. The exponent n_{ow} could also be adjusted, but this was not done.

k_{rg}

The equation for the two-phase gas relative permeability in the presence of oil, k_{rg}, is

$$k_{rg} = k_{rgcw}\left(\frac{S_g - S_{gr}}{1 - S_{wc} - S_{gr}}\right)^{n_g} \qquad (3)$$

where S_g is the gas saturation, n_g is the gas equation exponent, S_{wc} is the connate water saturation, S_{gr} is the residual gas saturation to an oilflood, and k_{rgcw} is the endpoint (maximum) relative permeability of gas at the connate water saturation.

The effects of changes in S_{gr} are investigated.

k_{rs}

An equation specifically for the solvent relative permeability, k_{rs}, can also be formulated to include features required for CO_2 relative permeability.

$$k_{rs} = k_{rse}\left(\frac{S_g - S_{sr}}{1 - S_{wir} - S_{sr} - S_{orm}}\right)^{n_s} \qquad (4)$$

where S_g is the gas (i.e.,solvent) saturation, n_s is the solvent equation exponent, S_{wir} is the irreducible water saturation, S_{sr} is the residual gas (i.e., solvent) saturation, S_{orm} is the residual oil saturation to solvent, k_{rse} is the endpoint (maximum) relative permeability of solvent at the irreducible water saturation.

This formulation allows the inclusion of a miscible residual S_{orm} and the setting of an appropriate endpoint CO_2 relative permeability at the S_{orm}.

The effects of both k_{rse} and S_{orm} are investigated.

Miscible Flow Relationships

In a mixing parameter model under conditions of completely miscible flow, there are conceptually only two phases, water and a miscible phase composed of solvent and oil. The water relative permeability is the same as in immiscible flow and remains a function of only the water saturation. However, the miscible phase relative permeability, which is denoted k_{rm}, must be computed since it is not measured.

There is no definitive way to compute or handle the miscible phase relative permeability, and four formulations are considered here. One of the primary objectives of this study was to investigate the differences in predicted CO_2 flood performance for these methods. The miscible phase relative permeability, k_{rm}, can be represented as

a saturation weighted average of k_{row} and k_{rs}

$$k_{rm} = \frac{S_o - S_{orm}}{1 - S_w - S_{orm}} k_{row} + \frac{S_g}{1 - S_w - S_{orm}} k_{rs} \quad (5)$$

an average of k_{row} and k_{rg}

$$k_{rm} = 0.5(k_{row} + k_{rg}) \quad (6)$$

equal to k_{row}

$$k_{rm} = k_{row} \quad (7)$$

either k_{rg} or k_{row}

k_{rg}	if $S_g \geq S_o$
k_{row}	if $S_o > S_g$

The first option, which makes k_{rm} a saturation weighted average, can incorporate a reduced CO_2 relative permeability. When the CO_2 saturation is at a maximum (with an immobile oil saturation at S_{orm}), the miscible phase relative permeability equals the endpoint CO_2 relative permeability.

The second option makes the miscible phase relative permeability a simple average of the gas and oil relative permeabilities.

The third option, in which the miscible phase relative permeability is set equal to that of the oil, is the standard formulation which is used in mixing parameter models. However, it can not incorporate a reduced CO_2 relative permeability, as pointed out by Stern[2]. This is important because laboratory data show that endpoint CO_2 relative permeabilities can be substantially reduced[1,2,3].

The fourth option, the either/or method, was added for completeness. The solvent relative permeability could have been used instead of the gas relative permeability.

The solvent and oil are tracked separately even though they are miscible. This is done by dividing the miscible phase relative permeability and assigning to the solvent and oil the correct fractions. The correct fractions are based on saturation. Under miscible conditions, the gas relative permeability is

$$\frac{S_g}{1 - S_w - S_{orm}} k_{rm} \quad (8)$$

and the oil relative permeability is

$$\frac{S_o - S_{orm}}{1 - S_w - S_{orm}} k_{rm} \quad (9)$$

In some formulations the miscible residual is left out of the denominator. However, when this is done, the non-aqueous phase permeability is not completely distributed between the CO_2 and oil.

An oil residual due to water-blocking is not investigated because it would function the same way as S_{orm}. Remaining saturations due to water blocking are probably indistinguishable from residuals due to another mechanism.

Formulations for immiscible and partially miscible conditions are provided in Appendix B.

The effective viscosities are calculated in the standard fashion for mixing parameter models. The equations are provided in Appendix C.

Basic Approach

The basic approach was to define a case which would be representative of the CO_2 floods in west Texas and then to modify the input relative permeability parameters over reasonable ranges. The base input values are described in Appendix D. The mixing parameter was not varied and was set to 2/3 for all cases.

A quarter-five spot pattern was simulated. The basic flooding sequence was a hybrid-WAG process which included a 1.5 HCPV (hydrocarbon pore volume) waterflood started at the connate water saturation, followed by a 0.15 HCPV CO_2 slug, followed by a 1:1 WAG with 0.45 HCPV CO_2, followed by 2.0 HCPV water chase. The total HCPV CO_2 injected was 0.6 HCPV. Expressed in terms of total HCPV after the initial waterflood, this sequence was

0.0 to 0.15 HCPV	CO_2 slug
0.15 to 1.05 HCPV	1:1 WAG
1.05 to 3.05 HCPV	Water chase

The WAG process was actually modeled as simultaneous injection. An alternate simulated injection method was continuous CO_2 injection of 0.60 HCPV CO_2 followed by a water chase.

RESULTS

The discussion of the results is organized to address the objectives stated earlier. In particular, the objectives were to investigate how predicted CO_2 flood performance is affected by: a reduced CO_2 relative permeability, the presence of a miscible residual oil saturation, a large residual CO_2 saturation, and hysteresis in the oil and water relative permeability curves. An additional objective was to investigate the effects of different choices for the formulation of the miscible phase relative permeability.

Table and Figure Format. The results presented in the figures and tables show tertiary recovery after the end of the initial waterflood as a function of HCPV. These are not incremental tertiary recoveries as usually defined, because they do not exclude the oil which would have been recovered just by the continued waterflood. Instead, these values are additional amounts recovered after the end of the waterflood (i.e., the recovery at the end of the waterflood has been subtracted). The injected HCPV (hydrocarbon pore volume) is the HCPV injected after the end of the waterflood (i.e, the water injected during the waterflood has been subtracted). The injected HCPV includes both the injected water and CO_2.

