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POST WATERFLOOD CO_2 MISCIBLE FLOOD IN LIGHT OIL FLUVIAL DOMINATED DELTAIC RESERVOIR – PROJECT PERFORMANCE YEARS 1993-1994

Final Report
June 1, 1993-December 31, 1997

By:
Sami-Bou-Mikael

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New Orleans, Louisiana

National Energy Technology Laboratory
National Petroleum Technology Office
U.S. DEPARTMENT OF ENERGY
Tulsa, Oklahoma

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Project Performance Years 1993-1994

By
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February 2002

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TABLE OF CONTENTS

		PAGE
1.	Introduction	1
2.	Executive Summary	3
3.	Reservoir Performance	4
4.	Reservoir Characterization	6
5.	Field Implementation	7
6.	CO_2/ CO_2 Pipeline	8
6.	Environmental	9
7.	Technology Transfer	9

Figures:	**1) Geographic Location Map**	**10**
	2) Reservoir Structure Map	**10**
	3) Reservoir BHP	**11**
	4) Reservoir Voidage	**11**
	5) Allocated Production	**13**
	6) Reservoir Yield & Production	**14**
	7) Well #38 Yield & Production	**15**
	8) Well #33 Yield & Production	**16**
	9) Well #15R Yield & Production	**17**
	10)Well #14 Yield & Production	**18**
	11)Well #8 Yield & Production	**19**
Appendices:	**A) Facilities Photographs**	**20**
	B) SIDE Papers	**29**
	C) Prophet School Attendees List	**51**
	D) DOE Documents:	
	Notice Of Energy RD&D Project	**53**
	Cost Summary Report	**55**
	Milestone Schedule	**60**
	Milestone Schedule Attachment	**65**
	Financial Status Report	**71**
	Fed. Cash Transaction Report	**77**

FISCAL YEAR 1994

INTRODUCTION

Production during 1994 closely matched the July 1993 forecast submitted with the Project Management Plan. During this period, Texaco purchased an average of 4.3 MMCF/D of CO_2 from Cardox that was to inject into 3 wells. The production averaged 325 to 400 BOPD from 3 wells. This represented 4 folds increase from the production level prior to commencing CO_2 injection. The reservoir pressure increased with CO_2 injection form 2460 psi in September 1993 to and averages of 2810 psi in 1994. Early CO_2 breakthrough from some wells required taking corrective measures, such as alternating water and CO_2 injection (WAG). This was the first time a WAG process had been applied with success in sandstone reservoirs. In 1994 the 3-D seismic data was processed The reservoir model was updated based on the 3-D seismic survey evaluation. The model indicated a need for aquifer supports in order to history match the production. The model also indicated the highest oil saturation was in the updip portion of the reservoir, which is supported by production for #15-R. The simulation prediction runs indicated higher recovery than actually observed in the field. During this time producing response was slightly higher than anticipated. The following pages contain the annual report for fiscal year 1994.

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

DE-FC22-93BC14960

Introduction

Texaco Exploration and Production Inc. (TEPI) and the U.S. Department of Energy (DOE) entered into a cost sharing cooperative agreement to conduct an Enhanced Oil Recovery demonstration project at Port Neches. The field is located in Orange County near Beaumont, Texas, and shown in Figure 1. The project will demonstrate the effectiveness of the CO_2 miscible process in Fluvial Dominated Deltaic reservoirs. It will also evaluate the use of horizontal CO_2 injection wells to improve the overall sweep efficiency. A database of FDD reservoirs for the gulf coast region will be developed by LSU, using a screening model developed by Texaco Research Center in Houston. Finally, the results and the information gained from this project will be disseminated throughout the oil industry via a series of SPE papers and industry open forums.

Reservoir characterization efforts for the Marginulina sand shown in Figure 2, are in progress utilizing conventional and advanced technologies including 3-D seismic. Sidewall and conventional cores were cut and analyzed, lab tests were conducted on reservoir fluids, reservoir BHP pressure and reservoir voidage were monitored as shown in Figures 3 & 4. Texaco is utilizing the above data to develop a Stratamodel to best describe and characterize the reservoir and to use it as input for the compositional simulator. The current compositional model is being revised to integrate the new data from the 3-D seismic and field performance under CO_2 injection, to ultimately develop an accurate economic model.

All facilities work has been completed and placed in service including the CO_2 pipeline and metering equipment, CO_2 injection and production equipment, water injection equipment, well work and injection/production lines. Photographs of the facilities are shown in Appendix "A". All workovers have been performed except for Area 2 wells that were deferred till 1995. The horizontal injection well was drilled and completed on January 15,1994.

CO_2 purchases from Cardox continue at an average rate of 3600 MCFD. The CO_2 is being injected at line pressure of 1350 psi. Recycled CO_2 is higher than anticipated due to the low movable oil saturation in the reservoir. Volume of recycled gas has reached 8000 MCFD level earlier this year, but it dropped to 5000 MCFD after inverting water/CO_2 injection.

Environmentally, Texaco has taken all the necessary steps to reduce air and fluid emission. By improving the underground water injection system, reducing the NO_x and CO emission from the injection compressors and placing vapor recovery units on storage tanks, Texaco ensured compliance with or exceeded all environmental standards requirements.

TEPI plans to perform the necessary drilling and workovers to prepare Area 2 of the project for CO_2 injection early next year. Response from this area is anticipated to exceed the main body of the reservoir due to the higher movable oil saturation in the pore space.

Technology transfer regarding the progress and results of this project is ongoing. This year Texaco presented two papers at the SPE/DOE symposium in Tulsa. The first paper entitled "Project Design of a CO_2 Miscible Flood in a Waterflooded Sandstone Reservoir", and the second paper covered a PC based screening model, and was entitled "A Stream Tube Model for The PC". Copies of the two papers are shown in Appendix "B". Additionally, Texaco held several presentations in the Midland area concerning the screening model. Representatives from independents and major producers attended the

presentations.

Executive Summary

The Port Neches CO_2 project is progressing on schedule. Early production from the project is closely matching the July 1993 forecast submitted with the Project Management Plan. CO_2 purchases are also on schedule with Cardox staying on line over 95% of the time. The only interruption occurred when Dupont shut down the CO_2 generation facility for maintenance. Early CO_2 breakthrough from some wells required taking corrective measures, such as alternating water and CO_2 injection. This is the first time a WAG process has been applied, and with a pleasant success, in sandstone reservoirs. The CO_2 pipeline and field facilities are operating properly. The compressor station remained on line over 94% of the time. 3-D seismic data is currently being processed and interpreted for the CO_2 project area. It is anticipated that this data will be extremely valuable for the project, especially Area 2, where some additional work is anticipated to take place next year. TEPI donated this data in-kind toward the project. The compositional reservoir simulation efforts are progressing with the anticipated completion of the Stratamodel by the end of November 1994. The following table summarizes the reservoir history under CO_2 flooding:

	Current Rates September 1994	Cumulative data
Oil Production	500 BOPD	114 MBO
Water Production	3000 BWPD	1075 MBW
Gas-CO_2 Production	5400 MCFD	1100 MMCF
Water Injection	1800 BWPD	940 MBW
Gas (CO_2) Injection	9300 MCFD	2100 MMCF
Purchased CO_2	3600 MCFD	1400 MMCF

Reservoir performance

The reservoir mapping is being updated to incorporate new data from the 3-D interpretation. The recent interpretation divides the first area of the reservoir into two segments separated by a fault through the center. Reservoir behavior and performance under CO2 injection support this.

Since the early stages of this project, water was injected to increase the reservoir pressure closer to the MMP. This was followed by CO_2 injection in September of the same year. The daily water injection and purchased CO_2 injection to date is 1600 BWPD and 3600 MCFD respectively. The cumulative injected volumes are 940 MBW and 2.1 BCF including 1.4 BCF of purchased CO_2.

As a result of the water and CO_2 injection, the reservoir production has increased from 25 BOPD prior to project initiation, to an average of 500 BOPD during the month of September. The results are shown in Figure 5. Production is anticipated to increase from existing wells due to alternating water and CO_2 injection, and from new wells in Area 2, that will be completed early next year. Area 2 is anticipated to outperform Area 1 because the remaining oil saturation at the start of the CO_2 flood is 12% higher. This higher mobile oil saturation is a significant contributor to the oil banking mechanism and high recovery rate. Utilizing this process TEPI is hoping to produce an additional 19% of the OOIP, thus increasing the ultimate recovery to 73% of the OOIP. Based on the actual project performance TEPI's current assessment of the project's forecast remains unchanged at this time. The project's performance curves are shown in Figures 6 through 11.

Cumulative oil and water production to date is 114 MBO and 1075 MBW respectively. The table below shows recent well tests for each producing and injection well as of September 15, 1994:

Khun #15R	134 BOPD,	756 BWPD,	810 MCFD,	17 CHOKE,	860 TBG.
Khun #38	384 BOPD,	896 BWPD,	2182 MCFD,	31 CHOKE,	1000 TBG.
Khun #33	72 BOPD,	578 BWPD,	1950 MCFD,	20 CHOKE,	1170 TBG.
Stark #8	109 BOPD,	668 BWPD,	970 MCFD,	29 CHOKE,	380 TBG.
Khun #6	0 BOPD,	330 BWPD,	208 MCFD,	40 CHOKE,	100 TBG.
Khun #14	0 BOPD,	700 BWPD,	314 MCFD,	30 CHOKE,	80 TBG.

Marg Area 1#1H	3658 MCFD,	337 TBG (INJ).
Stark #7	1080 BWPD,	1500 TBG (INJ).
Khun #36	1012 BWPD,	1480 TBG (INJ).
Khun #17	3694 MCFD,	1337 TBG (INJ).
Stark #10	3072 MCFD,	1337 TBG (INJ).

Additionally, the radioactive tracer injected in well Khun #36 passed undetected in surrounding wells. Most likely it passed prior or between sampling of the surrounding wells, indicating lower sweep efficiency than anticipated originally. Steps have been taken to improve the sweep efficiency problem by alternating injection of CO_2 and water. Some improvement has been detected through the improved producing rates of wells Khun #8 and #38. Three months after alternating water and CO_2 injection in wells Khun #17, #36, Stark #7 and #10, the producing rates of wells Khun #8 and #38 increased about two folds.

Reservoir Characterization,

The Port Neches CO_2 project is being conducted in a 235 acre sandstone reservoir named the Marginulina sand. The sand was deposited in a typical FDD environment where a dominant river source was not confined to a single channel. As channel migration and abandonment occurred the coarser grained sands graded upward through time into finer grained sands. The reservoir, deposited at about 5800 ft deep, has an average porosity of 30% and permeability of 750 md. The reservoir was formed when the sand was uplifted by deep-seated salt dome, creating sealing faults as a trapping mechanism. The depletion drive mechanism of the reservoir led to the implementation of waterflood project and eventual application of the CO_2 miscible process. The acquisition of the 3-D seismic data verified the current reservoir boundaries and confirmed the presence of a North-South fault running through the center of the reservoir. However, the reservoir remains interconnected as proven by the homogeneous pressure measured throughout the reservoir. The compositional simulator is currently being updated to accommodate these changes. CO_2 injection is taking place on both sides of the center fault insuring a complete sweep of the reservoir oil. Based on the reservoir performance during the CO_2 injection period we were able to conclude that the center fault is sealing toward the southern end of the reservoir since the throw of the fault is larger than the sand thickness. However, this fault dies out as it moves north toward wells Stark #7 and #29. CO_2 injected in well Khun #17 was not able to reach well Khun #6 even though the pressure in the later well has equalized with the rest of the reservoir.

The following is a summary of reservoir properties:

	Waterflooded Area 1	Partial Water Drive 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

Field Implementation

The horizontal well Marg Area 1 #1-H was drilled and completed January 15, 1994 along the original oil-water contact of the waterflooded fault block. The horizontal section of the well was reduced from 1500' to 250 ft, after the hole collapsed twice while drilling the horizontal section. The well was completed with prepacked screen for sand control.

TEPI designed and installed project facilities consisting of:

* High and low pressure compressors capable of handling 15 MMCFD of CO_2 @ 2000 psi.
* CO_2 injection pump with 4.3 MMCFD capacity @ 2000 psi.
* Water injection pumps to handle 3000 BWPD @ 2000 psi.
* Production vessels and storage tanks to process a minimum of 6000 Bbls of fluid.
* Production/Injection metering equipment. Mass meter was used for accurate CO_2 metering.
* Installed 4.5 miles of 4" CO2 pipeline.
* Installed flowlines/injection lines.
* Performed 10 workovers as injectors/producers.
* Drilled one horizontal injection well.

The Production equipment was mostly barge-mounted due to the location of the field on inland water. Photographs showing the field installations are included in Appendix "A" of this report.

Equipment performance during the first year of the project has been favorable. Only some minor repairs or modifications had to be made on one injection compressor foundations, in order to eliminate vibration problems. Also we had to perform a workover on one producing well to eliminate communication through the gas lift valves. Most equipment has been operational over 94% of the time, with the downtime occurring early during the startup period.

CO_2 Pipeline / CO_2 Purchases

TEPI installed a 4.5 mile, 4" pipeline for CO_2 transportation from a Cardox CO_2 pipeline tie-in point to the Port Neches Field. Cardox gathers, dehydrates and compresses the CO_2 stream to 1500 psi via a 4-stage compressor. The dry CO2 is shipped as a supercritical fluid. A CO_2 metering facility was installed on the Barge at Port Neches. A mass meter is being used to ensure accuracy of the measurement. CO_2

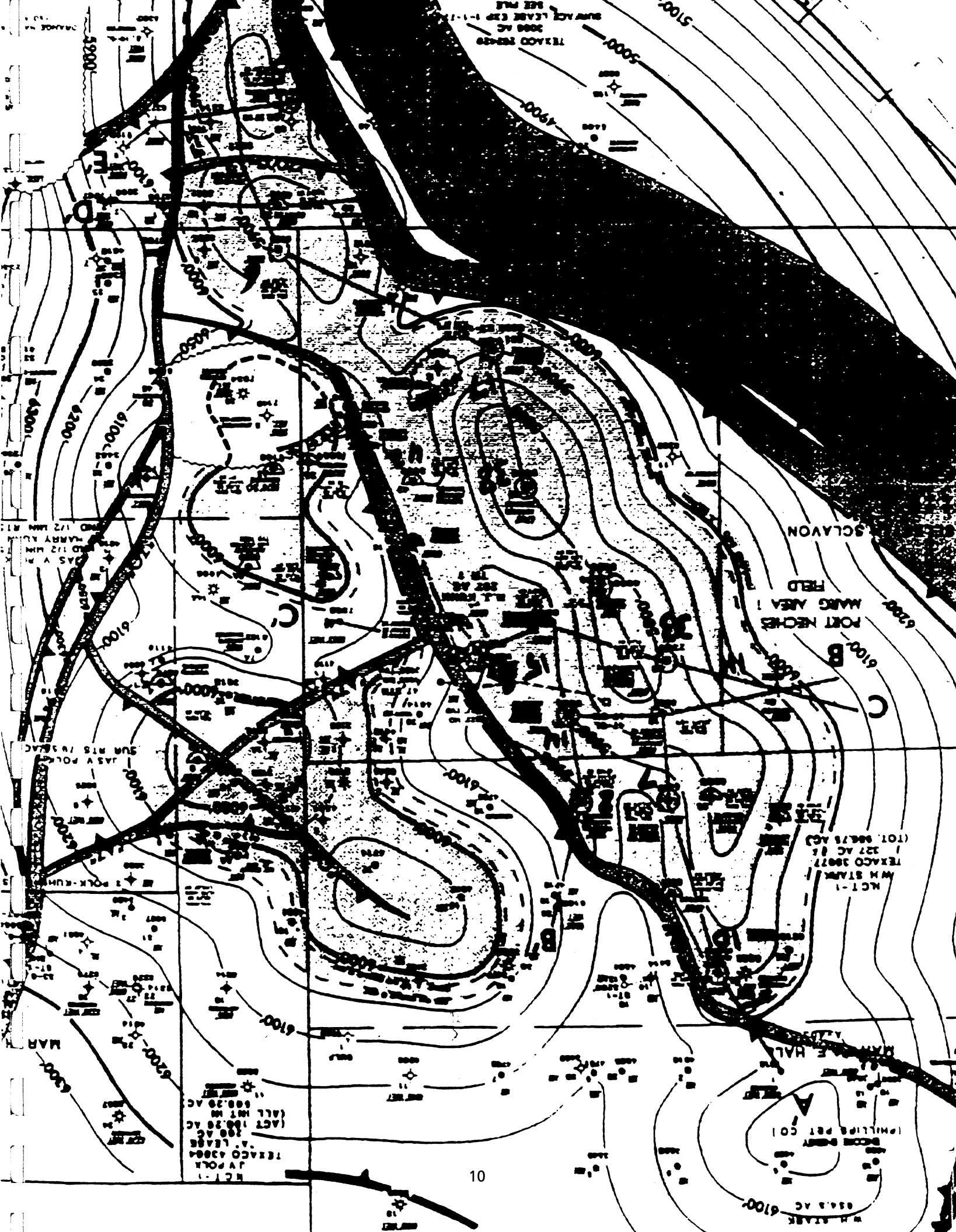
purchases began on September 22, 1994 at an average rate of 4000 MCFD, the cumulative CO_2 purchased from Cardox to date is 1.4 BCF.

Environmental

Texaco is operating this project under the strictest environmental regulations. All VOCs and NO_x emissions from the compressors, pumps and other facilities are monitored and minimized by the use of Vapor Recovery Units where possible. The majority of the produced salt water from this project will be reinjected in the ground for pressure maintenance, while the remaining portion will be decontaminated and discharged in a tidal disposal facility permitted by the state of Texas. The CO_2 pipeline is operating under DOT regulation. The DOT manual that was specifically prepared for this pipeline explains the design criteria, operating procedures, testing procedures, mitigation measures and emergency response procedures. The Project Management Plan discusses in detail Texaco's environmental policies and procedures covering a wider range of issues than what is discussed above.

Technology Transfer

To promote the technology transfer TEPI presented two SPE papers at the SPE/DOE symposium in Tulsa this year. Also TEPI released to the public a reservoir-screening model "PROPHET", capable of evaluating potential application of the CO_2 process to a variety of reservoirs. The PC-based model developed by Texaco's research center in Houston has been tested against other compositional simulators and is found to be very reliable. Additionally, Texaco held several presentations in the Midland area, concerning the screening model. Representatives from independents and major producers attended the presentations. TEPI continue to work with Louisiana State University (LSU), Texaco's Exploration and Production Technology Division (EPTD) and Science Application International Corporation (SAIC) on a plan to promote technology transfer to other companies.


PORT NECHES
MARG AREA 1
FIELD
SCLAVON
TEXACO 39077
MC T-1
W H STARK
(TOT. 906.78 AC)
TEXACO 43064
"A" LEASE
(ACT 100.26 AC
(ALL INT IN
508.20 AC
(PHILLIPS PET CO)
6100'
6200'
6300'
5000'
4900'
5100'

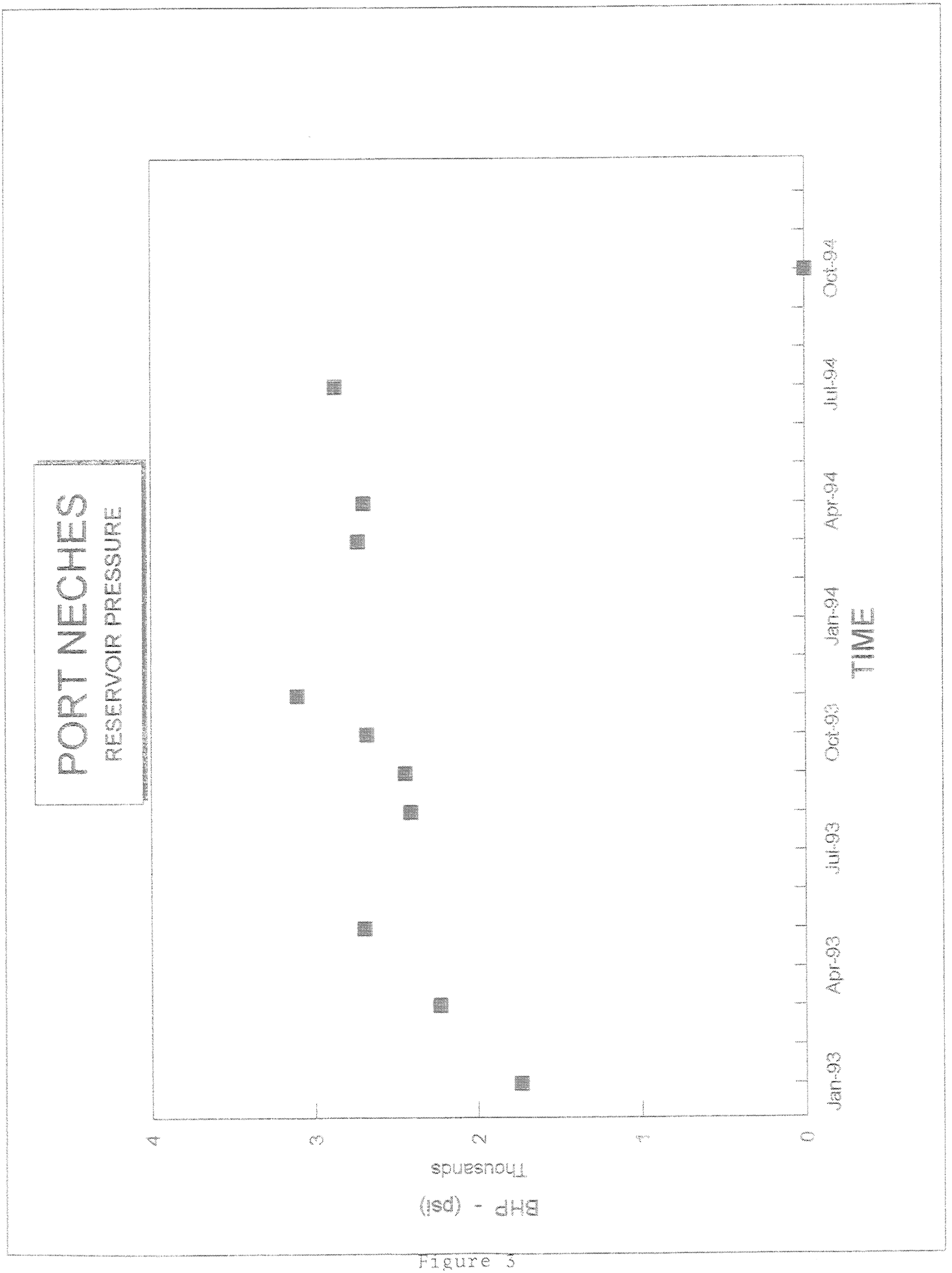

PORT NECHES
RESERVOIR PRESSURE
BHP - (psi)
Thousands
4
3
2
1
0
Jan-93
Apr-93
Jul-93
Oct-93
Jan-94
Apr-94
Jul-94
Oct-94
TIME

Figure 3

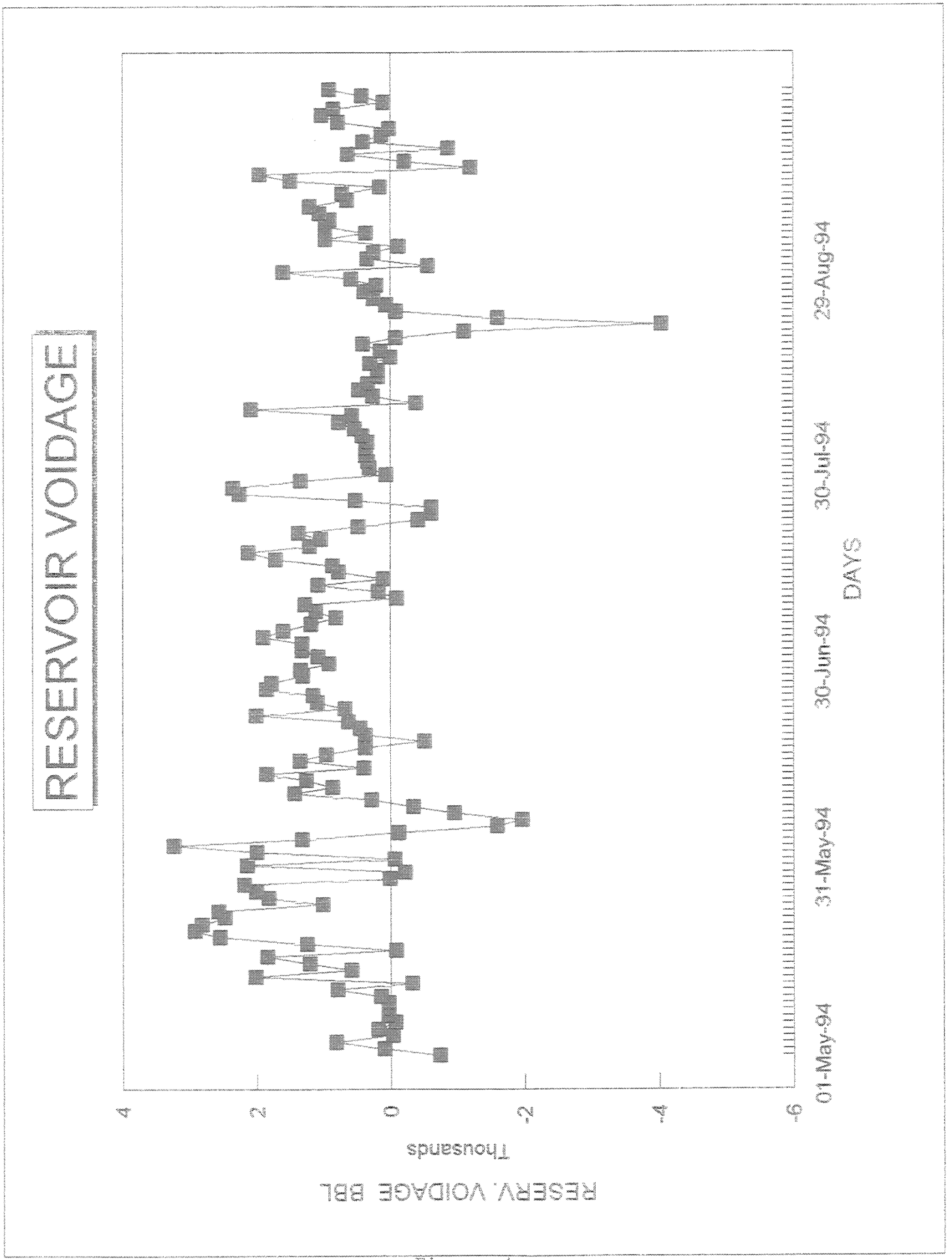

RESERVOIR VOIDAGE
RESERV. VOIDAGE BBL
Thousands
4
2
0
-2
-4
-6
01-May-94
31-May-94
30-Jun-94
30-Jul-94
29-Aug-94
DAYS

Figure 4

Port Neches CO2 Project

Allocated Production

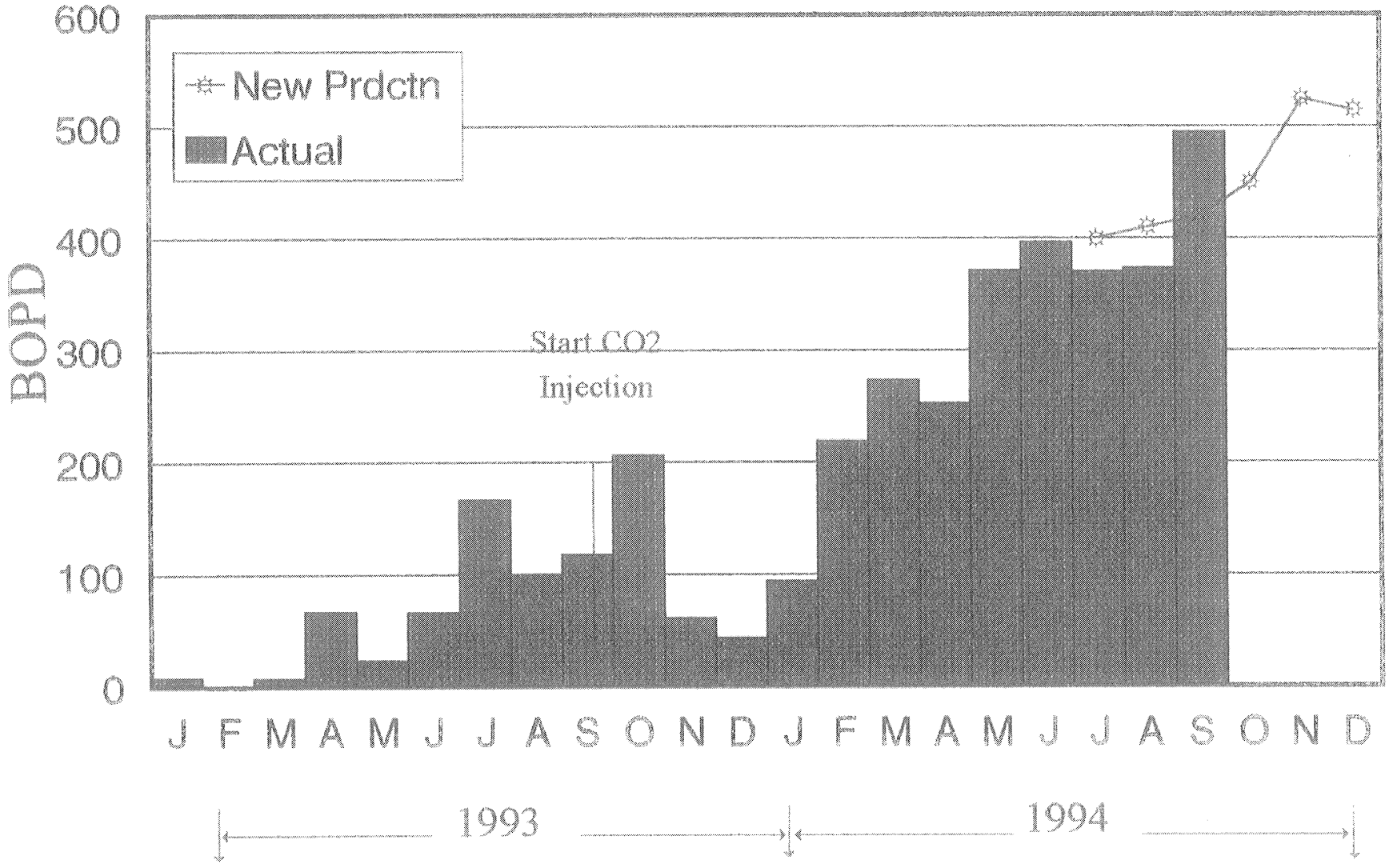


Figure 5

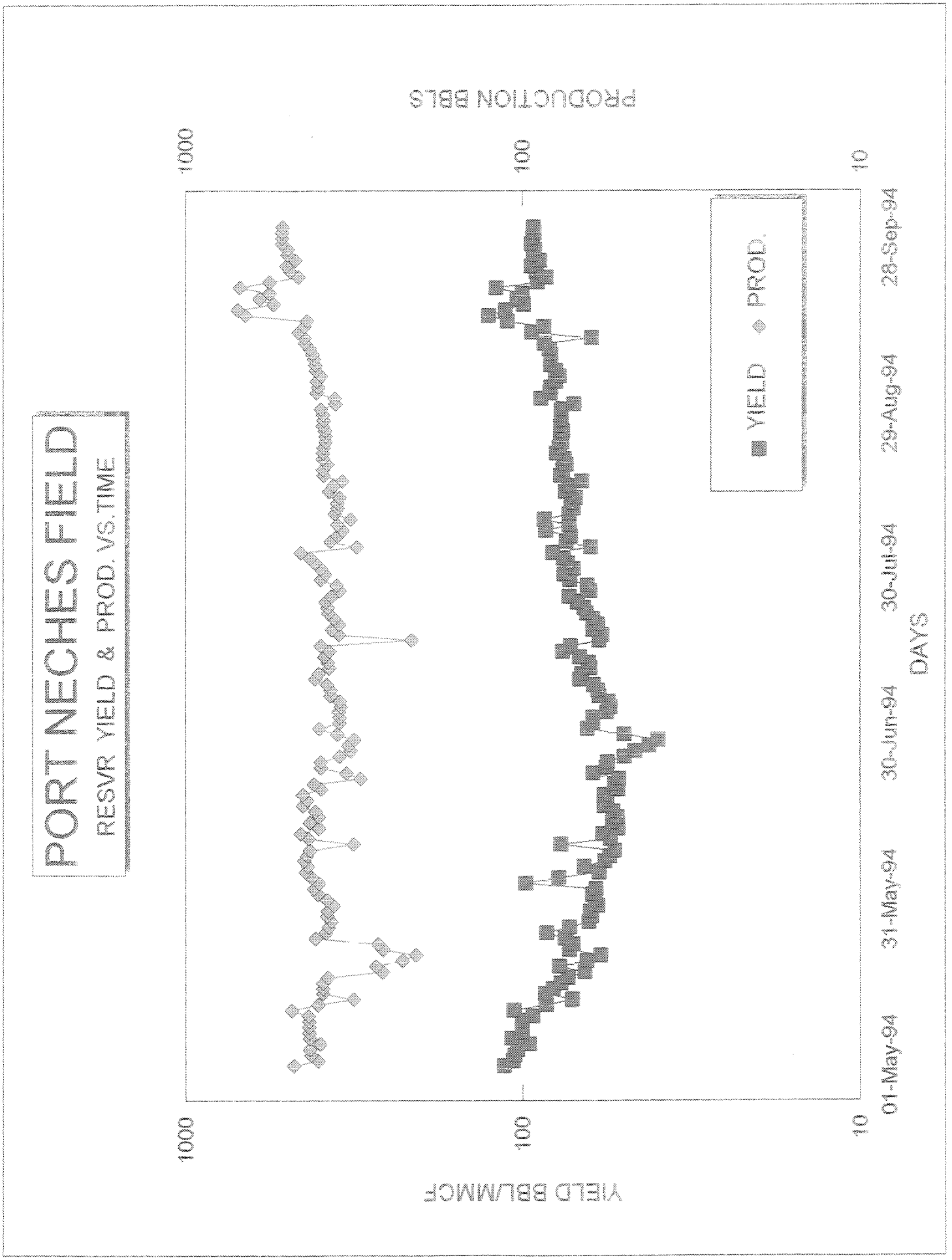

PORT NECHES FIELD
RESVR YIELD & PROD. VS.TIME
YIELD BBL/MMCF
PRODUCTION BBLS
1000
100
10
01-May-94
31-May-94
30-Jun-94
30-Jul-94
29-Aug-94
28-Sep-94
DAYS
YIELD
PROD.

Figure 6

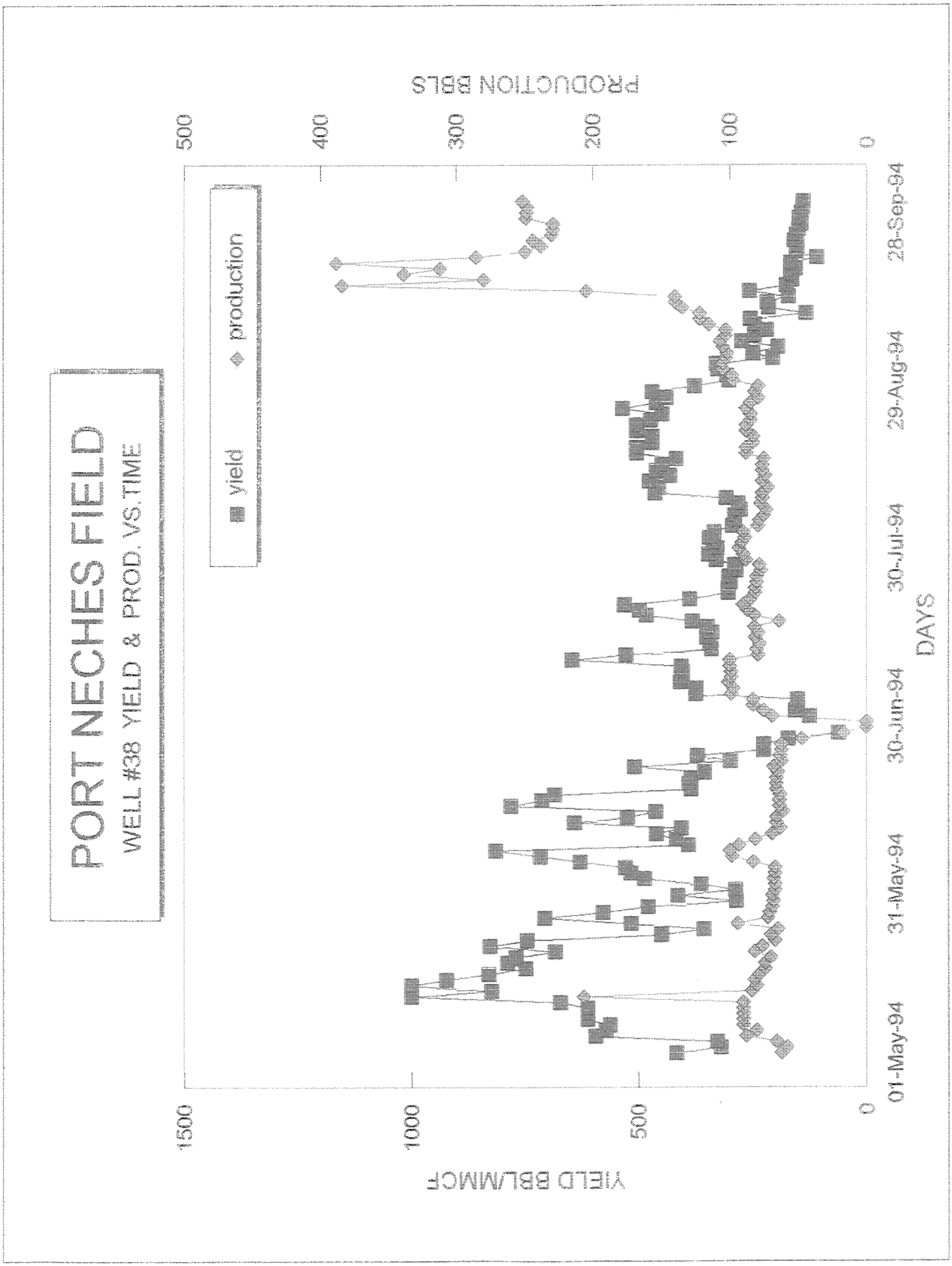

PORT NECHES FIELD
WELL #38 YIELD & PROD. VS.TIME
yield
production
PRODUCTION BBLS
500
400
300
200
100
0
YIELD BBL/MMCF
1500
1000
500
0
01-May-94
31-May-94
30-Jun-94
30-Jul-94
29-Aug-94
28-Sep-94
DAYS

Figure 7

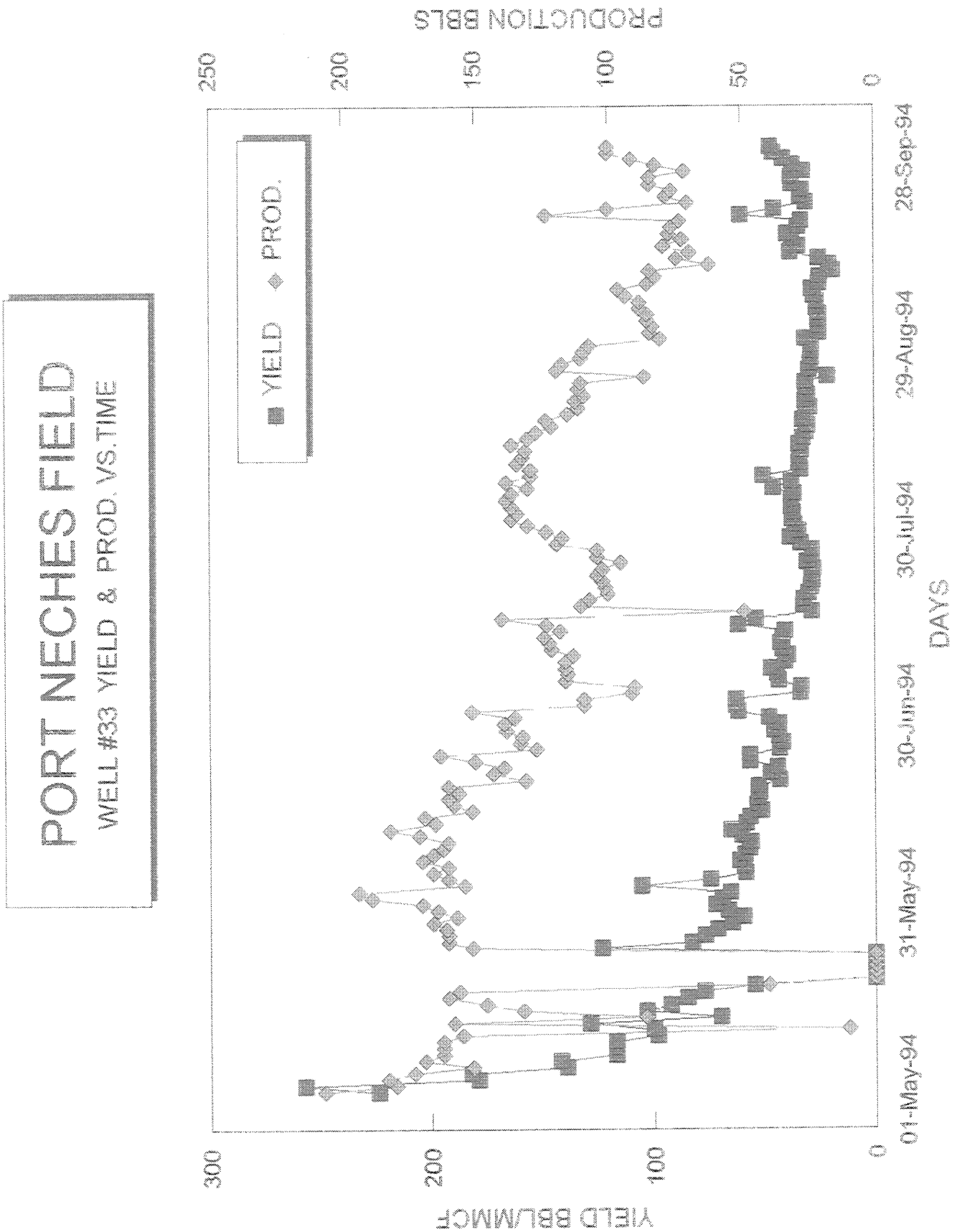

PORT NECHES FIELD
WELL #33 YIELD & PROD. VS. TIME
YIELD
PROD.
PRODUCTION BBLS
250
200
150
100
50
0
YIELD BBL/MMCF
300
200
100
0
01-May-94
31-May-94
30-Jun-94
30-Jul-94
29-Aug-94
28-Sep-94
DAYS

Figure 8

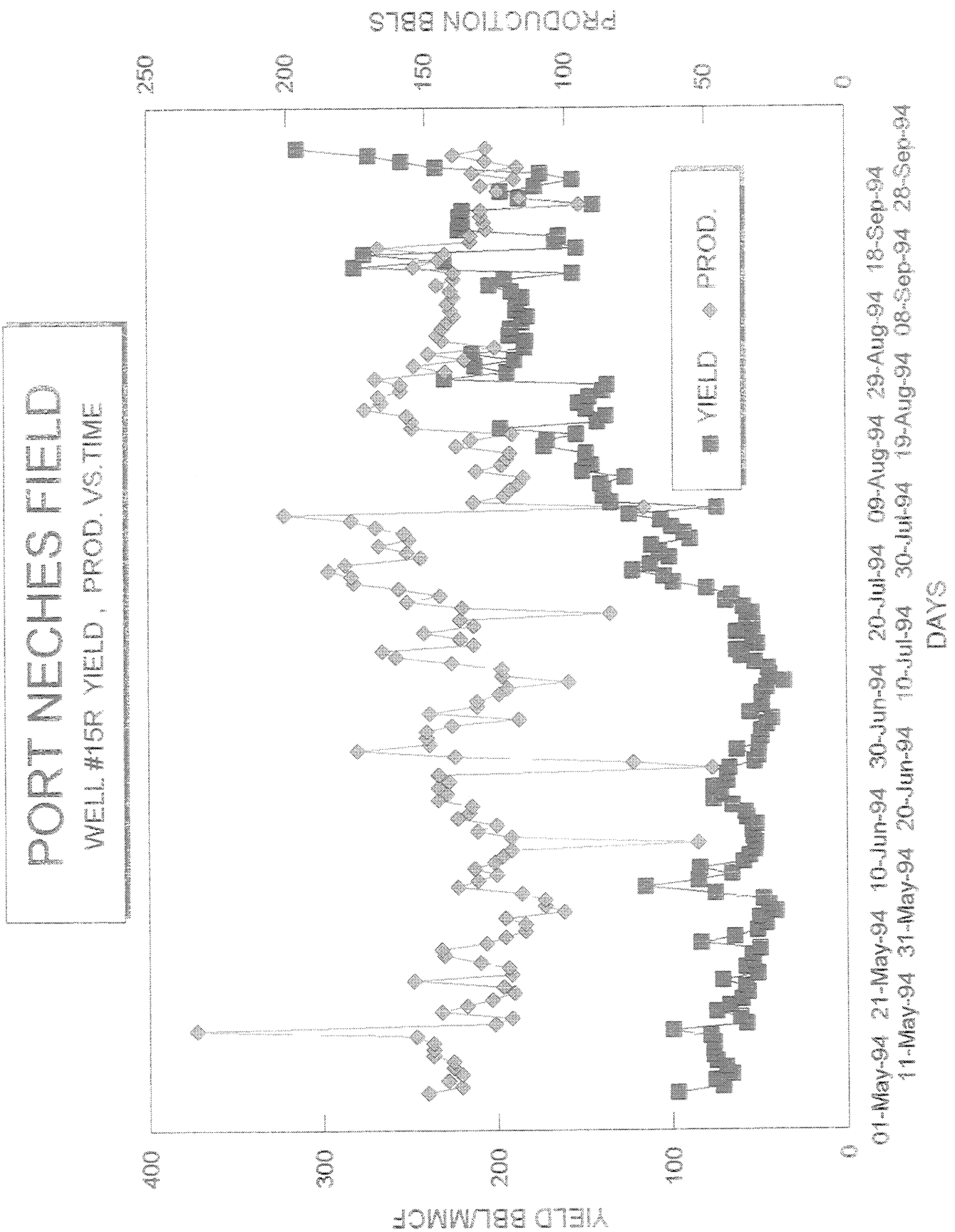

PORT NECHES FIELD
WELL #15R YIELD , PROD. VS. TIME
YIELD
PROD.
PRODUCTION BBLS
250
200
150
100
50
0
YIELD BBL/MMCF
400
300
200
100
0
01-May-94
21-May-94
10-Jun-94
30-Jun-94
20-Jul-94
09-Aug-94
29-Aug-94
18-Sep-94
11-May-94
31-May-94
20-Jun-94
10-Jul-94
30-Jul-94
19-Aug-94
08-Sep-94
28-Sep-94
DAYS

Figure 9

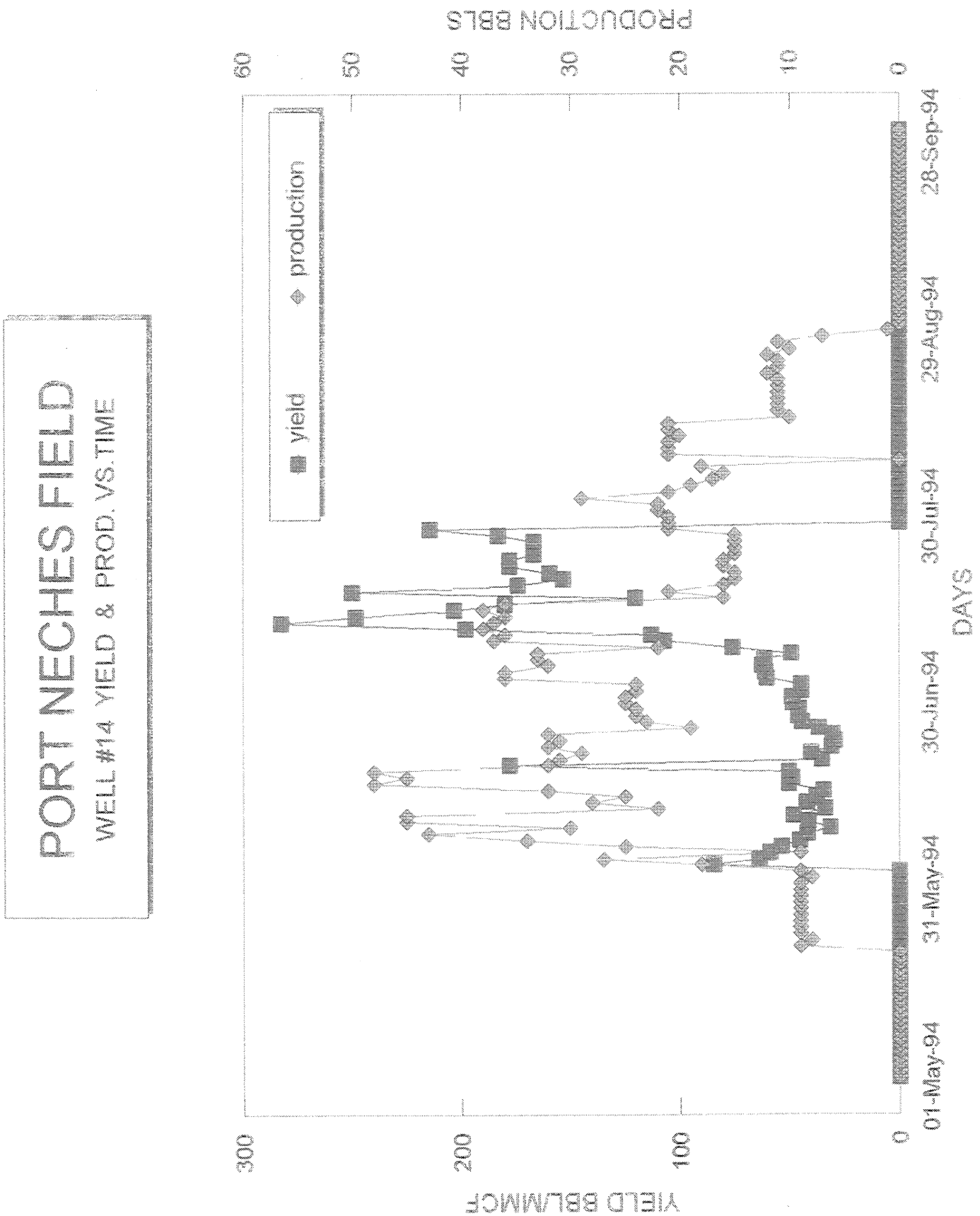

PORT NECHES FIELD
WELL #14 YIELD & PROD. VS. TIME
yield
production
PRODUCTION BBLS
60
50
40
30
20
10
0
YIELD BBL/MMCF
300
200
100
0
01-May-94
31-May-94
30-Jun-94
30-Jul-94
29-Aug-94
28-Sep-94
DAYS