CO_2 Relative Permeability

The main difference among the alternatives for formulating the miscible phase relative permeability is how the CO_2 (or gas) relative permeability is incorporated. Representative CO_2 endpoint relative permeabilities are probably about one-tenth (rather than equal to) the magnitude of the endpoint oil relative permeabilities in west Texas carbonates[1,2,3].

A small CO_2 relative permeability would be expected to affect predicted CO_2 flood performance in several ways. Lower CO_2 injectivity, smaller CO_2 production, and increased oil recovery would all be expected.

Cases were simulated to investigate whether the expected effects of small CO_2 relative permeabilities actually did occur and whether predicted CO_2 flood performance varied for the different formulations. The results can be interpreted in terms of a CO_2/oil endpoint relative permeability ratio (R_k). Situations were considered in which this ratio was 1.0 (or almost 1.0) and cases in which it was 0.1 and less. A summary of the results is presented in Tables 1 and 2. An overall conclusion is:

> If there are large differences between the CO_2 (or gas) and oil relative permeabilities, then the different formulations produce differences in predicted CO_2 flood performance. In contrast, if the gas (or CO_2) and oil relative permeability curves are similar, then it is not important how the miscible relative permeability is defined because the predicted CO_2 flood performance is very similar for all the formulations.

The differences in predicted CO_2 flood performance are summarized in the subsequent discussion. Only two of the four methods, the "saturation weighted" and the "either/or" methods, can incorporate a reduced CO_2 relative permeability. These two methods assign a low CO_2 relative permeability to high CO_2 saturation locations.

NOT effective in using reduced CO_2 permeability

Equal to krow. If the miscible phase relative permeability is set equal to the oil relative permeability k_{row} (which is the standard formulation), there can be no effect of the gas relative permeability. CO_2 (or gas) relative permeability cannot be incorporated in this method; consequently, reduced CO_2 relative permeability data cannot be used in the standard method. This is a significant shortcoming of this method when there is a large difference between the gas and oil relative permeabilities.

Average. Reduced CO_2 relative permeability in the simple averaging method does not significantly affect predicted recovery behavior during the WAG process or during a continuous CO_2 slug injection. Figure 1 shows that the oil recovery does not change much as the endpoint CO_2/oil relative permeability ratio is changed from 2.0 to 0.2. In fact, a slight decrease in oil recovery during the hybrid-WAG process is predicted when the endpoint CO_2 relative permeability is reduced. This is contrary to what would be expected, and means that the simple averaging method may produce incorrect results.

Effective in using reduced CO_2 permeability

Saturation weighted. The saturation weighted method permits the CO_2 relative permeability to have an effect. The trend is as might be expected. The oil recovery is greater and the CO_2 production is smaller for small values of CO_2 relative permeability. The CO_2 relative permeability must be made extremely small, though, to produce large increases in predicted oil recovery, especially for a WAG process.

Results are presented in Figures 2 through 6, in addition to Tables 1 and 2. Figure 2 shows differences in predicted oil recovery for a large range of CO_2/oil relative permeability ratios. Figure 3 shows oil recovery histories. A reduction in the CO_2/oil endpoint relative permeability ratio by a factor of 10 (from 1.0 to 0.1) increases oil recovery at the end of the WAG from 0.19 to 0.21 HCPV. An even larger reduction in the ratio by a factor of 100 (from 1.0 to 0.01), increases the oil recovery at the end of the WAG to 0.245 HCPV.

Reduced CO_2 relative permeability affects predicted oil recovery and CO_2 production more for continuous CO_2 injection followed by chase water than for a WAG process (as can be seen by a comparison of Figures 4 and 2). When the endpoint CO_2/oil relative permeability ratio is reduced from 1.0 to 0.1, the oil recovery at the end of CO_2 injection is increased from 0.08 to 0.13 HCPV for the continuous CO_2 injection process.

Reduced CO_2 relative permeability decreases CO_2 production more than it increases oil production in both the continuous CO_2 and WAG processes (as can be seen in Figures 5 and 6).

Significant predicted differences in oil recovery and CO_2 production occur in the early stage of CO_2 injection. As the CO_2 relative permeability is reduced, the early oil banking effect is increased; that is, the predicted early production of oil as well as CO_2 is reduced even though the ultimate oil recovery is increased.

Large differences also occur for predicted injectivity if there are large differences in CO_2 relative permeability. A normalized injectivity, I_R, can be defined which is the injectivity at the end of the initial CO_2 slug divided by the injectivity at the end of the waterflood. This injectivity can be compared for different values of R_k (i.e., the endpoint CO_2 relative permeability divided by the endpoint oil relative permeability). The results are as follows:

R_k	I_R
1.0	2.9
0.1	1.5
0.01	1.1

The injectivity defined here is the injection rate divided by the pressure drop between the injection well and production well. Different injectivities such as this cannot be predicted with the standard formulation which defines the CO_2 relative permeability as equal to the oil relative permeability.

Either/Or. The largest predicted effect of a reduced CO_2 relative permeability occurs with the option that the miscible phase relative permeability is either that of the gas or oil depending on the larger saturation. This method, however, does not seem to be conceptually as sound as the saturation weighted method.

Miscible Residual Oil Saturation

All the methods of defining the miscible phase relative permeability can include a miscible residual oil saturation, S_{orm}, and the predicted oil recovery is reduced by the presence of a miscible residual for all the methods. In fact, predicted oil recovery is very sensitive to the miscible residual. Moderate increases in the miscible residual significantly reduce predicted recovery, and the reduction begins early in a flood. These conclusions also apply to water-blocked oil.

Figure 7 shows the effects of selected levels of the miscible residual oil saturation. The oil recovery at the end of the WAG period is 0.19 HCPV for the case of no miscible residual. However, the recovery is reduced to 0.14 HCPV when the miscible residual is set to 0.15. These particular results are for the simple averaging method of formulating the miscible phase relative permeability. (The gas and oil relative permeabilities are almost the same for this case). Results for the other formulations are similar.

Miscible Residual Combined With Reduced CO_2 Relative Permeability

Recent laboratory data show that the CO_2 relative permeability is reduced at the same time that the miscible residual oil saturation is increased[2,3]. Shyeh-Yung[3] reports endpoint CO_2 relative permeabilities as a function of the miscible residual oil saturation for San Andres carbonates. The following is a relationship derived from Shyeh-Yung's work.

S_{orm}	CO_2/oil endpoint permeability ratio
0.0	1.0
0.05	0.4
0.10	0.1
0.15	0.04
0.2	0.01

When the saturation weighted method is used for the miscible phase relative permeability, there can be a simultaneous change in the CO_2 relative permeability and the miscible residual. As pointed out by Stern[2], this is not possible if the miscible phase relative permeability is defined as equal to the oil phase relative permeability.

Figure 8 shows the predicted oil recovery when the CO_2 relative permeability to miscible residual relationship derived from Shyeh-Yung's work is used. The mixing parameter remained constant for all these cases. If the CO_2 relative permeability is reduced at the same time that the miscible residual saturation is increased, the recovery is not decreased as much as it would be without the change in relative permeability. In fact, there is very little if any reduction in recovery as the miscible residual is increased. For the present case, the loss in microscopic displacement efficiency is almost completely compensated by the increase in sweep efficiency. This result is for a San Andres carbonate; the same result might not occur in a sandstone.

Although such a complete compensation cannot be expected for all cases, the importance of including a reduced CO_2 relative permeability along with a miscible residual oil saturation is evident.

Using just a miscible residual oil saturation, may reduce recovery too much. This also applies to water-blocked oil, since the CO_2 relative permeability also would be expected to decrease because of water-blocked oil.

Residual Gas Saturation

Residual gas saturations, S_{gr}, larger than critical gas saturations occur both in carbonates[1] and in sandstones[7]. The residual CO_2 saturation is typically about the magnitude of the residual oil saturation to a waterflood in representative west Texas rock material[1].

The presence of a residual gas saturation reduces the recovery of both oil and CO_2. The reductions occur primarily during the chase water drive. Figure 9 shows the differences in predicted oil recovery for different residual gas saturations. The largest predicted oil recovery reductions occur for the largest residual CO_2 saturations.

Hysteresis Effects

Description of Water Curve Hysteresis. The typical water hysteresis effect for San Andres carbonates is a new and higher irreducible water saturation[1,5,8,9,10]. The water hysteresis effect occurs after CO_2 is injected. Both the CO_2 which is injected and the oil bank which is created reduce the water saturation from the levels achieved during the waterflood. However, the water saturation typically does not go back all the way to the original connate water saturation (S_{wc}). Instead, the water saturation reaches a new minimum value which is larger than the connate water saturation and which is termed the irreducible water saturation (S_{wir}).

Description of Oil Curve Hysteresis. There is also the potential for hysteresis in the oil relative permeability curve[1,10]. In the laboratory, it was found that for San Andres cores the oil relative permeabilities measured during an oil flood (which followed a waterflood) were larger than the oil relative permeabilities measured during the initial waterflood[1].

In particular, the new oil relative permeabilities could be several times larger than the original values.

Results for Saturation Weighted Method. CO_2 and oil move through the reservoir faster if there is a large increase in the irreducible water saturation. Presented in Figures 10 and 11 are results for the saturation weighted miscible relative permeability method. When water relative permeability curve hysteresis (in the form of a larger irreducible water saturation) is included, the early production of both CO_2 and oil is increased. The largest and most dramatic predicted change is at the beginning of the CO_2 flood. Effects of an increase in irreducible water from 0.2 to 0.3 and

0.4 are shown. The largest effects occur for the largest irreducible water saturation S_{wir}.

The predicted oil recoveries for the subsequent WAG and brine chase periods are also increased. The largest predicted increases are for intermediate increases in the irreducible water saturation.

When oil curve hysteresis (in the form of increased oil relative permeability) is also included for the saturation weighted method, the ultimate predicted oil recovery is even larger, and the early behavior is not changed. For the present case, the oil relative permeability was set to equal one-half the original oil endpoint relative permeability at S_{wir}. Specifically, S_{wir} was set to 0.4 and k_{row} was made to equal 0.25 at S_{wir} rather than 0.11 (which would have been the value of k_{row} without hysteresis).

Other Formulations. Presented in Table 3 are results for the other formulations of the miscible relative permeability. All the formulations predict increased early CO_2 and oil production when water hysteresis is used. However, the predicted changes in the oil recovery during the subsequent WAG and water chase periods are not as large as those for the saturation weighted method. Also, oil hysteresis (in addition to water hysteresis) has a smaller effect.

Oil Relative Permeability

The oil relative permeability was not one of the parameters to be investigated. Actually, in CO_2 flood simulation the oil curve is usually not adjusted; any changes are typically made during a history match of the waterflood. However, to get a more complete picture of the effect of relative permeabilities, the effect of the oil relative permeability curve was examined for the standard formulation in which the miscible phase relative permeability is set equal to the oil relative permeability.

Results are presented in Table 4 for cases of typical and lowered endpoint oil relative permeabilities. Reducing the oil endpoint relative permeability by a factor of 10, greatly reduced oil recovery during the waterflood but did not much affect recovery during the WAG process.

For the continuous CO_2 injection process, the predicted oil recovery was actually larger for smaller oil relative permeabilities. The predicted oil recovery in a 1:2 WAG was also improved by reduced oil permeability but not as much as for continuous CO_2 injection.

These results are contrary to what might be expected. For the case of a continuous CO_2 slug in which the reservoir geology is held constant, the standard formulation predicts that the best CO_2 flood oil recovery will occur for cases of the worst waterflood recovery. For a high ratio of water to CO_2 in the WAG, the predicted recovery is independent of the waterflood recovery.

General Comparison of Formulations

An overview of the predicted CO_2 flood performance is presented in Tables 5 and 6. The standard formulation in which the miscible phase relative permeability is equal to the oil relative permeability is used as the base case. Results from the other formulations are compared with this case.