Figure 10

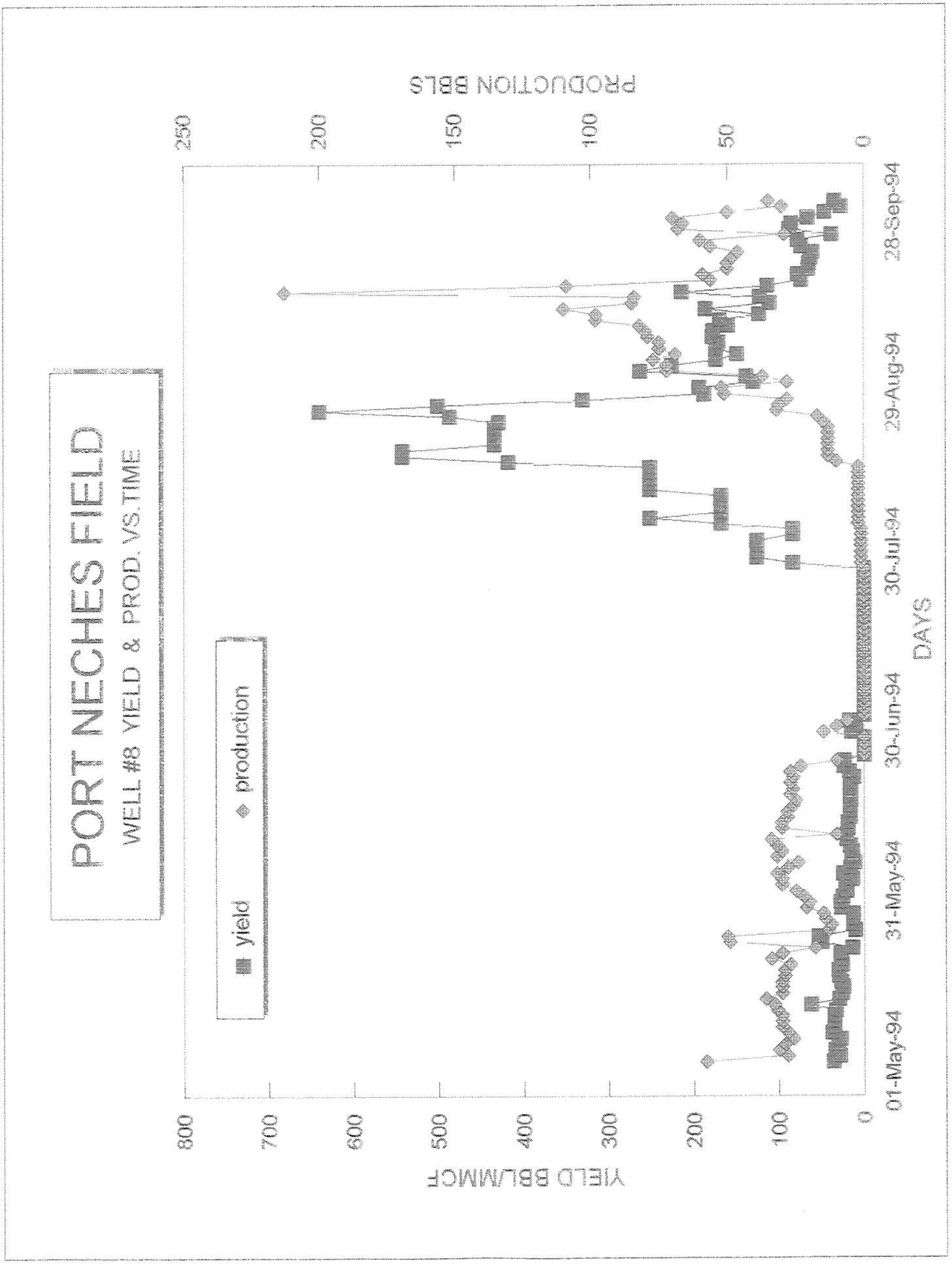
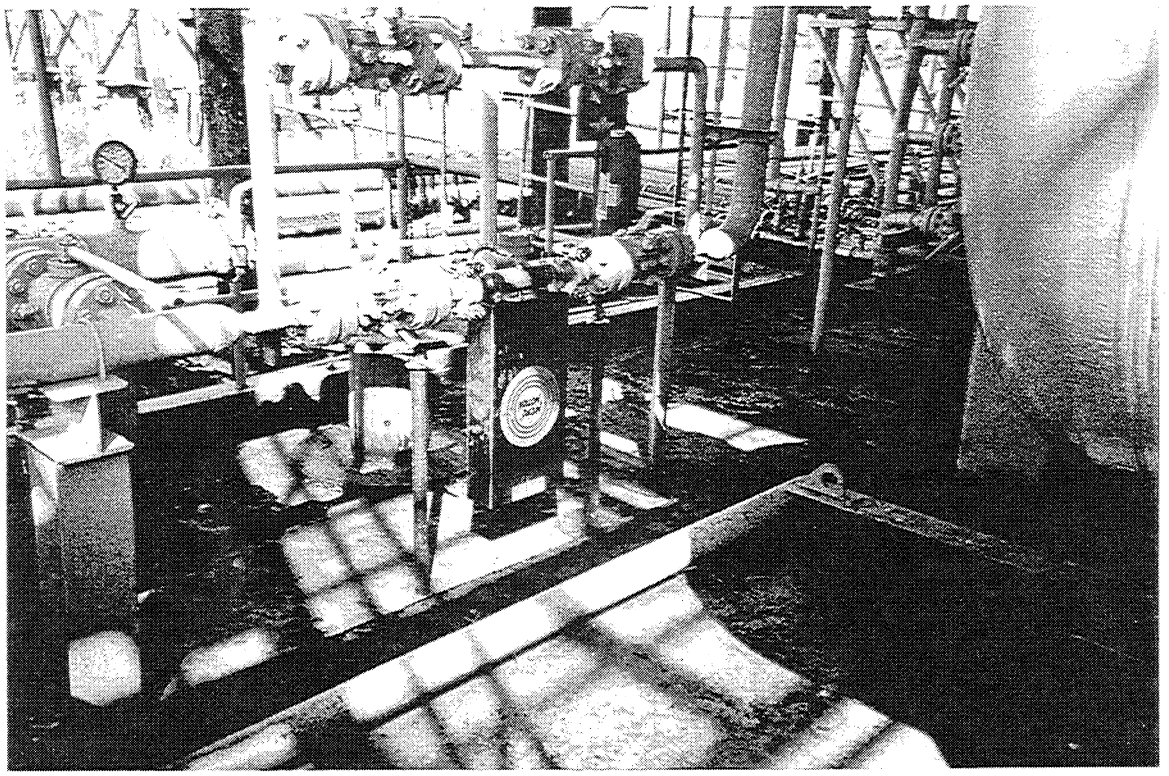
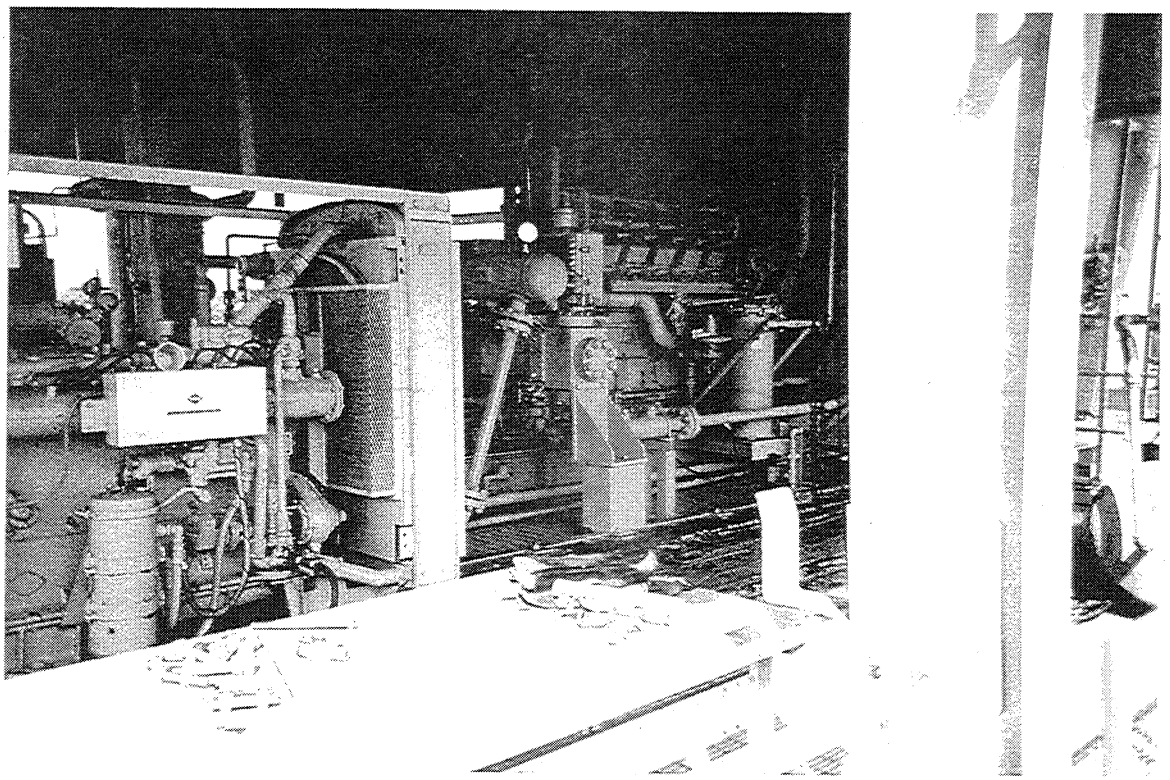

PORT NECHES FIELD
WELL #8 YIELD & PROD. VS. TIME
yield
production
YIELD BBL/MMCF
PRODUCTION BBLS
DAYS
01-May-94
31-May-94
30-Jun-94
30-Jul-94
29-Aug-94
28-Sep-94
0
100
200
300
400
500
600
700
800
0
50
100
150
200
250

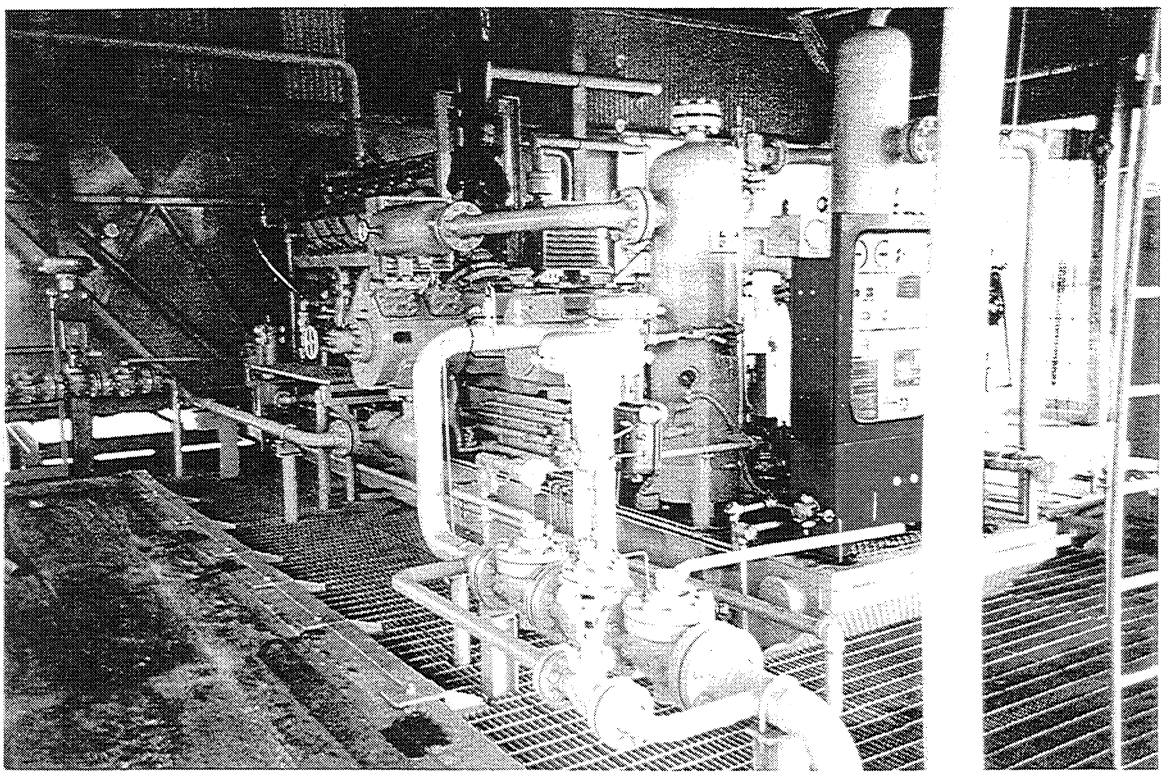
Figure 11



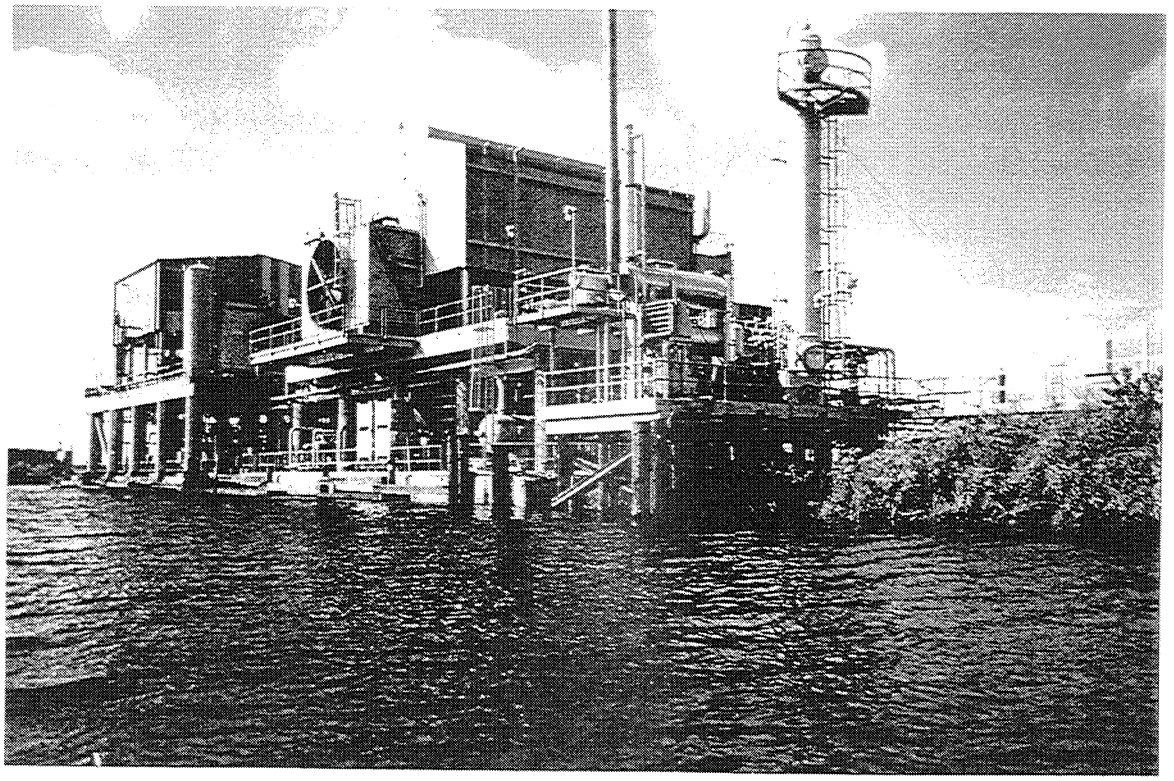
CO_2 Mass Meter



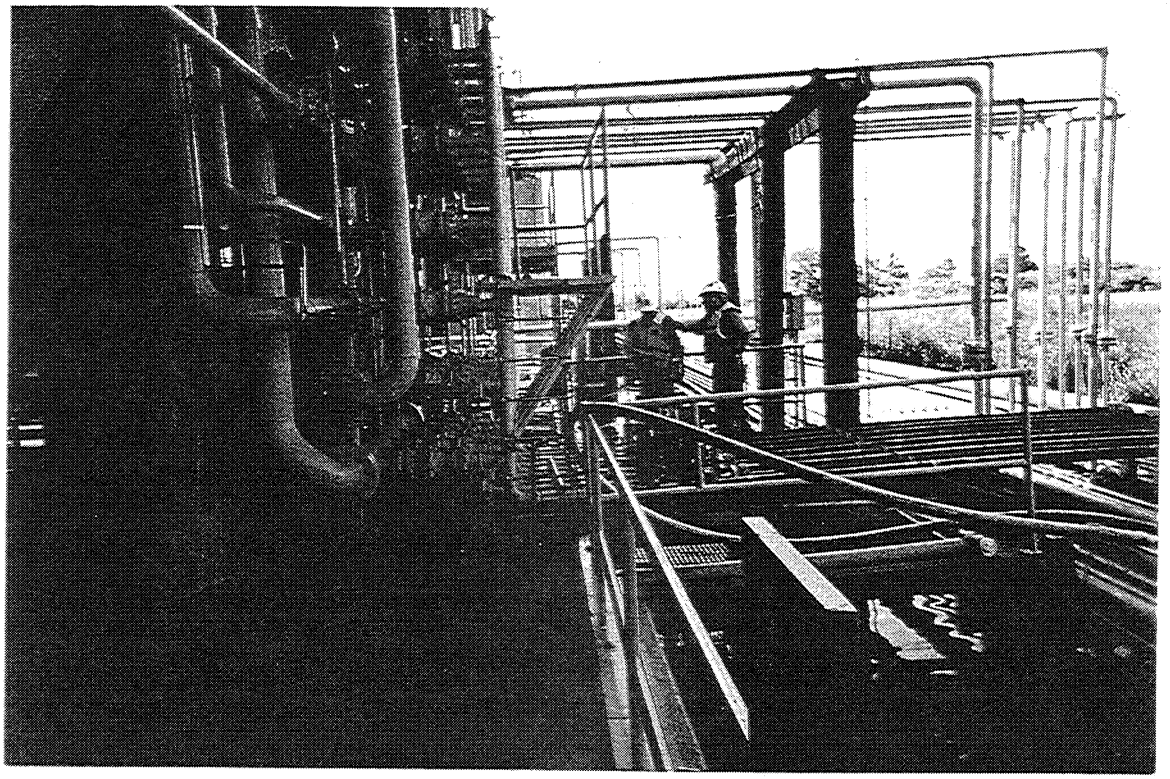
Injection Compressor



Low Pressure Compressor



Compressor Station



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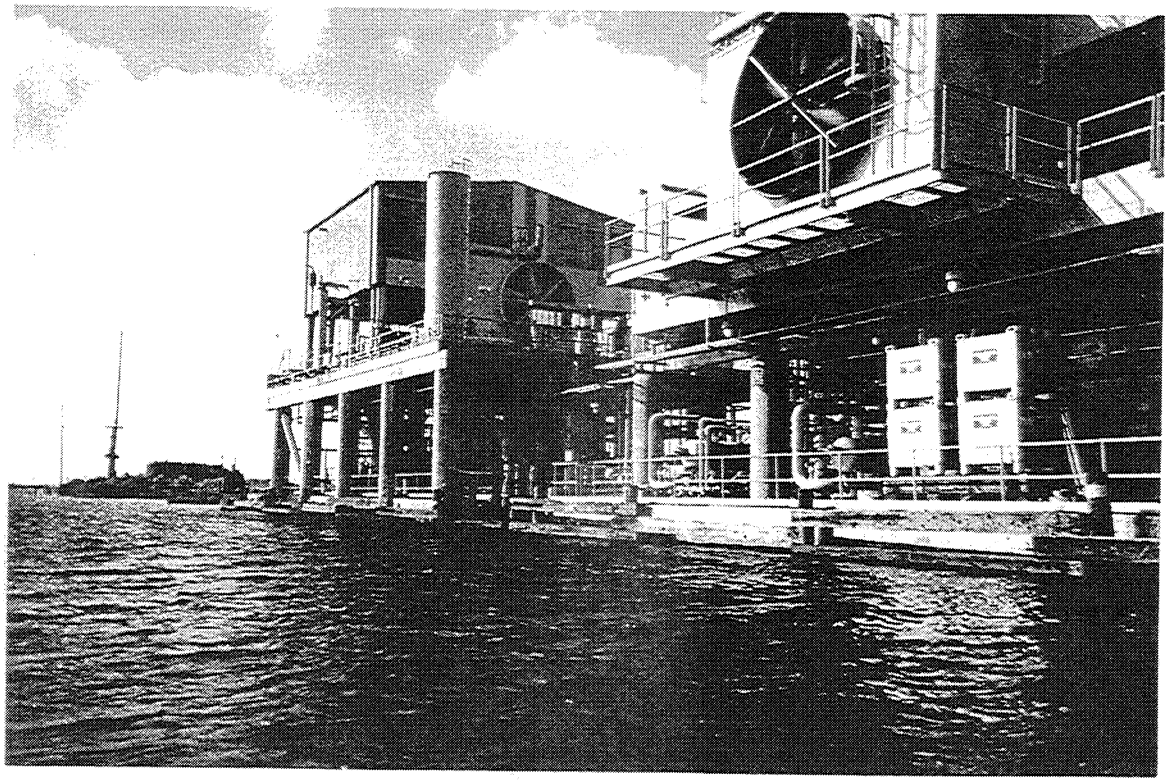
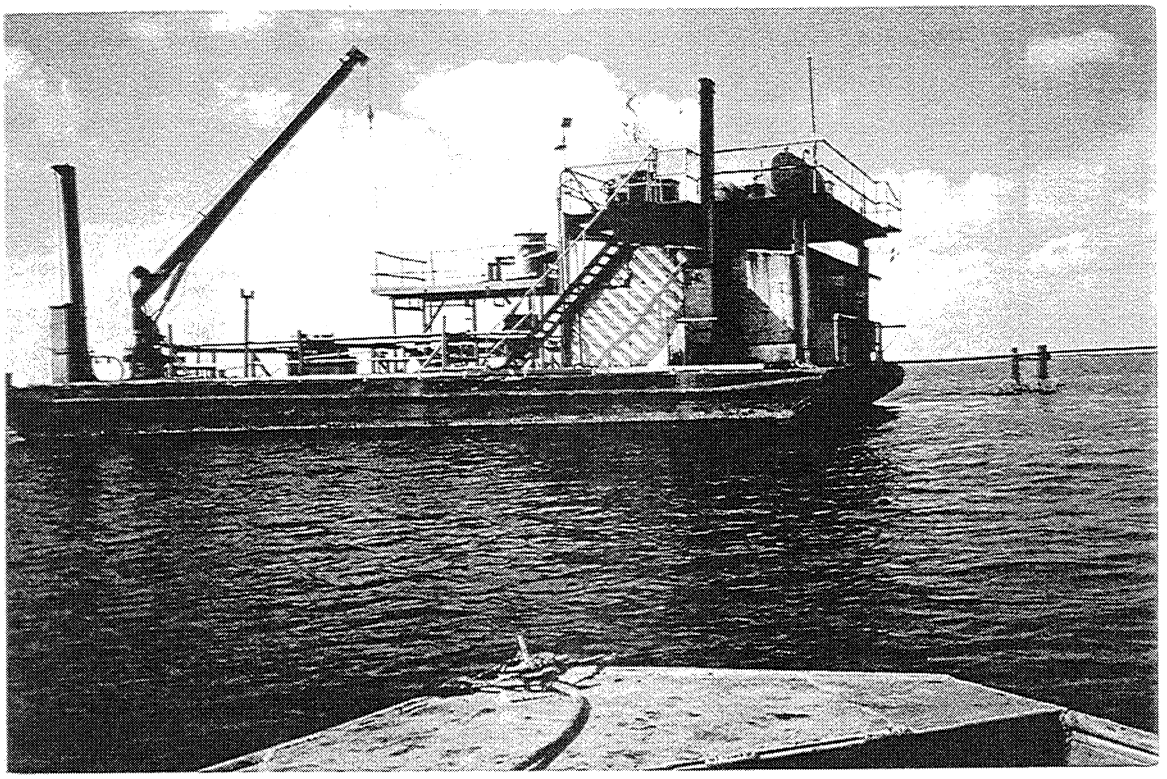
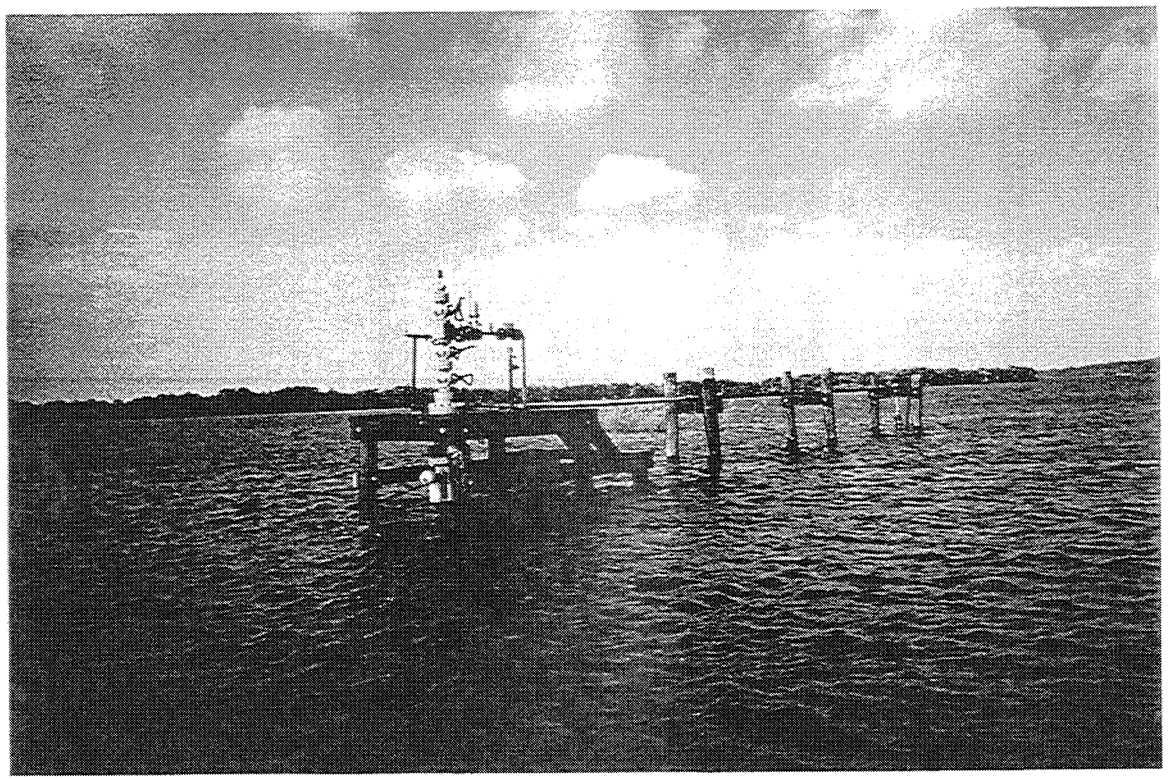


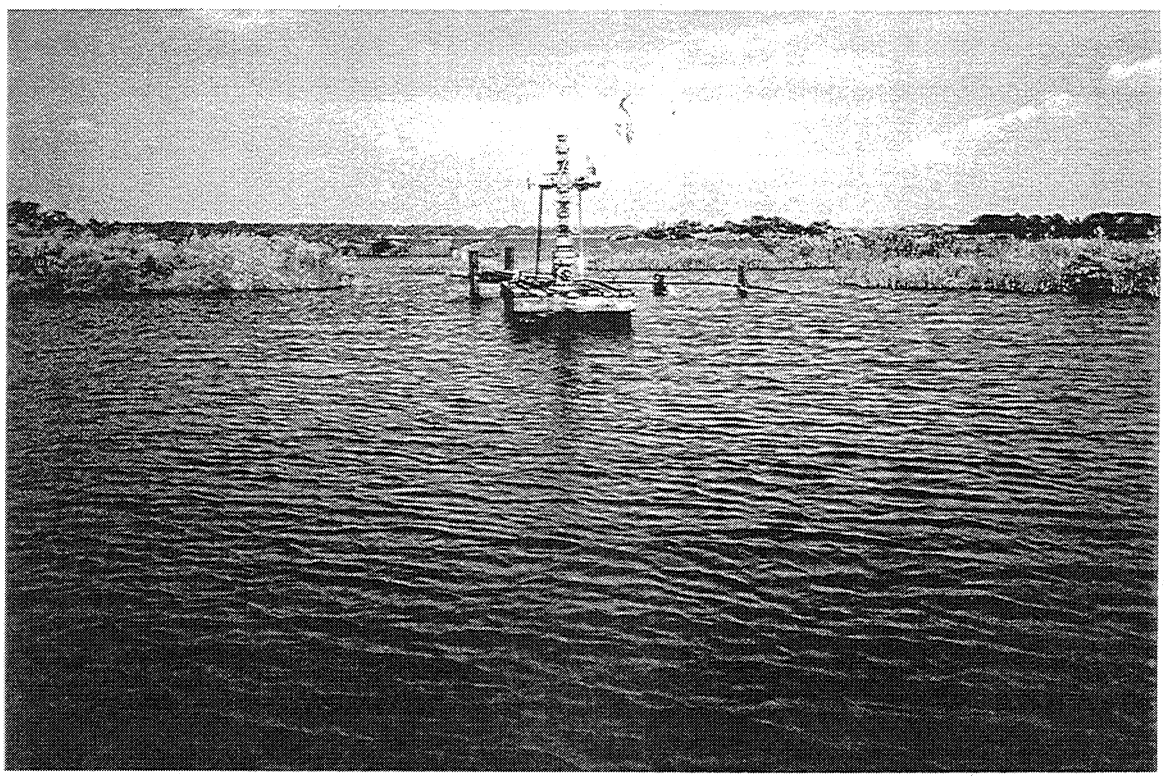
Compressor Station



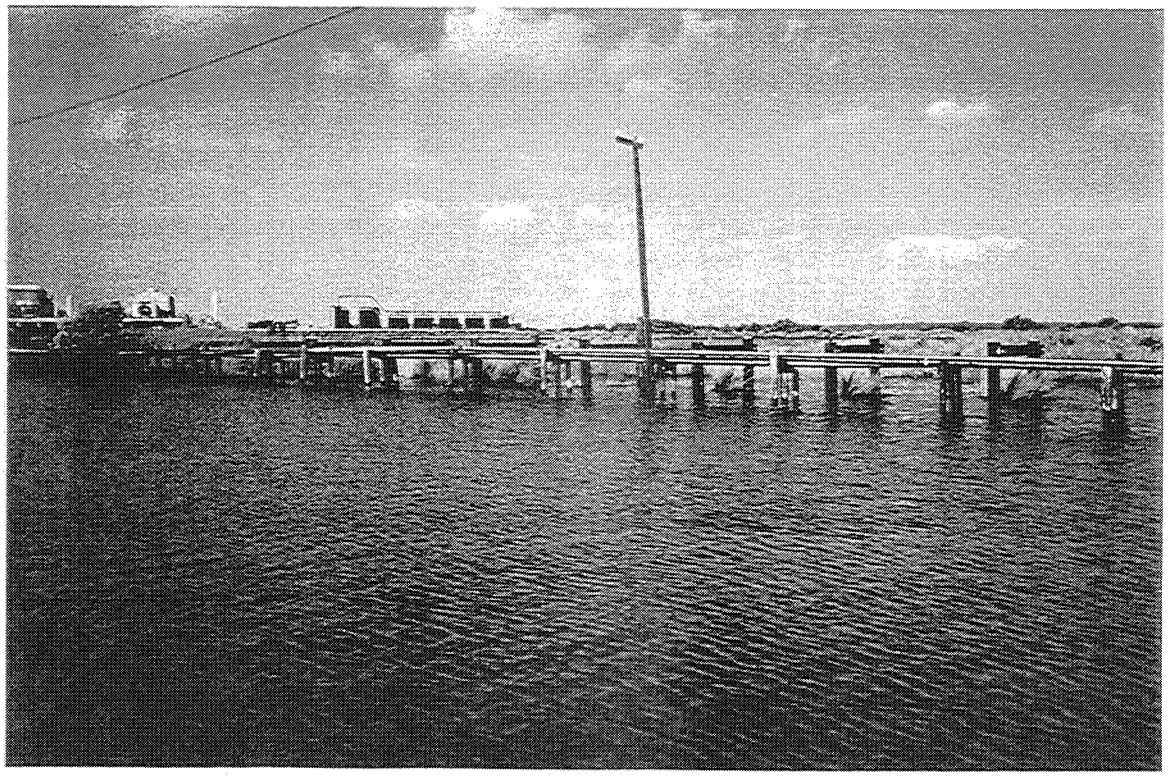
Barge Laying a CO_2 Injection Link



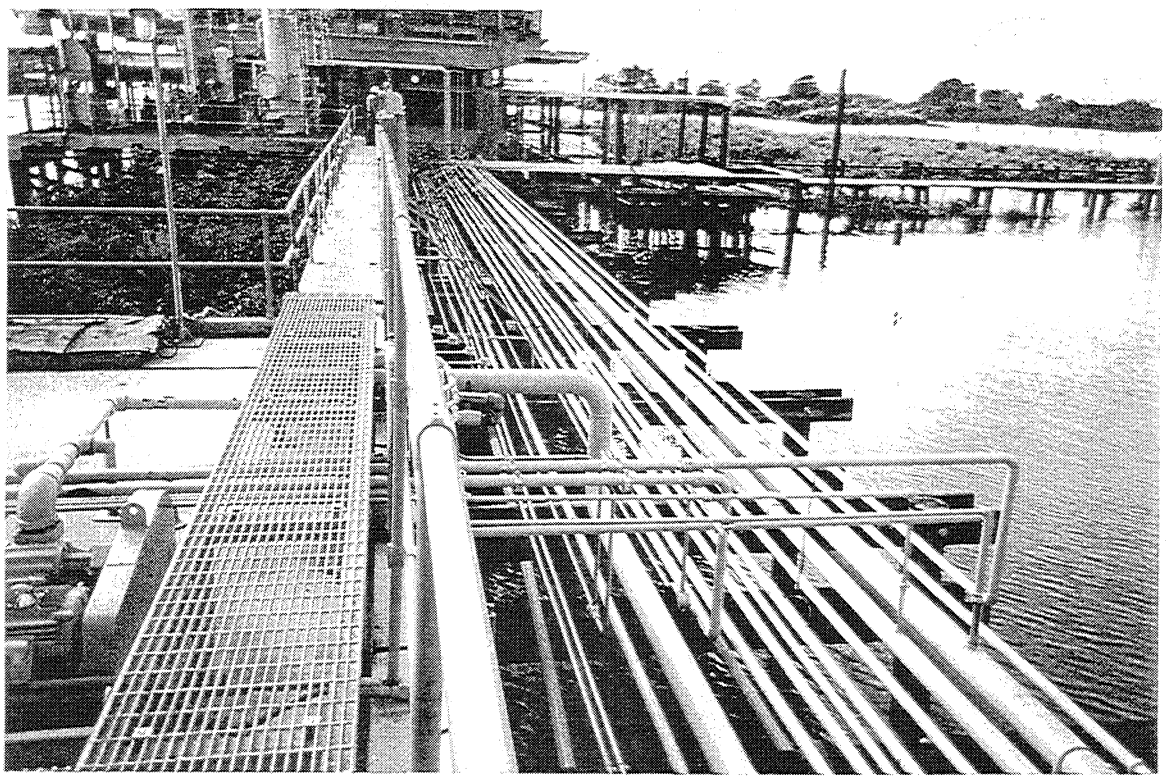
Horizontal CO_2 Injection Well



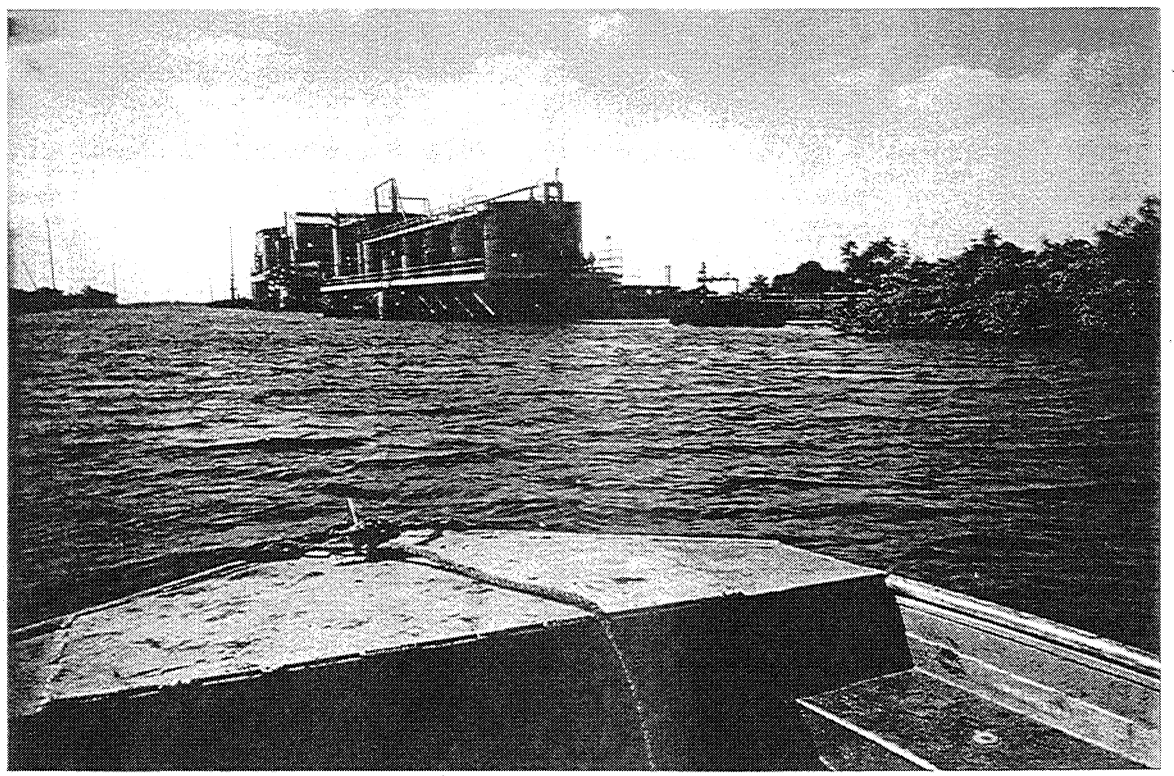
Producing Well



Pipe Rack

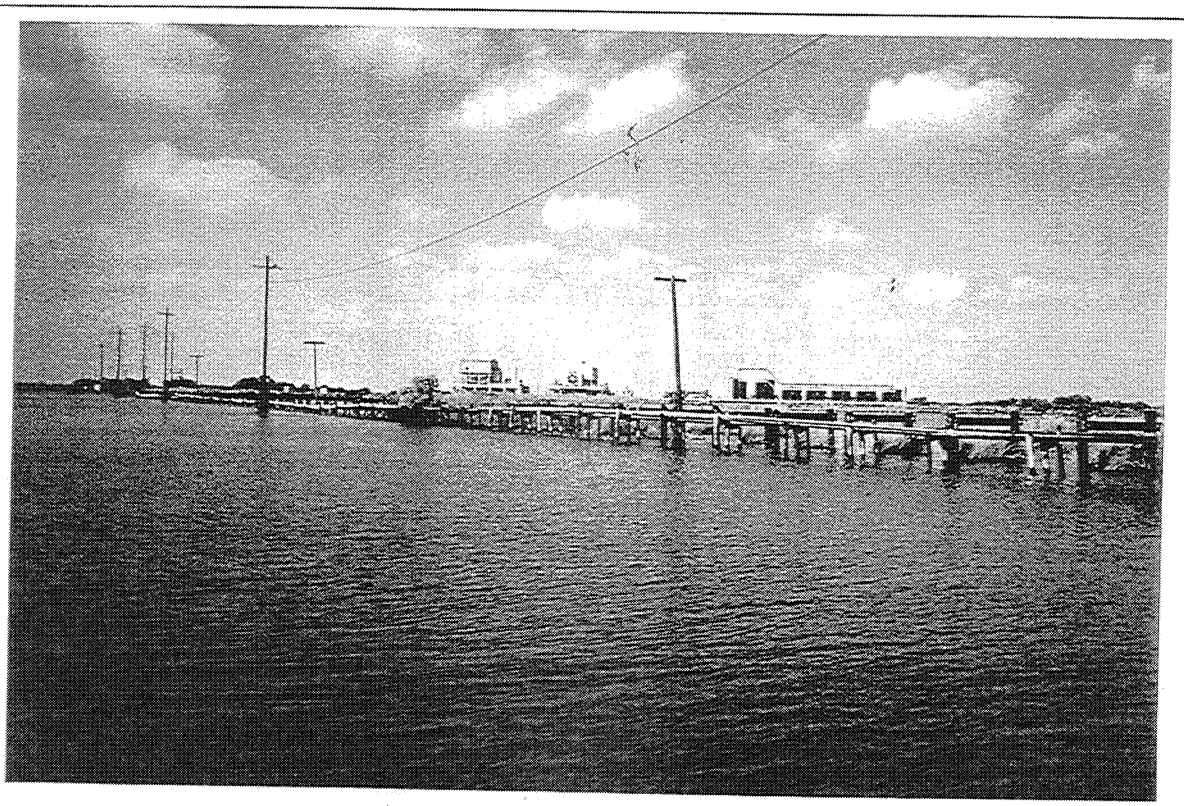


Pipe Rack at Production Facility

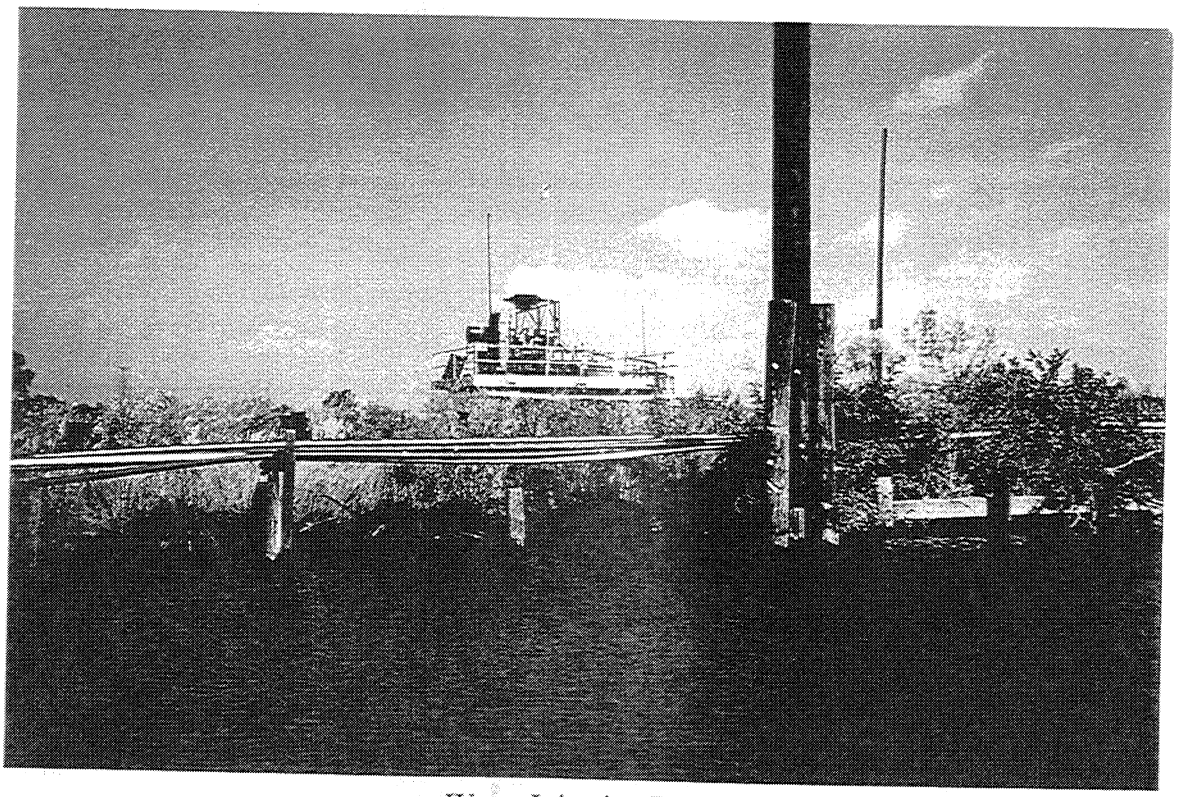


Storage Tanks

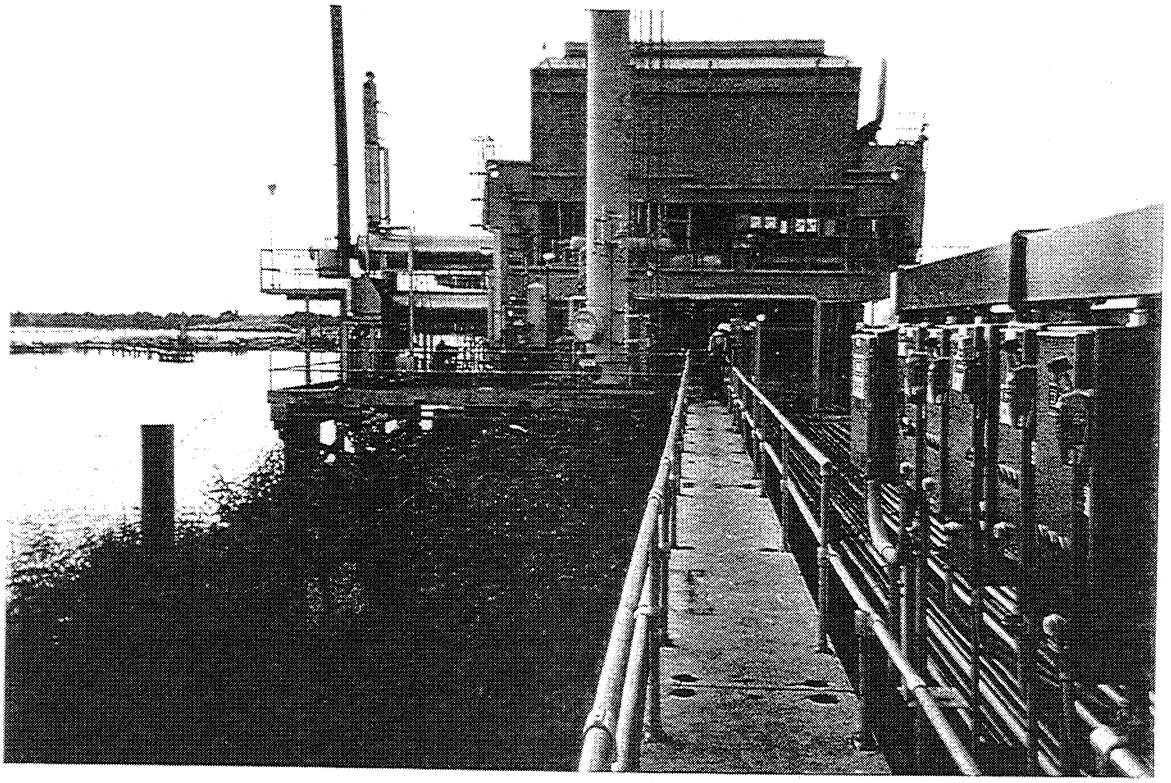
Project Development Photographs



Distant View of Tank Battery and Compressor Station



Water Injection Pumps



Dehydration Tower

ABSTRACT

The Port Neches CO_2 miscible flood project began CO_2 injection in September, 1993 into a waterflooded sandstone reservoir along the Texas Gulf Coast. Sponsored by the U.S. Department of Energy (DOE) in their Class I Oil Program, this project will determine the recovery efficiency of CO_2 flooding a sandstone reservoir which has been extensively waterflooded down to a residual oil saturation of 30%. The design of this project utilized the various tools available for predicting the recovery performance of such projects, with DOE's CO_2 Predictive Model CO_2PM[1] and a compositional model being used. In addition a streamtube model[2,3] has been developed to predict the recoveries associated with the waterflood and CO_2 recovery processes. The validity of this streamtube model, the CO_2PM program, and previous compositional reservoir simulation work, has been evaluated by the use of a compositional five-spot model where an equation-of-state for the current reservoir oil is incorporated. This work points out the streamtube model's ability as an effective screening device for CO_2 flood prediction. Furthermore, the importance of properly characterizing the permeability within each layer of the reservoir is demonstrated by the improved recoveries seen in fining-upward sequence reservoirs.

References and illustrations are at the end of paper.

INTRODUCTION

The Port Neches Field, located in Orange County, Texas, was discovered during 1929 near the historic Spindletop oil field between Beaumont and Port Arthur, Texas. In 1934 the Marginulina sandstone reservoir was encountered at a depth of approximately 5900 feet and the oil zone was rapidly developed by infill drilling.

As shown in Figure 1, the sand has two project areas where a CO_2 miscible flood will be conducted. The upper fault block is approximately 235 acres in size and has an average thickness of 30 feet. This segment of the sand underwent pressure depletion during primary production from 2700 psi original reservoir pressure down to below 100 psi by 1965. At this time, the reservoir had produced 4.2 million barrels of oil (MMBO), 40% of the 10.4 MMBO original oil in place (OOIP), and a waterflood was initiated. An additional 1.5 MMBO, (14% OOIP), has been produced from the sand as a result of this operation. Analysis of open-hole logs from two sidetracked wells obtained during 1993 and high watercuts from producing wells, indicate that this reservoir is very near its residual oil saturation of 30%. A miscible CO_2 flood is currently being conducted to extend the life of the reservoir and will attempt to recover an additional 19% OOIP by applying this tertiary process.