The assumption is made that the maximum CO_2 relative permeability is actually one-tenth that of the oil. The reduced CO_2 relative permeability cannot be incorporated into the standard formulation.

Simple Average. If the simple average formulation for the miscible phase relative permeability is used, then the recovery is about the same as for the base case if the gas relative permeability is assumed to be close to that of the oil. However, if the gas relative permeability is assumed to be one-tenth that of the oil, then the predicted recovery is slightly reduced. This result does not seem valid. The simple averaging method does not appear to give valid results when the gas and oil relative permeabilities are substantially different.

Reduced CO_2 Permeability. If the saturation weighted method is used with the assumptions of no miscible residual and a maximum CO_2 relative permeability one-tenth that of the oil, then the predicted oil recovery at the end of the WAG is increased. The recovery may be increased too much because of the absence of a miscible residual. The early oil recovery, however, is delayed.

Sorm. The reason for the reduced CO_2 relative permeability could be the presence of a miscible residual. If a miscible residual of 0.10 is used in the standard formulation, then the predicted oil recovery is probably reduced too much. If the same residual is used in the saturation weighted method (with reduced CO_2 relative permeability), predicted recovery at the end of the WAG is still reduced but not by as much. The early recovery, though, is delayed substantially.

All Mechanisms. The best predictions are probably obtained if all the mechanisms (water and oil hysteresis, a miscible residual of 0.10, and reduced CO_2 relative permeability) are used in the saturation weighted method. The early recovery is no longer so small. Actually, the predicted oil recoveries are very close to those of the original base case. However, differences in predicted gas production and injectivity are significant.

The interesting result is that the closest predictions for oil recovery are from the initial base case and the final case which includes all the mechanisms. Adding only some features, such as only a miscible residual, appears to make the predictions worse if no other special features are added.

The predicted gas production and injectivity are much more sensitive to the formulation which is used for the miscible phase permeability. Predicted differences in gas production are larger than predicted differences in oil production for different formulations and for different magnitudes of gas permeability. Predicted differences in injectivity are also very large for different magnitudes of the gas permeability.

If features such as a reduced CO_2 relative permeability, an increased residual gas saturation, and hysteresis are to be used to improve the predictions of CO_2 flood performance, the standard method of defining the miscible phase permeability (as equal to the oil phase permeability) must be modified. A saturated weighted method is one way of doing this.

CONCLUSIONS

1. The standard method of defining the miscible phase relative permeability as equal to the oil relative permeability in mixing parameter models cannot incorporate laboratory data which indicates CO_2 relative permeabilities can be very small.

2. An alternate method which defines the miscible phase relative permeability as a saturated weighted combination of CO_2 and oil relative permeability can incorporate reduced CO_2 relative permeabilities.

3. Reduced CO_2 relative permeabilities increase predicted oil recovery and reduce predicted CO_2 production. In general, the permeability reduction must be substantial to produce large effects. Gas production and injectivity are affected more than oil recovery by reduced CO_2 permeability.

4. Without other changes, the presence of a miscible residual oil saturation substantially reduces predicted oil recovery.

5. Since the presence of a miscible residual probably reduces CO_2 relative permeability, these two effects should be applied together. When they are, they tend to cancel. Reduced recovery from a miscible residual tends to be canceled by increased recovery from lowered CO_2 mobility. Use of just a miscible residual in simulation studies may give pessimistic results.

6. The presence of a large residual CO_2 saturation has a large effect on predicted CO_2 flood performance during the final chase water drive.

7. Water hysteresis makes the predicted CO_2 breakthrough earlier and increases the predicted early oil and CO_2 production.

8. If characteristics such as a miscible residual, reduced CO_2 relative permeability, water and oil hysteresis, and an increased residual gas saturation are to be effectively used to improve the prediction of CO_2 flood performance, the standard mixing parameter formulation must be modified.

ACKNOWLEDGEMENTS

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APPENDIX A
COMPARISON WITH PREVIOUS SIMULATION RESULTS

Figure A-1 shows that the present model produces results very similar to those of the Higgins-Leighton method presented by Willhite[11] for a waterflood in a five-spot pattern. Similar agreement was also found for other mobility ratios.

Figure A-2 shows a comparison with Todd and Longstaff's[6] results for secondary miscible floods in a five-spot. Again the results are very similar.

APPENDIX B
COMBINED MISCIBLE AND IMMISCIBLE FLOW

The equations actually used in the model can handle miscible, immiscible, and partially miscible flow.

The equation for the effective relative permeability of oil, k_{roeff}, is

$$k_{roeff} = (1-\alpha)k_{ro}+\alpha\frac{S_o-S_{orm}}{1-S_w-S_{orm}}k_{rm} \qquad \text{(B-1)}$$

The equation for the effective permeability of the solvent (i.e., gas), k_{rgeff}, is

$$k_{rgeff} = (1-\alpha)k_{rg}+\alpha\frac{S_g}{1-S_w-S_{orm}}k_{rm} \qquad \text{(B-2)}$$

If complete miscibility exists and the reservoir pressure is greater than the minimum miscibility pressure, MMP, then

$$\alpha = 1.0 \qquad \text{(B-3)}$$

If complete immiscibility exists and the reservoir pressure is less than a specified pressure, then

$$\alpha = 0.0 \qquad \text{(B-4)}$$

If a condition of partial miscibility exists and the reservoir pressure, P, is less than the MMP but greater than the specified pressure, then

$$0.0 < \alpha < 1.0 \qquad \text{(B-5)}$$

APPENDIX C
MIXING PARAMETER EQUATIONS

The mixing parameter ω (Omega) is used to adjust the viscosities of the solvent and the oil.

The effective solvent viscosity μ_{se} is given by

$$\mu_{se} = (1-\alpha)\mu_s + \alpha\mu_{sm} \tag{C-1}$$

The effective oil viscosity μ_{oe} is given by

$$\mu_{oe} = (1-\alpha)\mu_o + \alpha\mu_{om} \tag{C-2}$$

α is a parameter which adjusts the degree of miscibility and is discussed in Appendix B.