Due to the proximity of an industrial CO_2 source, the

Appendix B

Port Neches Field was selected as a site where enhanced oil recovery using CO_2 injection could be performed. The Marginulina sandstone reservoir was determined to be the best candidate due to its light oil properties and moderate depth. A laboratory slimtube test performed on the 34.6° API crude oil indicates that the minimum miscibility pressure (MMP) for the oil is 3310 psia, which is 1460 psia above its waterflood operating pressure of 1850 psia. The reservoir was pressured up with water and CO_2, and is currently operating at a reservoir pressure of 3350 psia. A horizontal well has been drilled along the reservoir's original oil-water contact and has a 250 foot horizontal section. Production from the reservoir has increased from 80 barrels of oil per day (BOPD) to 250 BOPD. Peak production of 800 BOPD is anticipated during 1995.

PROJECT DESIGN

In the design of the CO_2 flood, DOE's CO_2PM, a personal computer program, was used during the initial phase of the design due to its ease of operation and adaptability to waterflooded reservoirs. As shown in Figure 2, the CO_2PM program simulates the CO_2 recovery process for a five spot injection pattern with four corner injectors surrounding a center producer. Reservoir properties data, as shown in Table 1 for Port Neches' Marginulina reservoir, can be entered in the program and results can be obtained within minutes. A dimensionless oil recovery curve versus hydrocarbon pore volumes (HCPVs) of CO_2 injected, and a dimensionless oil yield curve versus HCPVs of CO_2 injected are obtained from the output, and a prediction of the performance of the flood is generated. The program gives an output for a fixed daily rate of CO_2 injection but can, by using a spreadsheet similar to the one shown in Figure 3, be set up to account for the reinjection of produced CO_2. As CO_2 is injected, the oil is recovered at rates which satisfy the dimensionless oil recovery curve, and given the point along the HCPV injected curve, the yield (i.e., BO/MMCF) curve determines the amount of CO_2 being returned with the oil. What may appear to be a very lengthy injection process due to limited daily injection volumes can be shortened dramatically by the reinjection of recycled CO_2 in these high permeability reservoirs.

The CO_2PM program is felt to give reliable results for the five- spot pattern, but what can be done for the asymmetrical pattern seen at Port Neches? The Port Neches Marginulina 235 acre waterflooded fault block is typical of other salt dome fields where wells are often irregularly spaced above the oil-water contact. Some assumptions will have to be made in order for the CO_2PM program to be utilized. The breakthrough of CO_2 to producing wells will occur much sooner than predicted by a 235 acre five spot pattern due to the irregular well spacings, thus affecting the oil response. In order to use CO_2PM for this prediction, the assumption is made that the reservoir will be flooded as though it is three independent five-spot patterns. A 60 acre five-spot pattern will be flooded first, then another 60 acre five-spot, and finally a 115 acre five-spot. CO_2 produced from these first two patterns will be used to flood the final pattern, thus speeding up the process. An initial injection of 4.3 MMCFPD purchased CO_2 will increase to a peak injection of 15 MMCFPD within 4 years. The injection of produced saltwater is also being used to offset fluid withdrawals. This also allows for greater withdrawals from the producing wells (See Figure 4).

COMPOSITIONAL MODEL

Recognizing that CO_2PM has many limitations when attempting to simulate a full field project, a compositional model was developed for the 235 acre project area. Fifty-seven years of primary and secondary waterflood production and pressure history was matched using the limited data available for the project area. The equation-of-state for the original reservoir oil was fine tuned by supplying laboratory constant composition and swelling tests data of a recombined live oil sample to the PVT program[4]. The composition of the original reservoir oil was unknown; however, the bubble point pressure and solution gas/oil ratio could be approximated by field performance data. Methane gas was recombined with the stock tank oil in order to establish the estimated initial gas/oil ratio of 500 SCF/STB and a bubble point pressure of 2685 psia. After further evaluation of the cumulative gas production and oil in place volumes, propane and butane concentrations were added to the oil composition within the PVT program in order to lower the bubble point pressure and solution gas/oil ratio. Reservoir pressure dropped below 100 psia prior to waterflood; therefore, essentially all of the solution gas was produced from the reservoir leaving only 11 SCF/STB of solution gas.

Lack of core data and porosity logs limited reservoir characterization prior to project initiation. After cutting and analyzing a conventional core during a

workover in 1993, the estimated average permeability within the reservoir was increased to 3000 md from 750 md estimated originally. Vertical permeability within the reservoir is seen to be restricted by thin shale streaks that are less than one foot thick. The effect of these shale streaks is difficult to quantify in a reservoir model due to limited knowledge of their lateral extent. Therefore, the reservoir was modeled by a two- layer system with the top layer being 420 md and the bottom layer being 1080 md. Next, the two aquifers affecting the performance of this reservoir were adjusted in strength in the model to obtain the proper pressure distributions and water influx in the reservoir. The compositional model supported the CO_2PM prediction that the CO_2 flood can recover an additional 19% OOIP. It also supported the adjustment of the production profile curve generated by CO_2PM to account for an earlier oil production response.

After comparing current performance to the model's results, the importance of making a proper determination of the reservoir's residual oil saturation to waterflood becomes apparent. It was initially assumed that since only three water injection wells were utilized during the waterflood operation, areas of upswept oil above the residual oil saturation existed in the reservoir. An average oil saturation prior to the CO_2 flood of 30% was calculated for the reservoir, and a residual oil saturation to waterflood of 20% was estimated based upon data obtained from other high permeability sands in the area. However, as open-hole log and core data became available, it was found that the true residual oil saturation to waterflood is 30%. This leaves the reservoir with very little additional mobile oil.

One area of the reservoir has been found to have a higher oil saturation than 30%, and with a change in water injection pattern, has increased oil production from 30 BOPD to 220 BOPD. The higher residual oil saturation will require that higher water percentages be produced until the CO_2-contacted oil reaches the producers.

STREAMTUBE MODEL

A streamtube model has been developed for this project which overcomes many of the limitations of CO_2PM, but can still be run quickly on a personal computer. The model develops streamlines which represent the flowpaths of the injectant and produced fluids and can either be set up as a custom pattern (as shown in Figure 5 for Port Neches' reservoir) or can use standard five-spot, modified seven-spot, inverted nine-spot, regular four-spot, or direct line drive patterns. Utilizing a five-spot pattern as used in CO_2PM, the streamtube model was initialized at different oil saturations to show its effect upon oil recovery and yield (see figures 6 and 7). Upon reviewing this model's prediction of the recoverable CO_2 reserves versus HCPVs of CO_2 injected, some major concerns arise in the project's ability to recover an additional 19% of the OOIP. The oil yield curve also poses major questions about the recycle CO_2 volumes necessary to recover these reserves. As a result of these concerns, a rigorous investigation into the prediction of CO_2 flood performance using CO_2PM, the streamtube model, and compositional models has been completed.

FIVE-SPOT COMPOSITIONAL MODEL

A 29 X 29 X 3, 40-acre five-spot compositional model was developed to determine the accuracies which one can expect from the PC-based simulation programs such as CO_2PM and the streamtube model. An equation-of-state for the current reservoir oil (as opposed to the original reservoir oil) was determined by running the PVT program with laboratory constant composition data input. This was accomplished by splitting the C7+ fraction into four pseudocomponents. In order to have consistent parameters, the oil/water relative permeability curve used in CO_2PM and the streamtube model is used and absolute permeabilities are set equal to those used in CO_2PM of 6404 md, 1991 md, and 605 md (Dykstra Parsons[5] coefficient of 0.7) for layers one, two and three, respectively. Each sand layer is 10 feet thick. An oil viscosity of 3.3 cp is obtained from laboratory data at 3400 psia. CO_2PM and the streamtube model were run with this same viscosity. (It may be pointed out that without the AVIS viscosity correction in the equation-of-state, the oil viscosity calculated by the compositional model is 1.4 cp.)

These properties closely represent a reservoir oil with a solution gas/oil ratio of 11 SCF/STB. The actual stock tank oil composition differs from the oil composition predicted by the compositional model used to obtain the production history match, with the current reservoir oil having fewer lighter components (See Table 3). This lack of lighter components results in a poorer oil recovery than seen previously and may contribute to some of the uncertainties associated

with our previous history match, particularly when the original oil composition was not known.

RESULTS

A comparison of the dimensionless curves for the three models is shown in Figures 8 and 9. It is seen that the streamtube and compositional models provide similar results up to 2.0 HCPVs of CO_2 injection, and then deviate from that point. CO_2PM has a much slower production response than the other models, but has a higher ultimate recovery. The yield curves show quite substantial deviation, with the compositional model showing extremely low yields after approximately 1.3 HCPVs of CO_2 injection. To explain this phenomenon, a closer look at the compositional model's results reveal some important observations.

The CO_2PM and streamtube programs both use a Dykstra Parsons coefficient to represent heterogeneity within the reservoir. For the three layer model run, the highest permeability of 6400 md is automatically placed as the top layer of the reservoir and the lowest, i.e., 605 md, is placed on the bottom. The density segregation of the CO_2 in the high permeability upper layer results in poor vertical sweep efficiency of the sand (See Figure 10). A model using three layers of equal permeability of 3000 md gives very similar results to the coarsening upward sequence case. The five-spot compositional model allows for these layers to be rearranged.

If the lower permeability layer of 605 md is placed on top of the 1991 md and 6404 md second and third layer intervals, respectively, still maintaining a Dykstra Parsons coefficient of 0.7, the projected oil recovery from the model is greatly improved (See Figures 11 and 12). This fining upward sequence is typical of fluvial-dominated deltaic reservoirs and may contribute to improved recoveries through application of the CO_2 flooding process at Port Neches.

To extend these concepts one step further, all models were run with varied permeability, initial oil saturation, vertical to horizontal permeability ratios (Kv/Kh), and reduced permeability-feet (Kh) (See Figures 13 through 16). In high permeability sands (i.e., greater than 250 md), the recoveries were mostly dependent upon oil saturation at the start of the CO_2 flood, but as seen by the fining upward sequence example discussed, the recovery is also very sensitive to permeability profile. This wide range in recovering efficiencies resulting from changes in oil composition, vertical layering, and HCPVs of CO_2 injected, supports the use of multi-disciplinary teams of engineers and geoscientists to improve the prediction phase of these projects. Actual field implementation will determine the accuracy of these predictions.

CONCLUSIONS

1. The Port Neches CO_2 miscible flood will attempt to lower the oil saturation from 30% residual to an average of 17% in a fluvial-dominated deltaic reservoir. As a result, an additional 2 MMBO, or 19% OOIP, will be recovered.

2. A streamtube model that was developed as part of the technology transfer for this project, is capable of accurately predicting the recoveries associated with waterflood and CO_2 flood processes. This model is expected to benefit the design of CO_2 projects in various types of reservoirs and will be released to the oil industry during 1994 through SPE/DOE.

3. A five-spot compositional model utilizing the equation-of-state of the stock tank oil from Port Neches was used to determine the accuracy of the CO_2PM and streamtube models. The streamtube model was shown to be an effective screening tool for applying CO_2 floods.

4. Results from the streamtube and five-spot compositional models indicate that the risk of accurately predicting the outcome of CO_2 floods is highly dependent upon the vertical sweep efficiency obtained within the reservoir.

5. The results obtained by using an equation-of-state of the currently existing reservoir oil, as opposed to the original reservoir oil, may improve the prediction phase of compositional modeling. By initializing the model with this improved equation-of-state, an average oil saturation across the oil zone equal to 30%, and the best geological description available, a more realistic forecast may occur.

ACKNOWLEDGEMENTS

The author wishes to thank Texaco Exploration and Production Inc. and DOE for permission to present this paper (DOE Contract No. DE-FC22-93BC14960). Special thanks goes out to Joe Babineaux, Jr., Sami Bou-Mikael, and D. Lee Martin in Texaco's New Orleans office for their guidance and support of the project and John Dobitz, John Prieditis, Bob Brugman, and Jim Stevens in Texaco's EPTD office for their development of the streamtube model. Mr. Bob Alston (deceased) is also remembered for his contributions.

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2. Dobitz, J.K. and Prieditis, J.; " A Stream Tube Model for the PC," paper SPE 27750 presented at the 1994 Ninth Symposium on Improved Oil Recovery, Tulsa, April 17-20.

3. Prieditis, J. and Brugman, R.J.; "Effects of Recent Relative Permeability Data on CO_2 Flood Modeling," paper SPE 26650 presented at the 1993 68th Annual SPE Technical Conference and Exhibition, Houston, October 3-6.

4. Scientific Software-Intercomp: "Equation of State PVT Program - Release 4.0," November, 1984.

5. Dykstra, H. and Parsons, R. L., "The Prediction of Oil Recovery by Waterflooding," Secondary Recovery of Oil in the United States, Second Edition, (New York: American Petroleum Institute, 1950), p. 160.

TABLE 1
CO2PM INPUT

PARAMETER	VALUE	PARAMETER	VALUE
Depth	5900 feet	N_{oil}	2
Porosity	30%	N_{wat}	2
Permeability	Variable	K_{ro} @ S_{wi}	1.0
API Gravity	34.6°	K_{rw} @ S_{or}	0.116
Area	40 acres	S_{wc}	0.20
Height	30 feet	S_{orw}	0.30
No. Layers	3	B_o	1.05
Reservoir Pressure	3400 psi	μ_o	3.28
Temperature	165° F	R_s	11
K_V/K_H	0.85	SG (gas)	0.6
Oil Cut	0.001	Salinity	100,000 ppm
Injection Rate	2150 BFPD	V	0.7
WAG Ratio	0.05	HCPV	5.0

TABLE 2
STREAMTUBE MODEL INPUT

PARAMETER	VALUE	PARAMETER	VALUE
Dykstra Parsons	0.7	K_{wro}	0.116
Temperature	165°F	S_{wir}	0.20
Reservoir Pressure	3400 psi	S_{orw}	0.30
MMP	3310 psi	N_{wat}	2.0
μ_o	3.28 cp	K_{rocw}	1.0
B_o	1.05	S_{wc}	0.20
Solution GOR	11.0	N_{oil}	2.0
Oil Gravity	34.6° API	K_{rgcw}	0.477
Gas Specific Gravity	0.6	S_{gr}	0.30
μ_w	0.47	N_{gas}	2.0
Salinity	100,000 ppm	S_{org}	0.30
Layers	3	S_{orm}	0.001
Pre-Set Pattern	5-Spot	S_{oi}	0.3001

TABLE 3 - PVT COMPOSITION OF CURRENT RESERVOIR OIL

PVT COMPOSITION

COMPONENT	PC	TC	MW	OMEGA	OMEGB	ZCRIT	CRITZ	PCHOR	AC	REFD	REFT	TBOIL
1 PC1	550.7	765.6	58.12	0.42748023	0.08664035	0.2742	0.2742	189.900	0.1930	0.58440	60.0	31.1
2 CO2	1070.0	547.8	44.01	0.44910847	0.09215464	0.2749	0.2527	79.700	0.2250	0.77700	68.0	-109.2
3 PC2	453.8	895.5	82.27	0.42445979	0.08657156	0.2657	0.2666	260.028	0.2835	0.61480	139.4	139.4
4 F7	379.4	1078.5	124.49	0.30164148	0.09831126	0.2614	0.2614	401.739	0.3576	0.75344	60.0	285.0
5 F8	265.3	1247.6	191.13	0.49320023	0.08208457	0.2418	0.2418	593.821	0.5107	0.80675	60.0	453.5
6 F9	182.9	1440.8	293.24	0.56240752	0.10033184	0.2208	0.2208	880.971	0.7269	0.86339	60.0	660.6
7 F10	98.3	1694.1	469.21	-0.48377806	0.07069124	0.1609	0.1609	1529.928	0.9862	0.93121	60.0	939.7

VISD .0087398 -.0171533 .0076849 .0068290 .0056734 .0046768 -.032690

AVIS -2.03281 1.41452 .441014 -.450068 .078543

	PC1	CO2	PC2	F7	F8	F9
BIN	0.106000	0.018813	-0.096436	-0.096436	-0.096436	-0.096436
	0.106000	0.066277	0.066277	0.066277	0.066277	
	-0.003985	-0.003985	-0.003985	-0.003985		
	0.000000	0.000000	0.000000			
	0.000000	0.000000				
	0.000000					

OIL COMPOSITION OF CURRENT RESERVOIR OIL

	PC1	CO2	PC2	F7	F8	F9	F10
Z	.00040	.00000	.00360	.18062	.38380	.29739	.13420

OIL COMPOSITION OF CURRENT RESERVOIR OIL BY HISTORY MATCH

	PC1	CO2	PC2	F7	F8	F9
Z	.04580	.00000	.05300	.33690	.41360	.15070

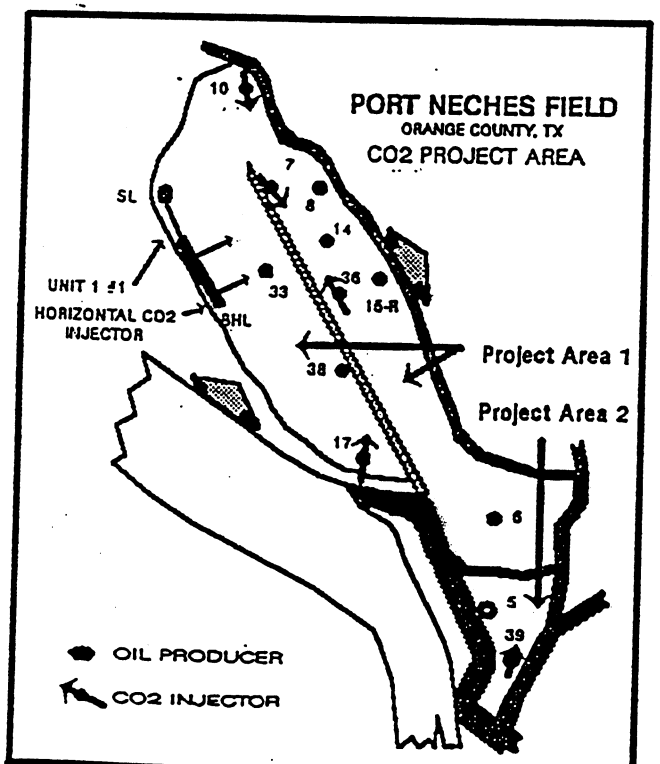

Figure 1 - Field Injection Pattern

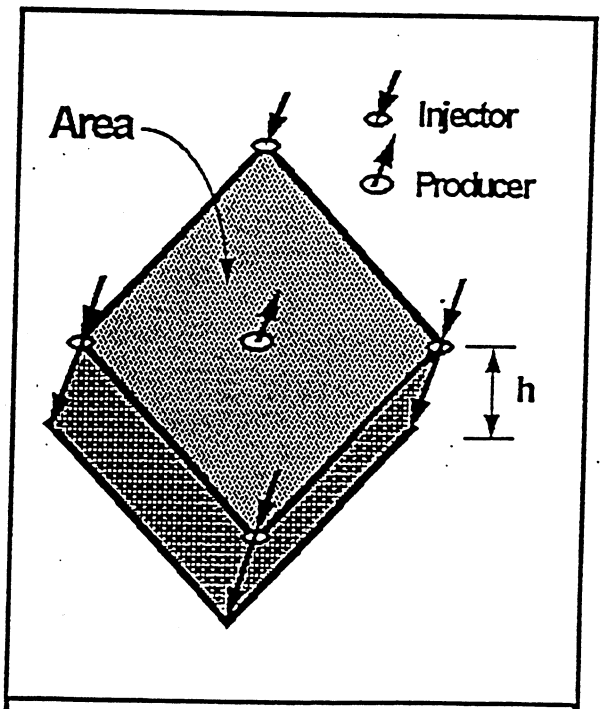

Figure 2 - Five Spot Injection Pattern

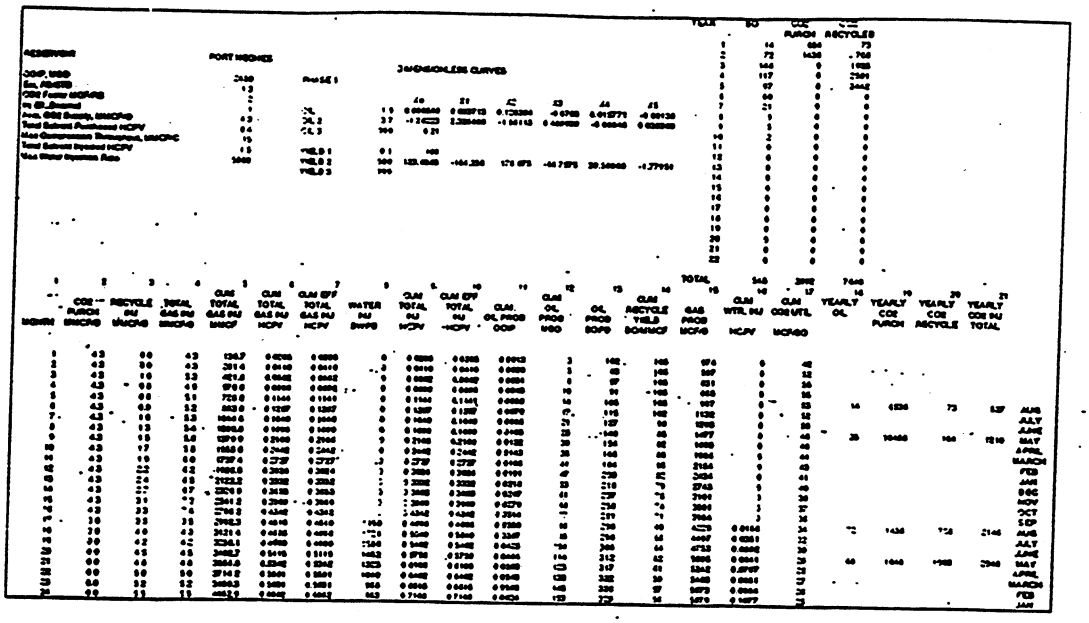

Figure 3 - CO_2 Recycle Volume Determination Spreadsheet

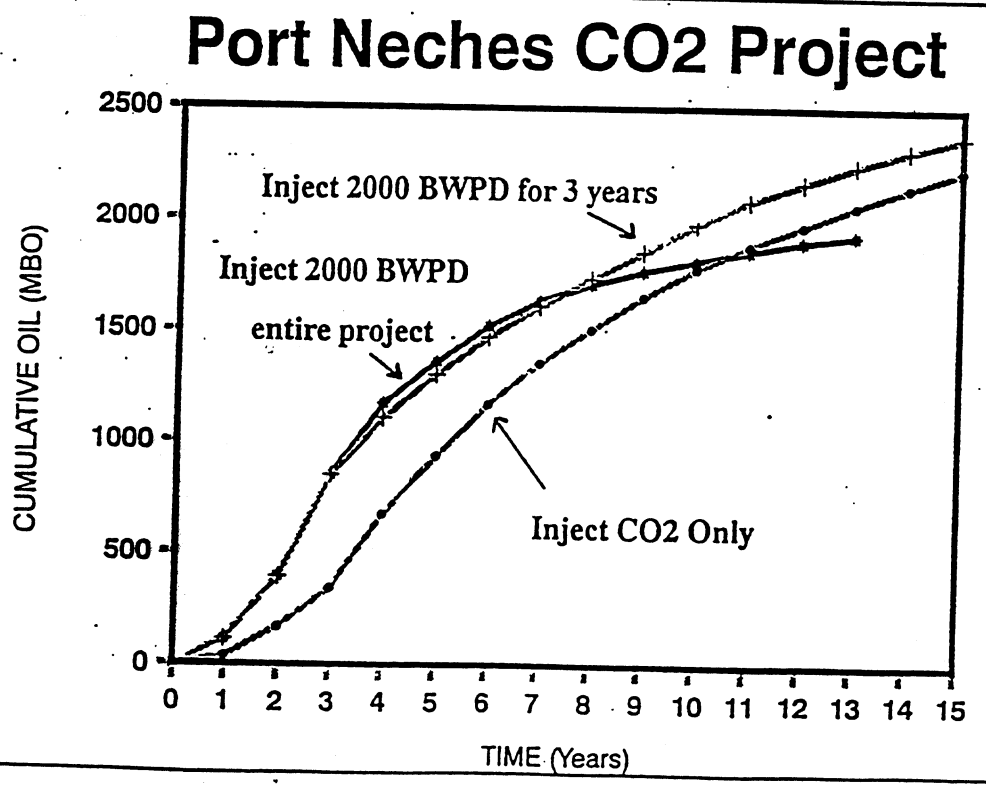

Figure 4 -Advantages of Water Injection

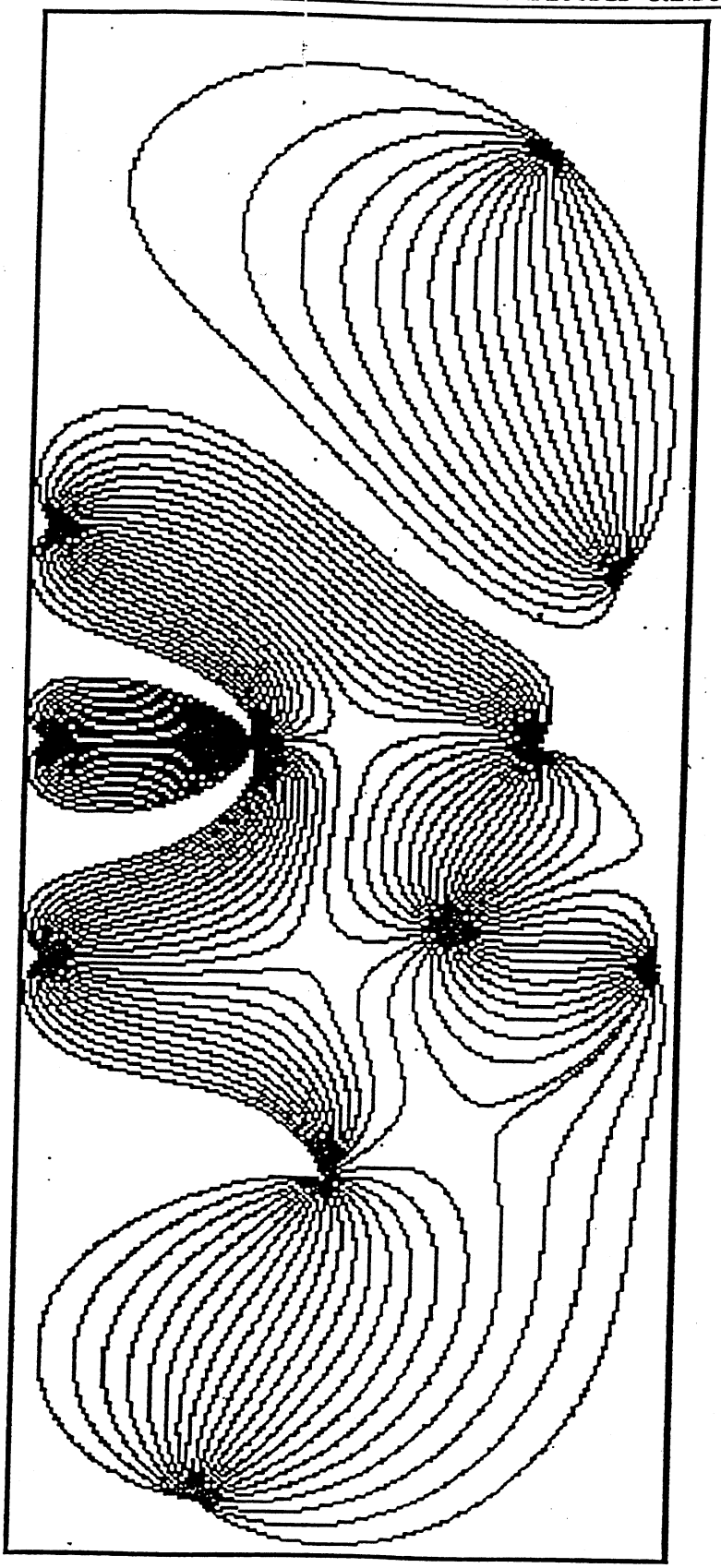

FIGURE 5

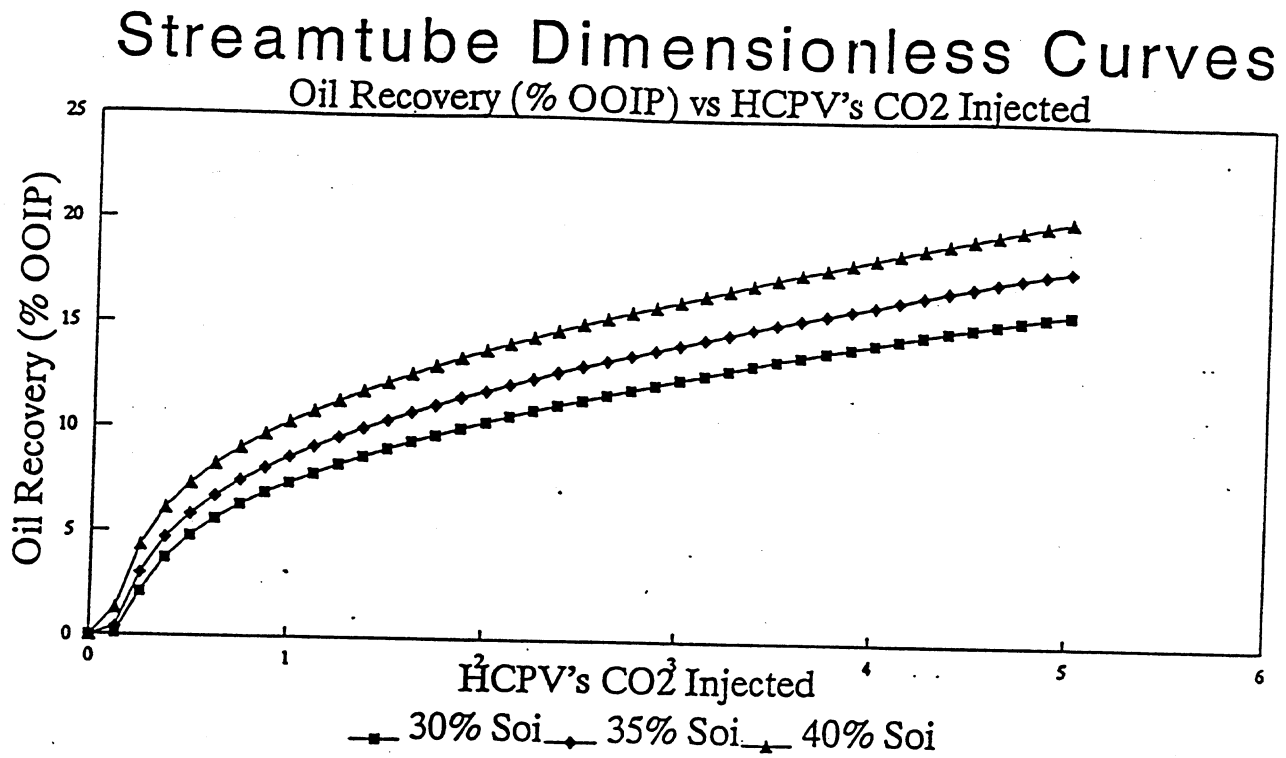

Figure 6. Streamtube Dimensionless Oil Recovery Curve versus HCPV's CO2 injected at varying initial oil saturation.

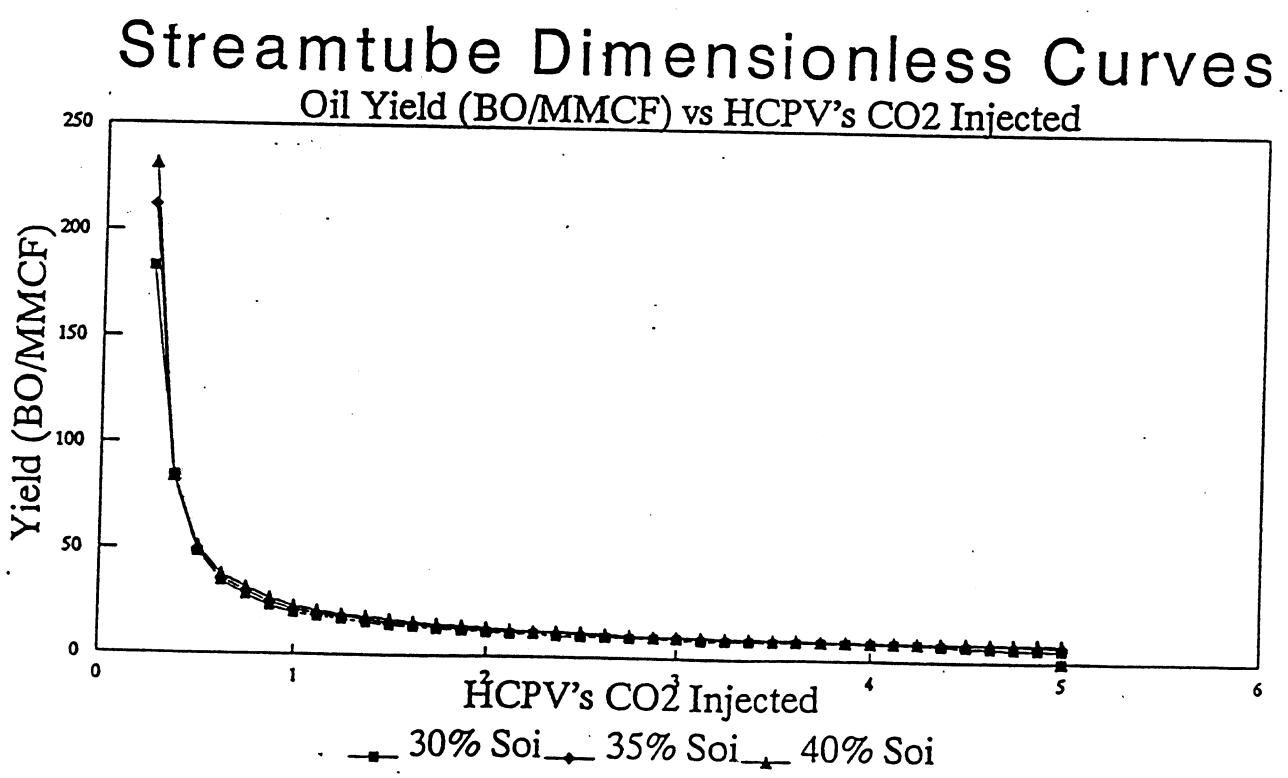

Figure 7. Streamtube Oil Yield Curve versus HCPV's CO2 injected at varying initial oil saturation.

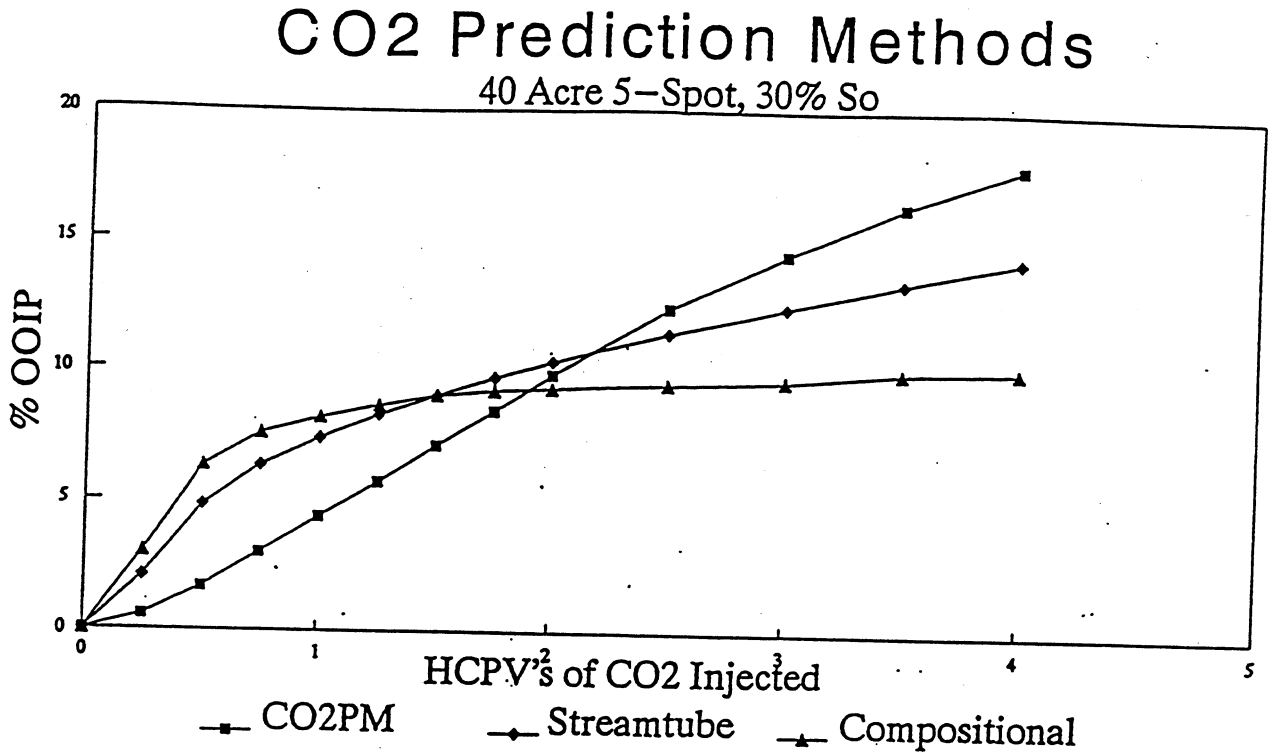

Figure 8. Comparison of Dimensionless Oil Recovery Curves versus HCPV's CO2 injected for three different models.

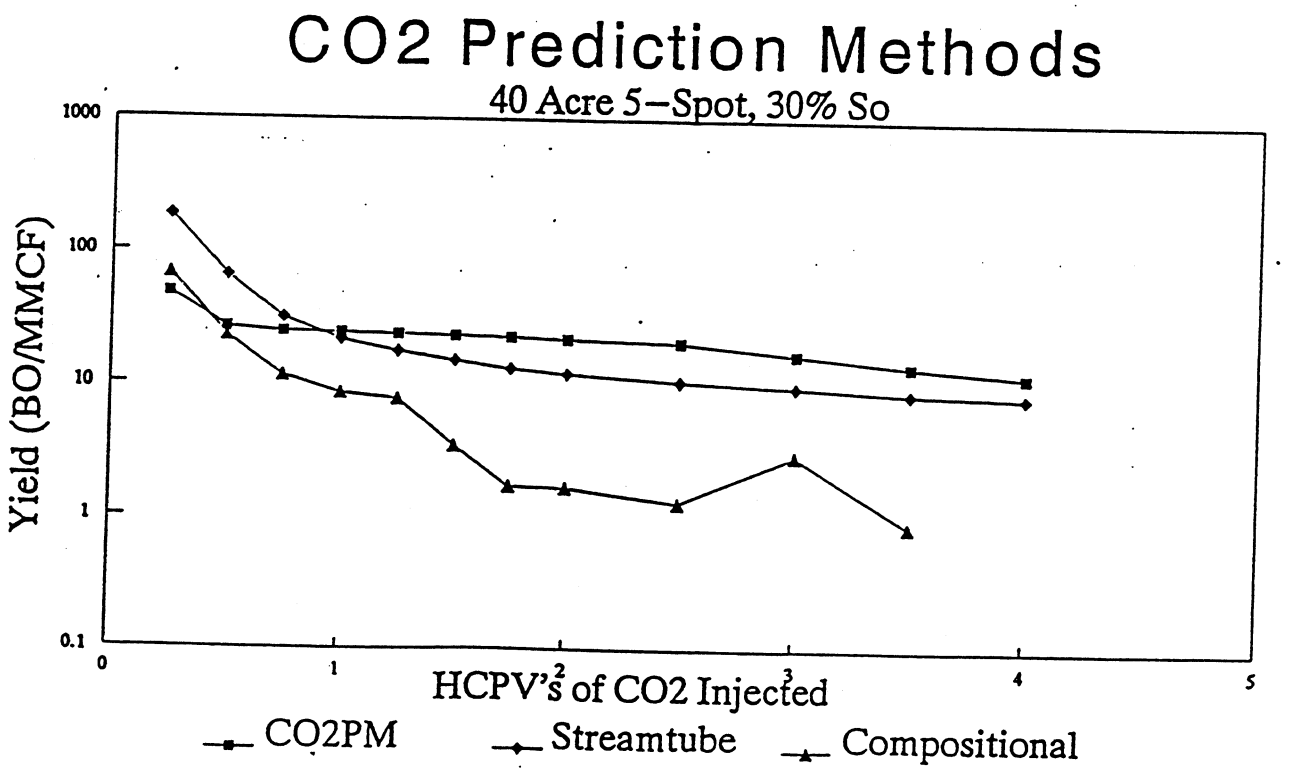

Figure 9. Comparison of Oil Yield Curves versus HCPV's CO2 injected for three different models.

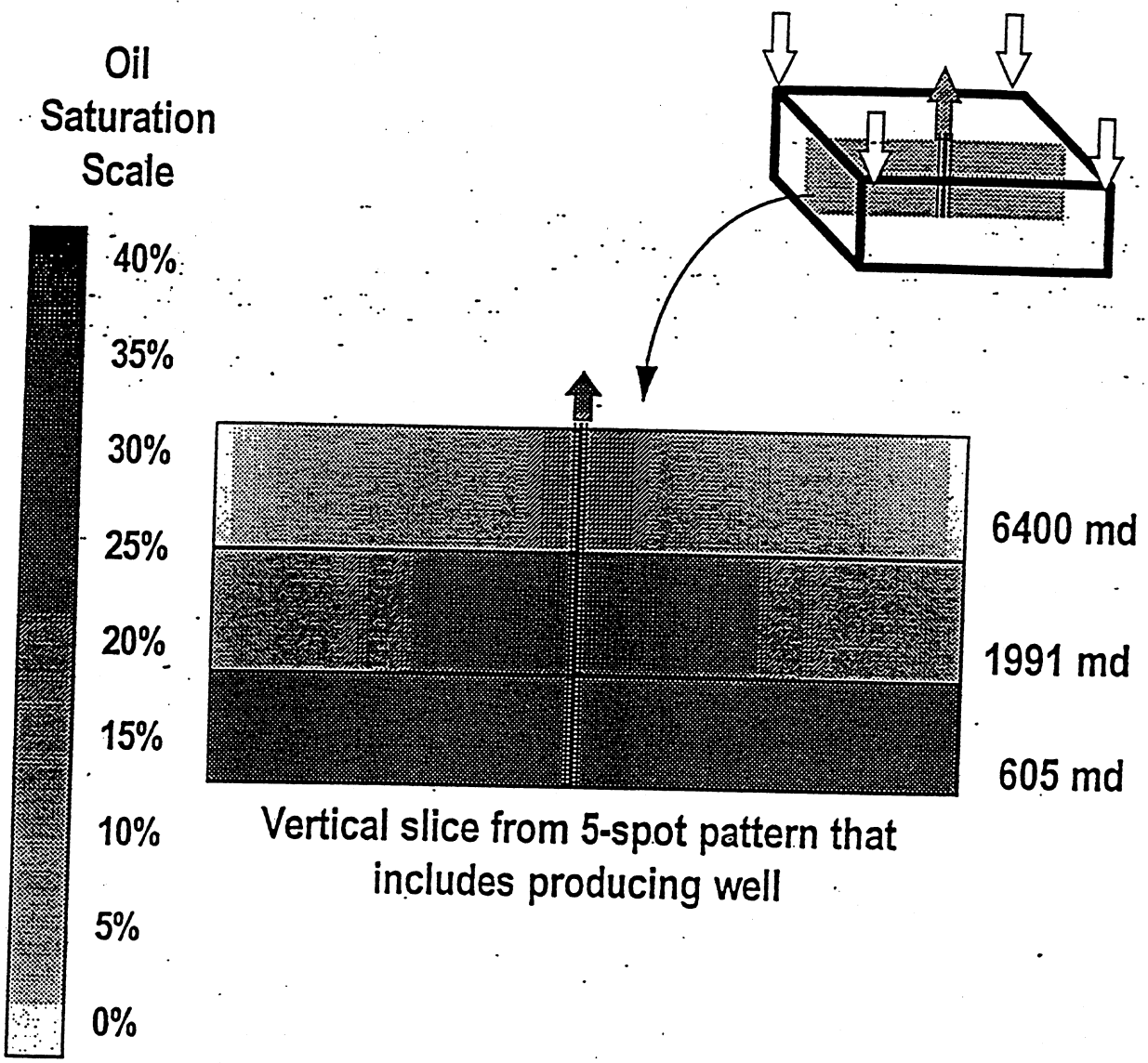

Figure 10 - Remaining Oil Saturation After CO_2 Injection

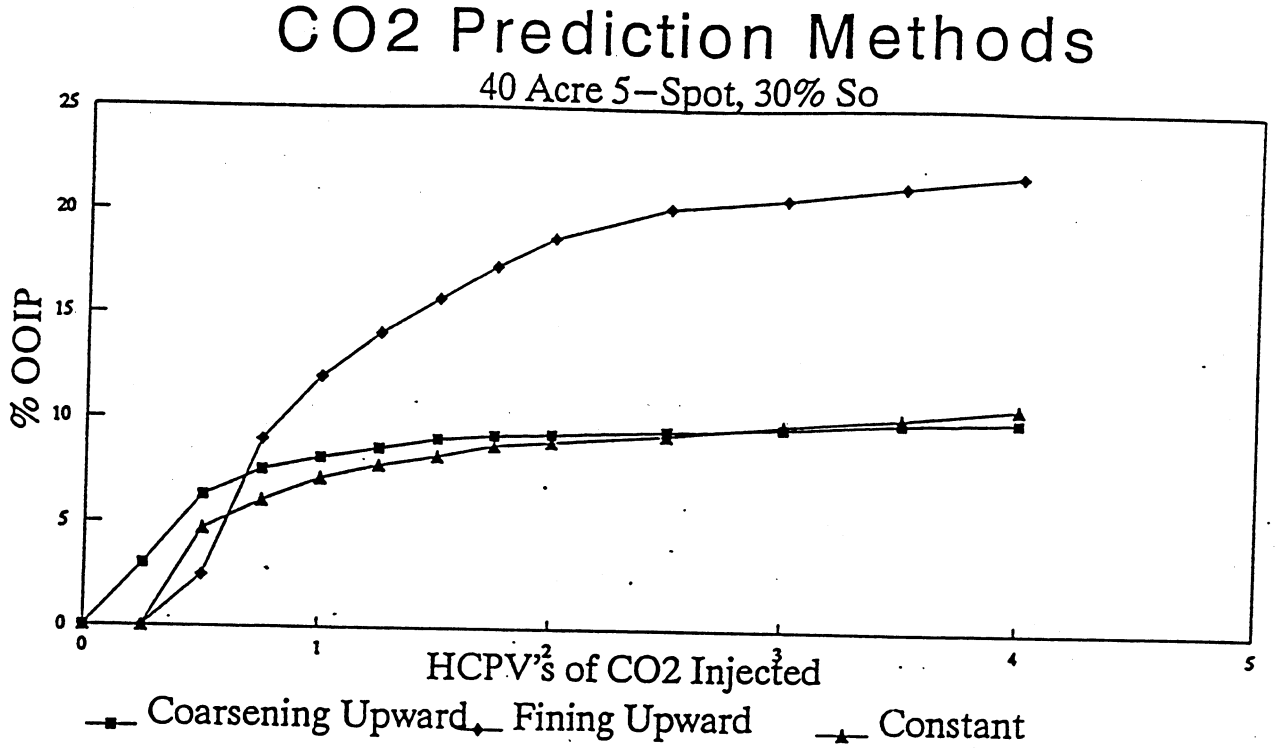

Figure 11. Oil Recovery versus HCPV's CO2 Injection for Five–spot Compositional model with permeability of layers varied.

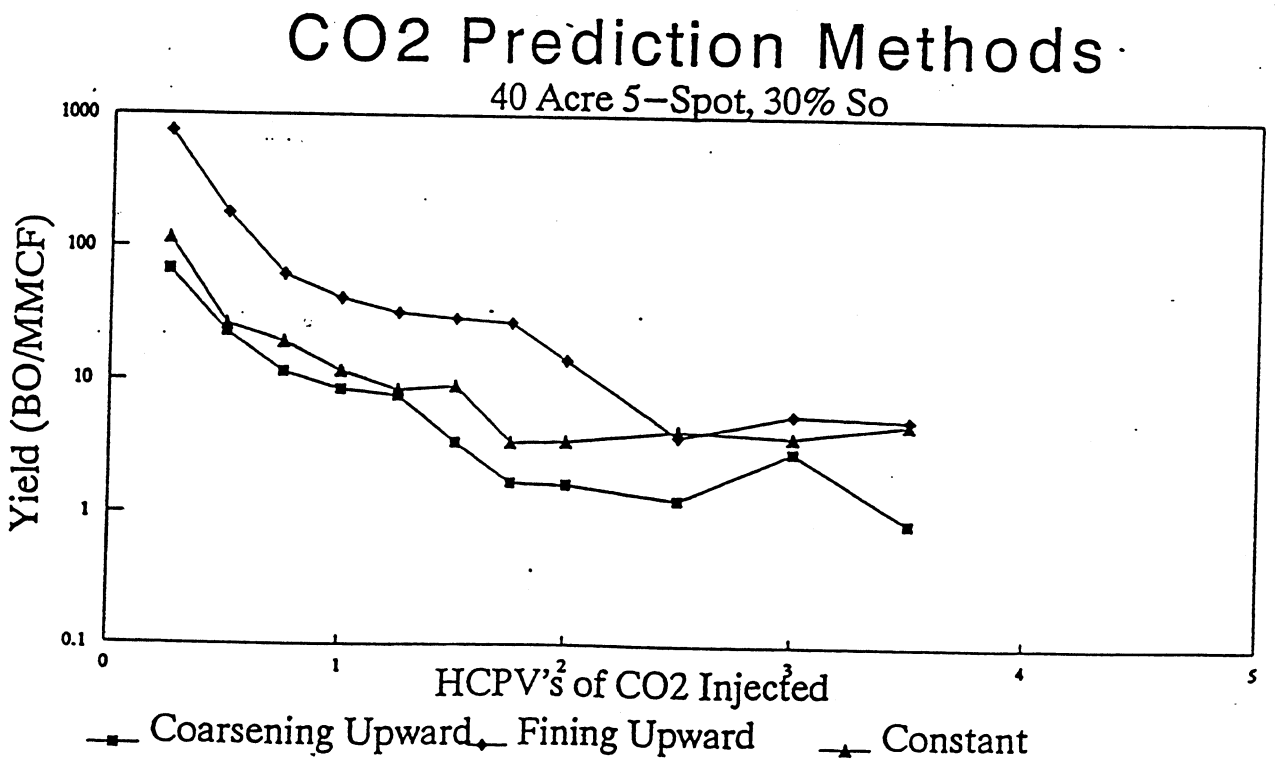

Figure 12. Oil Yield versus HCPV's CO2 Injection for Five–spot Compositional model with permeability of layers varied.

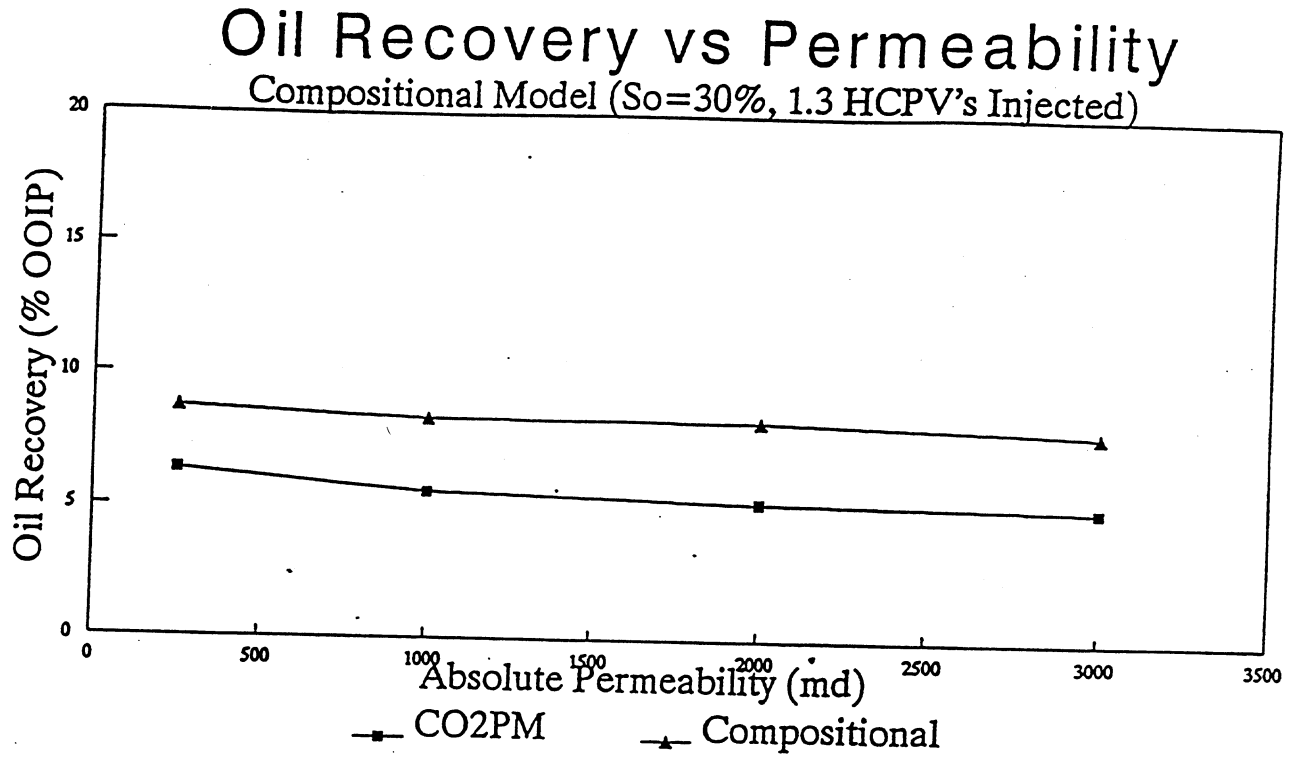

Figure 13. Oil Recovery after 1.3 HCPV's CO2 Injection versus Absolute permeability, as determined by Compositional Five–spot and CO2PM models.

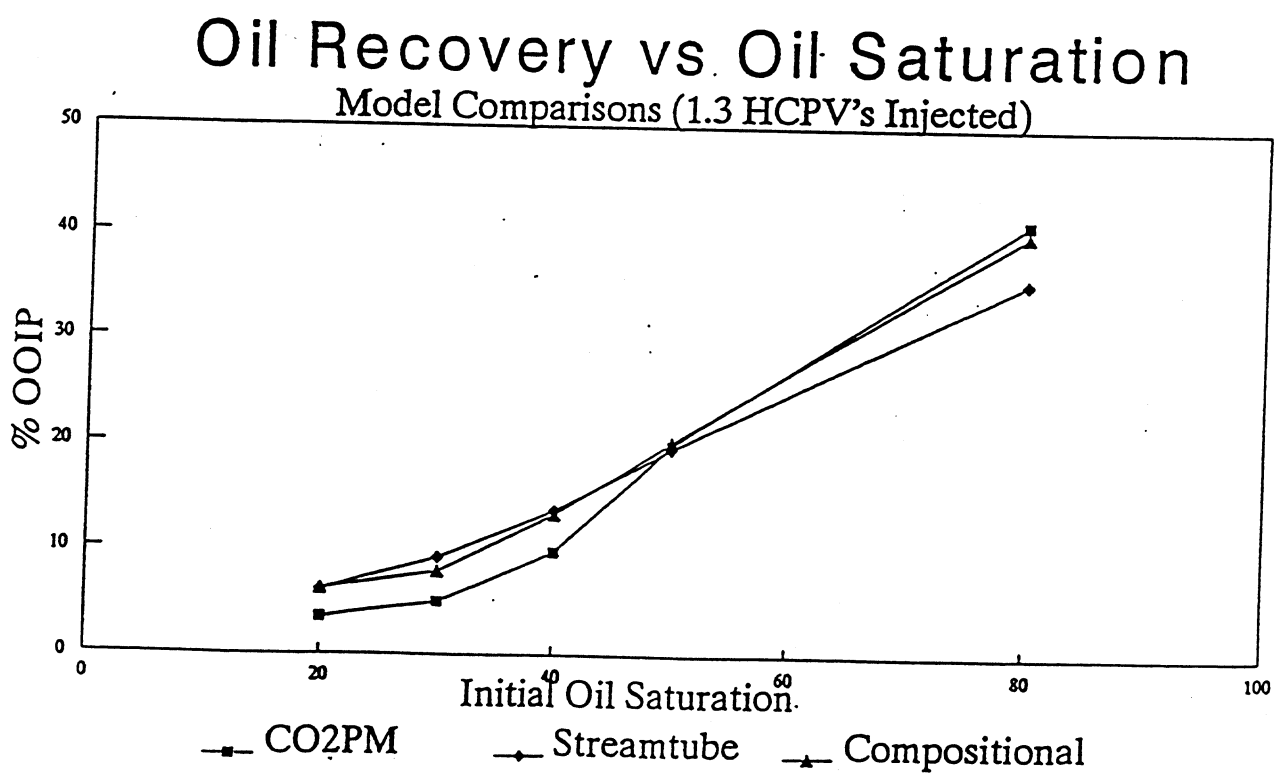

Figure 14. Oil Recovery after 1.3 HCPV's CO2 Injection versus Initial Oil Saturation, as determined by three models.

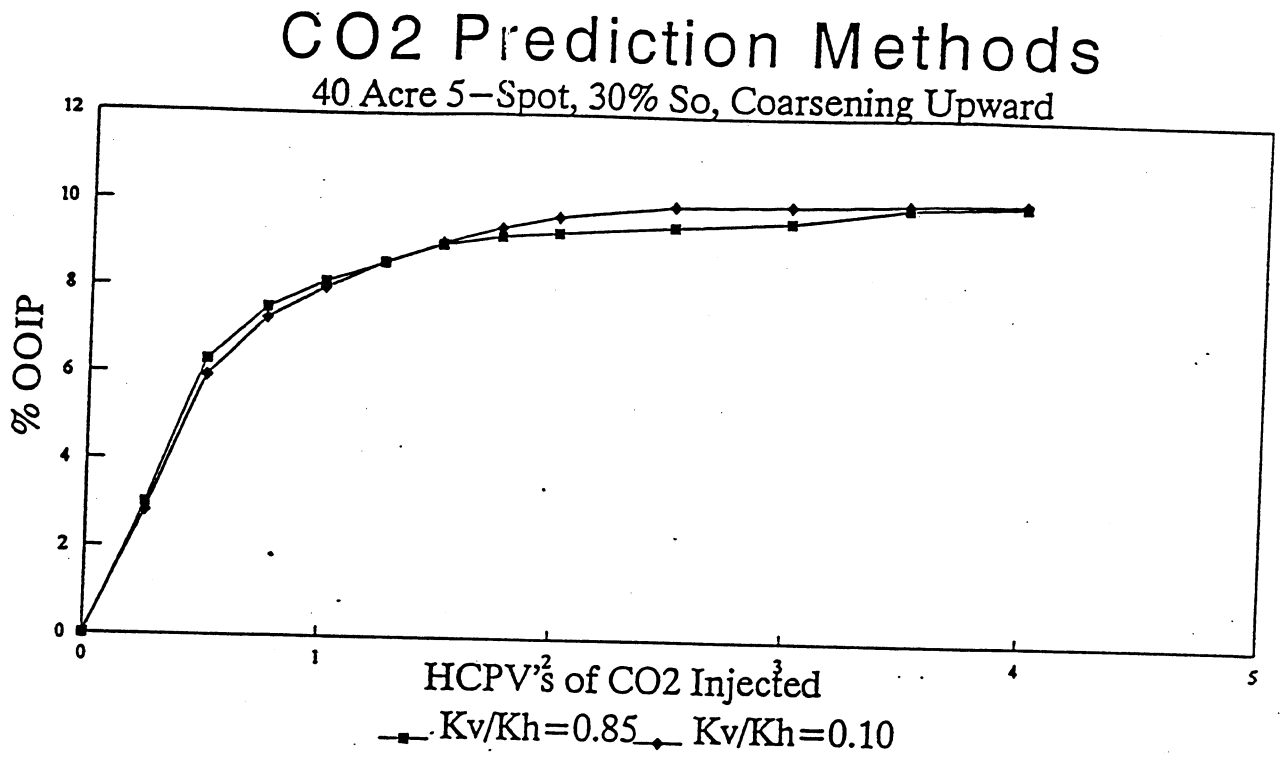

Figure 15. Oil Recovery versus HCPV's CO2 Injection for Five–spot Compositional model with vertical to horizontal permeability varied.

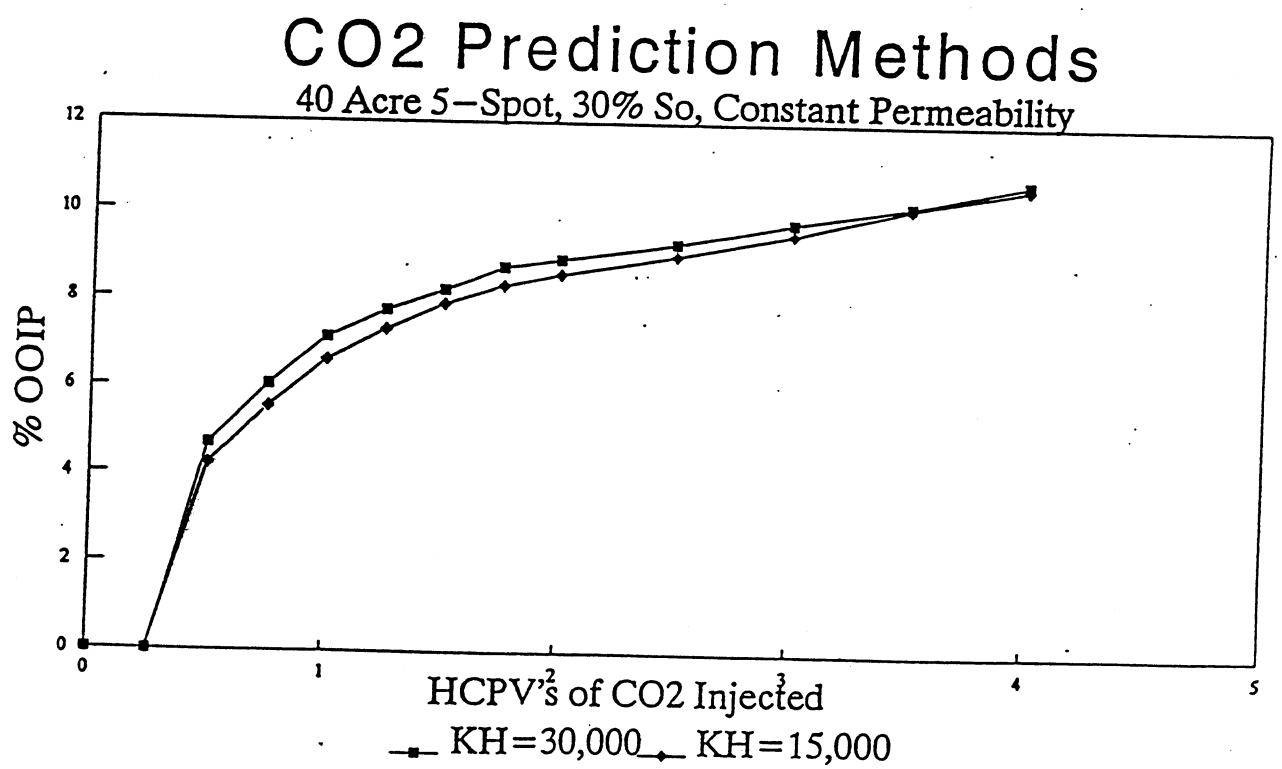

Figure 16. Oil Recovery versus HCPV's CO2 Injection for Five–spot Compositional model with varying KH values.

ABSTRACT

CO2-Prophet, a water and gas flood prediction software product, has been developed by Texaco with support of the U.S. Department of Energy (DOE). This paper describes the model and presents case comparisons with physical models and commercial reservoir simulators.

CO2-Prophet has been shown to be a good tool for screening and reservoir management and is being released to the industry complete with a detailed user manual. Ease of use was emphasized in the development of the user interface. CO2-Prophet runs on PC compatible computers and following are some of its features:

- A front end for easy reservoir parameter input.
- Several predefined patterns to simplify use.
- The ability to design patterns to fit most situations
- Fast computation.
- Multiple flood regimes so water, gas, and miscible floods can be modeled.
- Output in surface units and dimensionless formats.
- Output designed for importing into a spreadsheet

CO2-Prophet computes streamlines between injection and production wells to form stream tubes. It then makes flow computations along the stream tubes. The mixing parameter approach, proposed by Todd and Longstaff[1], is used for simulation of the miscible process. CO2-Prophet uses the Dykstra-Parsons[2] coefficient to distribute the initial injection into a maximum of ten layers, and then fractional flow calculations determine the flows and fluid saturations along the stream tubes. Program inputs are pattern description, relative permeability curves, initial saturations, injection rates, and reservoir-to-surface conversions. A new case can be set up and run in a few minutes making this program ideal for the screening of EOR projects and pattern comparisons.

The hardware requirements to run CO2-Prophet are an Intel® 386 based PC or better with at least 4 megabytes of RAM and 4 megabytes of disk space free. A math coprocessor is required for 386 or 486SX systems.

References and illustrations at end of paper.

INTRODUCTION

CO2-Prophet was developed with partial support of the DOE as part of the Class I cost share program "Post Waterflood, CO_2 Flood in a Light Oil, Fluvial Dominated Deltaic Reservoir." It was written as an alternative to the DOE distributed CO_2 miscible predictive model (CO2PM). CO2PM has limitations that interfere with the accurate prediction of CO_2 flood response when the field realities do not match the assumptions made in CO2PM. The most limiting restrictions are the five spot well configuration and not being able to handle alternate injection schemes such as hybrid WAG and tapered WAG. It has also been recognized that the predictions made by CO2PM are generally optimistic in terms of oil rate and recovery.

CO2-Prophet was written to be a flexible tool that does not suffer from the limitations of CO2PM and, at the same time, is easy to use. CO2-Prophet has been extensively

tested and has been used for prediction of waterflood and CO_2 flood performance and for screening purposes. Also, it has been used for rate prediction for economic analysis of planned CO_2 floods. CO2-Prophet is also a good tool for the prediction and analysis of waterfloods. It produces results very close to those of much more sophisticated reservoir simulators when the reservoir description is fairly uncomplicated.

CO2-Prophet can be used with virtually any flooding pattern. It comes with files generated for common patterns such as the five spot or inverted nine spot (Table 1). It is also possible to generate the stream tube files for any pattern that you wish (Figure 1). Patterns are input by defining pattern boundaries and locating the injectors and producers with X and Y coordinates and specifying well rates. Up to ten injectors and ten producing wells can be input.

CO2-Prophet can simulate many different injection schemes including waterfloods, CO_2 floods, WAG (with different ratios), or any combination of these. Individual rates can be specified for each injection well for each of four injection periods.

Output is in three formats: dimensionless (hydrocarbon pore volumes), surface units readable by people, and surface units suitable for importing into a spreadsheet. Time between surface unit report times can be annual, biannual, quarterly, or monthly. Graphical output was not incorporated so that changes in hardware would have minimal effect on the operation of the program.

Overall operation of CO2-Prophet is easy. A front end with drop down menus and entry fields is supplied to generate input files and control the main program. Default values are included to get the program running for the novice user. Error and consistency checks are done on entry fields. The input file can also be manipulated directly by the experienced user to gain flexibility of operation.

DESCRIPTION OF THE MODEL

CO2-Prophet creates a stream tube model of a reservoir. Stream lines are constructed using potentials based on the user-specified injection and production rates and well locations in an areally homogenous field. Stream tubes are formed from these stream lines, and the tubes are divided into sections for finite difference calculations. The lengths and areas of these sections are written to files to be used for future runs. The area of the reservoir is mapped into these stream tubes to make all the pore volume of the pattern accessible to flow. Areal heterogeneity is modeled by the difference in the lengths and areas of the stream tubes as seen in Figure 1.

The reservoir is further divided into a user specified number of equal thickness layers to model three dimensional flow. The Dykstra-Parsons coefficient is used to calculate the comparative permeabilities of the layers. All reservoir heterogeneity in CO2-Prophet is introduced through the Dykstra-Parsons coefficient. The total thickness of these layers can be calculated from a specified OOIP or input by the user in which case CO2-Prophet calculates OOIP. From one to ten layers can be specified, and five layers seem to work well for most situations. Cross flow between layers is not allowed, and gravity effects are not included.

Overall layer resistances are used to determine the fraction of the injection that will be routed into each layer. Figure 2 illustrates the distribution of initial relative injectivity with a Dykstra-Parsons coefficient of 0.7. Injection into each layer is determined by the product of the formation resistance and the mobility resistance as determined by relative permeabilities and fluid viscosities. The relative injections change as saturations change during the flood. Miscible fluids are handled by varying the viscosity using the Todd and Longstaff mixing parameter. No empirical correlations are used for areal or vertical sweep efficiency.

In typical mixing parameter models, the miscible phase relative permeability is set equal to the oil relative permeability. CO2-Prophet does not have this limitation. The miscible phase relative permeability can be handled in three different ways.

The first option makes the miscible phase relative permeability, k_{rm}, a saturation weighted average of the solvent and oil relative permeabilities.

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

This method directly incorporates the relative permeability of the solvent and is similar to the Solvent Relative Permeability (SRP) method presented by Chopra, Stein, and Dismuke [3]. The solvent relative permeability can be defined as the gas relative permeability, but it does not have to be.

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

$$k_{rm} = 0.5\,(k_{row} + k_{rg}) \quad \text{.....(2)}$$

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.

$$k_{rm} = k_{row} \quad \text{.....(3)}$$

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:

$$k_{rg} = \frac{S_g}{1 - S_w - S_{orm}} k_{rm} \quad \text{.....(4)}$$

and the oil relative permeability is:

$$k_{ro} = \frac{S_o - S_{orm}}{1 - S_w - S_{orm}} k_{rm} \quad \text{.....(5)}$$

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 the oil.

Simple material balances are used throughout. There are no terms in the flow equations for compressibility; so, the volume injected is the volume produced. Also, permeability is not input into the model. The average permeability of the formation is expressed in the rate of injection. Conversions between surface units to reservoir units are done for both injection and production.

VERIFICATION

The output of CO2-Prophet has been compared with the Higgins-Leighton[4] waterflood model as presented by Willhite[5] and two commercial compositional simulators for miscible displacement, COMP III from Scientific Software-Intercomp, Inc. and VIP-EXEC(COMP) from Western Atlas Software.

The Higgins-Leighton displacement data was converted to the same dimensionless basis as CO2-Prophet and compared directly. The Higgins-Leighton stream tube model was designed to model fluid flow consistent with Buckley-Leverett[6] displacement. Figure 3 shows that the agreement between the Higgins-Leighton model and CO2-Prophet is quite good. This result is from a five spot pattern as are the rest of the comparisons.

The remaining comparisons were performed using data from a Permian Basin CO_2 flood prospect (Appendix). A five spot pattern was modeled using five layers with no vertical transmissibility. Each of the layers was homogenous. Three different flooding scenarios were used; 1:1 Water Alternating Gas (WAG) tertiary injection, continuous CO_2 tertiary injection, and continuous CO_2 secondary injection. The saturation weighted method was used to calculate the miscible phase relative permeability in CO2-Prophet. The gas to oil endpoint relative permeability ratio was 0.34. A ratio other than 1.0 makes it a difficult test for a mixing parameter model. The miscible residual oil saturation was set to zero. No attempt was made to match the results of CO2-Prophet to the compositional simulators by adjusting input parameters. The same input data were used for all three simulators, and the output results were compared. A nine-point finite difference formulation was used for the compositional simulators to reduce grid orientation effects.

Figure 4 shows the results of the waterflood comparison between CO2-Prophet, COMP III and VIP-EXEC(COMP). The outputs of the three simulators are nearly identical.

A 1:1 WAG injection after waterflood was then simulated. The WAG was modeled as simultaneous injection rather than as discreet alternating slugs. Figures 5 and 6 show generally good agreement between CO2-Prophet and the other simulators. The agreement is especially good through the period of WAG injection, which lasts until 0.67 HCPV has been injected. The oil recovery prediction flattens more for the compositional simulators than it does for CO2-Prophet during the chase water drive which follows the WAG injection. The peak oil rate of CO2-Prophet is somewhat lower, and the production declines more slowly for an overall recovery of about 3% OOIP more. Even with the higher total recovery CO2-Prophet is probably more conservative than the two other simulators when economics are taken into consideration since the oil rate is lower until approximately 0.5 HCPV injection.

Figure 7 shows the comparison of CO2-Prophet and COMP3 with a continuous tertiary CO_2 flood (CO_2 injection after a waterflood). Both rates and total recovery are slightly lower for CO2-Prophet though the final difference is only about 2% OOIP. CO_2 is injected for 0.31 HCPV followed by chase water.

Figure 8 shows the results of the last comparison, a secondary CO_2 flood (CO_2 is injected continuously). The initial water saturation is at the connate level, and the rest of the pore space initially contains oil. CO2-Prophet predicts a slightly lower recovery, but the difference is not very large.

CO2-Prophet predicts oil recoveries very similar to those of compositional simulators for reasonably simple reservoir descriptions. Such descriptions are ones with no areal heterogeneity and no vertical transmissibility. The results are especially good for WAG processes. Consequently, CO2-Prophet is a very good tool for screening and even for forecasting when a great deal of reservoir description is not available.

Gas Relative Permeability

CO2-Prophet has a feature which makes it more versatile than other mixing parameter models. The saturation weighted formulation for the miscible phase relative permeability makes it possible for CO2-Prophet to more closely match the results of compositional simulators when the gas and oil relative permeability curves are very different.

Compositional simulators predict different oil recoveries for different gas relative permeability curves. However, the traditional mixing parameter models do not do this because they do not use the gas relative permeability curve in their formulation of the miscible phase relative permeability.

Table 2 shows how the predicted oil recovery is changed when the gas relative permeability curve is changed. The saturation weighted formulation for the miscible phase relative permeability is used in CO2-Prophet. Incremental oil recoveries at the end of the WAG period are shown in the table for three different magnitudes of the endpoint gas to oil relative permeability ratio. All input parameters are the same as previously discussed except for the gas to oil endpoint relative permeability ratios. The predicted oil recovery increases for CO2-Prophet and the compositional simulators as this ratio is decreased. The predicted difference in oil recovery is less between CO2-Prophet and either of the two compositional simulators then between the two compositional simulators themselves.

The predicted recovery is also shown for the standard mixing parameter formulation (in which the miscible phase relative permeability is set equal to that of the oil). Under miscible conditions, this recovery does not change if the gas relative permeability is changed. The standard formulation produces good results if the gas relative permeability curve is similar to that for the oil. Situations in which the standard formulation introduces inaccuracies are discussed by Prieditis and Brugman[7].

CONCLUSIONS

1. A new water and CO2 flood prediction software product, CO2-Prophet, has been developed for use on personal computers. It overcomes many of the limitations of the DOE's CO2 Predictive Model (CO2PM). CO2-Prophet can simulate many different injection schemes including waterfloods, CO2 floods, WAG floods, or any combination of these.

2. CO2-Prophet computes streamtubes between injection and production wells. It then makes flow computations along the streamtubes. An enhanced mixing parameter approach is used for simulation of the miscible process. The enhancement permits the incorporation of gas relative permeabilities in modeling the miscible process.

3. Ease of use was emphasized in the development of the user interface. Easy to use drop down menus are available. A new case can be set up very quickly.

4. CO2-Prophet compares very favorably with the predictions of the Higgins-Leighton waterflood model and with the predictions of commercially available compositional simulators. The oil recovery predictions of CO2-Prophet are very similar to those of compositional simulators for cases without areal heterogeneity and without vertical transmissibility.

5. CO2-Prophet is a very good tool for screening and even for forecasting both waterfloods and CO2 floods when a great deal of reservoir description is not available.

6. CO2-Prophet is being made available to the industry.

NOMENCLATURE

k_{rg} = relative permeability to gas
k_{rm} = miscible phase relative permeability
k_{ro} = relative permeability to oil
k_{row} = oil-water relative permeability
k_{rs} = solvent relative permeability
S_g = gas saturation
S_o = oil saturation
S_{orm} = miscible residual oil saturation
S_w = water saturation

ACKNOWLEDGMENTS

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4. Higgins, R. V. and Leighton, A. J.: "A Computer Method to Calculate Two-Phase Flow in Any Irregularly Bounded Porous Medium," J. Pet. Tech. (June 1962) 679-83; Trans. AIME, 225.

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6. Buckley, S. E. and Leverett, M. C.: "Mechanism of Fluid Displacement in Sands," Trans., AIME, (1942) 146, 107-16.

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APPENDIX

INPUT TO MODELS

Fluids:

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

Reservoir parameters:

Dykstra-Parsons coefficient	0.75
Number of layers	5
Pattern type	5-spot
ω mixing parameter	0.666

Relative permeability curve parameters:

S_{orw}	residual oil to waterflood	0.40
S_{org}	residual oil to gas flood	0.25
S_{gr}	residual gas saturation	0.05
S_{sr}	residual solvent saturation	0.05
Swc	connate water saturation	0.15
Swir	residual water saturation	0.15
krocw	endpoint oil rel perm	0.295
kwro	endpoint water rel perm	0.27
krse	endpoint solvent rel perm	0.10
krgcw	endpoint gas rel perm	0.10
now	oil curve exponent	2.36
nw	water curve exponent	2.10
ns	solvent curve exponent	3.17
ng	gas curve exponent	3.17

These parameters are used in analytical relative permeability equations. The equations are provided in reference 7 and the CO2-Prophet manual.

TABLE 1

PRE-SET PATTERNS

5 Spot
7 Spot (incomplete inverted nine spot)
Inverted 9 Spot
Line Drive (opposed wells)
4 Spot (same as true 7 spot)
2 Spot (isolated 2 well pattern)

TABLE 2

INCREMENTAL OIL RECOVERY (%OOIP) AT END OF WAG PERIOD

Model	Gas to oil endpoint relative permeability ratio.			
	3.4	1.00	0.34	0.034
CO2-Prophet	15.7	16.9	17.1	17.8
VIP-EXEC(COMP)	15.3	-	17.4	18.8
COMP 3	15.4	-	16.5	16.9

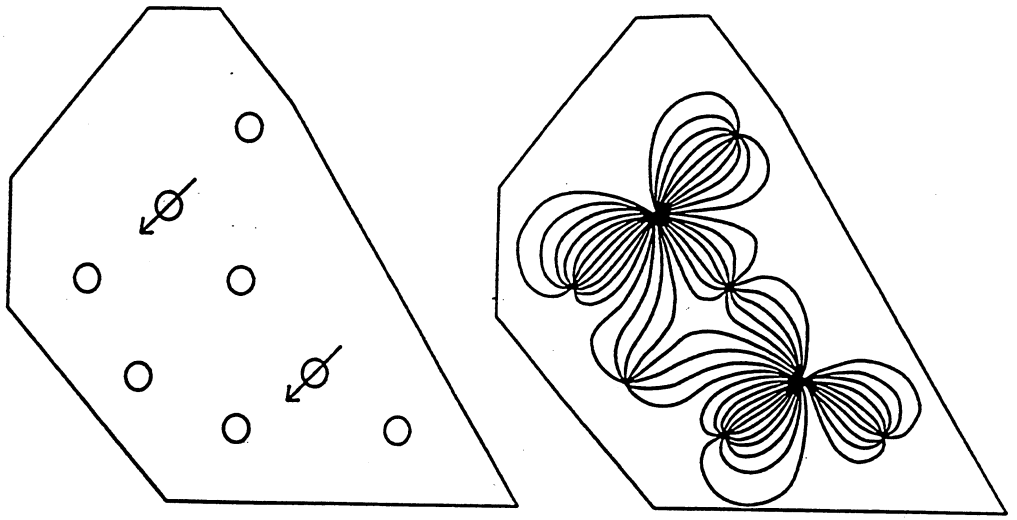

Figure 1. Example pattern and streamlines generated by CO2-Prophet.

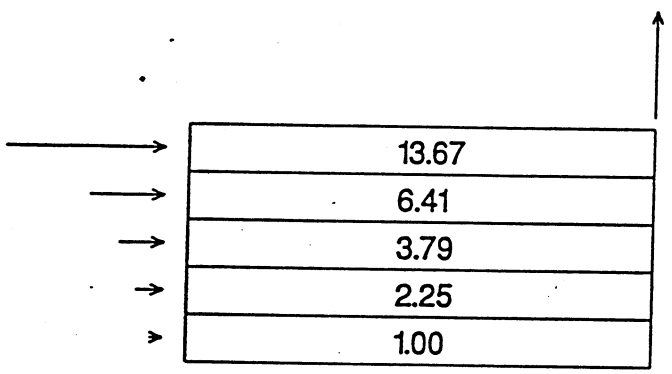

Figure 2. CO2-Prophet initial relative injectivity resulting from a Dykstra-Parsons coefficient of 0.7.

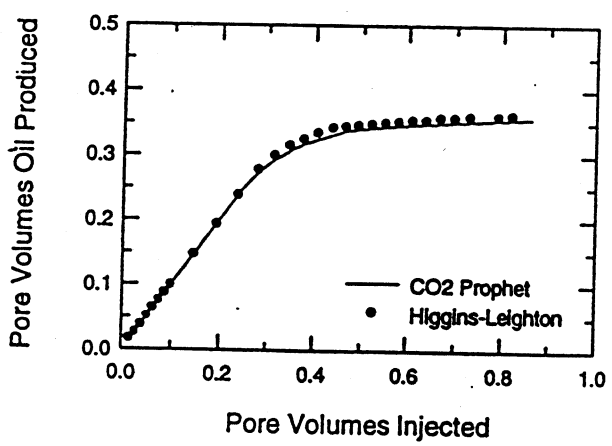

Figure 3. Comparison of CO2-Prophet with Higgins-Leighton model.

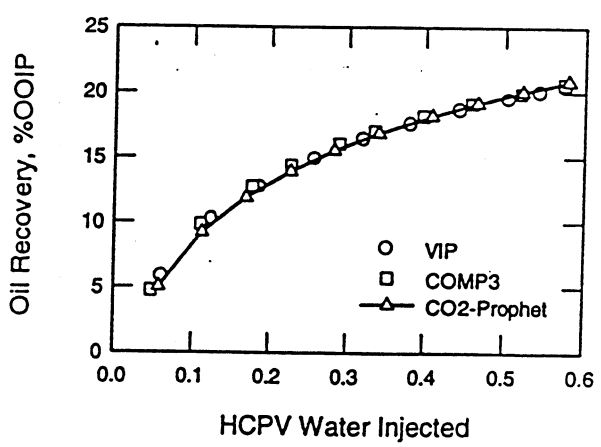

Figure 4. Waterflood comparison between VIP, COMP3, and CO2-Prophet.

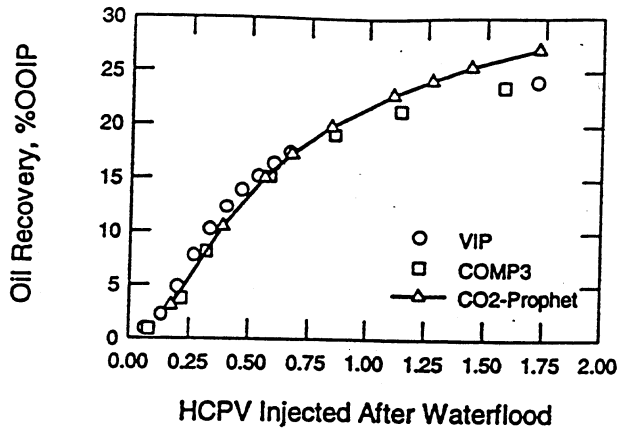

Figure 5. Comparison of CO2-Prophet with VIP and COMP3, 1:1 WAG, cummulative oil production.

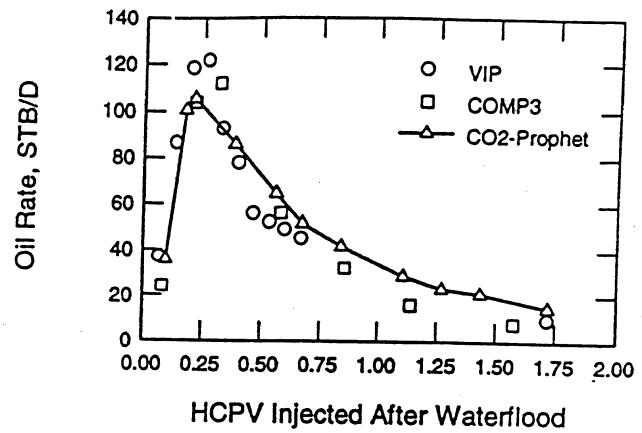

Figure 6. Comparison of CO2-Prophet with VIP and COMP3, 1:1 WAG, oil rate.

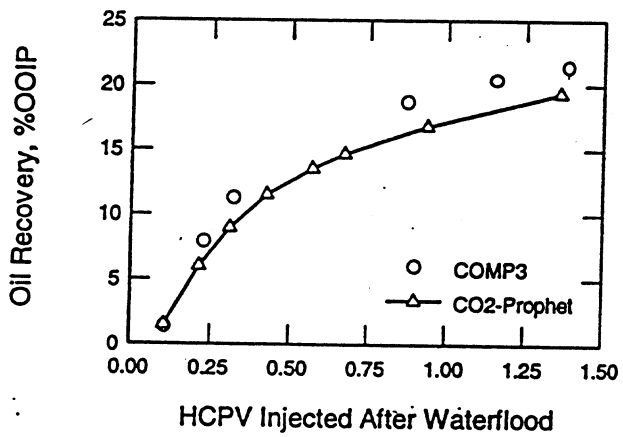

Figure 7. Comparison of CO2-Prophet with COMP3, continuous tertiary CO2 flood.

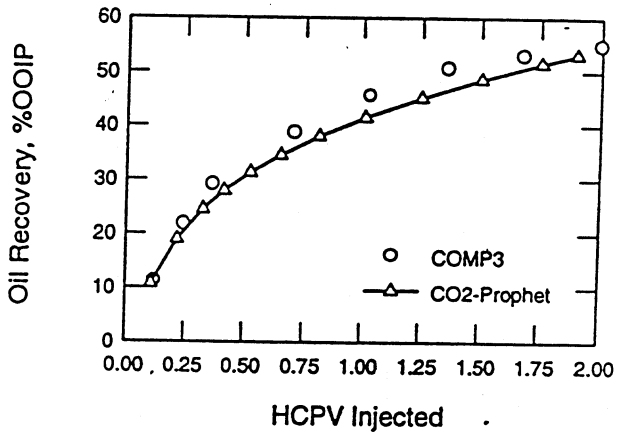

Figure 8. Comparison of CO2-Prophet with COMP3, continuous secondary CO2 flood.

CO2 Prophet

(Tuesday 24 May 1994)

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   C. Street Address 400 Poydras St.

   City New Orleans State Louisiana Zip 70130

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   EG–Electric or gas utility
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3. PRINCIPAL OR SENIOR INVESTIGATOR

   A. Last Davis First Darrell MI W.

   B. Phone: Commercial (504) 593-4567 ~~FTS~~ FAX 593-4542

4. DOE SPONSORING OFFICE OR DIVISION Bartlesville Project Office

5. TITLE OF PROJECT

   Post Waterflood CO2 Miscible Flood in Light Oil Fluvial Dominated Deltaic Reservoir, Port Neches Field, Orange County, Texas

6. DESCRIPTIVE SUMMARY (limit to 200 words)

   See Attachment

7. RESPONDENT INFORMATION. List name and address of person filling out this form. Give telephone number and extension where person can be reached. Record the date this form was completed or updated. This information will not be published.

   Last Davis First Darrell MI W.

   Address 400 Poydras St.

   City New Orleans State Louisiana Zip 70130

   Phone (504) 593-4567 Date May 17, 1993

U.S. DEPARTMENT OF ENERGY
NOTICE OF ENERGY RD&D PROJECT

6. DESCRIPTIVE SUMMARY (limit to 200 words)

A carbon dioxide (CO_2) miscible flood of a fluvial dominated deltaic (FDD) sandstone reservoir will be conducted as a Midterm demonstration project for DOE's Class I Oil Program. A 4.5 mile CO_2 pipeline, field production and compression facilities, and a flowline and injection line system will be constructed and installed in the field. Twelve wells will be reworked to install corrosion resistant tubulars and sand control, and two new wells will be drilled, one of which is a horizontal CO_2 injection well. CO_2 will be purchased from a third party CO_2 supplier, transported via a 4" pipeline, raised to injection pressure by a pump, and injected into the CO_2 injection wells. The CO_2 will enter the perforations of the well and move through the oil reservoir where it will swell the oil, reduce the oil viscosity, and miscibly displace oil which is immobile by water displacement. As CO_2 is produced with the oil and water from the formation, it will be separated from the liquids, compressed, and reinjected into the formation. Recovery of an additional 19% of the original oil-in-place, or 2.2 million barrels, will be recovered as a result of this process.

DOE F1332.2
(11-84)

U.S. DEPARTMENT OF ENERGY

SUMMARY REPORT

FORM APPROVED
OMB NO. 1901-1400

1. IDENTIFICATION NUMBER	2. PROGRAM/PROJECT TITLE	3. REPORTING PERIOD
DE-FC22-93BC14960	CLASS I / POST WATERFLOOD	10-1-93 to 12-31-93

4. PARTICIPANT NAME AND ADDRESS
TEXACO EXPLORATION AND PRODUCTION, INC.
400 POYDRAS ST.
NEW ORLEANS, LA 70130

5. START DATE: 6-1-93

6. COMPLETION DATE: 12-31-97

7. FY 94 | 8. MONTHS: O N D J F M A M J J A S O N D

9. COST STATUS

a. $ Expressed in: MILLIONS

b. Budget and Reporting No. AC1510100

c. Cost Plan Date 6-23-93

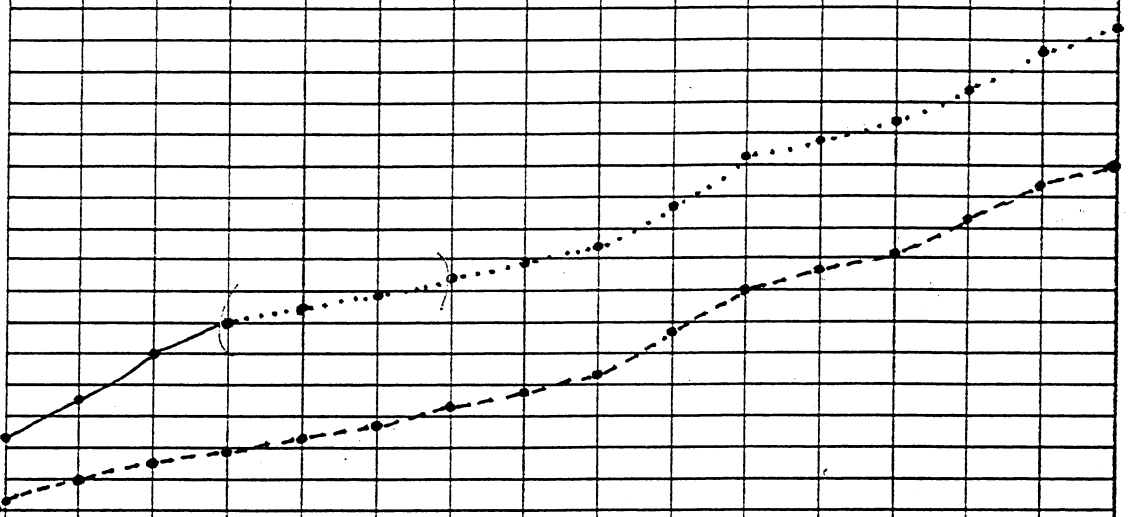
d. Actual Costs Prior Years $11,217

e. Planned Costs Prior Years $10,149

f. Total Estimated Cost for Contract $646

g. Total Contract Value $5407

h. Estimated Subsequent Reporting Period $1,834



Accrued Costs	O	N	D	J	F	M	A	M	J	J	A	S	O	N	D
g. Planned	352	280	209	206	210	230	256	255	706	704	277	248	630	630	214
h. Actual	634	607	593												
i. Variance	(282)	(327)	(384)												
j. Cumulative Variance	(1719)	(2046)	(2430)												

10. LABOR STATUS

a. Labor Expressed in: THOUSANDS

b. Labor Plan Date: N/A DIRECT LABOR

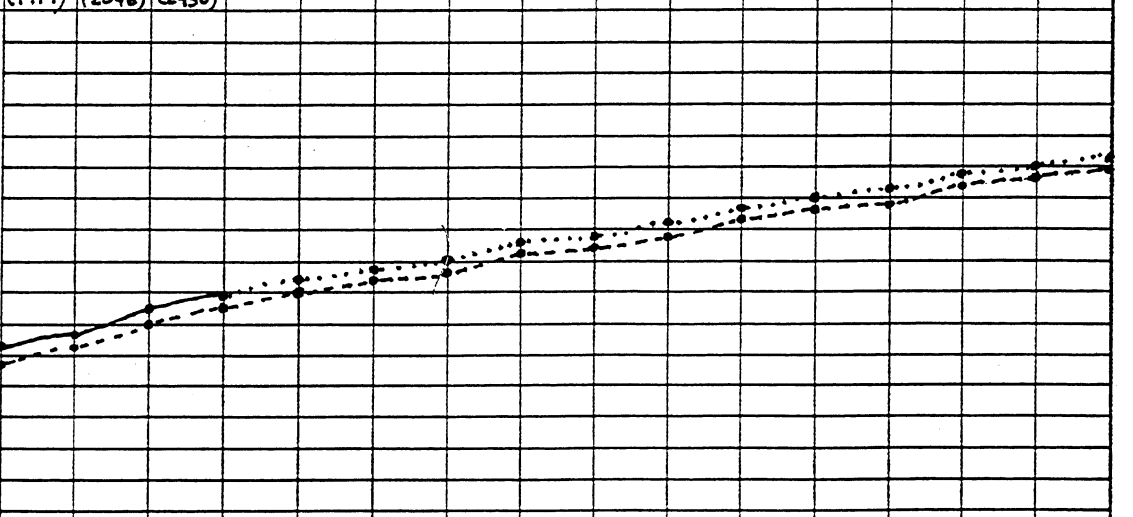
c. Planned Labor Prior Fiscal Years $290

d. Actual Labor Prior Fiscal Years $308

e. Total Estimated Labor for Contract $1,275

f. Total Contract Labor N/A

LEGEND
Planned: - - - - - -
Actual: ———
Projected: . . . . . .



Labor	O	N	D	J	F	M	A	M	J	J	A	S	O	N	D
g. Planned	30	30	25	25	20	20	15	15	15	15	15	15	15	15	15
h. Actual	25	27	20												
i. Variance	5	3	5												
j. Cumulative Variance	13	10	5												

11. MILESTONES	STATUS	COMMENTS
DRILL HORIZONTAL WELL	→	BEGAN 11/15

12. SIGNATURE OF PARTICIPANT'S PROJECT MANAGER AND DATE
Darell Davis 1/15/94

DOE F1332.2
(11-84)

U.S. DEPARTMENT OF ENERGY
SUMMARY REPORT

FORM APPROVED
OMB NO. 1901-1400

1. IDENTIFICATION NUMBER	2. PROGRAM/PROJECT TITLE	3. REPORTING PERIOD
DE-FC22-93BC14960	CLASS I / POST WATERFLOOD	1-1-94 to 9-30-94

4. PARTICIPANT NAME AND ADDRESS
TEXACO EXPLORATION AND PRODUCTION, INC
400 POYDRAS ST.
NEW ORLEANS, LA 70130

5. START DATE: 6-1-93

6. COMPLETION DATE: 12-31-97

7. FY | 8. MONTHS

9. COST STATUS

a. $ Expressed in: MILLIONS

b. Budget and Reporting No. AC1510100

c. Cost Plan Date 6-23-93

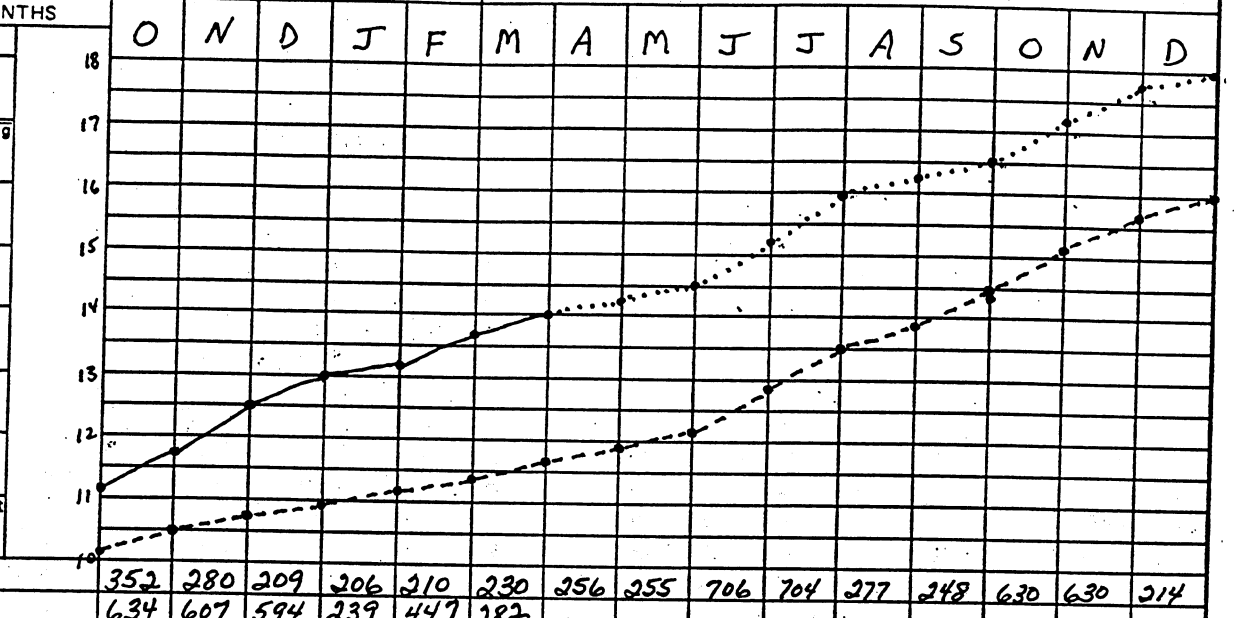
d. Actual Costs Prior Years $11,217

e. Planned Costs Prior Years $10,149

f. Total Estimated Cost for Contract $646

g. Total Contract Value $5,407

h. Estimated Subsequent Reporting Period



		O	N	D	J	F	M	A	M	J	J	A	S	O	N	D
Accrued Costs	g. Planned	352	280	209	206	210	230	256	255	706	704	277	248	630	630	214
	h. Actual	634	607	594	239	447	282									
	i. Variance	(282)	(327)	(385)	(33)	(237)	(52)									
	j. Cumulative Variance	(1719)	(2046)	(2431)	(2464)	(2701)	(2753)									

10. LABOR STATUS

a. Labor Expressed in: THOUSANDS

b. Labor Plan Date: N/A DIRECT LABOR

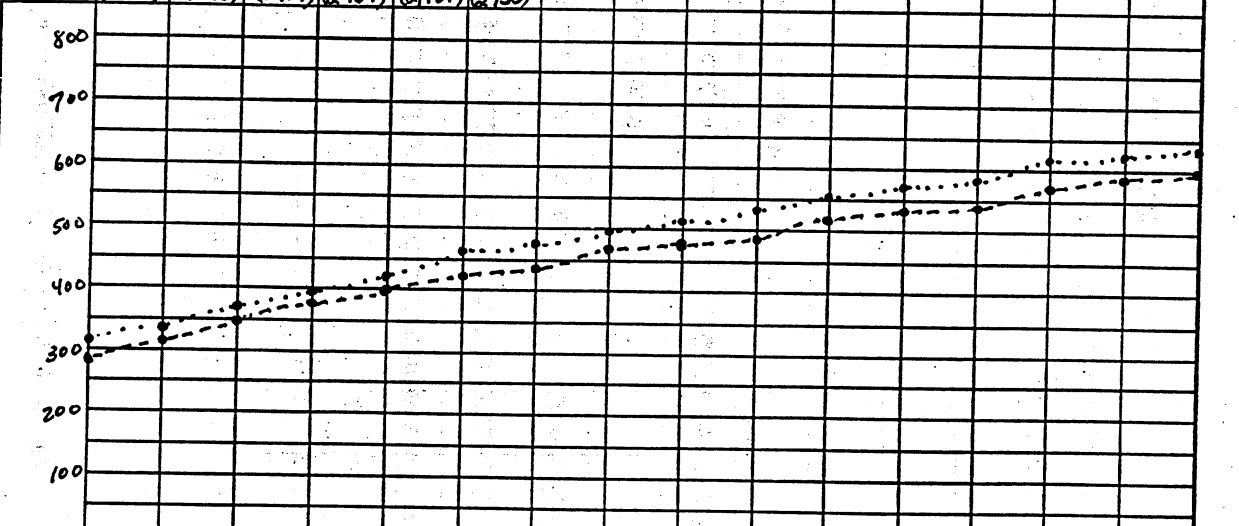
Planned Labor Prior Fiscal Years $290

Actual Labor Prior Fiscal Years $308

Total Estimated Labor for Contract $1,275

Total Contract Labor N/A

LEGEND
Planned: - - - - - -
Actual: _____
Projected: . . . . . .