μ_s is the solvent viscosity, and μ_o is the oil viscosity. μ_{sm} is the mixed solvent viscosity and is defined by

$$\mu_{sm} = \mu_s^{1-\omega}\mu_m^{\omega} \tag{C-3}$$

μ_{om} is the mixed oil viscosity and is defined by

$$\mu_{om} = \mu_o^{1-\omega}\mu_m^{\omega} \tag{C-4}$$

The mixed viscosity μ_m is defined by

$$\frac{1}{\mu_m^{0.25}} = \frac{1}{1-S_w}\left(\frac{S_o}{\mu_o^{0.25}}+\frac{S_g}{\mu_s^{0.25}}\right) \tag{C-5}$$

The mixing parameter, Omega, determines the effective viscosities of the solvent and oil. Omega can be varied between 0.0 and 1.0. If the mixing parameter is set to 0.0, then there is no mixing, and the solvent and oil viscosities are equal to their individual immiscible values. If the mixing parameter is set to 1.0, then there is complete mixing, and the oil and solvent viscosities are made equal. A typical value for Omega is 2/3.

APPENDIX D
INPUT TO MODEL

The input values were selected to model a representative flood in west Texas.

Fluid viscosities:

Oil viscosity	1.23 cp
Water viscosity	0.7 cp
CO_2 viscosity	0.065 cp

Reservoir parameters:

Dykstra-Parsons coeff.	0.75
Number of layers	5
Pattern type	5-spot

Relative permeability curve parameters:

S_{orw} (residual oil to waterflood)	0.35
S_{org} (residual oil to gas flood)	0.25
S_{gr} (residual gas saturation)	0.35
S_{sr} (residual solvent saturation)	varied, 0.35 base
S_{wc} (connate water saturation)	0.2
S_{wir} (residual water saturation)	varied, 0.2 base
k_{rocw} (endpoint oil rel perm)	0.5
k_{wro} (endpoint water rel perm)	0.3
k_{rse} (endpoint solvent rel perm)	varied, 0.05 base
k_{rgcw} (endpoint gas rel perm)	varied, 0.4 base
n_{ow} (oil curve exponent)	2.5
n_w (water curve exponent)	1.5
n_s (solvent curve exponent)	2.5 and 2.0
n_g (gas curve exponent)	2.5
ω (mixing parameter)	0.666

The relative permeability parameters represent an intermediate to oil wet condition.

If an endpoint relative permeability of 0.05 is used for the CO_2, then the endpoint mobility ratios for all the fluids are fairly close.

<u>Fluid Pair</u>	<u>Endpoint Mobility Ratio</u>
CO_2 / water	1.8
Water / oil	1.05
CO_2 / oil	1.9

TABLE 1

Dependence of Tertiary Oil Recovery on CO_2/Oil Permeability Ratio

		Tertiary Oil Recovery (HCPV)						
		Continuous CO_2				Hybrid - WAG		
k_{rm}	R_k	0.15 HCPV CO_2	0.33 HCPV CO_2	0.60 HCPV CO_2	Water Chase	CO_2 Slug	WAG	Water Chase
Sat. Weight	1.0	0.0230	0.0561	0.0801	0.2021	0.0230	0.1933	0.2908
Average	0.8	0.0223	0.0564	0.0812	0.2034	0.0223	0.1916	0.2891
Equal to k_{row}	---	0.0231	0.0560	0.0801	0.2021	0.0231	0.1928	0.2904
k_{rg} or k_{row}	0.08	0.0228	0.0583	0.0857	0.2091	0.0228	0.1968	0.2944
Sat. Weight	0.1	0.0191	0.0699	0.1295	0.2646	0.0191	0.2141	0.3141
Average	0.1	0.0182	0.0573	0.0870	0.2087	0.0182	0.1878	0.2828
k_{rg} or k_{row}	0.1	0.0164	0.0709	0.1342	0.2845	0.0164	0.2174	0.3205
Sat. Weight	0.01	0.0171	0.0729	0.1661	0.3191	0.0171	0.2451	0.3460

R_k = Endpoint CO_2/Oil relative permeability ratio

TABLE 2

Dependence of CO_2 Production on CO_2/Oil Permeability Ratio

		CO_2 Production (HCPV)						
		Continuous CO_2				Hybrid - WAG		
k_{rm}	R_k	0.15 HCPV CO_2	0.33 HCPV CO_2	0.60 HCPV CO_2	Water Chase	CO_2 Slug	WAG	Water Chase
Sat. Weight	1.0	0.0156	0.1326	0.3568	0.4549	0.0156	0.3262	0.3790
Average	0.8	0.0142	0.1285	0.3513	0.4518	0.0142	0.3249	0.3796
Equal to k_{row}	---	0.0157	0.1327	0.3569	0.4551	0.0156	0.3281	0.3814
k_{rg} or k_{row}	0.8	0.0143	0.1248	0.3441	0.4478	0.0143	0.3170	0.3735
Sat. Weight	0.1	0.0075	0.0795	0.2374	0.3857	0.0075	0.2558	0.3415
Average	0.1	0.0086	0.1086	0.3234	0.4350	0.0086	0.3069	0.3690
k_{rg} or k_{row}	0.1	0.0036	0.0508	0.2062	0.3640	0.0036	0.2340	0.3300
Sat. Weight	0.01	0.0052	0.0482	0.1560	0.3248	0.0052	0.1951	0.2979

R_k = Endpoint CO_2/Oil relative permeability ratio

TABLE 3

Tertiary Oil Recoveries with Hysteresis

		Tertiary Oil Recovery (HCPV)					
		Water Hysteresis Only			Water and Oil Hysteresis		
k_{rm}	S_{orm}	CO_2 Slug	WAG	Water Chase	CO_2 Slug	WAG	Water Chase
Equal to k_{row}	0.2	0.0231	0.1928	0.2904	---	---	---
	0.25	0.0244	0.1937	0.2910	0.0212	0.1959	0.2929
	0.3	0.0265	0.1974	0.2936	0.0262	0.1963	0.2929
	0.35	0.0290	0.1928	0.2880	0.0283	0.1960	0.2898
Sat. Weight	0.2	0.0187	0.2065	0.3059	---	---	---
	0.25	0.0201	0.2146	0.3115	0.0170	0.2069	0.3037
	0.3	0.0230	0.2205	0.3143	0.0224	0.2192	0.3132
	0.35	0.0266	0.2208	0.3115	0.0268	0.2326	0.3210
	0.4	0.0319	0.2124	0.3001	0.0317	0.2329	0.3157
Average (R_k = 0.8)	0.2	0.0223	0.1916	0.2891	---	---	---
	0.3	0.0266	0.1974	0.2929	0.0268	0.1976	0.2932
	0.35	0.0278	0.1935	0.2888	0.0276	0.1934	0.2878
Average (R_k = 0.1)	0.2	0.0181	0.1878	0.2828	---	---	---
	0.3	0.225	0.1931	0.2854	0.0229	0.1920	0.2845
	0.35	0.0246	0.1930	0.2837	0.0242	0.1968	0.2871