		O	N	D	J	F	M	A	M	J	J	A	S	O	N	D
Labor	g. Planned	30	30	25	25	20	20	15	15	15	15	15	15	15	15	15
	h. Actual	25	27	20	31	37	17									
	i. Variance	5	3	5	(6)	(17)	3									
	j. Cumulative Variance	(13)	(10)	(5)	(11)	(28)	(25)									

MILESTONES	STATUS	COMMENTS
DRILL HORIZONTAL WELL	→	COMPLETE 1/15/94

SIGNATURE OF PARTICIPANT'S PROJECT MANAGER AND DATE Sami Ben Mikael 4/29/94

DOE F1332.2
(11-84)

U.S. DEPARTMENT OF ENERGY
SUMMARY REPORT

FORM APPROVED
OMB NO. 1901-1400

1. IDENTIFICATION NUMBER	2. PROGRAM/PROJECT TITLE	3. REPORTING PERIOD
DE-FC22-93BC14960	CLASS I / POST WATERFLOOD	4-1-94 to 6-30-94

4. PARTICIPANT NAME AND ADDRESS
TEXACO EXPLORATION AND PRODUCTION, INC
400 POYDRAS ST
NEW ORLEANS, LA 70130

5. START DATE: 6-1-93

6. COMPLETION DATE: 12-31-97

7. FY | 8. MONTHS

	O	N	D	J	F	M	A	M	J	J	A	S	O	N	D

9. COST STATUS

a. $ Expressed in: MILLIONS

b. Budget and Reporting No. AC1510100

c. Cost Plan Date 6-23-93

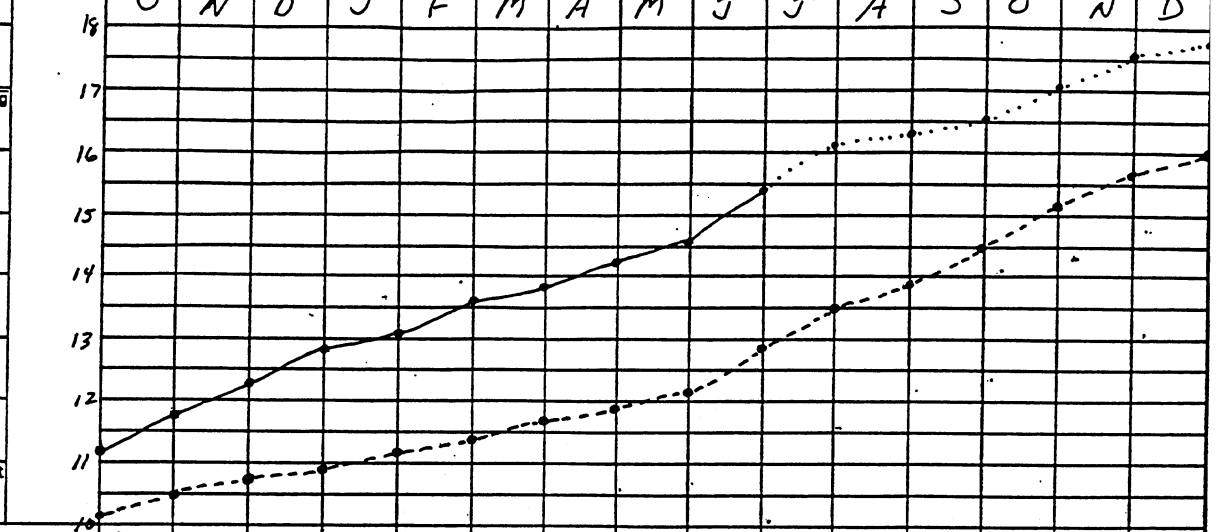
d. Actual Costs Prior Years 11,217

e. Planned Costs Prior Years 10,149

f. Total Estimated Cost for Contract $646

g. Total Contract Value $5,407

h. Estimated Subsequent Reporting Period



Accrued Costs		O	N	D	J	F	M	A	M	J	J	A	S	O	N	D
	g. Planned	352	280	209	206	210	230	256	255	706	704	277	248	630	630	214
	h. Actual	635	612	595	239	454	291	436	364	966						
	i. Variance	(283)	(332)	(386)	(33)	(244)	(61)	(180)	(109)	(260)						
	j. Cumulative Variance	(1351)	(1683)	(2069)	(2102)	(2346)	(2407)	(2587)	(2696)	(2956)						

10. LABOR STATUS

a. Labor Expressed in: THOUSANDS

b. Labor Plan Date: N/A DIRECT LABOR

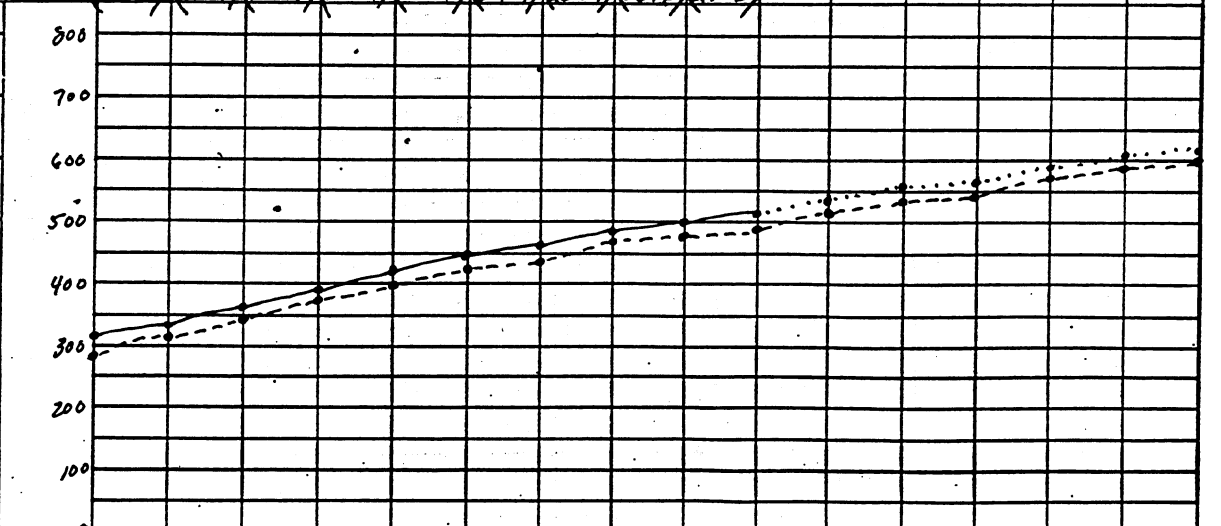
c. Planned Labor Prior Fiscal Years $290

d. Actual Labor Prior Fiscal Years $302

e. Total Estimated Labor for Contract $1,275

f. Total Contract Labor N/A

LEGEND
Planned: - - - - - -
Actual: _____
Projected: . . . . . .



Labor		O	N	D	J	F	M	A	M	J	J	A	S	O	N	D
	g. Planned	30	30	25	25	20	20	15	15	15	15	15	15	15	15	15
	h. Actual	26	29	20	31	38	17	18	18	17						
	i. Variance	4	1	5	(6)	(18)	3	(3)	(3)	(2)						
	j. Cumulative Variance	(18)	(17)	(12)	(18)	(36)	(33)	(36)	(39)	(41)						

11. MILESTONES

	STATUS												COMMENTS
a.													
b.													
c.													
d.													
e.													
f.													
g.													

12. SIGNATURE OF PARTICIPANT'S PROJECT MANAGER AND DATE

DOE F1332.2
(11-84)

U.S. DEPARTMENT OF ENERGY
SUMMARY REPORT

FORM APPROVED
OMB NO. 1901-1400

1. IDENTIFICATION NUMBER	2. PROGRAM/PROJECT TITLE	3. REPORTING PERIOD
DE-FC22-93BC14960	CLASS I / POST WATERFLOOD	7-1-94 to 9-30-94

4. PARTICIPANT NAME AND ADDRESS
TEXACO EXPLORATION AND PRODUCTION, INC
400 POYDRAS ST.
NEW ORLEANS, LA 70130

5. START DATE: 6-1-93

6. COMPLETION DATE: 12-31-97

7. FY | 8. MONTHS

9. COST STATUS

a. $ Expressed in: MILLIONS

b. Budget and Reporting No. AC1510100

c. Cost Plan Date 6-23-93

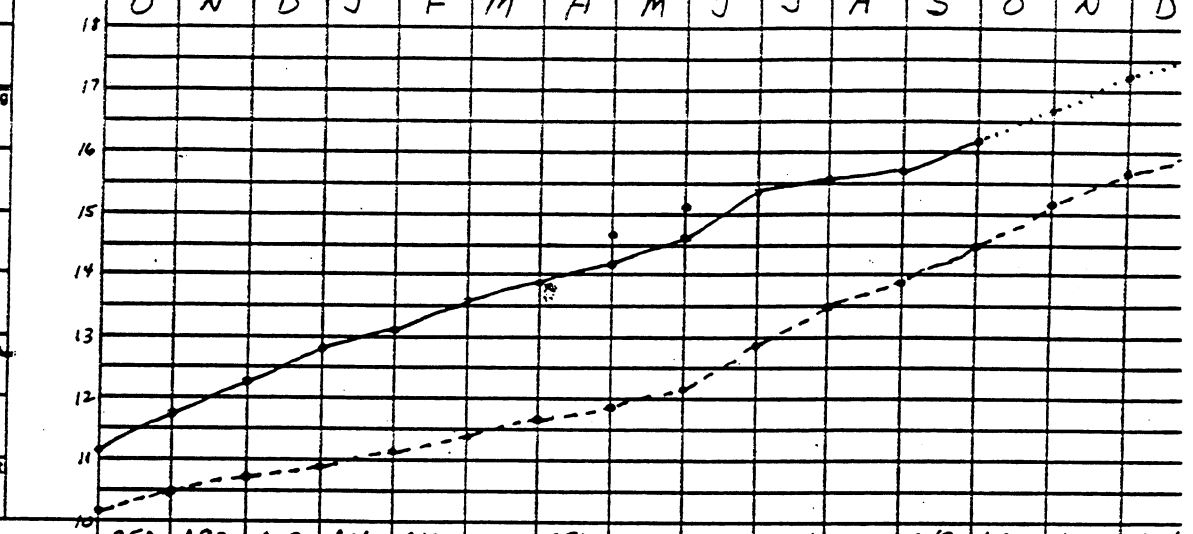
d. Actual Costs Prior Years 11,217

e. Planned Costs Prior Years 10,149

f. Total Estimated Cost for Contract $646

g. Total Contract Value 5,407

h. Estimated Subsequent Reporting Period



		O	N	D	J	F	M	A	M	J	J	A	S	O	N	D
Accrued Costs	g. Planned	352	280	209	206	310	230	256	255	706	704	277	248	630	630	314
	h. Actual	635	612	595	339	454	291	436	364	966	140	174	276			
	i. Variance	(283)	(332)	(386)	(33)	(244)	(61)	(180)	(109)	(260)	564	103	(28)			
	j. Cumulative Variance	(1351)	(1683)	(2069)	(2102)	(2346)	(2407)	(2587)	(2696)	(2956)	(2392)	(2289)	(2317)			

10. LABOR STATUS

a. Labor Expressed in: THOUSANDS

b. Labor Plan Date: N/A DIRECT LABOR

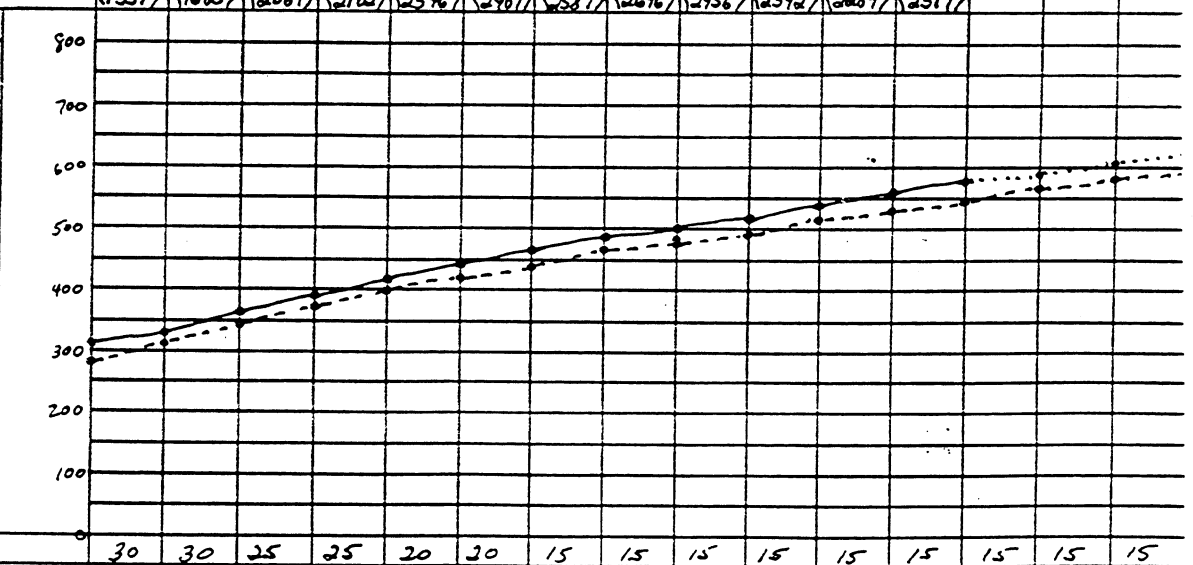
c. Planned Labor Prior Fiscal Years $390

d. Actual Labor Prior Fiscal Years $312

e. Total Estimated Labor for Contract $1,275

f. Total Contract Labor N/A

LEGEND
Planned: - - - - - -
Actual: _____
Projected: . . . . . .



Labor	g. Planned	30	30	25	25	20	20	15	15	15	15	15	15	15	15	15
	h. Actual	26	29	20	31	38	17	18	18	17	20	15	14			
	i. Variance	4	1	5	(6)	(18)	3	(3)	(3)	(2)	(5)	0	1			
	j. Cumulative Variance	(18)	(17)	(12)	(18)	(36)	(33)	(36)	(39)	(41)	(46)	(46)	(45)			

11. MILESTONES	STATUS												COMMENTS
a.													
b.													
c.													
d.													
e.													
f.													
g.													

12. SIGNATURE OF PARTICIPANT'S PROJECT MANAGER AND DATE

DOE F1332.2
(11-84)

U.S. DEPARTMENT OF ENERGY
SUMMARY REPORT

FORM APPROVED
OMB NO. 1901-1400

1. IDENTIFICATION NUMBER	2. PROGRAM/PROJECT TITLE	3. REPORTING PERIOD
DE-FC22-93BC14960	CLASS I	10-1-94 to 12/31/94

4. PARTICIPANT NAME AND ADDRESS
TEXACO EXPLORATION AND PRODUCTION, INC
400 POYDRAS ST.
NEW ORLEANS, LA 70130

5. START DATE: 6-1-93

6. COMPLETION DATE: 12-31-97

7. FY | 8. MONTHS

9. COST STATUS

a. $ Expressed in: MILLIONS

b. Budget and Reporting No. AC1510100

c. Cost Plan Date 6-23-93

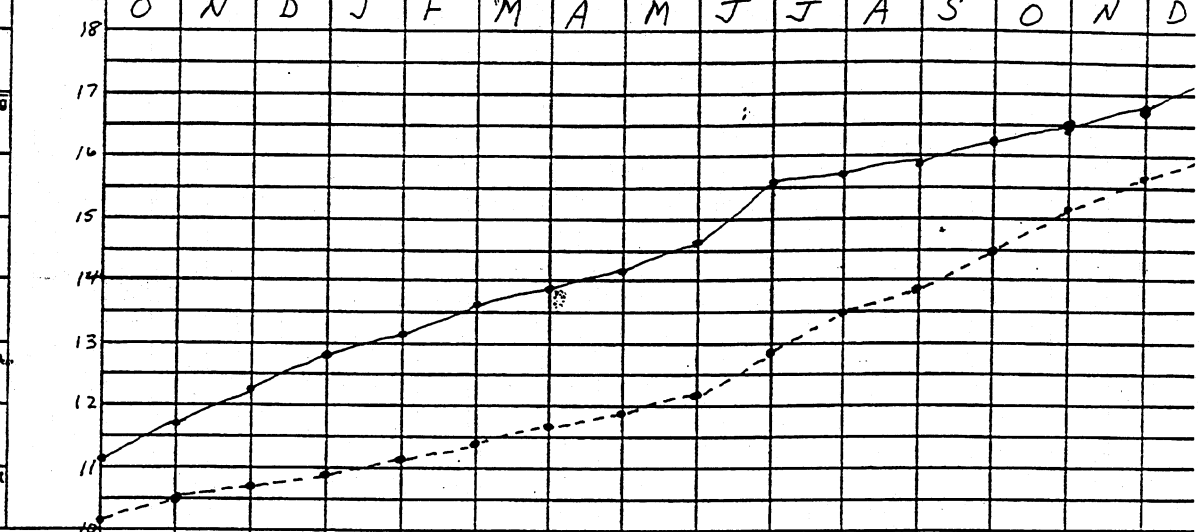
d. Actual Costs Prior Years 11,217

e. Planned Costs Prior Years 10,149

f. Total Estimated Cost for Contract $646

g. Total Contract Value $5,407

h. Estimated Subsequent Reporting Period



		O	N	D	J	F	M	A	M	J	J	A	S	O	N	D
Accrued Costs	g. Planned	352	280	209	206	210	230	256	255	706	704	277	248	630	630	214
	h. Actual	635	612	595	239	454	291	436	364	966	188	219	426	212	238	313
	i. Variance	(283)	(332)	(386)	(33)	(244)	(61)	(180)	(109)	(260)	516	60	(178)	418	392	(99
	j. Cumulative Variance	(1351)	(1683)	(2069)	(2102)	(2346)	(2407)	(2587)	(2696)	(2956)	(2440)	(2380)	(2558)	(2140)	(1748)	(184

10. LABOR STATUS

a. Labor Expressed in: THOUSANDS

b. Labor Plan Date: N/A DIRECT LABOR

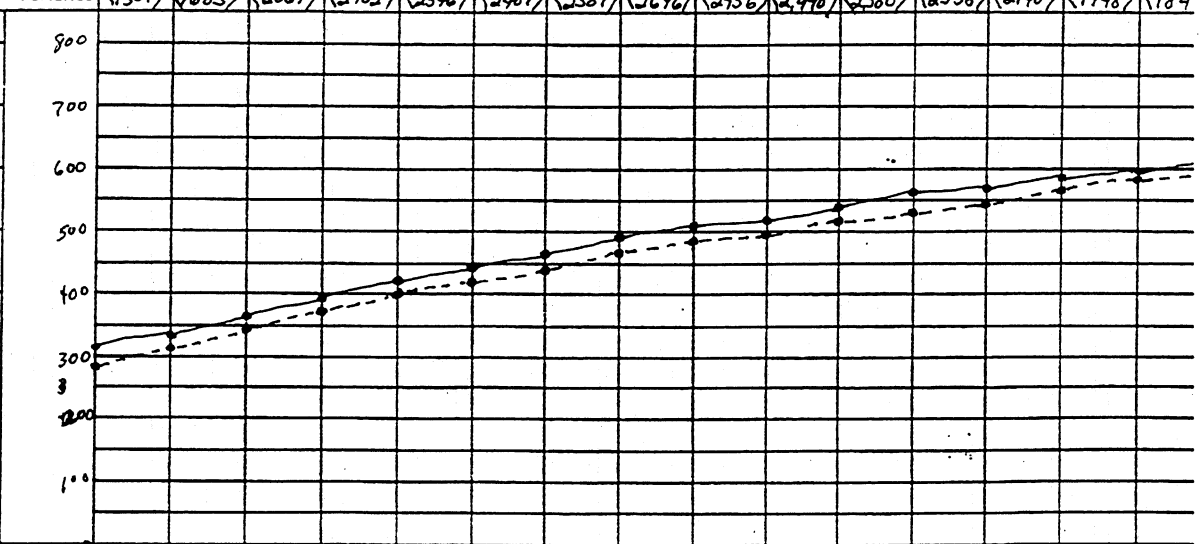
c. Planned Labor Prior Fiscal Years $390

d. Actual Labor Prior Fiscal Years $312

e. Total Estimated Labor for Contract $1,275

f. Total Contract Labor N/A

LEGEND
Planned: - - - - - -
Actual: _____
Projected: . . . . . .



		O	N	D	J	F	M	A	M	J	J	A	S	O	N	D
Labor	g. Planned	30	30	25	25	20	20	15	15	15	15	15	15	15	15	15
	h. Actual	26	29	20	31	38	17	18	18	17	20	15	14	13	11	9
	i. Variance	4	1	5	(6)	(18)	3	(3)	(3)	(2)	(5)	0	1	2	4	6
	j. Cumulative Variance	(18)	(17)	(12)	(18)	(36)	(33)	(36)	(39)	(41)	(46)	(46)	(45)	(43)	(39)	(33)

11. MILESTONES	STATUS	COMMENTS
a.		
b.		
c.		
d.		
e.		
f.		
g.		

12. SIGNATURE OF PARTICIPANT'S PROJECT MANAGER AND DATE

U.S. DEPARTMENT OF ENERGY

MILESTONE SCHEDULE [ ] PLAN [X] STATUS REPORT

DOE F1332.3
(11-84)

FORM APPROVED
OMB NO. 1901-1400

1. TITLE
Post Waterflood CO2 Miscible Flood in a Light Oil Fluvial Dominated Deltaic Reservoir

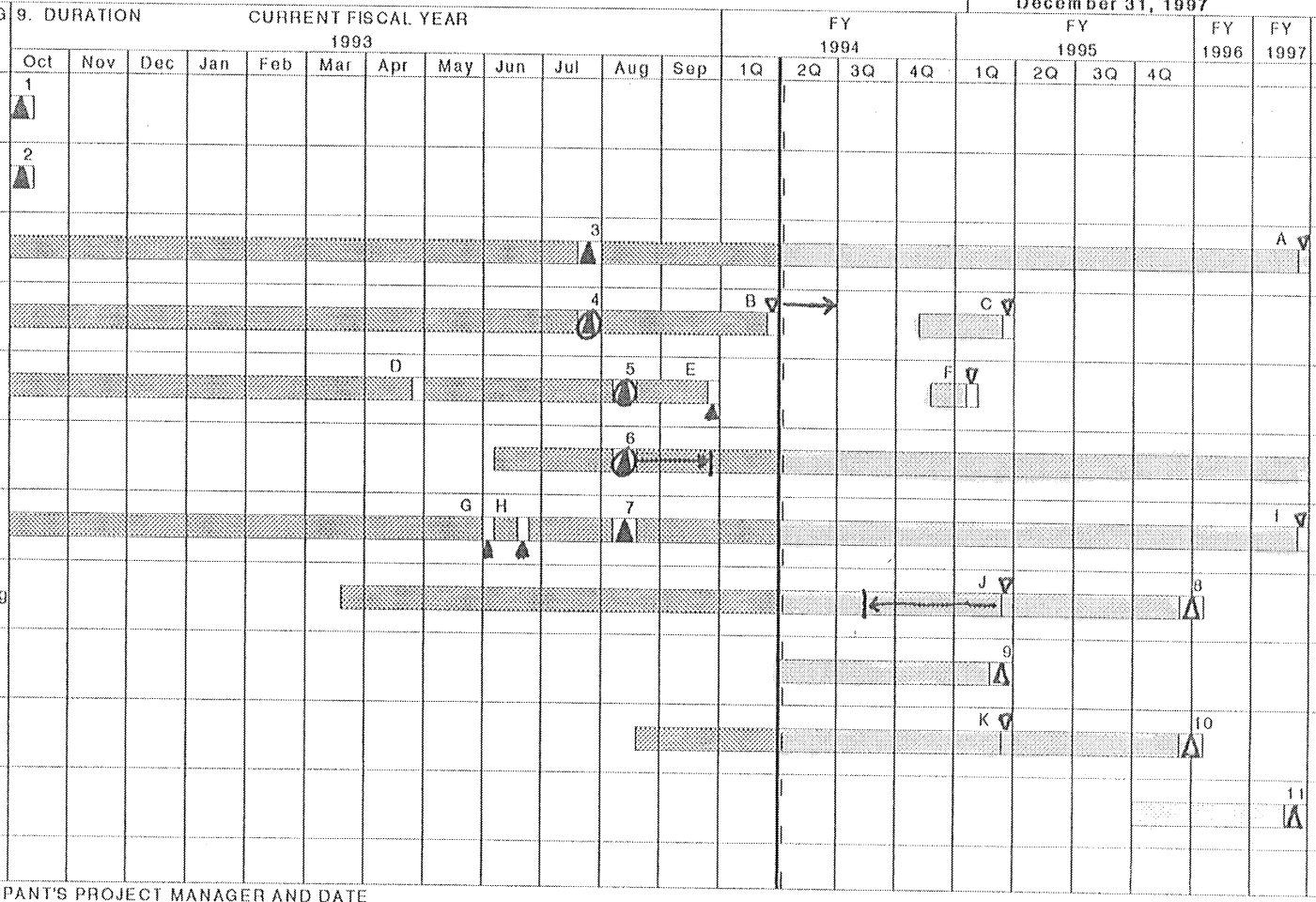
2. REPORTING PERIOD
Oct. 1, 1993 – Dec 31, 1993

3. IDENTIFICATION NUMBER
DE-FC22-93BC14960

4. PARTICIPANT NAME AND ADDRESS
Texaco Exploration and Production Inc.
400 Poydras St.
New Orleans, LA 70130

5. START DATE
June 1, 1993

6. COMPLETION DATE
December 31, 1997



11. SIGNATURE OF PARTICIPANT'S PROJECT MANAGER AND DATE
Darrell Davis 1/15/94

U.S. DEPARTMENT OF ENERGY

MILESTONE SCHEDULE [ ] PLAN [X] STATUS REPORT

DOE F1332.3
(11-84)

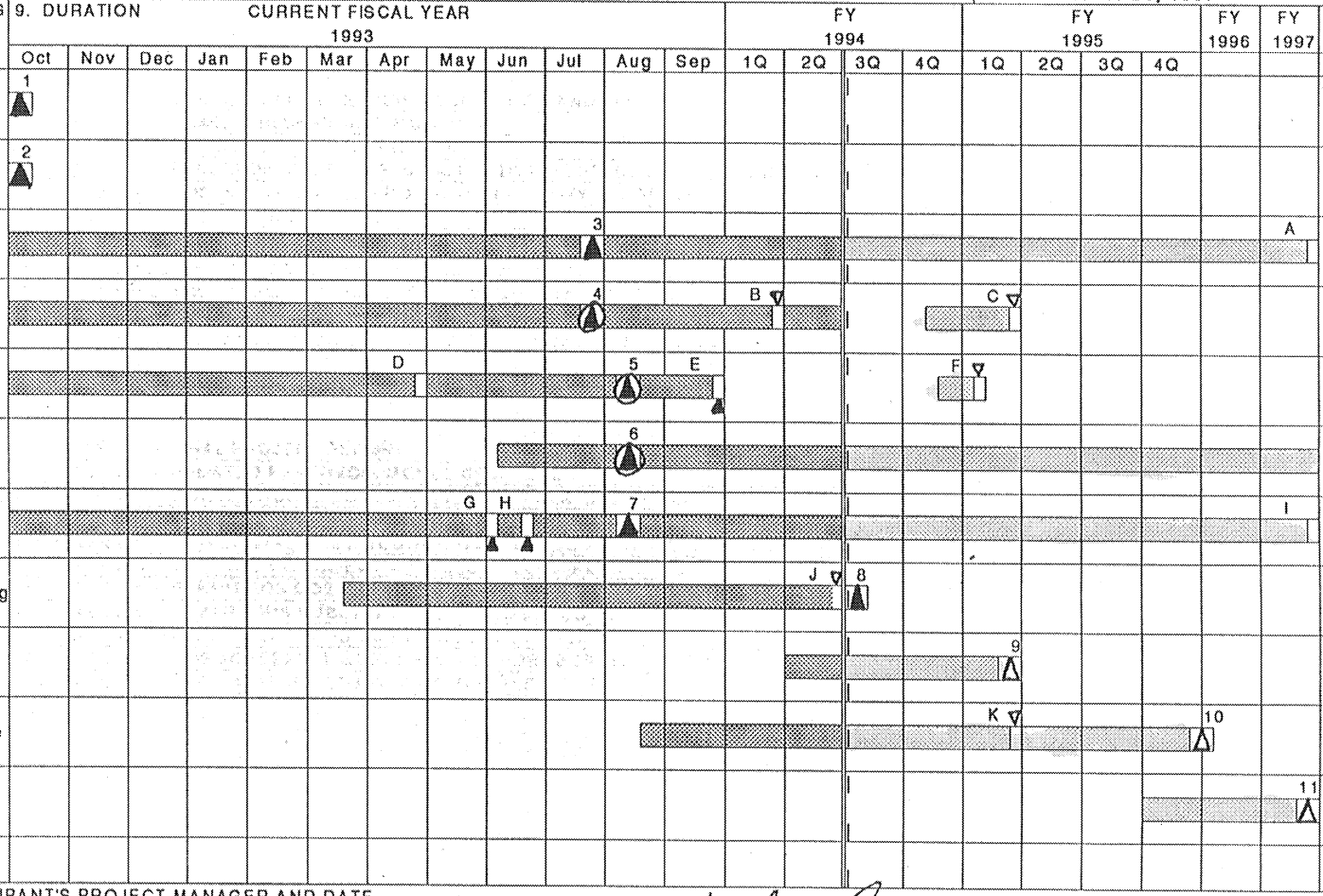
FORM APPROVED
OMB NO. 1901-1400

1. TITLE	2. REPORTING PERIOD	3. IDENTIFICATION NUMBER
Post Waterflood CO2 Miscible Flood in a Light Oil Fluvial Dominated Deltaic Reservoir	**Jan. 1, 1994 - Mar. 31, 1993**	**DE-FC22-93BC14960**

4. PARTICIPANT NAME AND ADDRESS
Texaco Exploration and Production Inc.
400 Poydras St.
New Orleans, LA 70130

5. START DATE
June 1, 1993

6. COMPLETION DATE
December 31, 1997



11. SIGNATURE OF PARTICIPANT'S PROJECT MANAGER AND DATE

Sami Bonhilead 4/29/94

U.S. DEPARTMENT OF ENERGY

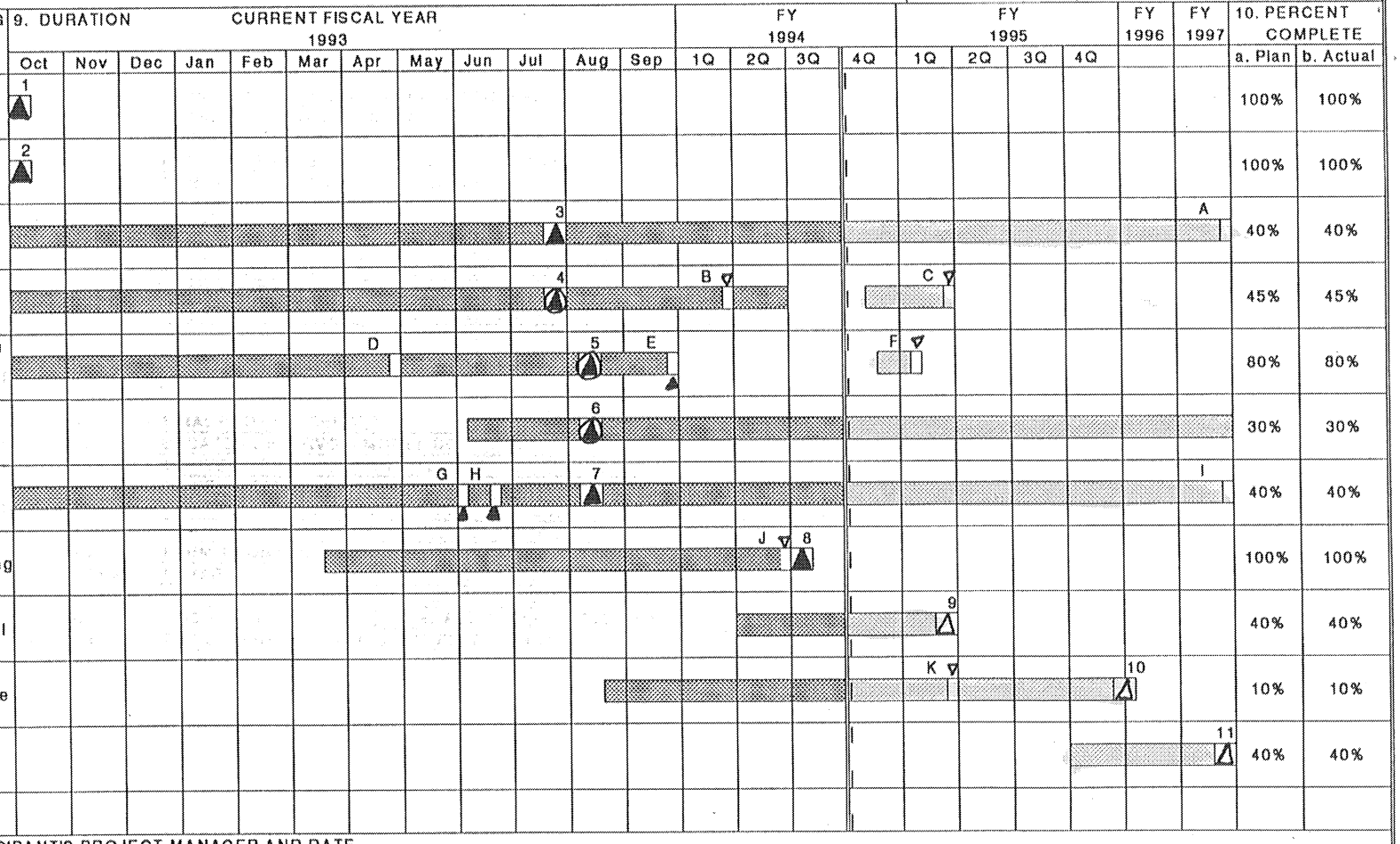
MILESTONE SCHEDULE [ ] PLAN [X] STATUS REPORT

DOE F1332.3
(11-84)

FORM APPROVED
OMB NO. 1901-1400

1. TITLE	2. REPORTING PERIOD	3. IDENTIFICATION NUMBER
Post Waterflood CO2 Miscible Flood in a Light Oil Fluvial Dominated Deltaic Reservoir	**Apr. 1, 1994 – Jun. 30, 1994**	**DE-FC22-93BC14960**

4. PARTICIPANT NAME AND ADDRESS	5. START DATE	6. COMPLETION DATE
Texaco Exploration and Production Inc. **400 Poydras St.** **New Orleans, LA 70130**	**June 1, 1993**	**December 31, 1997**



11. SIGNATURE OF PARTICIPANT'S PROJECT MANAGER AND DATE

U.S. DEPARTMENT OF ENERGY

MILESTONE SCHEDULE [ ] PLAN [X] STATUS REPORT

DOE F1332.3
(11-84)

FORM APPROVED
OMB NO. 1901-1400

1. TITLE
Post Waterflood CO2 Miscible Flood in a Light Oil Fluvial Dominated Deltaic Reservoir

2. REPORTING PERIOD
July 1, 1994 - Sept. 30, 1994

3. IDENTIFICATION NUMBER
DE-FC22-93BC14960

4. PARTICIPANT NAME AND ADDRESS
Texaco Exploration and Production Inc.
400 Poydras St.
New Orleans, LA 70130

5. START DATE
June 1, 1993

6. COMPLETION DATE
December 31, 1997

7. ELEMENT CODE	8. REPORTING ELEMENT	9. DURATION CURRENT FISCAL YEAR 1993 Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	FY 1994 1Q	2Q	3Q	4Q	FY 1995 1Q	2Q	3Q	4Q	FY 1996	FY 1997	10. PERCENT COMPLETE a. Plan	b. Actual
1.1	Geologic & Engineering	1																						100%	100%
1.2	Extraction Technology	2																						100%	100%
2.1	Recording Daily Production										3												A	40%	40%
2.2	Reservoir Charac-terization										4			B				C						45%	45%
2.3	Site Operation & Field Work							D				5	E				F							80%	80%
2.4	CO2											6												30%	30%
2.5	EH&S Monitoring & Compliance								G	H		7											I	40%	40%
3.1	CO2 Screening Model														J	8								100%	100%
3.2	Environmental Analysis																	9						95%	95%
3.3	FDD Database & Model																	K			10			10%	10%
3.4	Technical Publications																						11	40%	40%

11. SIGNATURE OF PARTICIPANT'S PROJECT MANAGER AND DATE

U.S. DEPARTMENT OF ENERGY

MILESTONE SCHEDULE [ ] PLAN [X] STATUS REPORT

DOE F1332.3
(11-84)

FORM APPROVED
OMB NO. 1901-1400

1. TITLE	2. REPORTING PERIOD	3. IDENTIFICATION NUMBER
Post Waterflood CO2 Miscible Flood in a Light Oil Fluvial Dominated Deltaic Reservoir	**Oct. 1, 1994 - Dec. 31, 1994**	**DE-FC22-93BC14960**
4. PARTICIPANT NAME AND ADDRESS **Texaco Exploration and Production Inc.** **400 Poydras St.** **New Orleans, LA 70130**		5. START DATE **June 1, 1993** 6. COMPLETION DATE **December 31, 1997**

7. ELEMENT CODE	8. REPORTING ELEMENT	9. DURATION	CURRENT FISCAL YEAR 1993											FY 1994				FY 1995				FY 1996	FY 1997	10. PERCENT COMPLETE	
			Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	1Q	2Q	3Q	4Q	1Q	2Q	3Q	4Q			a. Plan	b. Actual
1.1	Geologic & Engineering		1																						100%	100%
1.2	Extraction Technology		2																						100%	100%
2.1	Recording Daily Production											3												A	40%	40%
2.2	Reservoir Charac-terization											4			B				C						80%	80%
2.3	Site Operation & Field Work								D				5	E				F							90%	90%
2.4	CO2												6												35%	35%
2.5	EH&S Monitoring & Compliance									G	H		7											I	40%	40%
3.1	CO2 Screening Model															J	8								100%	100%
3.2	Environmental Analysis																		9						100%	100%
3.3	FDD Database & Model																		K				10		50%	50%
3.4	Technical Publications																	L						11	40%	40%

11. SIGNATURE OF PARTICIPANT'S PROJECT MANAGER AND DATE

U.S. DEPARTMENT OF ENERGY
MILESTONE SCHEDULE [ ] PLAN [X] SCHEDULE
(ATTACHMENT)

DOE F1332.3 ATTACHMENT
(11-84)

1. TITLE	2. REPORTING PERIOD	3. IDENTIFICATION NUMBER
Post Waterflood CO2 Miscible Flood in a Light Oil Fluvial Dominated Deltaic Reservoir	**Oct. 1, 1993 – Dec. 31, 1993**	**DE-FC22-93BC14960**
4. PARTICIPANT NAME AND ADDRESS **Texaco Exploration and Production Inc.** **400 Poydras St.** **New Orleans, LA 70130**		5. START DATE **June 1, 1993** 6. COMPLETION DATE **December 31, 1997**

MAJOR EVENTS	DATE	DESCRIPTION	STATUS
1	10/15/92	TASK 1.1 – GEOLOGICAL RESERVOIR DESCRIPTION AND LAB TESTS	COMPLETED
2	10/15/92	TASK 1.2 – PHASE 1 RESERVOIR SIMULATION	COMPLETED
3	08/01/93	TASK 2.1 – RECEIVE DOE APPROVAL TO INJECT CO2	COMPLETED
4	08/01/93	TASK 2.2 – RESERVOIR PRESSURE IS RAISED TO 2700 PSI BY WATER INJECTION	COMPLETED
5	08/15/93	TASK 2.3 – CO2 INJECTION AND PRODUCTION FACILITY IS COMPLETED	COMPLETED
6	08/15/93	TASK 2.4 – CO2 PIPELINE IS INSTALLED	COMPLETED
7	08/15/93	TASK 2.5 – NEPA CATEGORICAL EXCLUSION IS RECEIVED	COMPLETED
8	12/31/95	TASK 3.1 – SPE PAPER AND RELEASE OF CO2 SCREENING MODEL	WORK 65% COMPLETE
9	12/31/94	TASK 3.2 – TOPICAL REPORT ON ENVIRONMENTAL CONSTRAINTS	PROJECT INITIATED – 5% COMPLETE
10	12/31/95	TASK 3.3 – TOPICAL REPORT ON FDD DATABASE	PROJECT 10% COMPLETE
11	12/31/97	TASK 3.4 – SPE PAPER ON RESERVOIR CHARACTERIZATION	SPE PAPER WILL BE PRESENTED IN APRIL, 1994

INTERMEDIATE EVENTS	DATE	DESCRIPTION	STATUS
A	12/31/97	TASK 2.1 – FINAL PROJECT REPORT	TO BE COMPLETED DURING 1997
B	12/31/93	TASK 2.2 – UPDATED RESERVOIR MODEL COMPLETED	FINAL RESULTS TARGET DATE 3/31/94
C	12/01/94	TASK 2.2 – CONVENTIONAL CORE ANALYZED IN POLK "B" #39 WELL	TO BE PERFORMED DURING 1994
D	04/30/93	TASK 2.3 – 10 WELL WORKOVER PROGRAM COMPLETED	COMPLETED
E	10/01/93	TASK 2.3 – HORIZONTAL CO2 INJECTION WELL DRILLED, POLK "B" #2 W/O PERFORMED	HORIZ. WELL COMPLETE, POLK "B" W/O CANCELLED
F	12/01/94	TASK 2.3 – VERTICAL CO2 INJECTION WELL DRILLED (POLK "B" #39)	TO BE DRILLED DURING 1994
G	06/10/93	TASK 2.5 – PERMIT FOR CO2 PIPELINE RECEIVED FROM ARMY CORPS OF ENGINEERS	COMPLETED
H	06/30/93	TASK 2.5 – HAZARDOUS SUBSTANCE PLAN SUBMITTED TO DOE	COMPLETED
I	12/31/97	TASK 2.5 – FINAL HAZARDOUS SUBSTANCE PLAN SUBMITTED TO DOE	TO BE COMPLETED DURING 1997
J	12/31/94	TASK 3.1 – CO2 SCREENING MODEL FINAL REPORT SUBMITTED TO DOE	PAPER AND MODEL TO BE PRESENTED IN APRIL, 1994
K	12/31/94	TASK 3.3 – FDD DATABASE STUDY IS COMPLETED BY LSU	LSU WORK WILL BE COMPLETED IN SPRING, 1995

11. SIGNATURE OF PARTICIPANT'S PROJECT MANAGER AND DATE

Darrell Davis 1/15/94

U.S. DEPARTMENT OF ENERGY
MILESTONE SCHEDULE [ ] PLAN [X] SCHEDULE
(ATTACHMENT)

DOE F1332.3 ATTACHMENT
(11-84)

1. TITLE	2. REPORTING PERIOD	3. IDENTIFICATION NUMBER
Post Waterflood CO2 Miscible Flood in a Light Oil Fluvial Dominated Deltaic Reservoir	Jan. 1, 1994 – Mar. 31, 1994	DE-FC22-93BC14960
4. PARTICIPANT NAME AND ADDRESS Texaco Exploration and Production Inc. 400 Poydras St. New Orleans, LA 70130		5. START DATE June 1, 1993
		6. COMPLETION DATE December 31, 1997

MAJOR EVENTS	DATE	DESCRIPTION	STATUS
1	10/15/92	TASK 1.1 – GEOLOGICAL RESERVOIR DESCRIPTION AND LAB TESTS	COMPLETED
2	10/15/92	TASK 1.2 – PHASE 1 RESERVOIR SIMULATION	COMPLETED
3	08/01/93	TASK 2.1 – RECEIVE DOE APPROVAL TO INJECT CO2	COMPLETED
4	08/01/93	TASK 2.2 – RESERVOIR PRESSURE IS RAISED TO 2700 PSI BY WATER INJECTION	COMPLETED
5	08/15/93	TASK 2.3 – CO2 INJECTION AND PRODUCTION FACILITY IS COMPLETED	COMPLETED
6	08/15/93	TASK 2.4 – CO2 PIPELINE IS INSTALLED	COMPLETED
7	08/15/93	TASK 2.5 – NEPA CATEGORICAL EXCLUSION IS RECEIVED	COMPLETED
8	12/31/95	TASK 3.1 – SPE PAPER AND RELEASE OF CO2 SCREENING MODEL	COMPLETED
9	12/31/94	TASK 3.2 – TOPICAL REPORT ON ENVIRONMENTAL CONSTRAINTS	PROJECT 15% COMPLETE
10	12/31/95	TASK 3.3 – TOPICAL REPORT ON FDD DATABASE	PROJECT 10% COMPLETE
11	12/31/97	TASK 3.4 – SPE PAPER ON RESERVOIR CHARACTERIZATION	1ST SPE PAPER PRESENTED

INTERMEDIATE EVENTS	DATE	DESCRIPTION	STATUS
A	12/31/97	TASK 2.1 – FINAL PROJECT REPORT	TO BE COMPLETED DURING 1997
B	12/31/93	TASK 2.2 – UPDATED RESERVOIR MODEL COMPLETED	COMPLETED
C	12/01/94	TASK 2.2 – CONVENTIONAL CORE ANALYZED IN POLK "B" #39 WELL	TO BE PERFORMED DURING 1994
D	04/30/93	TASK 2.3 – 10 WELL WORKOVER PROGRAM COMPLETED	COMPLETED
E	10/01/93	TASK 2.3 – HORIZONTAL CO2 INJECTION WELL DRILLED, POLK "B" #2 W/O PERFORMED	HORIZ. WELL COMPLETE, POLK "B" W/O CANCELLED
F	12/01/94	TASK 2.3 – VERTICAL CO2 INJECTION WELL DRILLED (POLK "B" #39)	TO BE DRILLED DURING 1994
G	06/10/93	TASK 2.5 – PERMIT FOR CO2 PIPELINE RECEIVED FROM ARMY CORPS OF ENGINEERS	COMPLETED
H	06/30/93	TASK 2.5 – HAZARDOUS SUBSTANCE PLAN SUBMITTED TO DOE	COMPLETED
I	12/31/97	TASK 2.5 – FINAL HAZARDOUS SUBSTANCE PLAN SUBMITTED TO DOE	TO BE COMPLETED DURING 1997
J	12/31/94	TASK 3.1 – CO2 SCREENING MODEL FINAL REPORT SUBMITTED TO DOE	COMPLETED
K	12/31/94	TASK 3.3 – FDD DATABASE STUDY IS COMPLETED BY LSU	LSU WORK WILL BE COMPLETED IN SPRING, 1995

11. SIGNATURE OF PARTICIPANT'S PROJECT MANAGER AND DATE Sami Bou Mikael 4/29/94

U.S. DEPARTMENT OF ENERGY
MILESTONE SCHEDULE [ ] PLAN [X] SCHEDULE
(ATTACHMENT)

DOE F1332.3 ATTACHMENT
(11-84)

1. TITLE	2. REPORTING PERIOD	3. IDENTIFICATION NUMBER
Post Waterflood CO2 Miscible Flood in a Light Oil Fluvial Dominated Deltaic Reservoir	**Apr. 1, 1994 – Jun. 30, 1994**	**DE-FC22-93BC14960**
4. PARTICIPANT NAME AND ADDRESS **Texaco Exploration and Production Inc.** **400 Poydras St.** **New Orleans, LA 70130**		5. START DATE **June 1, 1993** 6. COMPLETION DATE **December 31, 1997**

MAJOR EVENTS	DATE	DESCRIPTION	STATUS
1	10/15/92	TASK 1.1 – GEOLOGICAL RESERVOIR DESCRIPTION AND LAB TESTS	COMPLETED
2	10/15/92	TASK 1.2 – PHASE 1 RESERVOIR SIMULATION	COMPLETED
3	08/01/93	TASK 2.1 – RECEIVE DOE APPROVAL TO INJECT CO2	COMPLETED
4	08/01/93	TASK 2.2 – RESERVOIR PRESSURE IS RAISED TO 2700 PSI BY WATER INJECTION	COMPLETED
5	08/15/93	TASK 2.3 – CO2 INJECTION AND PRODUCTION FACILITY IS COMPLETED	COMPLETED
6	08/15/93	TASK 2.4 – CO2 PIPELINE IS INSTALLED	COMPLETED
7	08/15/93	TASK 2.5 – NEPA CATEGORICAL EXCLUSION IS RECEIVED	COMPLETED
8	12/31/95	TASK 3.1 – SPE PAPER AND RELEASE OF CO2 SCREENING MODEL	COMPLETED
9	12/31/94	TASK 3.2 – TOPICAL REPORT ON ENVIRONMENTAL CONSTRAINTS	PROJECT 40% COMPLETE
10	12/31/95	TASK 3.3 – TOPICAL REPORT ON FDD DATABASE	PROJECT 10% COMPLETE
11	12/31/97	TASK 3.4 – SPE PAPER ON RESERVOIR CHARACTERIZATION	1ST SPE PAPER PRESENTED