R_k = Endpoint Gas/Oil relative permeability ratio

TABLE 4

Dependence of Tertiary Oil Recovery on Oil Relative Permeability (k_{rm} = k_{row})

		Tertiary Oil Recovery (HCPV)									
						Hybrid - WAG					
		Continuous CO_2				1:1 WAG			1:2 WAG		
k_{rocw}	WF	0.15 HCPV CO_2	0.33 HCPV CO_2	0.60 HCPV CO_2	Water Chase	CO_2 Slug	WAG	Water Chase	CO_2 Slug	WAG	Water Chase
0.5	0.4077	0.231	0.0561	0.0801	0.2091	0.0231	0.1928	0.2904	0.0231	0.1611	0.2728
0.05	0.2434	0.0197	0.0768	0.1212	0.2530	0.0197	0.1976	0.2904	0.0197	0.1779	0.2834

TABLE 5

Comparison of Miscible Relative Permeability Formulations Tertiary Oil Recovery (HCPV)

k_{rm}	R_k	S_{orm}	CO_2 Slug	WAG	Water Chase
Equal to k_{row}	---	0.0	0.0231	0.1928	0.2904
Average	0.8	0.0	0.0223	0.1916	0.2891
Average	0.1	0.0	0.0181	0.1878	0.2828
Sat. Weight	0.1	0.0	0.0187	0.2065	0.3059
Equal to k_{row}	---	0.10	0.0207	0.1659	0.2539
Sat. Weight	0.1	0.10	0.0167	0.1876	0.2767
Sat. Weight (oil hysteresis and water hysteresis with S_{orw} = 0.30)	0.1	0.10	0.0203	0.2002	0.2840

R_k = Endpoint CO_2 (or gas)/Oil Relative Permeability ratio.

TABLE 6

Comparison of Miscible Relative Permeability Formulations
CO_2 Production (HCPV)

k_{rm}	R_k	S_{orm}	CO_2 Slug	WAG	Water Chase
Equal to k_{row}	—	0.0	0.0156	0.3281	0.3814
Average	0.8	0.0	0.0142	0.3249	0.3796
Average	0.1	0.0	0.0086	0.3069	0.3690
Sat. Weight	0.1	0.0	0.0071	0.2709	0.3511
Equal to k_{row}	—	0.10	0.0201	0.3505	0.4151
Sat. Weight	0.1	0.10	0.0092	0.2713	0.3544
Sat. Weight (oil hysteresis and water hysteresis with S_{wir} = 0.30)	0.1	0.10	0.0102	0.2856	0.3504

R_k = Endpoint CO_2 (or gas)/Oil Relative Permeability ratio.

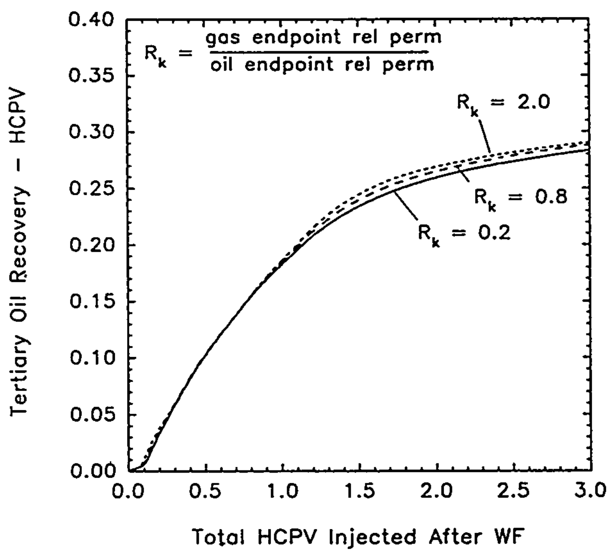


Figure 1. Impact of Endpoint Gas Relative Permeability on Oil Recovery for the Simple Average Method

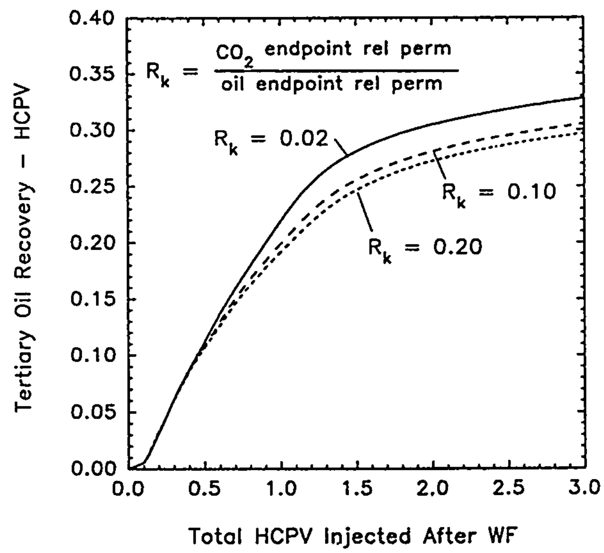


Figure 3. Impact of Endpoint CO_2 Relative Permeability on Oil Recovery for the Saturation Weighted Method