INTERMEDIATE EVENTS	DATE	DESCRIPTION	STATUS
A	12/31/97	TASK 2.1 – FINAL PROJECT REPORT	TO BE COMPLETED DURING 1997
B	12/31/93	TASK 2.2 – UPDATED RESERVOIR MODEL COMPLETED	COMPLETED
C	12/01/94	TASK 2.2 – CONVENTIONAL CORE ANALYZED IN POLK "B" #39 WELL	TO BE PERFORMED DURING 1995
D	04/30/93	TASK 2.3 – 10 WELL WORKOVER PROGRAM COMPLETED	COMPLETED
E	10/01/93	TASK 2.3 – HORIZONTAL CO2 INJECTION WELL DRILLED, POLK "B" #2 W/O PERFORMED	HORIZ. WELL COMPLETE, POLK "B" W/O CANCELLED
F	12/01/94	TASK 2.3 – VERTICAL CO2 INJECTION WELL DRILLED (POLK "B" #39)	TO BE DRILLED DURING 1995
G	06/10/93	TASK 2.5 – PERMIT FOR CO2 PIPELINE RECEIVED FROM ARMY CORPS OF ENGINEERS	COMPLETED
H	06/30/93	TASK 2.5 – HAZARDOUS SUBSTANCE PLAN SUBMITTED TO DOE	COMPLETED
I	12/31/97	TASK 2.5 – FINAL HAZARDOUS SUBSTANCE PLAN SUBMITTED TO DOE	TO BE COMPLETED DURING 1997
J	12/31/94	TASK 3.1 – CO2 SCREENING MODEL FINAL REPORT SUBMITTED TO DOE	COMPLETED
K	12/31/94	TASK 3.3 – FDD DATABASE STUDY IS COMPLETED BY LSU	LSU WORK WILL BE COMPLETED IN SPRING, 1995

11. SIGNATURE OF PARTICIPANT'S PROJECT MANAGER AND DATE

U.S. DEPARTMENT OF ENERGY
MILESTONE SCHEDULE [ ] PLAN [X] SCHEDULE
(ATTACHMENT)

DOE F1332.3 ATTACHMENT
(11-84)

1. TITLE	2. REPORTING PERIOD	3. IDENTIFICATION NUMBER
Post Waterflood CO2 Miscible Flood in a Light Oil Fluvial Dominated Deltaic Reservoir	July 1, 1994 - Sept. 30, 1994	DE-FC22-93BC14960
4. PARTICIPANT NAME AND ADDRESS Texaco Exploration and Production Inc. 400 Poydras St. New Orleans, LA 70130		5. START DATE June 1, 1993 6. COMPLETION DATE December 31, 1997

MAJOR EVENTS	DATE	DESCRIPTION	STATUS
1	10/15/92	TASK 1.1 - GEOLOGICAL RESERVOIR DESCRIPTION AND LAB TESTS	COMPLETED
2	10/15/92	TASK 1.2 - PHASE 1 RESERVOIR SIMULATION	COMPLETED
3	08/01/93	TASK 2.1 - RECEIVE DOE APPROVAL TO INJECT CO2	COMPLETED
4	08/01/93	TASK 2.2 - RESERVOIR PRESSURE IS RAISED TO 2700 PSI BY WATER INJECTION	COMPLETED
5	08/15/93	TASK 2.3 - CO2 INJECTION AND PRODUCTION FACILITY IS COMPLETED	COMPLETED
6	08/15/93	TASK 2.4 - CO2 PIPELINE IS INSTALLED	COMPLETED
7	08/15/93	TASK 2.5 - NEPA CATEGORICAL EXCLUSION IS RECEIVED	COMPLETED
8	12/31/95	TASK 3.1 - SPE PAPER AND RELEASE OF CO2 SCREENING MODEL	COMPLETED
9	12/31/94	TASK 3.2 - TOPICAL REPORT ON ENVIRONMENTAL CONSTRAINTS	PROJECT 95% COMPLETE
10	12/31/95	TASK 3.3 - TOPICAL REPORT ON FDD DATABASE	PROJECT 10% COMPLETE
11	12/31/97	TASK 3.4 - SPE PAPER ON RESERVOIR CHARACTERIZATION	1ST SPE PAPER PRESENTED

INTERMEDIATE EVENTS	DATE	DESCRIPTION	STATUS
A	12/31/97	TASK 2.1 - FINAL PROJECT REPORT	TO BE COMPLETED DURING 1997
B	12/31/93	TASK 2.2 - UPDATED RESERVOIR MODEL COMPLETED	COMPLETED
C	12/01/94	TASK 2.2 - CONVENTIONAL CORE ANALYZED IN POLK "B" #39 WELL	TO BE PERFORMED DURING 1995
D	04/30/93	TASK 2.3 - 10 WELL WORKOVER PROGRAM COMPLETED	COMPLETED
E	10/01/93	TASK 2.3 - HORIZONTAL CO2 INJECTION WELL DRILLED, POLK "B" #2 W/O PERFORMED	HORIZ. WELL COMPLETE, POLK "B" W/O CANCELLED
F	12/01/94	TASK 2.3 - VERTICAL CO2 INJECTION WELL DRILLED (POLK "B" #39)	TO BE DRILLED DURING 1995
G	06/10/93	TASK 2.5 - PERMIT FOR CO2 PIPELINE RECEIVED FROM ARMY CORPS OF ENGINEERS	COMPLETED
H	06/30/93	TASK 2.5 - HAZARDOUS SUBSTANCE PLAN SUBMITTED TO DOE	COMPLETED
I	12/31/97	TASK 2.5 - FINAL HAZARDOUS SUBSTANCE PLAN SUBMITTED TO DOE	TO BE COMPLETED DURING 1997
J	12/31/94	TASK 3.1 - CO2 SCREENING MODEL FINAL REPORT SUBMITTED TO DOE	COMPLETED
K	12/31/94	TASK 3.3 - FDD DATABASE STUDY IS COMPLETED BY LSU	LSU WORK WILL BE COMPLETED IN SPRING, 1995

11. SIGNATURE OF PARTICIPANT'S PROJECT MANAGER AND DATE

U.S. DEPARTMENT OF ENERGY
MILESTONE SCHEDULE [ ] PLAN [X] SCHEDULE
(ATTACHMENT)

DOE F1332.3 ATTACHMENT
(11-84)

1. TITLE	2. REPORTING PERIOD	3. IDENTIFICATION NUMBER
Post Waterflood CO2 Miscible Flood in a Light Oil Fluvial Dominated Deltaic Reservoir	**Oct. 1, 1994 - Dec. 31, 1994**	**DE-FC22-93BC14960**
4. PARTICIPANT NAME AND ADDRESS **Texaco Exploration and Production Inc.** **400 Poydras St.** **New Orleans, LA 70130**		5. START DATE **June 1, 1993** 6. COMPLETION DATE **December 31, 1997**

MAJOR EVENTS	DATE	DESCRIPTION	STATUS
1	10/15/92	TASK 1.1 - GEOLOGICAL RESERVOIR DESCRIPTION AND LAB TESTS	COMPLETED
2	10/15/92	TASK 1.2 - PHASE 1 RESERVOIR SIMULATION	COMPLETED
3	08/01/93	TASK 2.1 - RECEIVE DOE APPROVAL TO INJECT CO2	COMPLETED
4	08/01/93	TASK 2.2 - RESERVOIR PRESSURE IS RAISED TO 2700 PSI BY WATER INJECTION	COMPLETED
5	08/15/93	TASK 2.3 - CO2 INJECTION AND PRODUCTION FACILITY IS COMPLETED	COMPLETED
6	08/15/93	TASK 2.4 - CO2 PIPELINE IS INSTALLED	COMPLETED
7	08/15/93	TASK 2.5 - NEPA CATEGORICAL EXCLUSION IS RECEIVED	COMPLETED
8	12/31/95	TASK 3.1 - SPE PAPER AND RELEASE OF CO2 SCREENING MODEL	COMPLETED
9	12/31/94	TASK 3.2 - TOPICAL REPORT ON ENVIRONMENTAL CONSTRAINTS	COMPLETED
10	12/31/95	TASK 3.3 - TOPICAL REPORT ON FDD DATABASE	PROJECT 10% COMPLETE
11	12/31/97	TASK 3.4 - SPE PAPER ON RESERVOIR CHARACTERIZATION	TO BE PRESENTED 1997

INTERMEDIATE EVENTS	DATE	DESCRIPTION	STATUS
A	12/31/97	TASK 2.1 - FINAL PROJECT REPORT	TO BE COMPLETED DURING 1997
B	12/31/93	TASK 2.2 - UPDATED RESERVOIR MODEL COMPLETED	COMPLETED
C	12/01/94	TASK 2.2 - CONVENTIONAL CORE ANALYZED IN POLK "B" #39 WELL	TO BE PERFORMED DURING 1995
D	04/30/93	TASK 2.3 - 10 WELL WORKOVER PROGRAM COMPLETED	COMPLETED
E	10/01/93	TASK 2.3 - HORIZONTAL CO2 INJECTION WELL DRILLED, POLK "B" #2 W/O PERFORMED	HORIZ. WELL COMPLETE, POLK "B" W/O CANCELLED
F	12/01/94	TASK 2.3 - VERTICAL CO2 INJECTION WELL DRILLED (POLK "B" #39)	TO BE DRILLED DURING 1995
G	06/10/93	TASK 2.5 - PERMIT FOR CO2 PIPELINE RECEIVED FROM ARMY CORPS OF ENGINEERS	COMPLETED
H	06/30/93	TASK 2.5 - HAZARDOUS SUBSTANCE PLAN SUBMITTED TO DOE	COMPLETED
I	12/31/97	TASK 2.5 - FINAL HAZARDOUS SUBSTANCE PLAN SUBMITTED TO DOE	TO BE COMPLETED DURING 1997
J	12/31/94	TASK 3.1 - CO2 SCREENING MODEL FINAL REPORT SUBMITTED TO DOE	COMPLETED
K	12/31/94	TASK 3.3 - FDD DATABASE STUDY IS COMPLETED BY LSU	LSU WORK WILL BE COMPLETED IN SPRING, 1996
L	04/18/94	TASK 3.5-1ST SPE PAPER PRESENTED-PROJECT IMPLEMENTATION	SUBMITTED @ SPE/DOE SYMPOSIUM

11. SIGNATURE OF PARTICIPANT'S PROJECT MANAGER AND DATE

FINANCIAL STATUS REPORT
(Short Form)

1. Federal Agency and Organizational Element to Which Report is submitted	2. Federal Grant or Other Identifying Number Assigned By Federal Agency	OMB Approval No. 0348-0039	Page	of
U. S. Department of Energy	DE-FC22-93BC14960		1	1 pages

3. Recipient Organization (Name and complete address, including ZIP code)

Texaco Exploration and Production Inc. 400 Poydras St. New Orleans, LA 70130

4. Employer Identification Number	5. Recipient Account Number or Identifying Number	6. Final Report [ ] Yes [X] No	7. Basis [X] Cash [X] Accrual
51-0265713	323037151		

8. Funding/Grant Period (See Instructions) From: (Month, Day, Year)	To: (Month, Day, Year)	9. Period Covered by this Report From: (Month, Day, Year)	To: (Month, Day, Year)
June 1, 1993	December 31, 1994	10-01-93	12-31-93

10 Transactions	I Previously Reported	II This Period	III Cumulative
a. Total outlays	$11,586,311.42	$1,463,142.67	$ 13,049,454.09
b. Recipient share of outlays (64.39%)	$7,460,425.93	$942,117.57	8,402,543.50
c. Federal share of outlays (35.61%)	$4,125,885.49	$521,025.10	4,646,910.59
d. Total unliquidated obligations	0.00	0.00	0.00
e. Recipient share of unliquidated obligations	0.00	0.00	0.00
f. Federal share of unliquidated obligations	0.00	0.00	0.00
g. Total Federal share (Sum of lines c and f)	$4,125,885.49	$521,025.10	4,646,910.59
h. Total Federal funds authorized for this funding period	$5,539,225.00	($521,025.10)	5,539,225.00
i. Unobligated balance of Federal funds (Line h minus line g)	$1,413,339.51	3,017,968.91	892,314.41

11. Indirect Expense	a. Type of Rate (Place "X" in appropriate box) [X] Provisional	[ ] Predetermined	[ ] Final	[ ] Fixed
(Labor)	b. Rate 108.84%	c. Base $ 71,972.36	d. Total Amount $ 78,334.71	e. Federal Share $ 27,894.99

12. Remarks: Attach any explanations deemed necessary or information required by Federal sponsoring agency in compliance with governing legislation

13. Certification: I certify to the best of my knowledge and belief that this report is correct and complete and that all outlays and unliquidated obligations are for the purposes set forth in the award documents.

Typed or Printed Name and Title	Telephone (Area code, number and extension)
Darrell Davis – Project Manager	(504) 593-4567
Signature of Authorized Certifying Official	**Date Report Submitted**
Darrell Davis	January 15, 1994

Standard Form 269A (REV 4-88)
Prescribed by OMB Circulars A-102 and A-110

Previous Editions not Usable

FINANCIAL STATUS REPORT
(Short Form)

1. Federal Agency and Organizational Element to Which Report is submitted	2. Federal Grant or Other Identifying Number Assigned By Federal Agency	OMB Approval No. 0348-0039	Page	of
U. S. Department of Energy	DE-FC22-93BC14960		1	1 pages

3. Reciepient Organization (Name and complete address, including ZIP code)

Texaco Exploration and Production Inc. 400 Poydras St. New Orleans, LA 70130

4. Employer Identification Number	5. Recipient Account Number or Identifying Number	6. Final Report	7. Basis
51-0265713	323037151	[ ] Yes [X] No	[X] Cash [X] Accrual

8. Funding/Grant Period (See Instuctions) From: (Month, Day, Year)	To: (Month, Day, Year)	9. Period Covered by this Report From: (Month, Day, Year)	To: (Month, Day, Year)
June 1, 1993	December 31, 1994	01-01-94	03-31-94

10 Transactions	I Previously Reported	II This Period	III Cumulative
a. Total outlays	$13,049,454.09	$969,681.10	$ 14,019,135.19
b. Recipient share of outlays (64.39%)	$8,402,543.50	$624,377.65	$ 9,026,921.15
c. Federal share of outlays (35.61%)	$4,646,910.59	$345,303.45	$ 4,992,214.04
d. Total unliquidated obligations	0.00	0.00	0.00
e. Recipient share of unliquidated obligations	0.00	0.00	0.00
f. Federal share of unliquidated obligations	0.00	0.00	0.00
g. Total Federal share (Sum of lines c and f)	$4,646,910.59	$345,303.45	$ 4,992,214.04
h. Total Federal funds authorized for this funding period	$5,539,225.00	$0.00	$ 5,539,225.00
i. Unobligated balance of Federal funds (Line h minus line g)	$892,314.41	($345,303.45)	$ 547,010.96

11. Indirect Expense (Labor)	a. Type of Rate (Place "X" in appropriate box) [X] Provisional [ ] Predetermined [ ] Final [ ] Fixed			
	b. Rate	c. Base	d. Total Amount	e. Federal Share
	108.84%	$ 85,156.35	$ 92,684.17	$ 33,004.83

12. Remarks: Attach any explanations deemed necessary or information required by Federal sponsoring agency in compliance with governing legislation

13. Certification: I certify to the best of my knowledge and belief that this report is correct and complete and that all outlays and unliquidated obligations are for the purposes set forth in the award documents.

Typed or Printed Name and Title	Telephone (Area code, number and extension)
Sami Bou-Mikael – Project Manager	(504) 593-4565
Signature of Authorized Certifying Official	**Date Report Submitted**
Sami Bou-Mikael 4/29/94	April 15, 1994

Standard Form 269A (REV 4-88)
Prescribed by OMB Circulars A-102 and A-110

Previous Editions not Usable

FINANCIAL STATUS REPORT
(Short Form)

1. Federal Agency and Organizational Element to Which Report is submitted	2. Federal Grant or Other Identifying Number Assigned By Federal Agency	OMB Approval No. 0348-0039	Page	of
U. S. Department of Energy	DE-FC22-93BC14960		1	1 pages

3. Reciepient Organization (Name and complete address, including ZIP code)

Texaco Exploration and Production Inc. 400 Poydras St. New Orleans, LA 70130

4. Employer Identification Number	5. Recipient Account Number or Identifying Number	6. Final Report [ ] Yes [X] No	7. Basis [X] Cash [X] Accrual
51-0265713	323037151		

8. Funding/Grant Period (See Instuctions) From: (Month, Day, Year)	To: (Month, Day, Year)	9. Period Covered by this Report From: (Month, Day, Year)	To: (Month, Day, Year)
June 1, 1993	December 31, 1994	04-01-94	06-30-94

10 Transactions	I Previously Reported	II This Period	III Cumulative
a. Total outlays	$14,019,135.19	$1,942,528.41	$ 15,961,663.60
b. Recipient share of outlays (64.39%)	$9,026,921.15	$1,250,794.04	$ 10,277,715.19
c. Federal share of outlays (35.61%)	$4,992,214.04	$691,734.37	$ 5,683,948.41
d. Total unliquidated obligations	0.00	0.00	0.00
e. Recipient share of unliquidated obligations	0.00	0.00	0.00
f. Federal share of unliquidated obligations	0.00	0.00	0.00
g. Total Federal share (Sum of lines c and f)	$4,992,214.04	$691,734.37	$ 4,992,214.04
h. Total Federal funds authorized for this funding period	$5,539,225.00	$0.00	$ 5,539,225.00
i. Unobligated balance of Federal funds (Line h minus line g)	$547,010.96	($691,734.37)	$ 0.00

11. Indirect Expense (Labor)	a. Type of Rate (Place "X" in appropriate box) [X] Provisional [ ] Predetermined [ ] Final [ ] Fixed			
	b. Rate 108.84%	c. Base $ 53,334.98	d. Total Amount $ 58,049.79	e. Federal Share $ 20,671.53

12. Remarks: Attach any explanations deemed necessary or information required by Federal sponsoring agency in compliance with governing legislation

13. Certification: I certify to the best of my knowledge and belief that this report is correct and complete and that all outlays and unliquidated obligations are for the purposes set forth in the award documents.

Typed or Printed Name and Title	Telephone (Area code, number and extension)
Sami Bou-Mikael – Project Manager	(504) 593-4565
Signature of Authorized Certifying Official	Date Report Submitted: July 15, 1994

Standard Form 269A (REV 4-88)
Prescribed by OMB Circulars A-102 and A-110

Previous Editions not Usable

FINANCIAL STATUS REPORT
(Short Form)

leral Agency and Organizational Element Which Report is submitted	2. Federal Grant or Other Identifying Number Assigned By Federal Agency	OMB Approval No. 0348-0039	Page	of
S. Department of Energy	DE-FC22-93BC14960		1	1 pages

ciepient Organization (Name and complete address, including ZIP code)

xaco Exploration and Production Inc. 400 Poydras St. New Orleans, LA 70130

nployer Identification Number	5. Recipient Account Number or Identifying Number	6. Final Report [ ] Yes [X] No	7. Basis [X] Cash [X] Accrual
-0265713	323037151		

nding/Grant Period (See Instuctions) om: (Month, Day, Year)	To: (Month, Day, Year)	9. Period Covered by this Report From: (Month, Day, Year)	To: (Month, Day, Year)
ne 1, 1993	December 31, 1994	07-01-94	09-30-94

ransactions	I Previously Reported	II This Period	III Cumulative
otal outlays	$15,961,663.60	$590,273.78	$ 16,551,935.38
ecipient share of outlays (64.39%)	$10,277,715.19	$380,077.29	$ 10,657,791.19
ederal share of outlays (35.61%)	$5,683,948.41	$210,196.49	$ 5,894,144.19
otal unliquidated obligations	0.00	0.00	0.00
ecipient share of unliquidated obligations	0.00	0.00	0.00
ederal share of unliquidated obligations	0.00	0.00	0.00
otal Federal share (Sum of lines c and f)	$5,683,948.41	$210,196.49	$ 5,894,144.19
otal Federal funds authorized for this funding period	$5,539,225.00	$0.00	$ 5,539,225.00
nobligated balance of Federal funds (Line h minus line g)	($144,723.41)	($210,196.49)	$ 0.00

Indirect Expense (Labor)	a. Type of Rate (Place "X" in appropriate box) [X] Provisional [ ] Predetermined [ ] Final [ ] Fixed			
	b. Rate 108.84%	c. Base $ 48,814.83	d. Total Amount $ 53,130.06	e. Federal Share $ 18,919.61

Remarks: Attach any explanations deemed necessary or information required by Federal sponsoring agency in compliance with governing legislation

Certification: I certify to the best of my knowledge and belief that this report is correct and complete and that all outlays and unliquidated obligations are for the purposes set forth in the award documents.

ped or Printed Name and Title	Telephone (Area code, number and extension)
Sami Bou-Mikael - Project Manager	(504) 593-4565
nature of Authorized Certifying Official	Date Report Submitted
	October 14, 1994

Standard Form 269A (REV 4-88)
Prescribed by OMB Circulars A-102 and A-110

rvious Editions not Usable

FINANCIAL STATUS REPORT
(Short Form)

1. Federal Agency and Organizational Element to Which Report is submitted	2. Federal Grant or Other Identifying Number Assigned By Federal Agency	OMB Approval No. 0348-0039	Page	of
U. S. Department of Energy	DE-FC22-93BC14960		1	1 pages

3. Reciepient Organization (Name and complete address, including ZIP code)

Texaco Exploration and Production Inc. 400 Poydras St. New Orleans, LA 70130

4. Employer Identification Number	5. Recipient Account Number or Identifying Number	6. Final Report	7. Basis
51-0265713	323037151	[ ] Yes [X] No	[X] Cash [X] Accrual

8. Funding/Grant Period (See Instructions) From: (Month, Day, Year)	To: (Month, Day, Year)	9. Period Covered by this Report From: (Month, Day, Year)	To: (Month, Day, Year)
June 1, 1993	December 31, 1994	10-01-94	12-31-94

10 Transactions	I Previously Reported	II This Period	III Cumulative
a. Total outlays	$16,551,935.38	$1,003,494.99	$ 17,555,430.37
b. Recipient share of outlays (64.39%)	$10,657,791.19	$646,150.42	$ 11,303,941.62
c. Federal share of outlays (35.61%)	$5,894,144.19	$357,344.57	$ 6,251,488.75
d. Total unliquidated obligations	0.00	0.00	0.00
e. Recipient share of unliquidated obligations	0.00	0.00	0.00
f. Federal share of unliquidated obligations	0.00	0.00	0.00
g. Total Federal share (Sum of lines c and f)	$5,894,144.19	$357,344.57	$ 6,251,488.75
h. Total Federal funds authorized for this funding period	$5,539,225.00	$0.00	$ 5,539,225.00
i. Unobligated balance of Federal funds (Line h minus line g)	($354,919.19)	($357,344.57)	$ 0.00

11. Indirect Expense	a. Type of Rate (Place "X" in appropriate box)			
	[X] Provisional	[ ] Predetermined	[ ] Final	[ ] Fixed
(Labor)	b. Rate 108.84%	c. Base $ 32,907.26	d. Total Amount $ 35,816.26	e. Federal Share $ 12,754.17

12. Remarks: Attach any explanations deemed necessary or information required by Federal sponsoring agency in compliance with governing legislation

13. Certification: I certify to the best of my knowledge and belief that this report is correct and complete and that all outlays and unliquidated obligations are for the purposes set forth in the award documents.

Typed or Printed Name and Title	Telephone (Area code, number and extension)
Sami Bou-Mikael - Project Manager	(504) 593-4565
Signature of Authorized Certifying Official	Date Report Submitted: January 17, 1995

Standard Form 269A (REV 4-88)
Prescribed by OMB Circulars A-102 and A-110

Previous Editions not Usable

Approved by Office of Management and Budget No 80-R0182

FEDERAL CASH TRANSACTIONS REPORT

(See instructions on the back. If report is for more than one grant or assistance agreement, attach completed Standard Form 272-A.)

1. Federal sponsoring agency and organizational element to which this report is submitted: U. S. Department of Energy

2. RECIPIENT ORGANIZATION

Name: Texaco Exploration and Production Inc.

Number and Street: 400 Poydras St.

City, State and Zip Code: New Orleans, Louisiana 70130

4. Federal grant or other identification number: DE-FC22-93BC14960

5. Recipient's account number or identifying number: 323037151

6. Letter of credit number: NA

7. Last payment voucher number: –

Give total number for this period

8. Payment Vouchers credited to your account: –

9. Treasury checks received (whether or not deposited): 1

10. PERIOD COVERED BY THIS REPORT

FROM (month,day,year): 10/01/93

TO (month,day,year): 12/31/93

3. FEDERAL EMPLOYER IDENTIFICATION NO> 51-0265713

11. STATUS OF FEDERAL CASH	a. Cash on hand beginning of reporting period	$ 0.00
	b. Letter of credit withdrawals	0.00
	c. Treasury check payments	1,036,340.46
	d. Total receipts (Sum of lines b and c)	1,036,340.46
	e. Total cash available (Sum of lines a and d)	1,036,340.46
	f. Gross disbursements	1,036,340.46
	g. Federal share of program income	0.00
	h. Net disbursements (Line f minus line g)	1,036,340.46
	i. Adjustments of prior periods	0.00
	j. Cash on hand end of period	$ 0.00
12. THE AMOUNT ON LINE j. REPRESENTING	13. OTHER INFORMATION	
	k. Interest income	$ 0.00
	l. Advances to subgrantees or subcontractors	$ 0.00

14. REMARKS

15. CERTIFICATION

AUTHORIZED CERTIFYING OFFICIAL

SIGNATURE: Darrell Davis

DATE REPORT SUBMITTED: 01/15/94

TYPED OR PRINTED NAME AND TITLE: Darrell Davis – Project Manager

TELEPHONE (Area Code, Number, Extension): (504) 593-4567

THIS SPACE FOR PRIVATE USE

272-102

STANDARD FORM 272 (7-76)

Prescribed by Office of Management and Budget Cir. No. A-110

FEDERAL CASH TRANSACTIONS REPORT

(See instructions on the back. If report is for more than one grant or assistance agreement, attach completed Standard Form 272-A.)

Approved by Office of Management and Budget No 80-80182

1. Federal sponsoring agency and organizational element to which this report is submitted: U. S. Department of Energy

2. RECIPIENT ORGANIZATION

Name: Texaco Exploration and Production Inc.

Number and Street: 400 Poydras St.

City, State and Zip Code: New Orleans, Louisiana 70130

4. Federal grant or other identification number: DE-FC22-93BC14960

5. Recipient's account number or identifying number: 323037151

6. Letter of credit number: NA

7. Last payment voucher number: –

Give total number for this period

8. Payment Vouchers credited to your account: –

9. Treasury checks received (whether or not deposited): 0

10. PERIOD COVERED BY THIS REPORT

FROM (month,day,year): 01/01/94

TO (month,day,year): 03/31/94

3. FEDERAL EMPLOYER IDENTIFICATION NO> 51-0265713

11. STATUS OF FEDERAL CASH	a. Cash on hand beginning of reporting period	$ 0.00
	b. Letter of credit withdrawals	0.00
	c. Treasury check payments	0.00
	d. Total receipts (Sum of lines b and c)	0.00
	e. Total cash available (Sum of lines a and d)	0.00
	f. Gross disbursements	0.00
	g. Federal share of program income	0.00
	h. Net disbursements (Line f minus line g)	0.00
	i. Adjustments of prior periods	0.00
	j. Cash on hand end of period	$ 0.00
12. THE AMOUNT ON LINE j. REPRESENTING	13. OTHER INFORMATION	
	k. Interest income	$ 0.00
	l. Advances to subgrantees or subcontractors	$ 0.00

14. REMARKS

15. CERTIFICATION

AUTHORIZED CERTIFYING OFFICIAL	SIGNATURE: Sami Bou-Mikael 4/29/94	DATE REPORT SUBMITTED: 04/15/94
	TYPED OR PRINTED NAME AND TITLE: Sami Bou-Mikael – Project Manager	TELEPHONE (Area Code, Number, Extension): (504) 593-4565

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STANDARD FORM 272 (7-76)

Prescribed by Office of Management and Budget

Cir. No. A-110

Approved by Office of Management and Budget No 80-80182

FEDERAL CASH TRANSACTIONS REPORT

(See instructions on the back. If report is for more than one grant or assistance agreement, attach completed Standard Form 272-A.)

1. Federal sponsoring agency and organizational element to which this report is submitted: U. S. Department of Energy

2. RECIPIENT ORGANIZATION

Name: Texaco Exploration and Production Inc.

Number and Street: 400 Poydras St.

City, State and Zip Code: New Orleans, Louisiana 70130

4. Federal grant or other identification number: DE-FC22-93BC14960

5. Recipient's account number or identifying number: 323037151

6. Letter of credit number: NA

7. Last payment voucher number: –

Give total number for this period

8. Payment Vouchers credited to your account: –

9. Treasury checks received (whether or not deposited): 0

10. PERIOD COVERED BY THIS REPORT

FROM (month,day,year): 04/01/94

TO (month,day,year): 06/30/94

3. FEDERAL EMPLOYER IDENTIFICATION NO> 51-0265713

11. STATUS OF FEDERAL CASH	a. Cash on hand beginning of reporting period	$ 0.00
	b. Letter of credit withdrawals	0.00
	c. Treasury check payments	1,031850.89
	d. Total receipts (Sum of lines b and c)	1,031850.89
	e. Total cash available (Sum of lines a and d)	1,031850.89
	f. Gross disbursements	1,031850.89
	g. Federal share of program income	0.00
	h. Net disbursements (Line f minus line g)	1,031850.89
	i. Adjustments of prior periods	0.00
	j. Cash on hand end of period	$ 0.00
12. THE AMOUNT ON LINE j. REPRESENTING	13. OTHER INFORMATION	
	k. Interest income	$ 0.00
	l. Advances to subgrantees or subcontractors	$ 0.00

14. REMARKS

15. CERTIFICATION

AUTHORIZED CERTIFYING OFFICIAL	SIGNATURE	DATE REPORT SUBMITTED: 07/15/94
	TYPED OR PRINTED NAME AND TITLE: Sami Bou-Mikael – Project Manager	TELEPHONE (Area Code, Number, Extension): (504) 593-4565

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STANDARD FORM 272 (7-76)
Prescribed by Office of Management and Budget
Cir. No. A-110

Approved by Office of Management and Budget No 80-80182

DERAL CASH TRANSACTIONS REPORT

nstructions on the back. If report is for more than one grant or ance agreement, attach completed Standard Form 272-A.)

1. Federal sponsoring agency and organizational element to which this report is submitted: U. S. Department of Energy

ECIPIENT ORGANIZATION

Texaco Exploration and Production Inc.

er: 400 Poydras St.

treet

New Orleans, Louisiana 70130

State

ip Code:

4. Federal grant or other identification number: DE-FC22-93BC14960

5. Recipient's account number or identifying number: 323037151

6. Letter of credit number: NA

7. Last payment voucher number: -

Give total number for this period

8. Payment Vouchers credited to your account: -

9. Treasury checks received (whether or not deposited): 0

10. PERIOD COVERED BY THIS REPORT

FROM (month,day,year): 07/01/94

TO (month,day,year): 09/30/94

FEDERAL EMPLOYER IDENTIFICATION NO> 51-0265713

.STATUS OF FEDERAL CASH	a. Cash on hand beginning of reporting period	$ 0.00
	b. Letter of credit withdrawals	0.00
	c. Treasury check payments	0.00
	d. Total receipts (Sum of lines b and c)	0.00
	e. Total cash available (Sum of lines a and d)	0.00
	f. Gross disbursements	0.00
	g. Federal share of program income	0.00
	h. Net disbursements (Line f minus line g)	0.00
	i. Adjustments of prior periods	0.00
	j. Cash on hand end of period	$ 0.00
. THE AMOUNT ON LINE j. REPRESENTING	13. OTHER INFORMATION	
	k. Interest income	$ 0.00
	l. Advances to subgrantees or subcontractors	$ 0.00

. REMARKS

). CERTIFICATION

AUTHORIZED CERTIFYING OFFICIAL	SIGNATURE	DATE REPORT SUBMITTED: 10/14/94
	TYPED OR PRINTED NAME AND TITLE: Sami Bou-Mikael - Project Manager	TELEPHONE (Area Code, Number, Extension): (504) 593-4565

IIS SPACE FOR PRIVATE USE

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STANDARD FORM 272 (7-76)

Prescribed by Office of Management and Budget

Cir. No. A-110

Approved by Office of Management and Budget No 80-80182

FEDERAL CASH TRANSACTIONS REPORT

(See instructions on the back. If report is for more than one grant or assistance agreement, attach completed Standard Form 272-A.)

1. Federal sponsoring agency and organizational element to which this report is submitted **U. S. Department of Energy**

2. RECIPIENT ORGANIZATION

Name **Texaco Exploration and Production Inc.**

Number and Street **400 Poydras St.**

New Orleans, Louisiana 70130

City, State and Zip Code:

4. Federal grant or other identification number **DE-FC22-93BC14960**

5. Recipient's account number or identifying number **323037151**

6. Letter of credit number **NA**

7. Last payment voucher number **-**

Give total number for this period

8. Payment Vouchers credited to your account **-**

9. Treasury checks received (whether or not deposited) **0**

10. PERIOD COVERED BY THIS REPORT

FROM (month,day,year) **10/01/94**

TO (month,day,year) **12/31/94**

3. FEDERAL EMPLOYER IDENTIFICATION NO> **51-0265713**

11. STATUS OF FEDERAL CASH	a. Cash on hand beginning of reporting period	$ 0.00
	b. Letter of credit withdrawals	0.00
	c. Treasury check payments	0.00
	d. Total receipts (Sum of lines b and c)	0.00
	e. Total cash available (Sum of lines a and d)	0.00
	f. Gross disbursements	0.00
	g. Federal share of program income	0.00
	h. Net disbursements (Line f minus line g)	0.00
	i. Adjustments of prior periods	0.00
	j. Cash on hand end of period	$ 0.00
12. THE AMOUNT ON LINE j. REPRESENTING	13. OTHER INFORMATION	
	k. Interest income	$ 0.00
	l. Advances to subgrantees or subcontractors	$ 0.00

14. REMARKS

15. CERTIFICATION

AUTHORIZED CERTIFYING OFFICIAL	SIGNATURE	DATE REPORT SUBMITTED **01/17/95**
	TYPED OR PRINTED NAME AND TITLE **Sami Bou-Mikael - Project Manager**	TELEPHONE (Area Code, Number, Extension) **(504) 593-4565**

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STANDARD FORM 272 (7-76)

Prescribed by Office of Management and Budget

Cir. No. A-110

ANNUAL REPORT
1993

"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 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

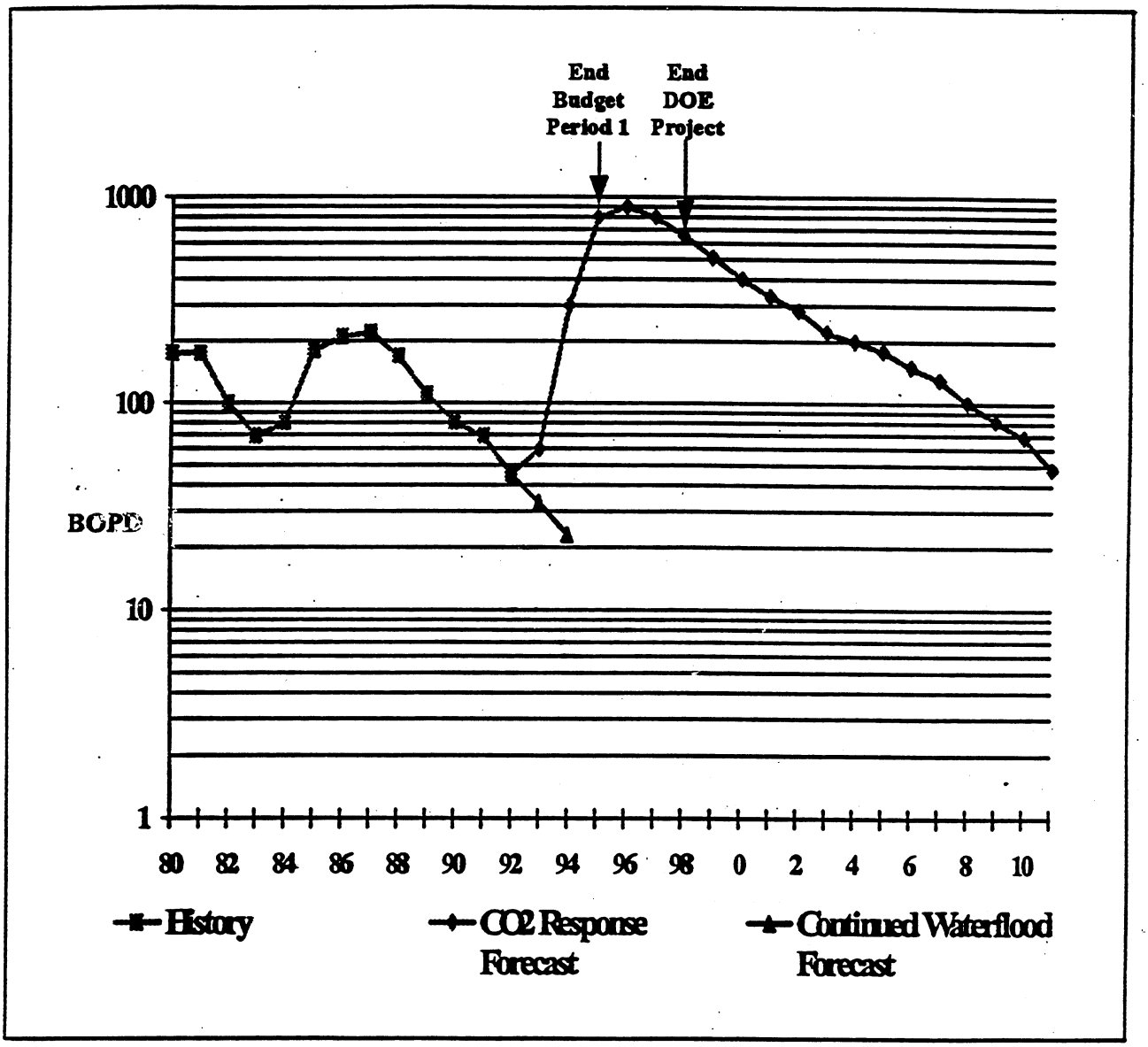


Figure 1-5

Short Term Production Forecast

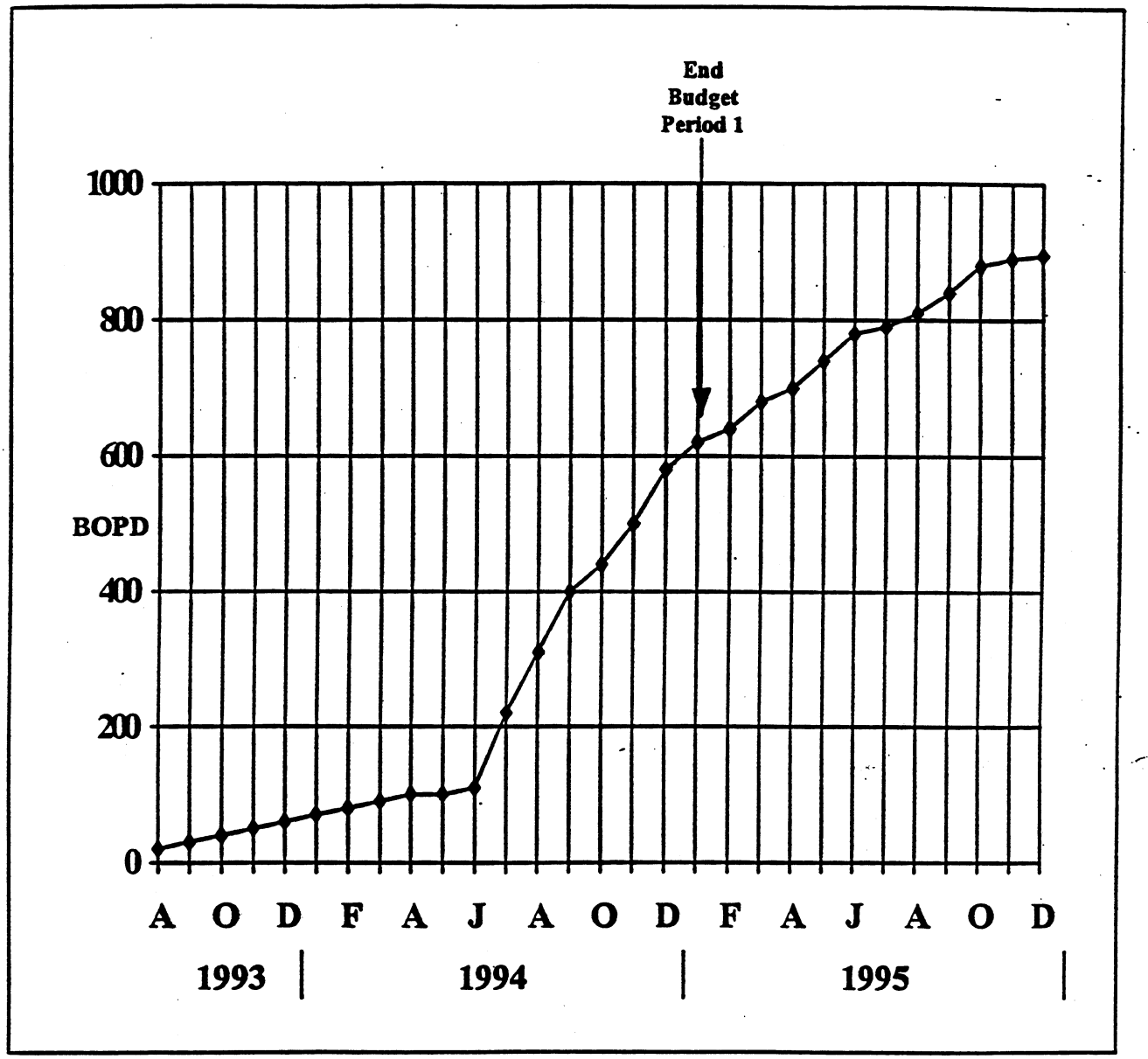


Figure 1-6

CO_2 Production/Injection Forecast

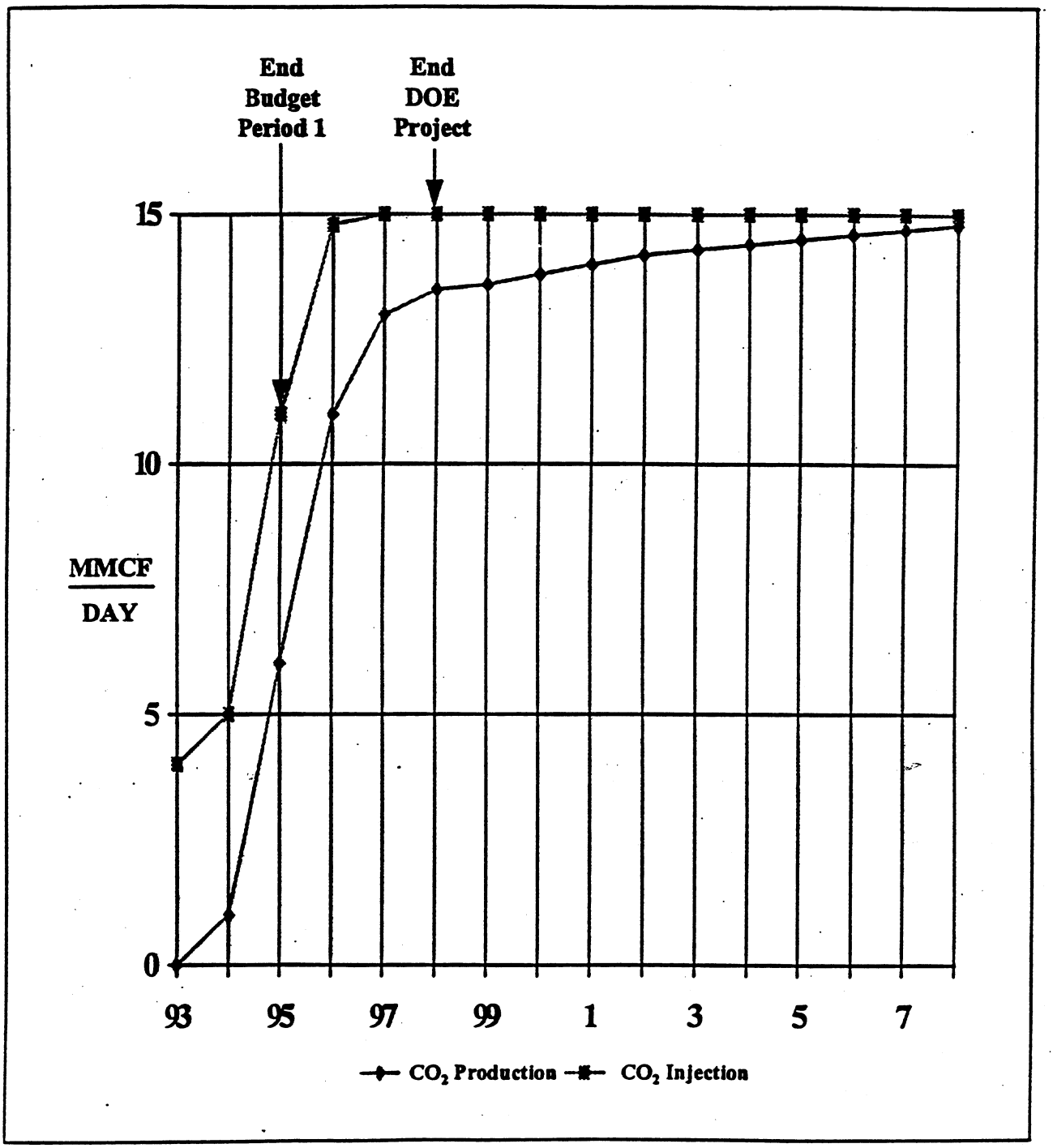
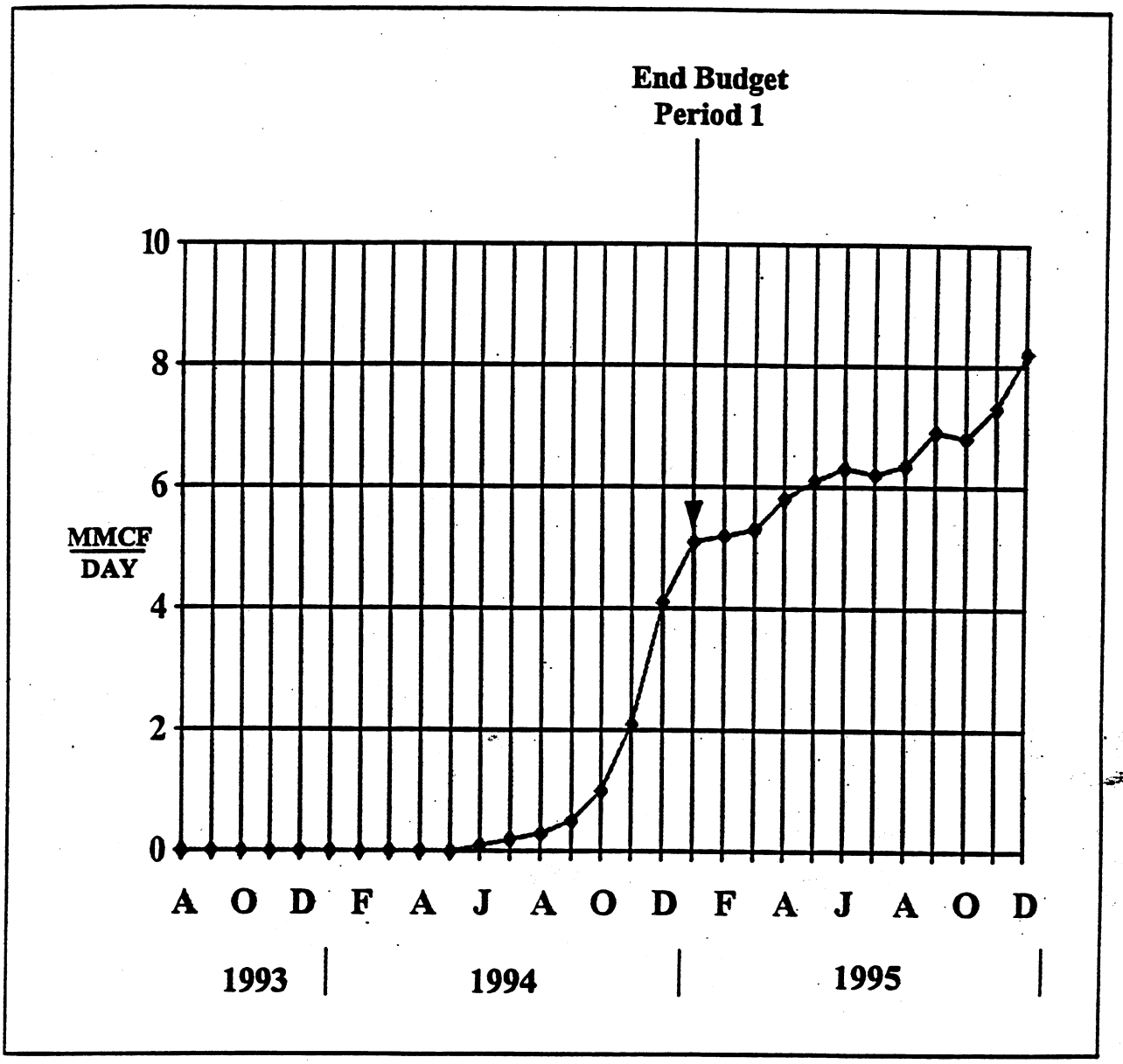
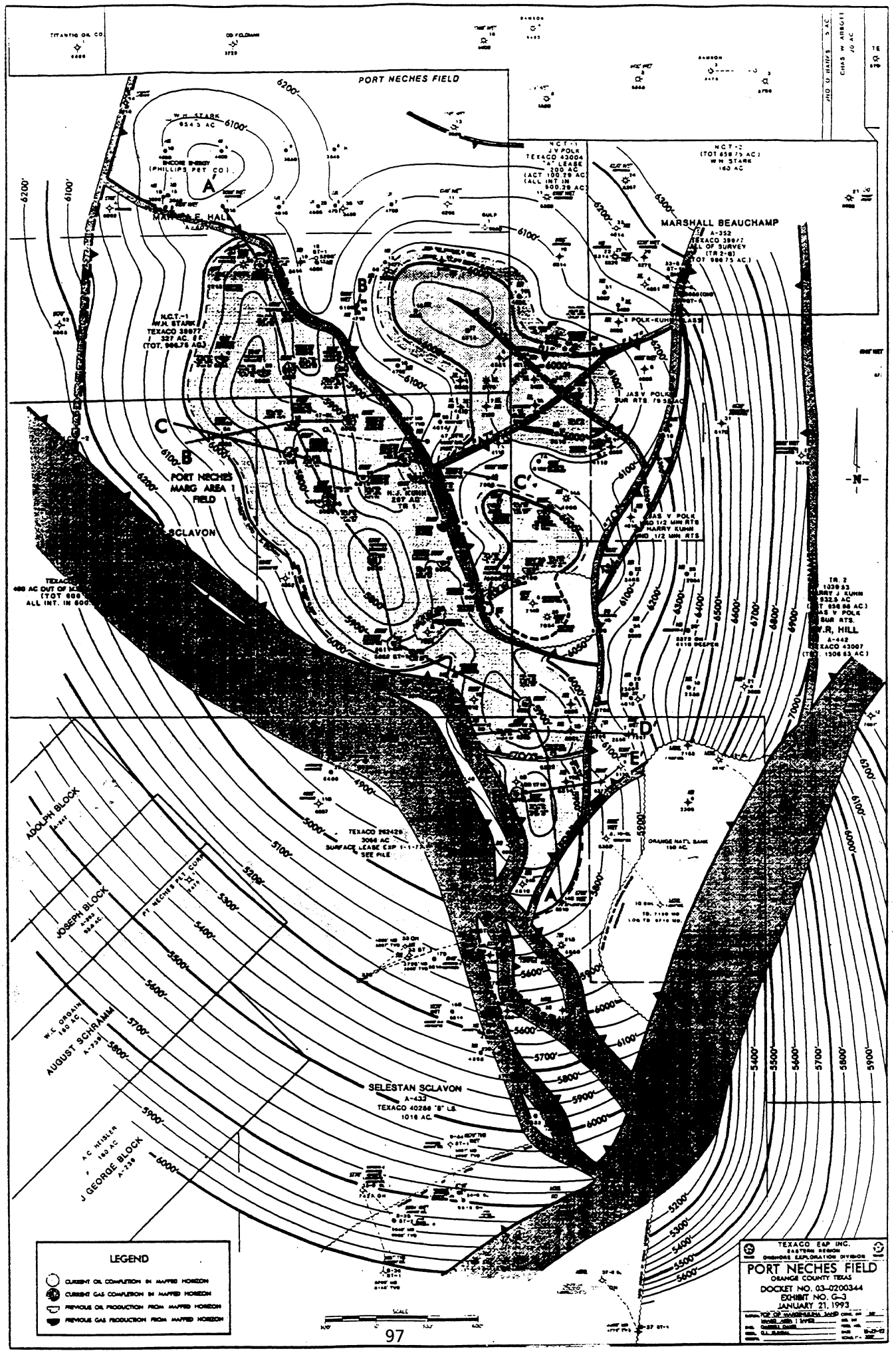


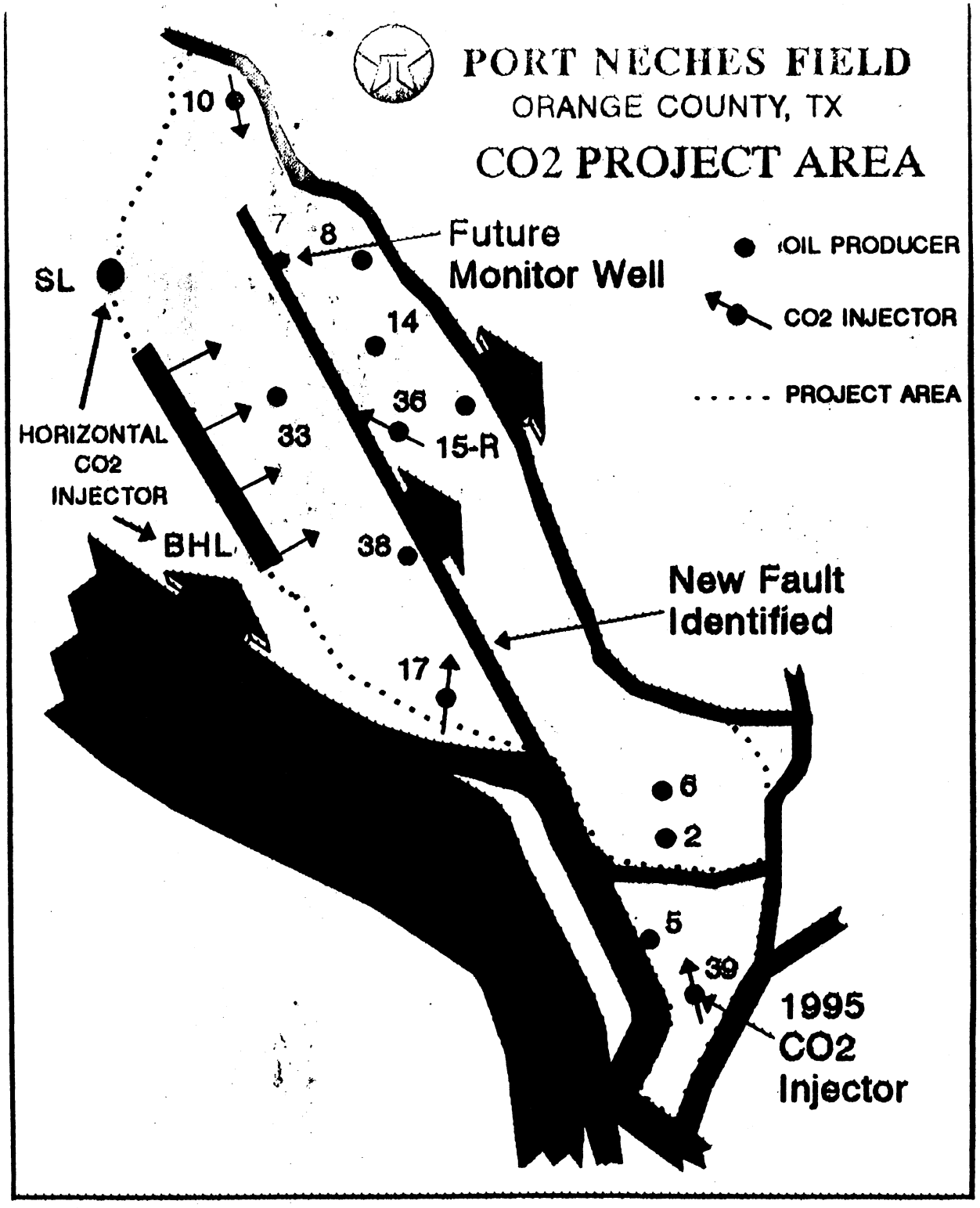
Figure 1-7

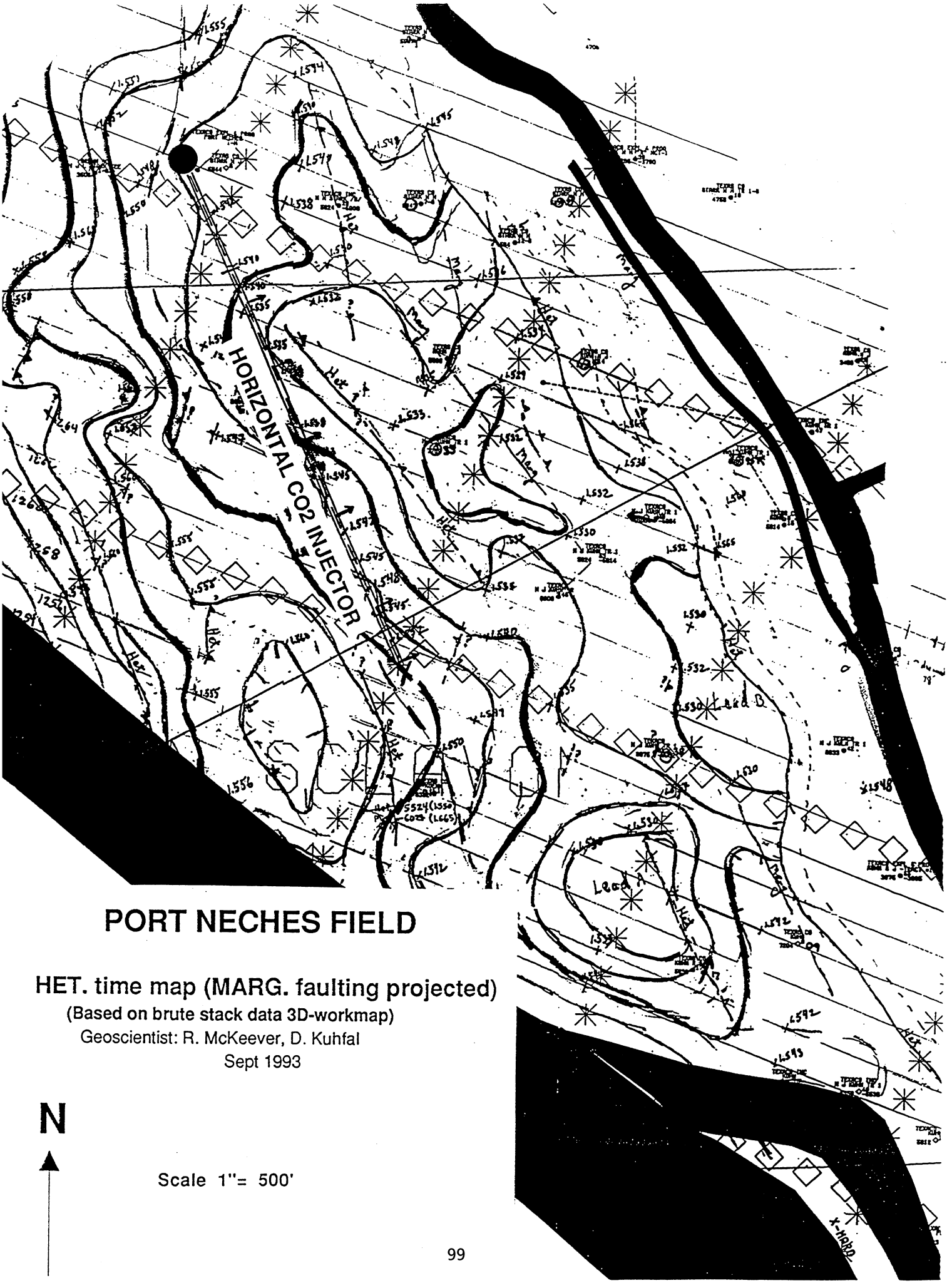
Short Term CO_2 Production Forecast



RESERVOIR DESCRIPTION


PORT NECHES FIELD
MARSHALL BEAUCHAMP
PORT NECHES MARG AREA 1 FIELD
SCLAVON
ADOLPH BLOCK
JOSEPH BLOCK
AUGUST SCHRAMM
J GEORGE BLOCK
SELESTAN SCLAVON
A-433
TEXACO 40288 "B" LS
1016 AC
TEXACO 262429
3066 AC
SURFACE LEASE EXP 1-1-73
SEE FILE
W.R. HILL
A-443
TEXACO 43007
LEGEND
CURRENT OIL COMPLETION IN MAPPED HORIZON
CURRENT GAS COMPLETION IN MAPPED HORIZON
PREVIOUS OIL PRODUCTION FROM MAPPED HORIZON
PREVIOUS GAS PRODUCTION FROM MAPPED HORIZON
SCALE
TEXACO E&P INC.
EASTERN REGION
ONSHORE EXPLORATION DIVISION
PORT NECHES FIELD
ORANGE COUNTY TEXAS
DOCKET NO. 03-0200344
EXHIBIT NO. G-3
JANUARY 21, 1993


PORT NECHES FIELD
ORANGE COUNTY, TX
CO2 PROJECT AREA
OIL PRODUCER
CO2 INJECTOR
PROJECT AREA
Future Monitor Well
New Fault Identified
1995 CO2 Injector
HORIZONTAL CO2 INJECTOR
SL
BHL
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)

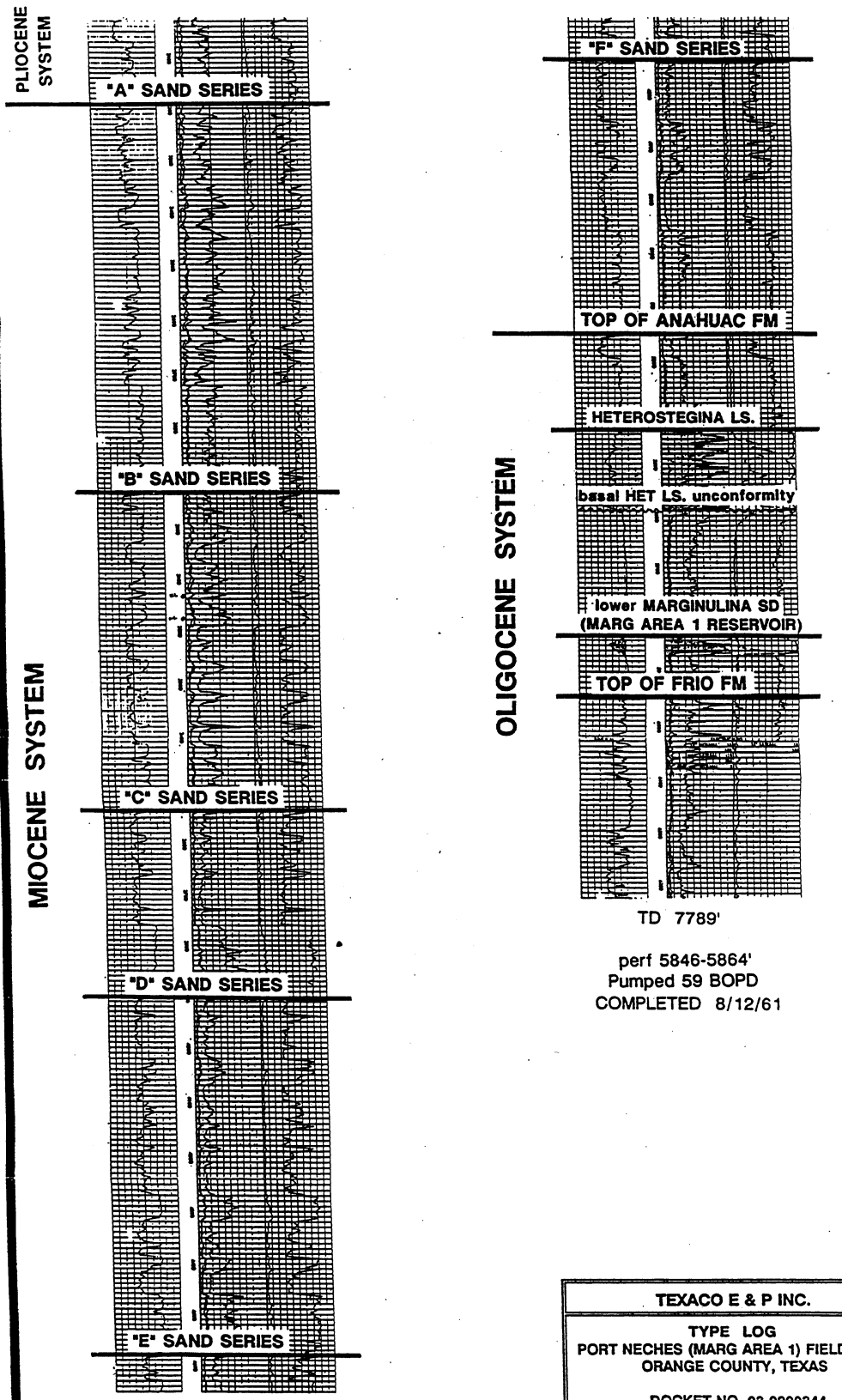
Geoscientist: R. McKeever, D. Kuhfal

Sept 1993

N

Scale 1"= 500'

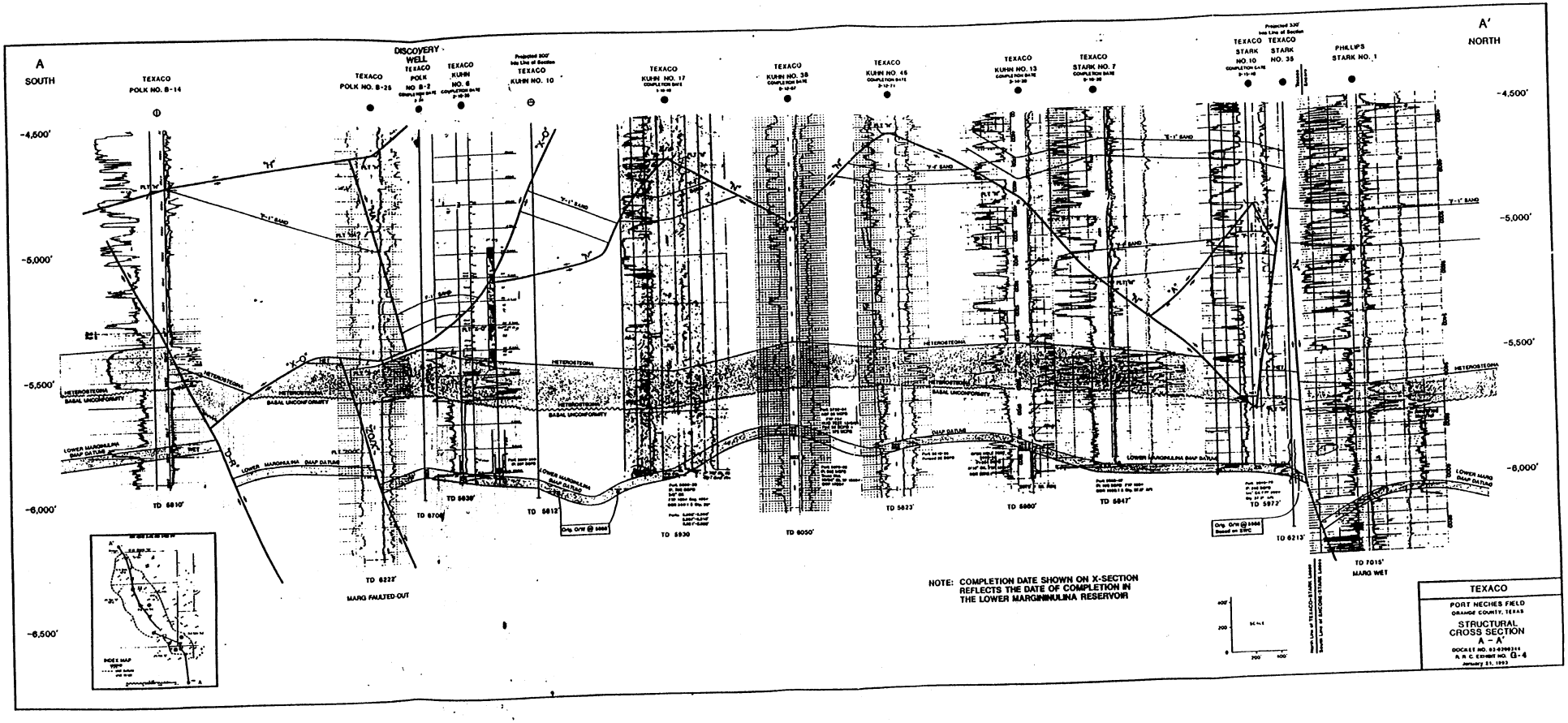
TYPE LOG
TEXACO NO. 33 KUHN

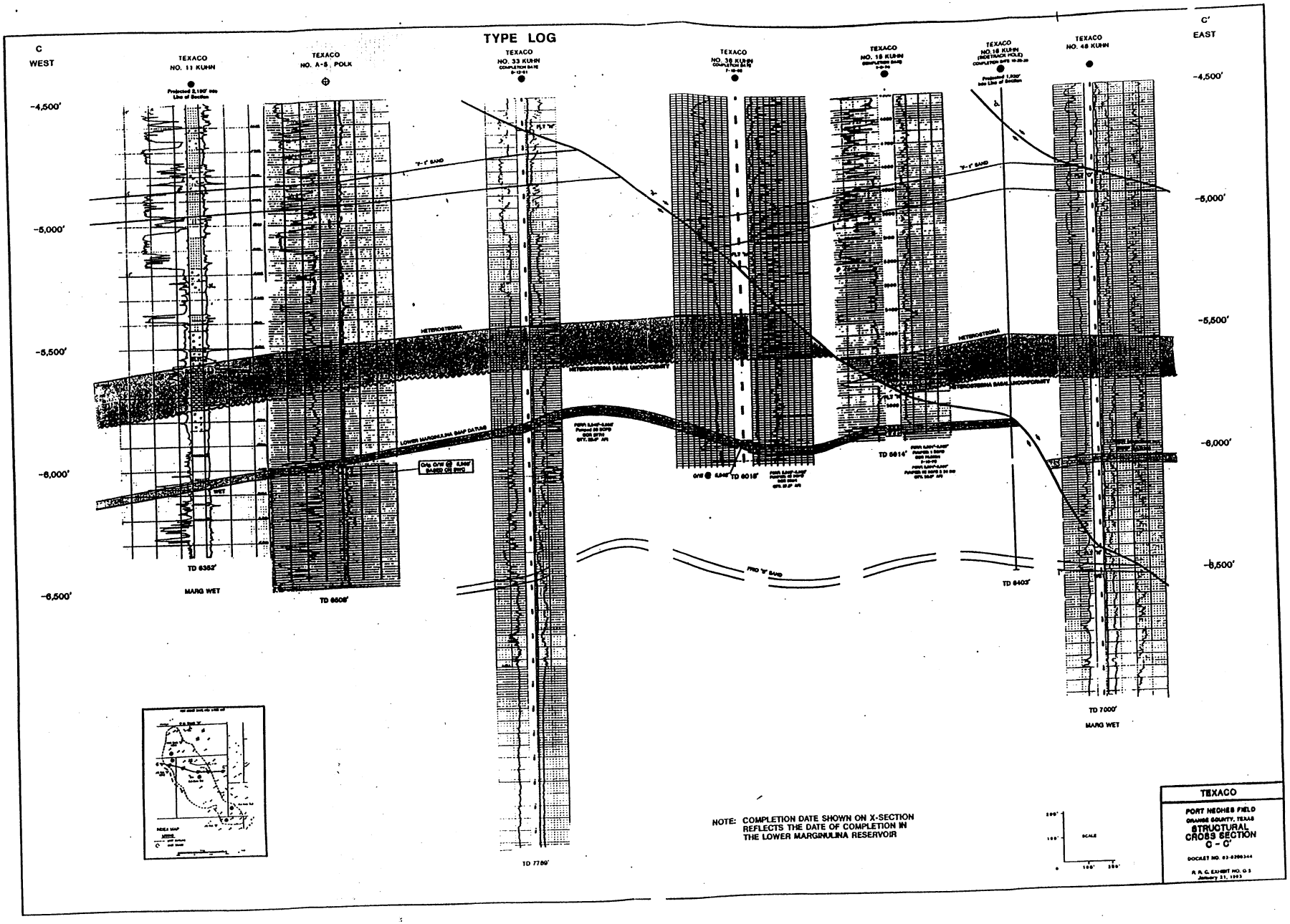


TD 7789'

perf 5846-5864'
Pumped 59 BOPD
COMPLETED 8/12/61

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
TEXACO POLK NO. B-14
TEXACO POLK NO. B-25
DISCOVERY WELL
TEXACO POLK NO. B-2
TEXACO KUHN NO. 6
TEXACO KUHN NO. 10
TEXACO KUHN NO. 17
TEXACO KUHN NO. 38
TEXACO KUHN NO. 45
TEXACO KUHN NO. 13
TEXACO STARK NO. 7
TEXACO STARK NO. 10
TEXACO STARK NO. 35
PHILLIPS STARK NO. 1
-4,500'
-5,000'
-5,500'
-6,000'
-6,500'
HETEROSTEGINA
BASAL UNCONFORMITY
LOWER MARGINULINA
MARG WET
TD 6810'
TD 6222'
MARG FAULTED-OUT
TD 6839'
TD 6706'
TD 6812'
TD 5930'
TD 6050'
TD 5823'
TD 5860'
TD 5847'
TD 5972'
TD 6213'
TD 7015'
MARG WET
NOTE: COMPLETION DATE SHOWN ON X-SECTION REFLECTS THE DATE OF COMPLETION IN THE LOWER MARGINULINA RESERVOIR
INDEX MAP
TEXACO
PORT NECHES FIELD
ORANGE COUNTY, TEXAS
STRUCTURAL CROSS SECTION
A - A'
DOCKET NO. 03-0290314
R.R.C. EXHIBIT NO. G-4
January 21, 1993


TYPE LOG
C
WEST
C'
EAST
TEXACO
NO. 11 KUHN
TEXACO
NO. A-5, POLK
TEXACO
NO. 33 KUHN
TEXACO
NO. 38 KUHN
TEXACO
NO. 18 KUHN
TEXACO
NO. 16 KUHN
TEXACO
NO. 48 KUHN
-4,500'
-5,000'
-5,500'
-6,000'
-6,500'
"Y-1" SAND
METROSTIGMA
METROSTIGMA BASAL UNCONFORMITY
LOWER MARGINULINA BASIC DATUM
FIRST "B" SAND
TD 6352'
MARG WET
TD 6608'
TD 7789'
TD 6016'
TD 6614'
TD 6403'
TD 7000'
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'
DOCKET NO. 03-0200344
R. R. C. EXHIBIT NO. G-3
January 21, 1993

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
0.396	0.04200	0.02905
0.458	0.05500	0.03804
0.532	0.07300	0.05049
0.597	0.09000	0.06225
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

<==Draw Graph on Semi-log to get Sw,obs at each Krw below

Lab Kro(oil)	Kro(air)
1.00000	0.69169
0.36800	0.25454
0.28900	0.19990
0.22000	0.15217
0.13600	0.09407
0.06100	0.04219
0.01900	0.01314
0.00570	0.00394
0.00200	0.00138
0.00034	0.00024
	0.00000

<==Draw Graph on Semi-log to get Sw,obs at each Krw below

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

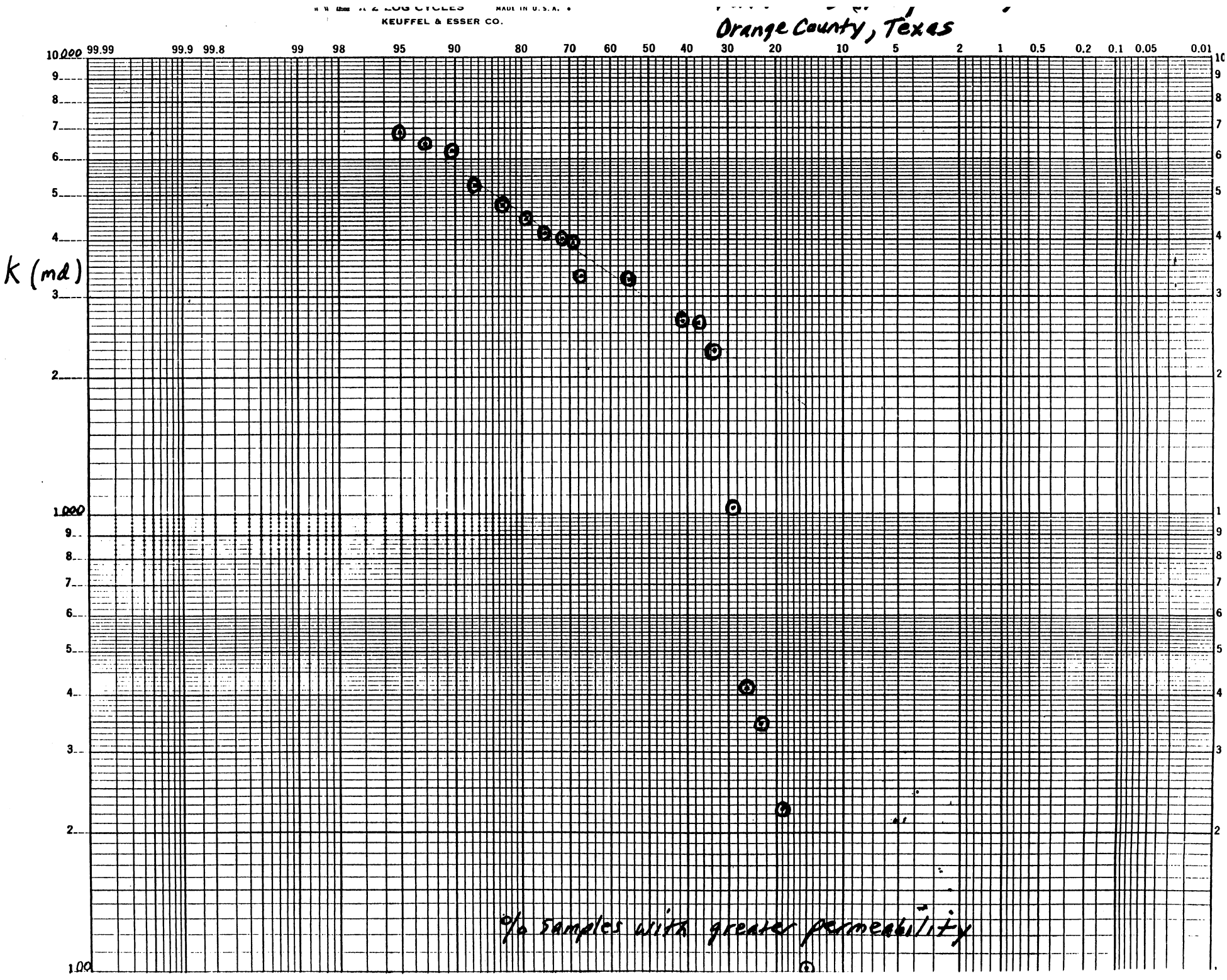
Swor,obs	Kro	Sw,obs	Sw,adj
0.654	0.001	0.660	0.706
0.654	0.005	0.630	0.674
0.654	0.010	0.605	0.648
0.654	0.020	0.578	0.619
0.654	0.030	0.560	0.599
0.654	0.040	0.540	0.578
0.654	0.050	0.522	0.559
0.654	0.060	0.501	0.536
0.654	0.070	0.483	0.517
0.654	0.080	0.470	0.503
0.654	0.090	0.450	0.482
0.654	0.100	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)		Kro(oil)	Kro(air)	
0.000	0.00000	0.00000		1.00000	0.69169	<==Must Match
0.035	0.00450	0.00311		0.73000	0.50493	Kro @ Swi
0.054	0.00820	0.00567	<=Final Results=>	0.62000	0.42885	
0.076	0.01300	0.00899		0.52000	0.35968	
0.105	0.02100	0.01453		0.42000	0.29051	
0.138	0.03000	0.02075		0.32000	0.22134	
0.184	0.04700	0.03251		0.22300	0.15425	
0.225	0.06700	0.04634		0.16100	0.11136	
0.268	0.09000	0.06225		0.11200	0.07747	
0.299	0.10900	0.07539		0.08400	0.05810	
0.337	0.13900	0.09614		0.05800	0.04012	
0.357	0.15500	0.10721		0.04800	0.03320	
0.384	0.18500	0.12796		0.03600	0.02490	
0.412	0.22000	0.15217		0.02600	0.01798	
0.430	0.24000	0.16601		0.02000	0.01383	
0.445	0.27000	0.18676		0.01600	0.01107	
0.455	0.29000	0.20059		0.01400	0.00968	
0.478	0.33500	0.23172		0.00800	0.00553	
0.532	0.47700	0.32994				


KEUFFEL & ESSER CO.
Orange County, Texas
99.99
99.9
99.8
99
98
95
90
80
70
60
50
40
30
20
10
5
2
1
0.5
0.2
0.1
0.05
0.01
10,000
1,000
100
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

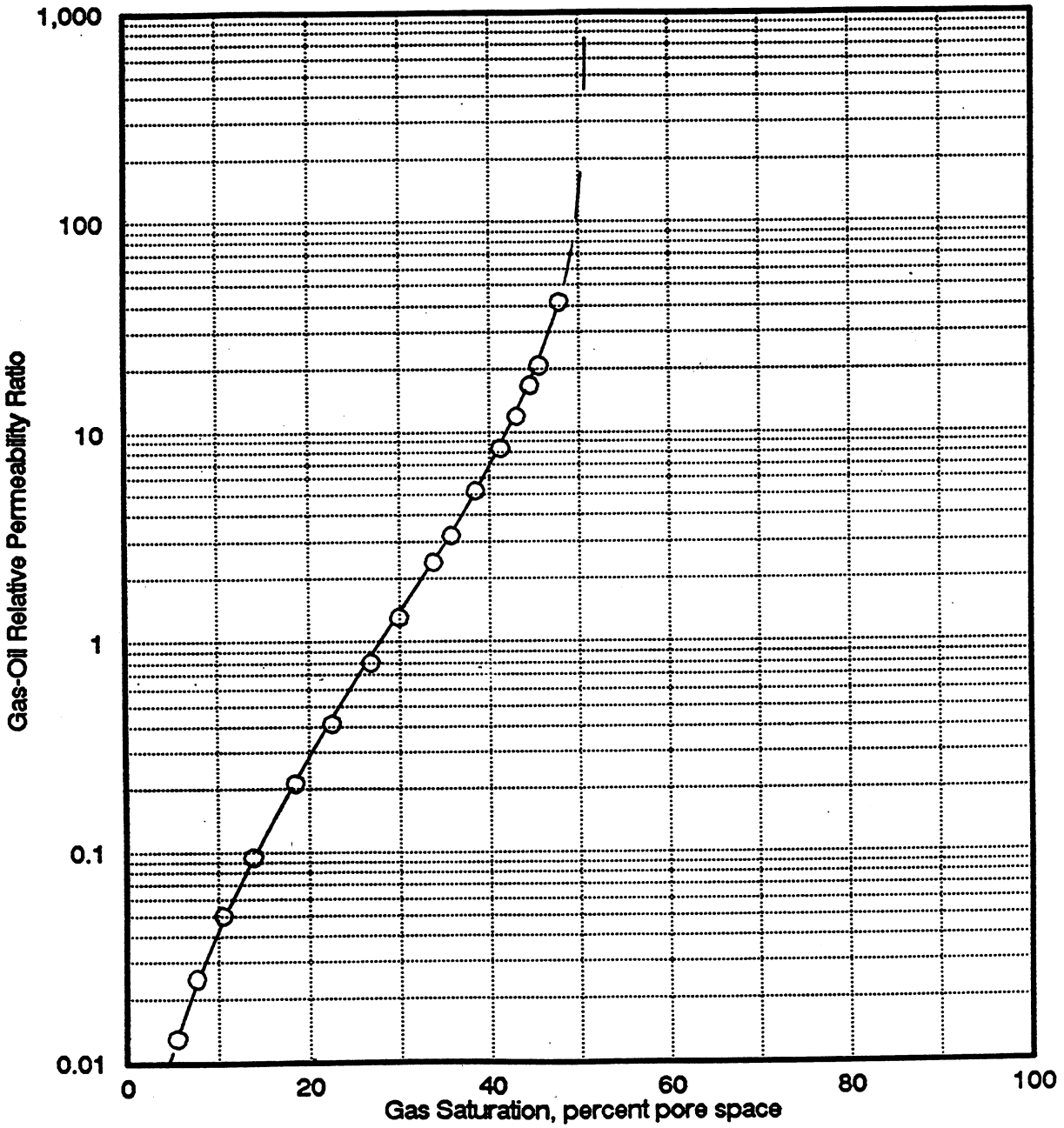
Gas Saturation, percent, pore space	Gas-Oil Relative Permeability Ratio	Relative Permeability to Gas,* fraction	Relative Permeability to Oil,* fraction
0.0	0.0000	0.0000	1.000
3.5	0.0062	0.0045	0.730
5.4	0.013	0.0082	0.620
7.6	0.025	0.013	0.520
10.5	0.050	0.021	0.420
13.8	0.095	0.030	0.320
18.4	0.213	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.	Sample I.D.:	24
Stark "B" No. 10 Well	Depth, feet:	5983.8
Port Neches Field	Permeability to Air, md:	3730
Orange County, Texas	Porosity, percent:	31.4
	Initial Water Saturation, percent:	13.3
	Effective Permeability to Oil at Swi, md:	2580



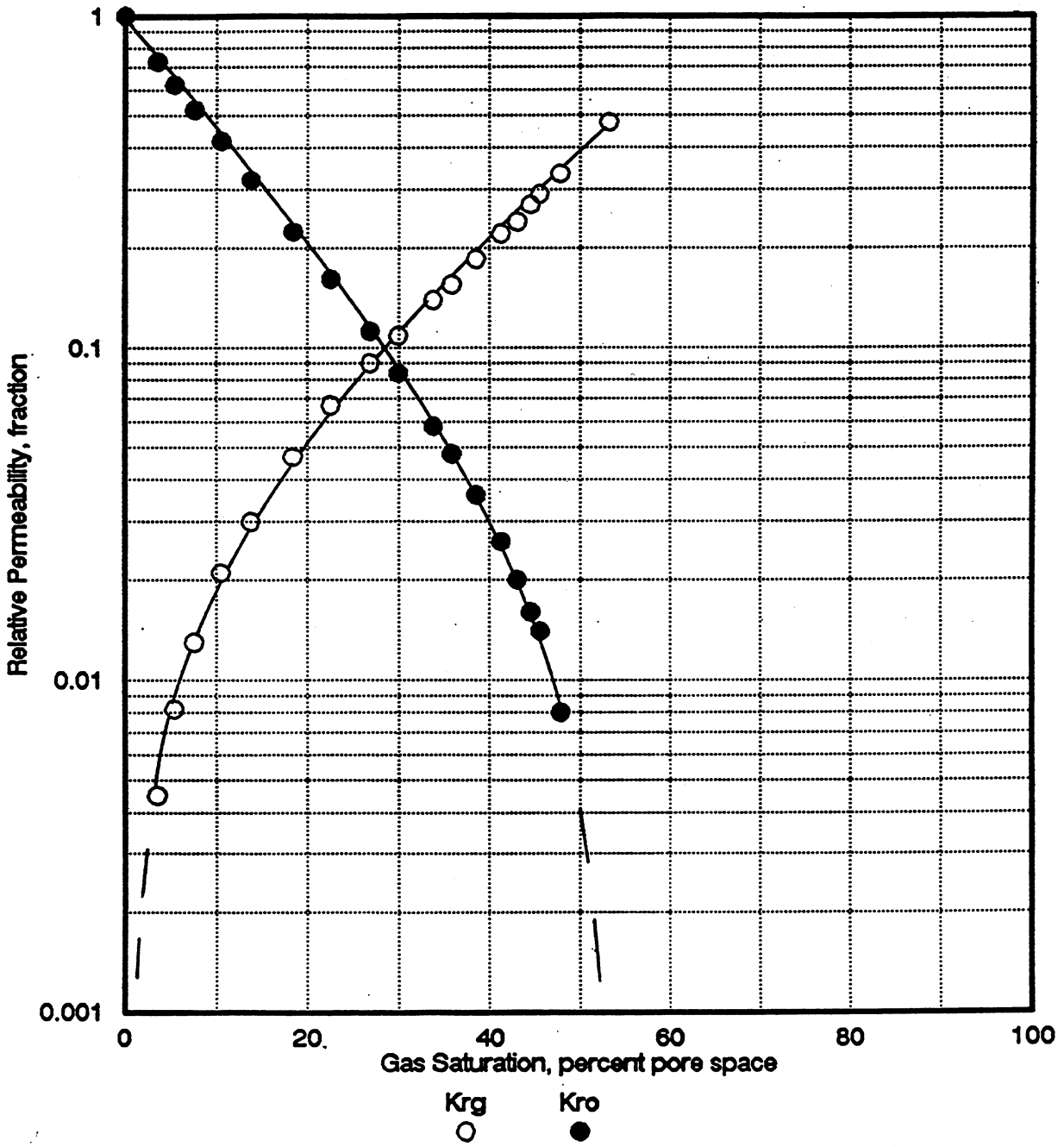
Core Laboratories

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

Sample I.D.	Depth, feet	Permeability to Air, millidarcies	Porosity, percent	Initial Conditions: Water Saturation, percent pore space	Initial Conditions: Effective Permeability to Oil, millidarcies	Terminal Conditions: Oil Saturation, percent pore space	Terminal Conditions: Effective Permeability to Water, millidarcies	Terminal Conditions: Relative Permeability to Water,* fraction	Oil Recovered, percent pore space	Oil Recovered, 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

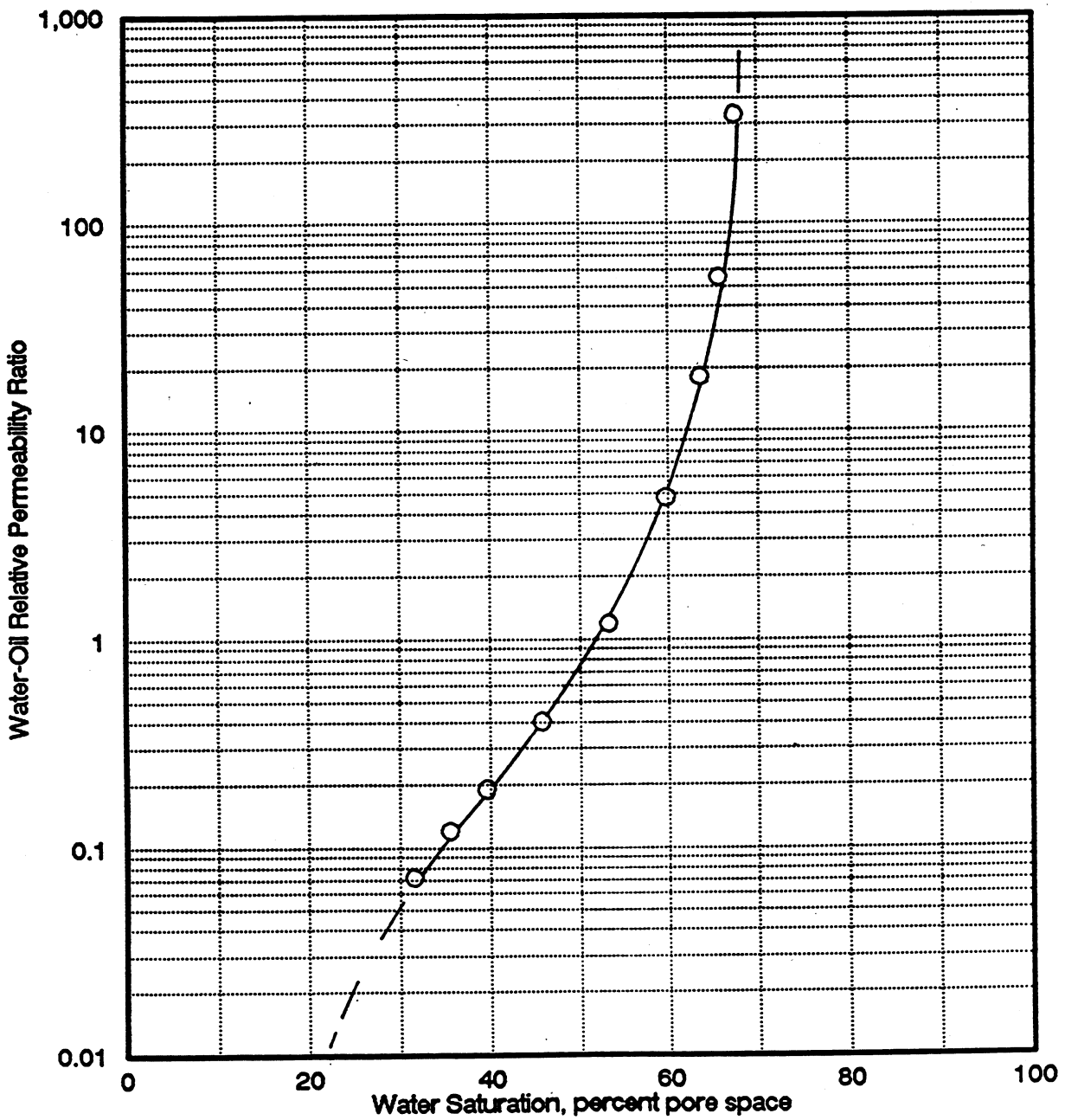
Water Saturation, percent, pore space	Water-Oil Relative Permeability Ratio	Relative Permeability to Water,* fraction	Relative Permeability to Oil,* fraction
13.3	0.000	0.000	1.000
31.5	0.072	0.027	0.368
35.5	0.121	0.035	0.289
39.6	0.191	0.042	0.220
45.8	0.405	0.055	0.136
53.2	1.19	0.073	0.061
59.7	4.79	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.	Sample I.D.:	24
Stark "B" No. 10 Well	Depth, feet:	5983.8
Port Neches Field	Permeability to Air, md:	3730
Orange County, Texas	Porosity, percent:	31.4
	Initial Water Saturation, percent:	13.3
	Effective Permeability to Oil at Swi, md:	2580



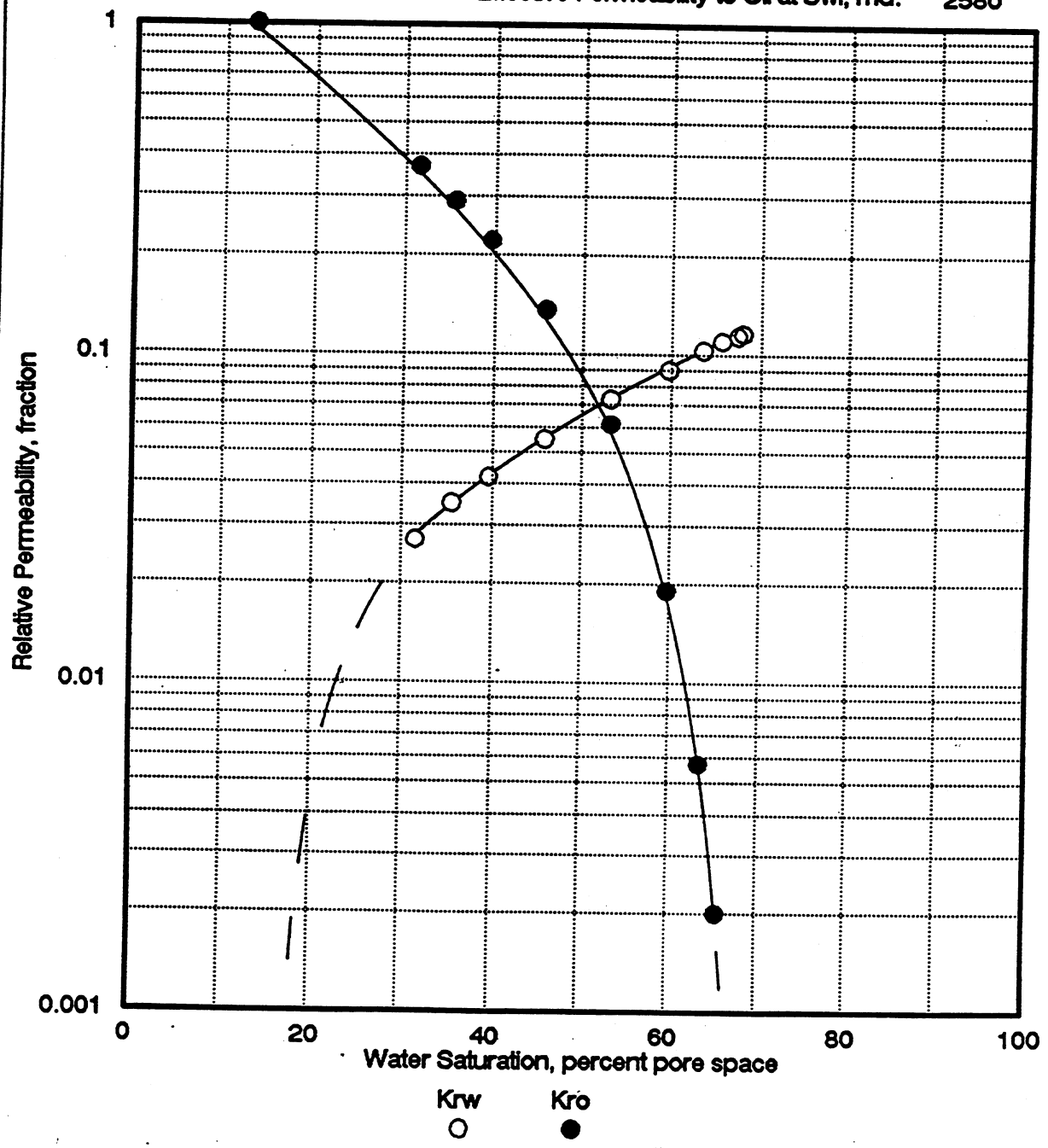
Core Laboratories

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

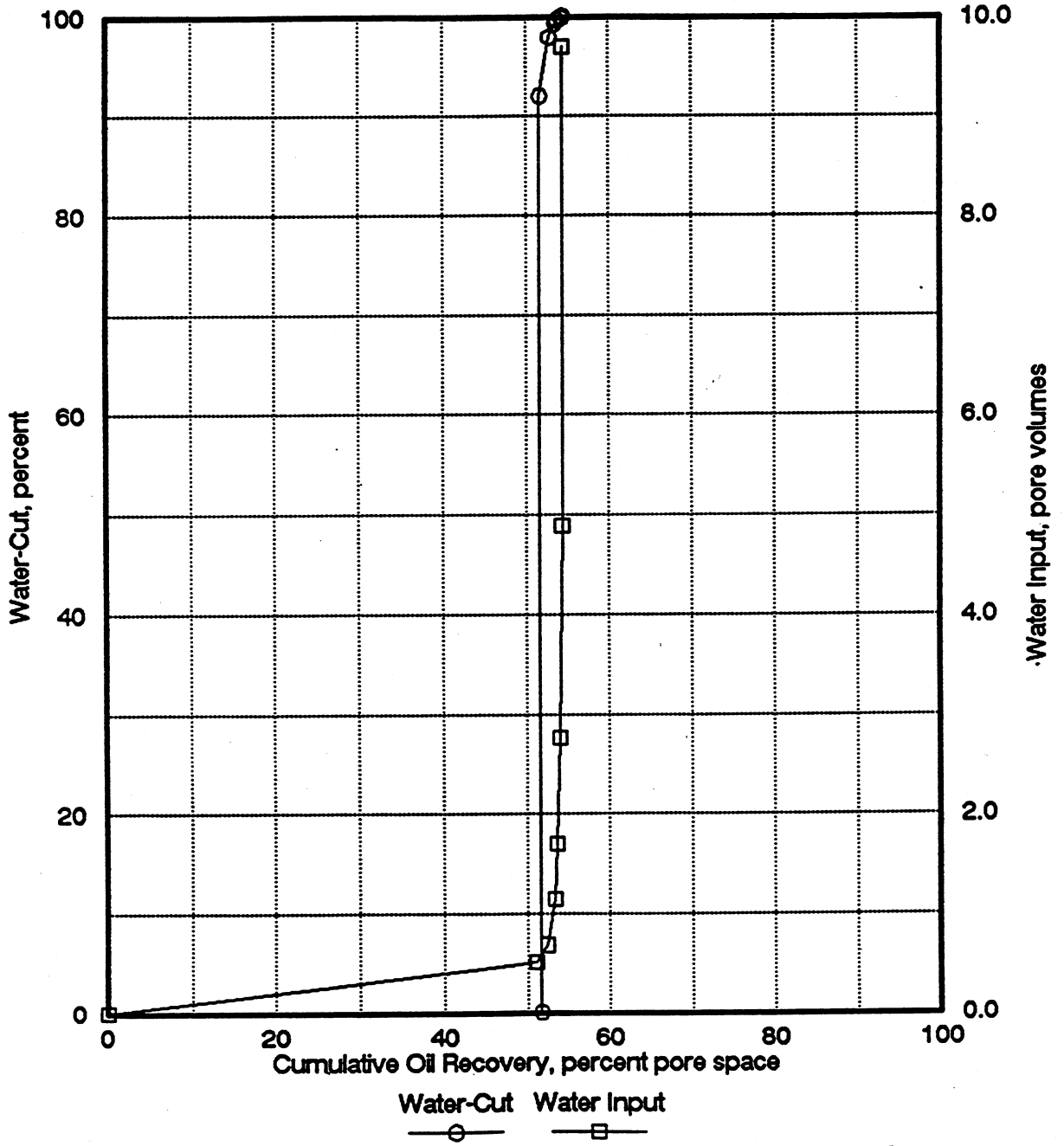
Water Input, pore volumes	Cumulative Oil Recovery, percent pore space	Average Oil Recovery*, percent pore space	Average Water Cut**, percent
0.511	51.1***	-	-
0.683	52.4	51.7	92.0
1.15	53.4	52.9	97.9
1.70	53.7	53.6	99.3
2.76	54.1	53.9	99.6
4.89	54.4	54.3	99.86
9.69	54.5	54.5	99.98