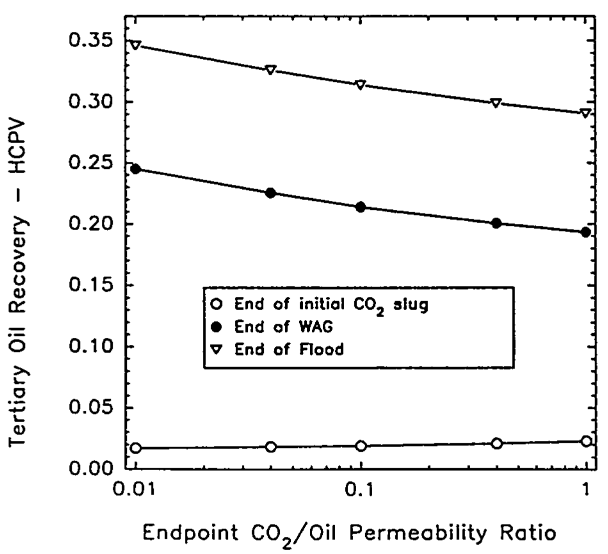


Figure 2. Effect of Endpoint CO_2/Oil Relative Permeability Ratio on Tertiary Oil Recovery for the Hybrid WAG Process

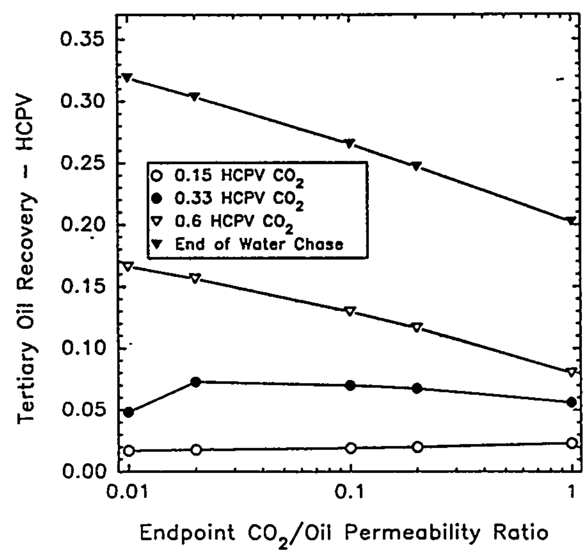


Figure 4. Effect of Endpoint CO_2/Oil Relative Permeability Ratio on Tertiary Oil Recovery for the Continuous CO_2 Process

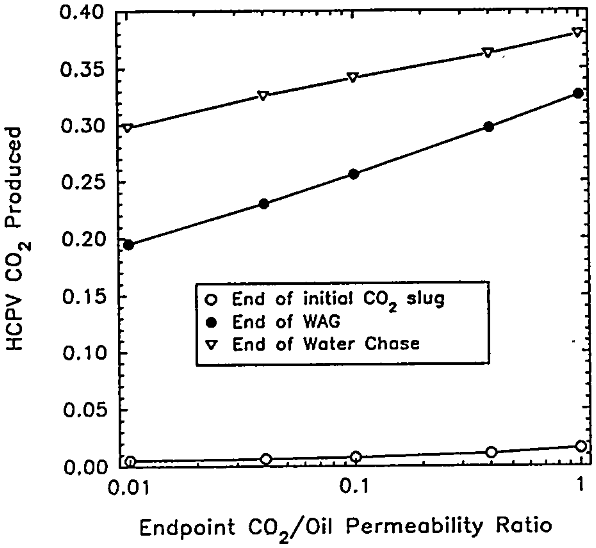


Figure 5. Effect of Endpoint CO_2/Oil Relative Permeability Ratio on CO_2 Production for the Hybrid WAG Process

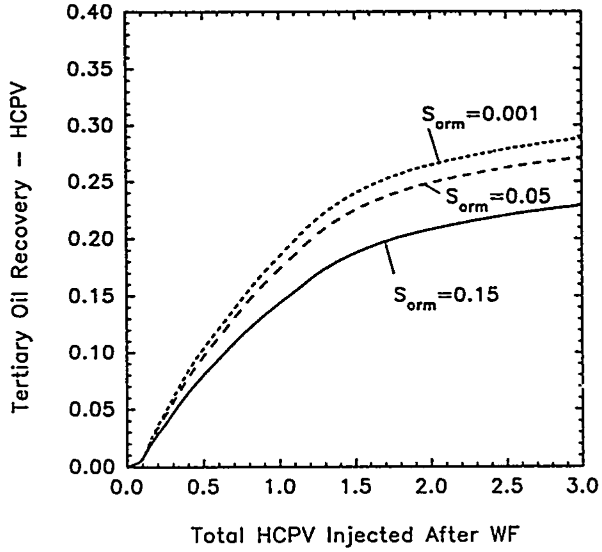


Figure 7. Effect of a Miscible Residual Oil Saturation on Tertiary Oil Recovery

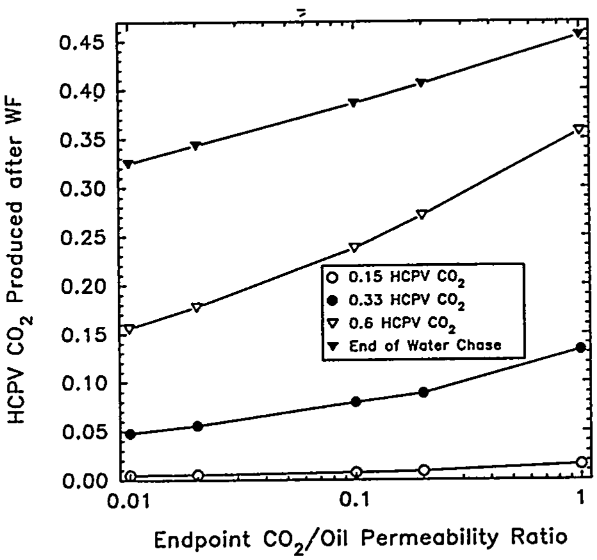


Figure 6. Effect of Endpoint CO_2/Oil Relative Permeability Ratio on CO_2 Production for the Continuous CO_2 Process

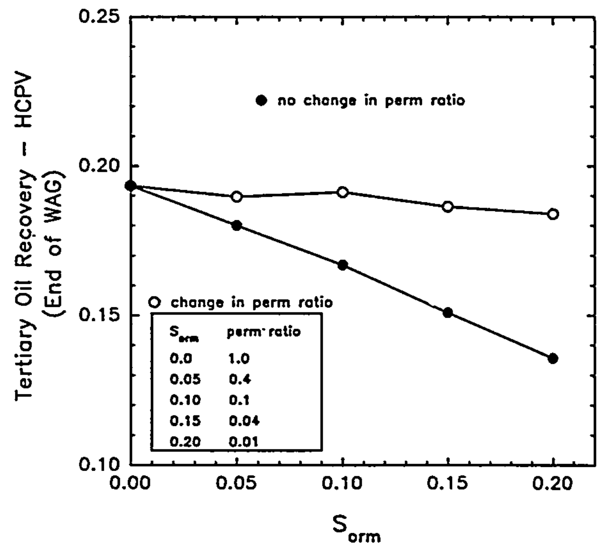


Figure 8. Effect of S_{orm} on Oil Recovery With and Without Change in CO_2 Relative Permeability

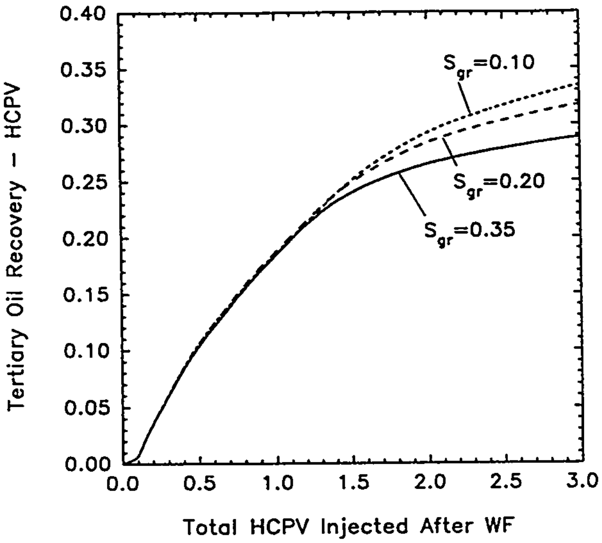


Figure 9. Effect of Residual Gas Saturation on CO_2 Flood Performance

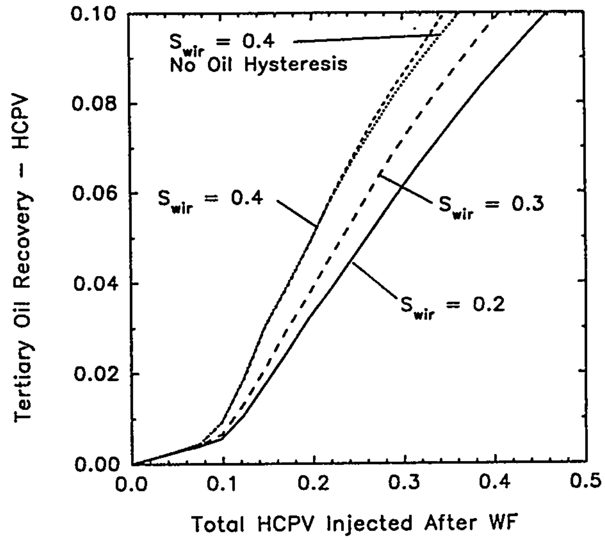


Figure 11. Hysteresis Effects in Early Stages of CO_2 Flood

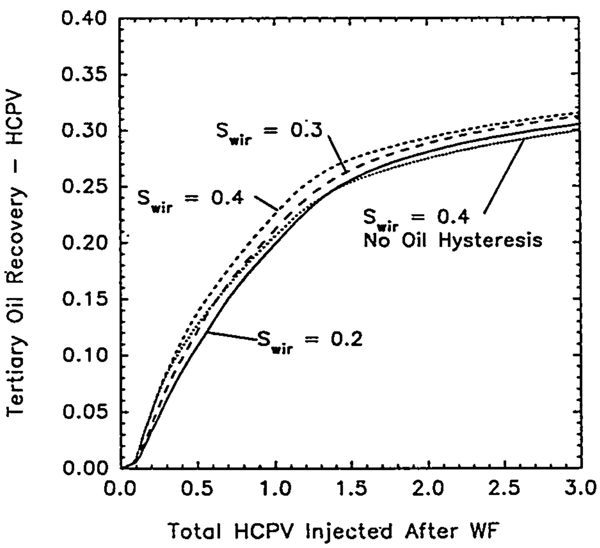


Figure 10. Effects of Water and Oil Relative Permeability Hysteresis on CO_2 Flood Performance

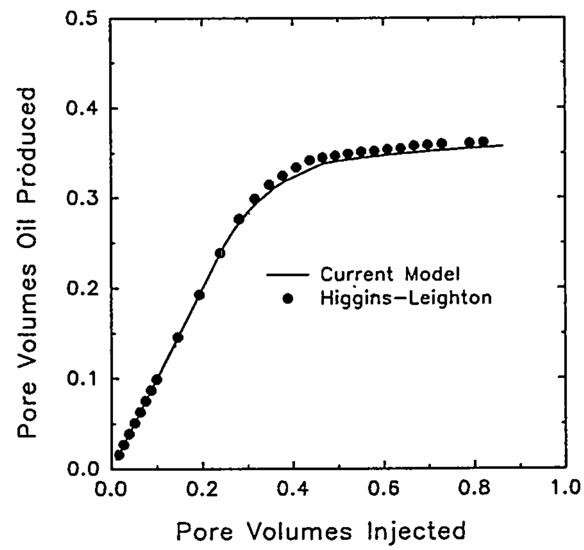
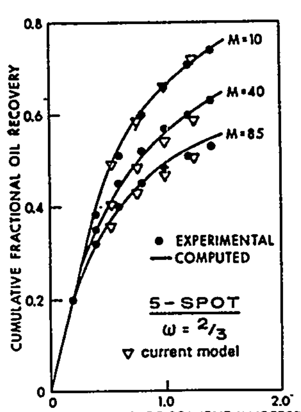


Figure A-1. Comparison of Current Model and Higgins-Leighton Method (Ref. 11) for Predicted Waterflood Performance in a Five-Spot



Miscible displacement performance in a confined, five-spot pattern for various unfavorable mobility ratios.

Figure A-2. Comparison of Current Model with Todd and Longstaff Results (This is Fig. 5 from Ref. 6)

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