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

WATERFLOOD SUSCEPTIBILITY

Unsteady-State Clean Sample

Texaco, Inc.	Sample I.D.:	23
Stark "B" No. 10 Well	Depth, feet:	5982.8
Port Neches Field	Permeability to Air, md:	3380
Orange County, Texas	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

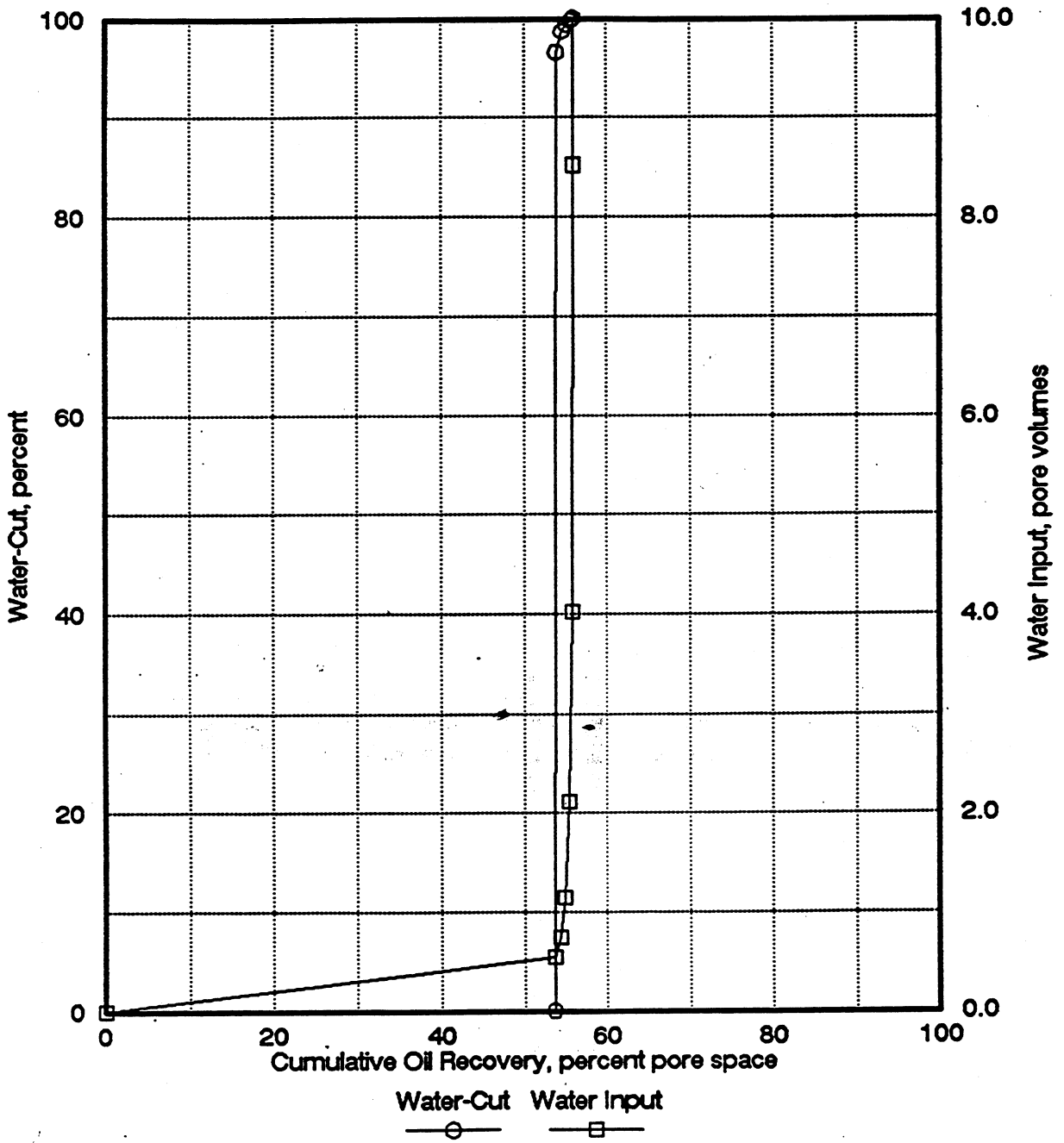
Water Input, pore volumes	Cumulative Oil Recovery, percent pore space	Average Oil Recovery*, percent pore space	Average Water Cut**, percent
0.539	53.6	53.6	-
0.749	54.3	53.9	96.6
1.15	54.8	54.6	98.7
2.12	55.4	55.1	99.4
4.02	55.8	55.6	99.8
8.52	55.9	55.8	99.97
17.1	55.9	55.9	99.996

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

WATERFLOOD SUSCEPTIBILITY

Unsteady-State Clean Sample

Texaco, Inc.	Sample I.D.:	24
Stark "B" No. 10 Well	Depth, feet:	5983.8
Port Neches Field	Permeability to Air, md:	3730
Orange County, Texas	Porosity, percent:	31.4
	Initial Water Saturation, percent:	7.5
	Effective Permeability to Oil at Swi, md:	2800



Core Laboratories

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

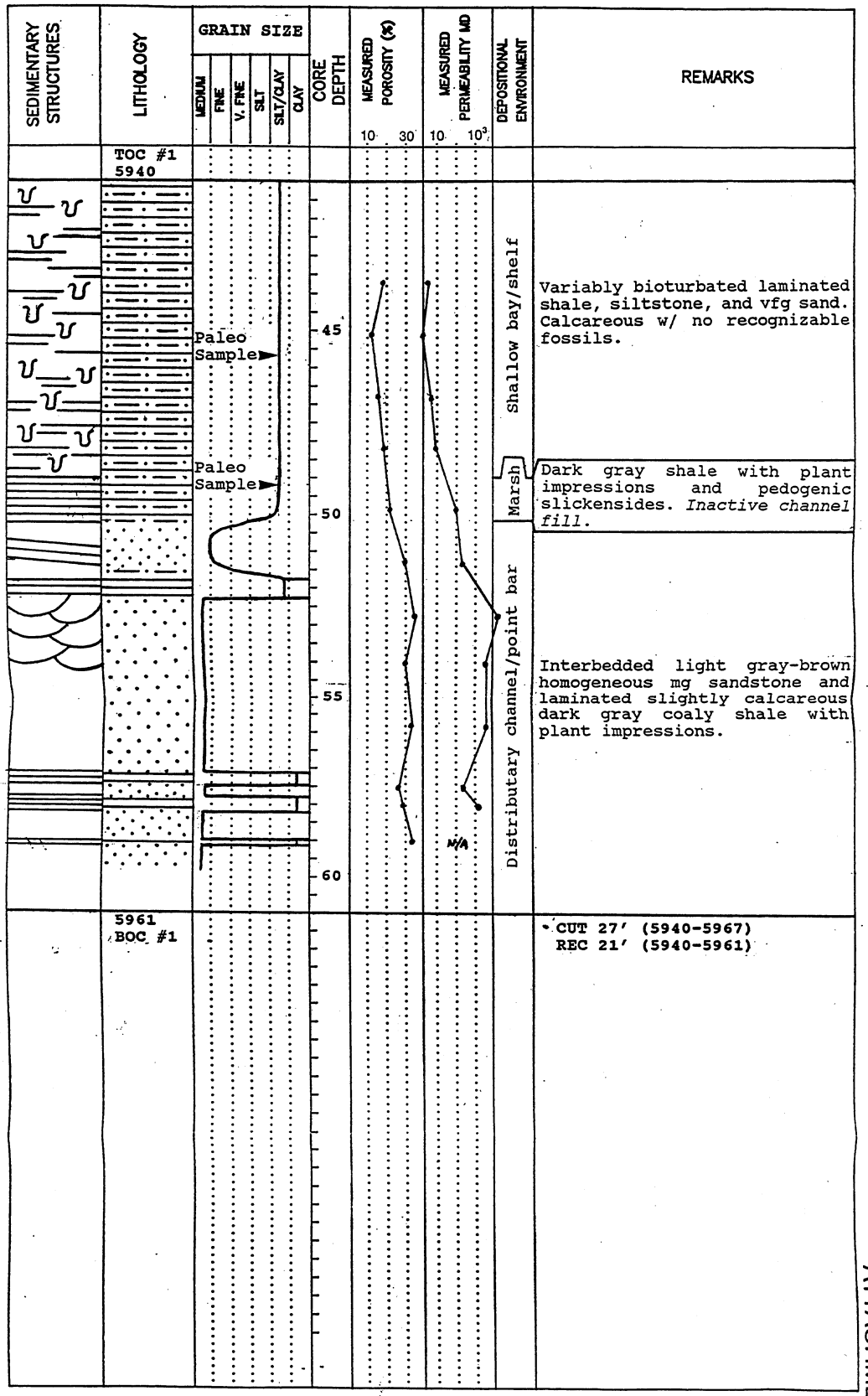
Michael D. Hogg

cc: Darrell Davis
Dennis Kuhfal

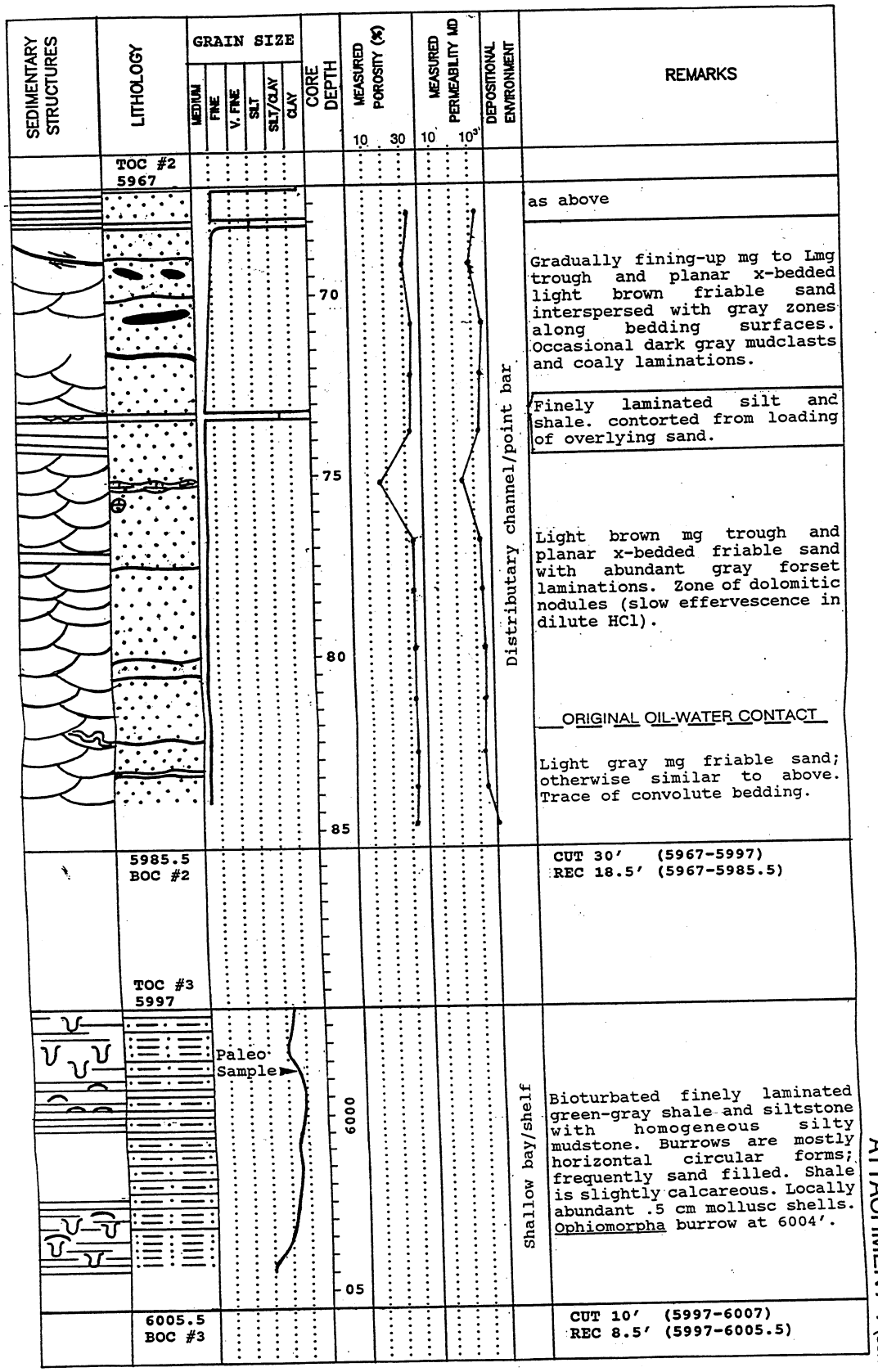
STARK "B" No. 10 COMPARATOR CHART - BELOW MARGINULINA SAND

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	

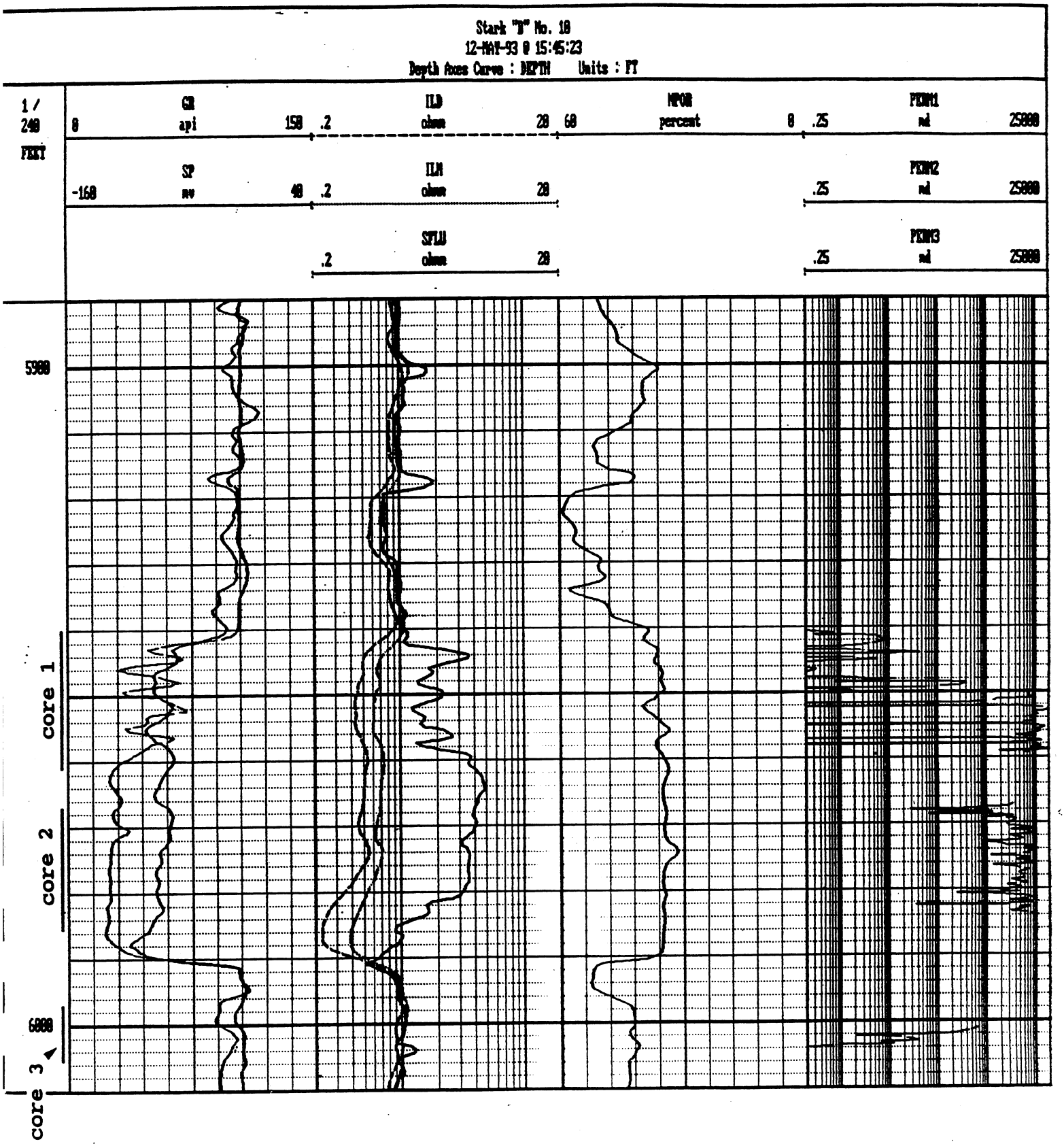


ATTACHMENT 1



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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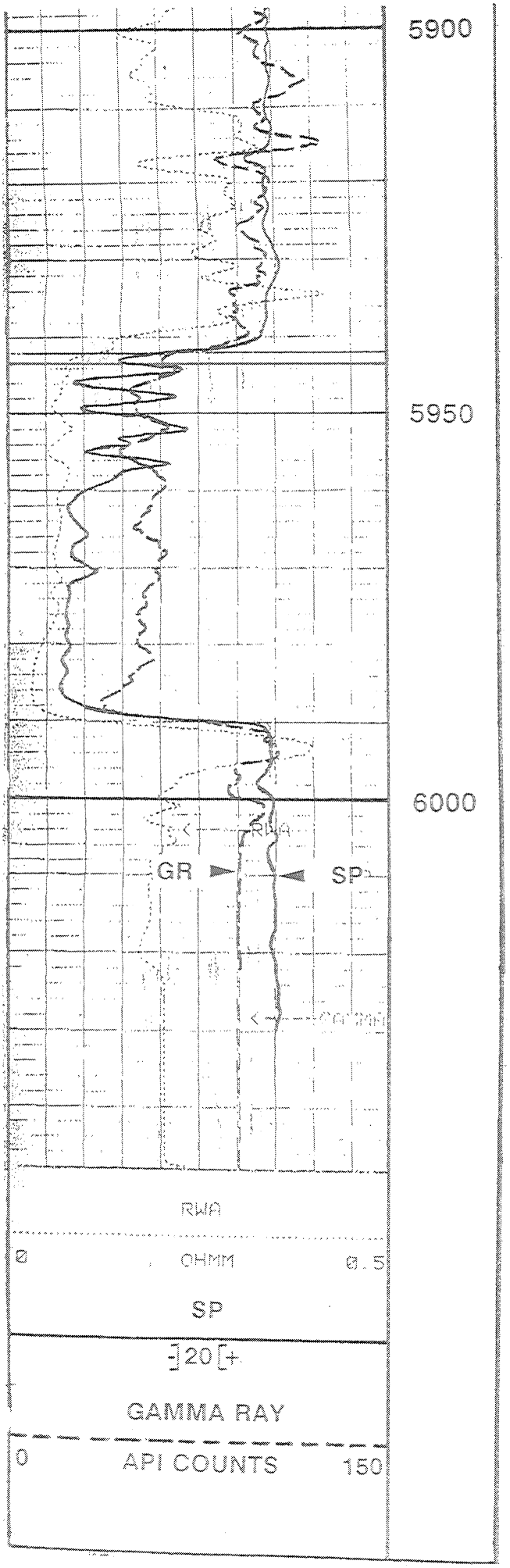
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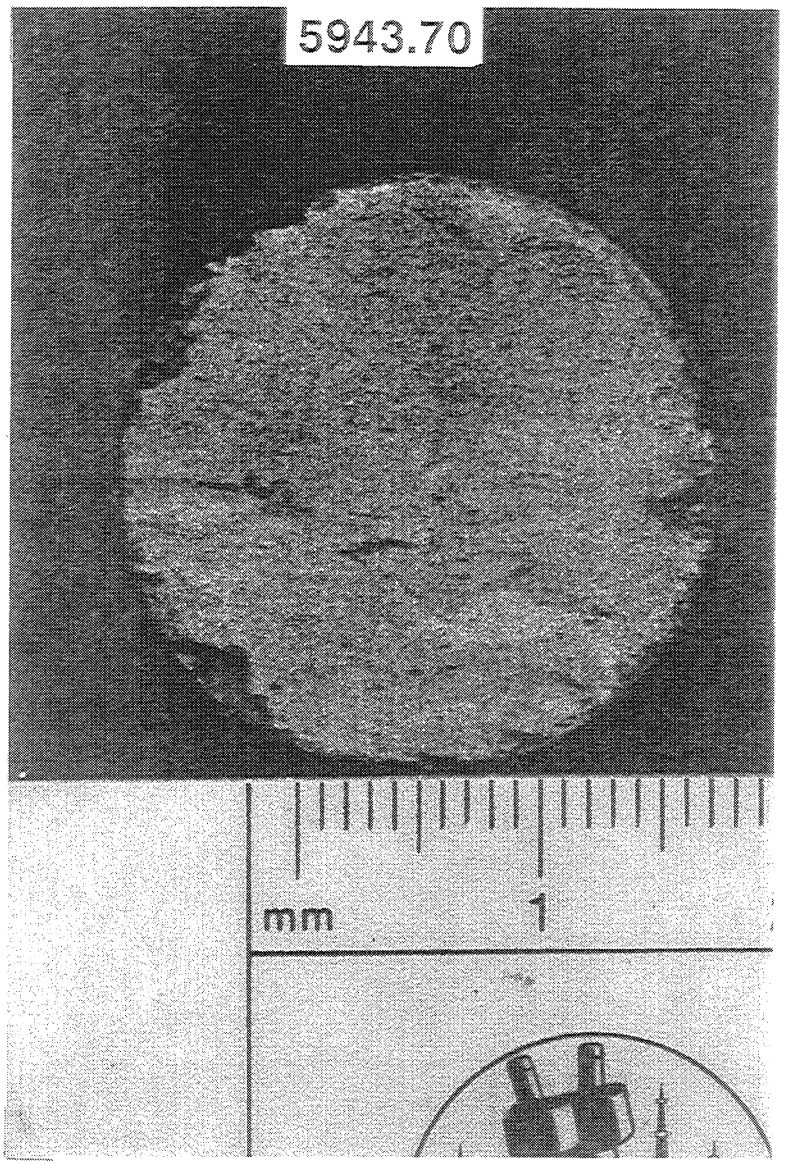
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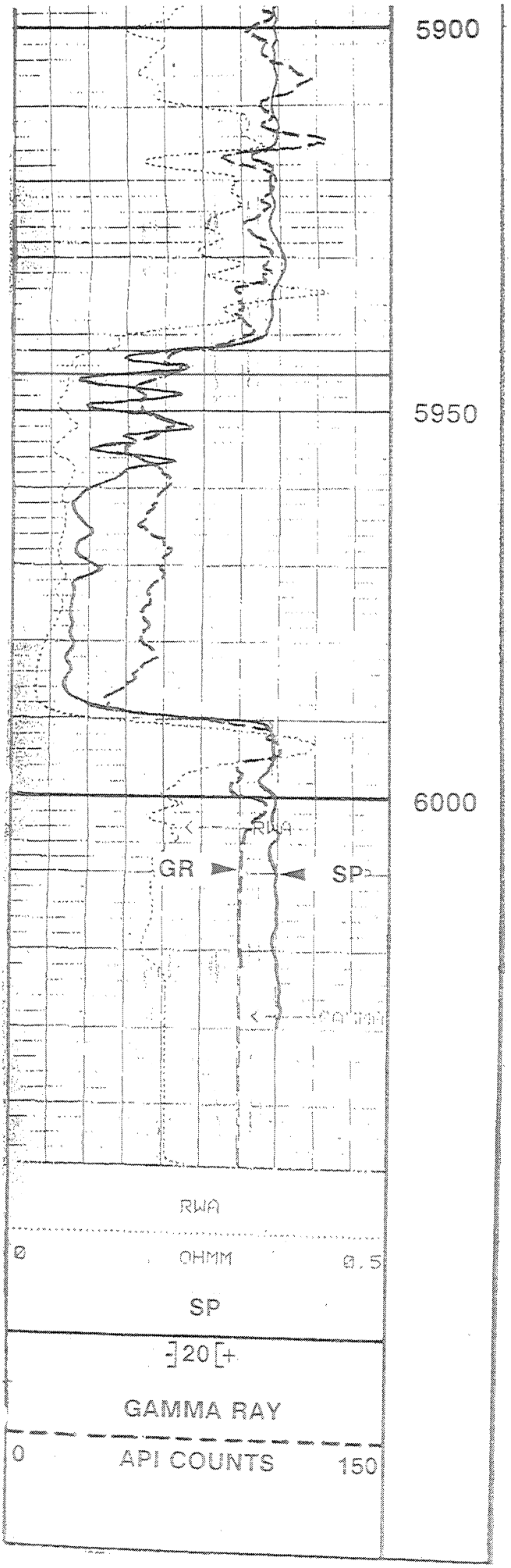
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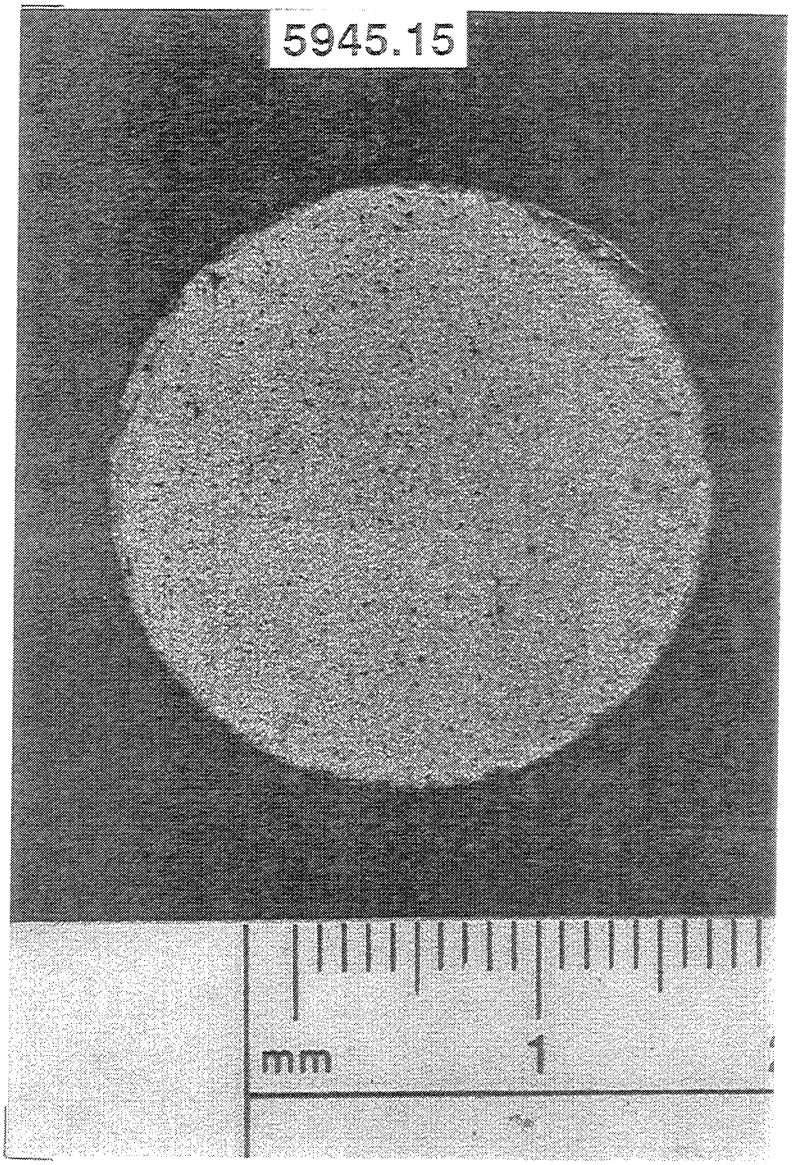
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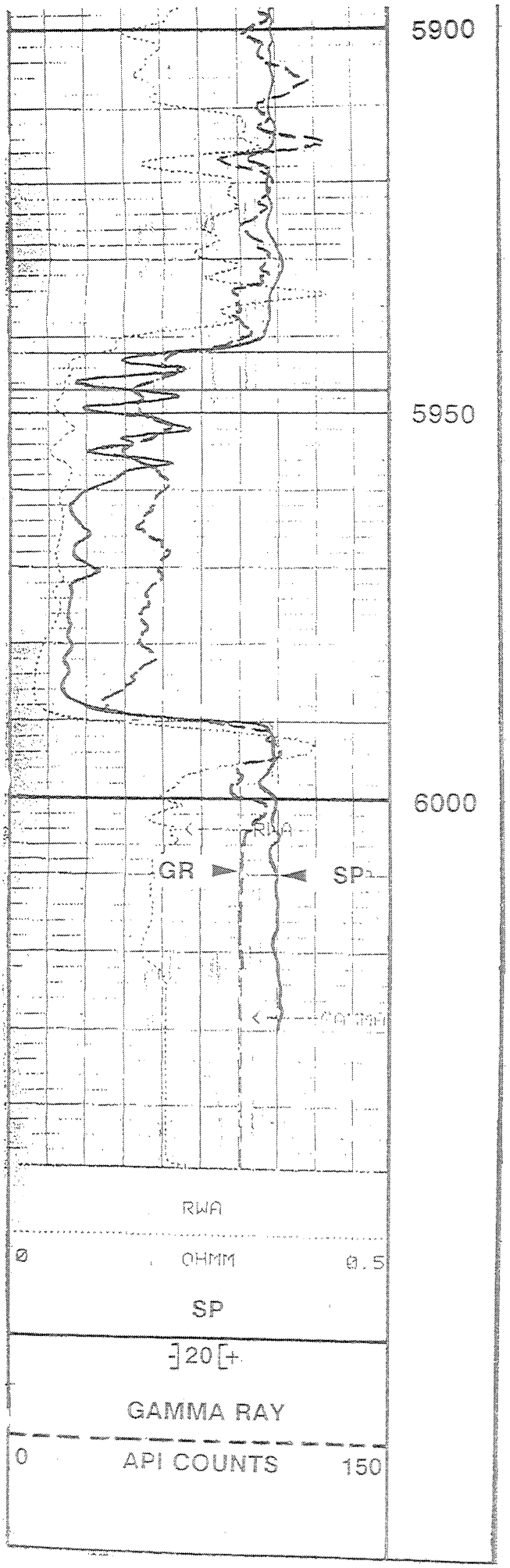
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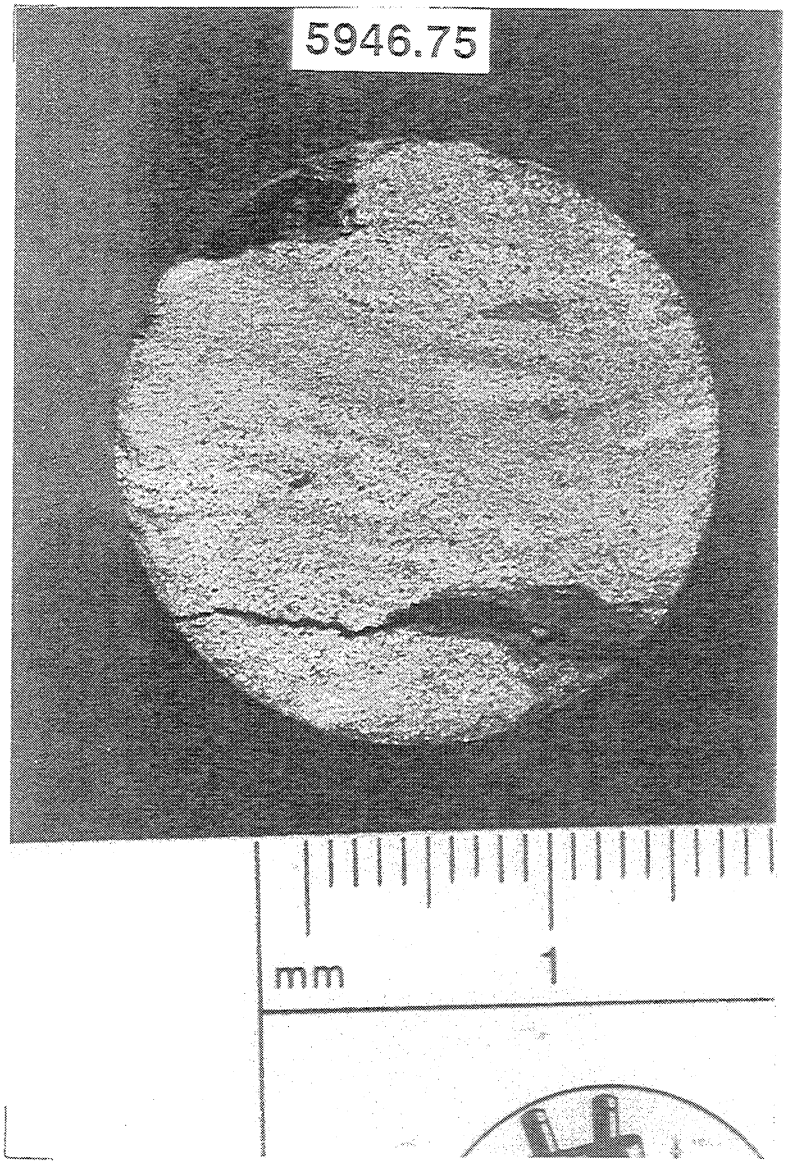
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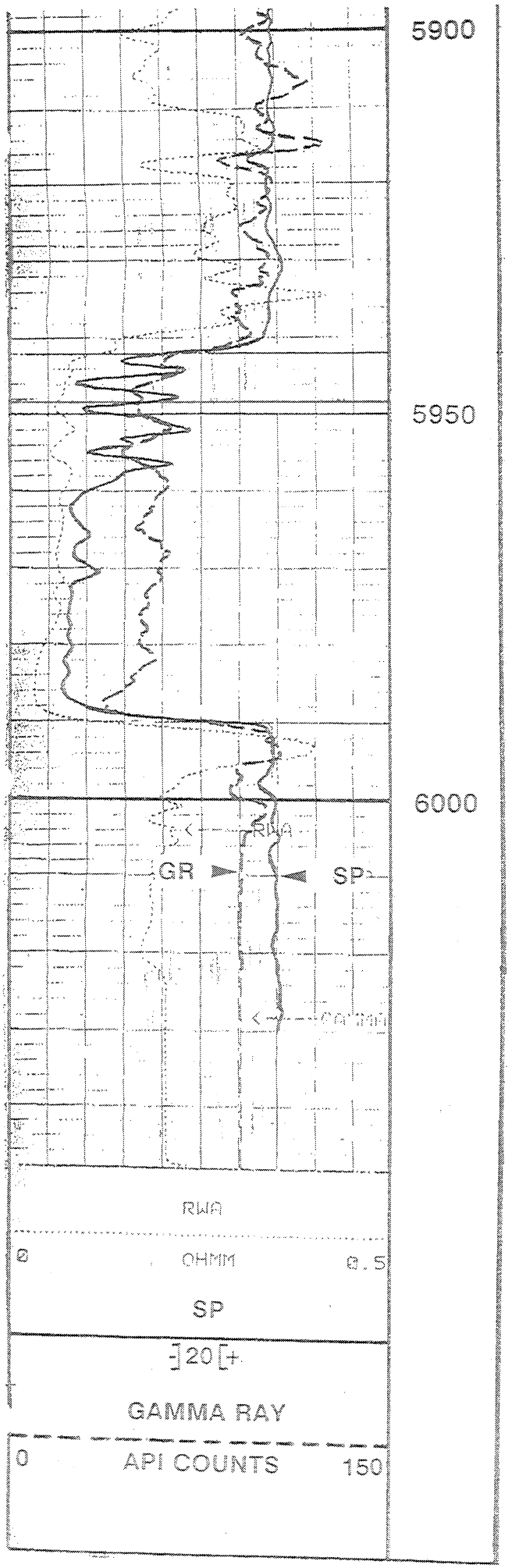
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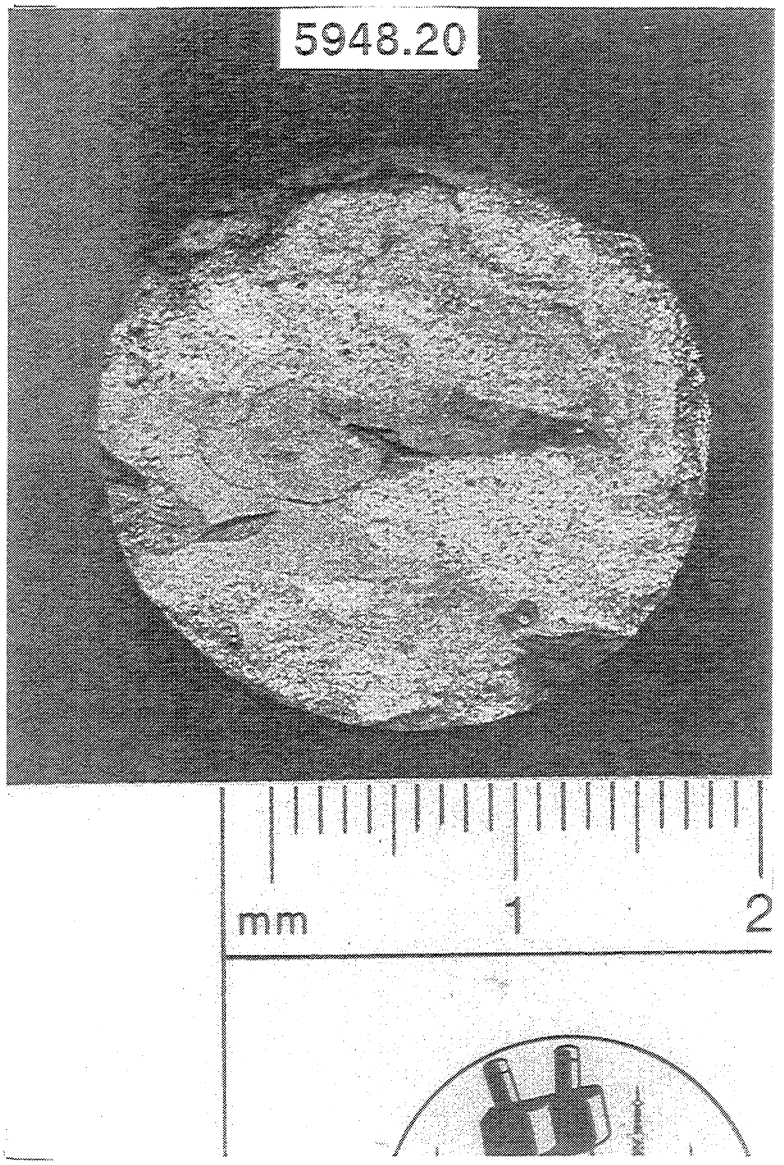
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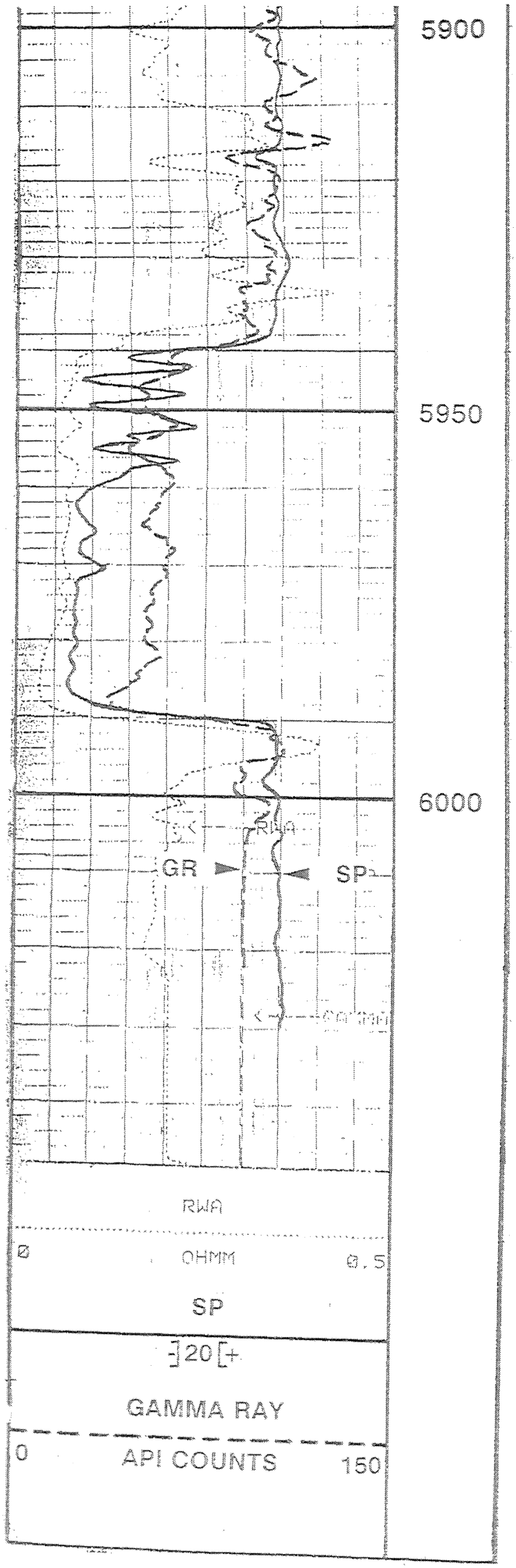
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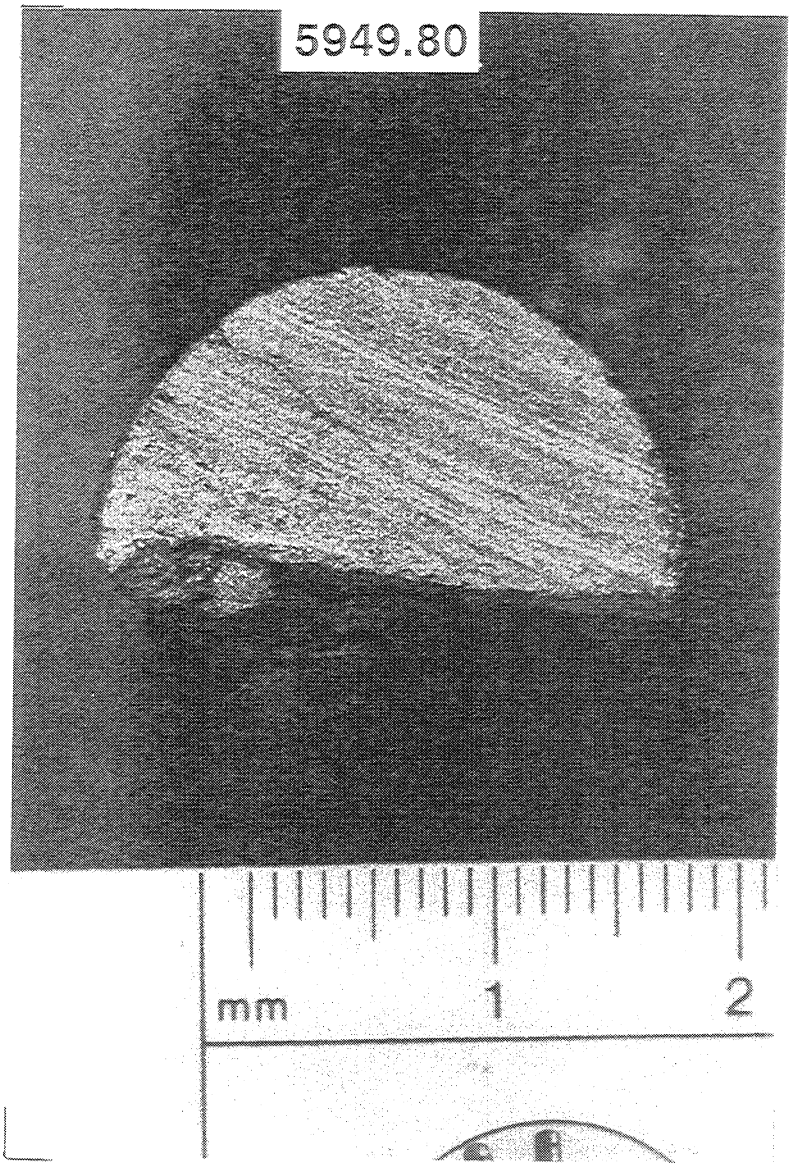
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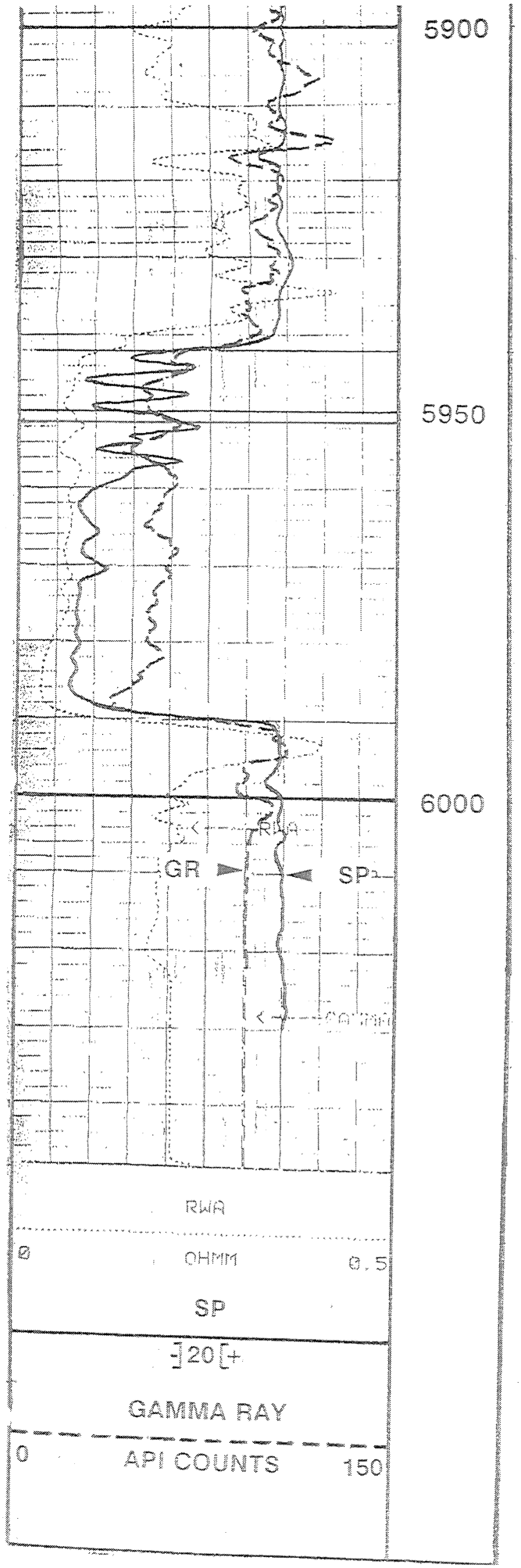
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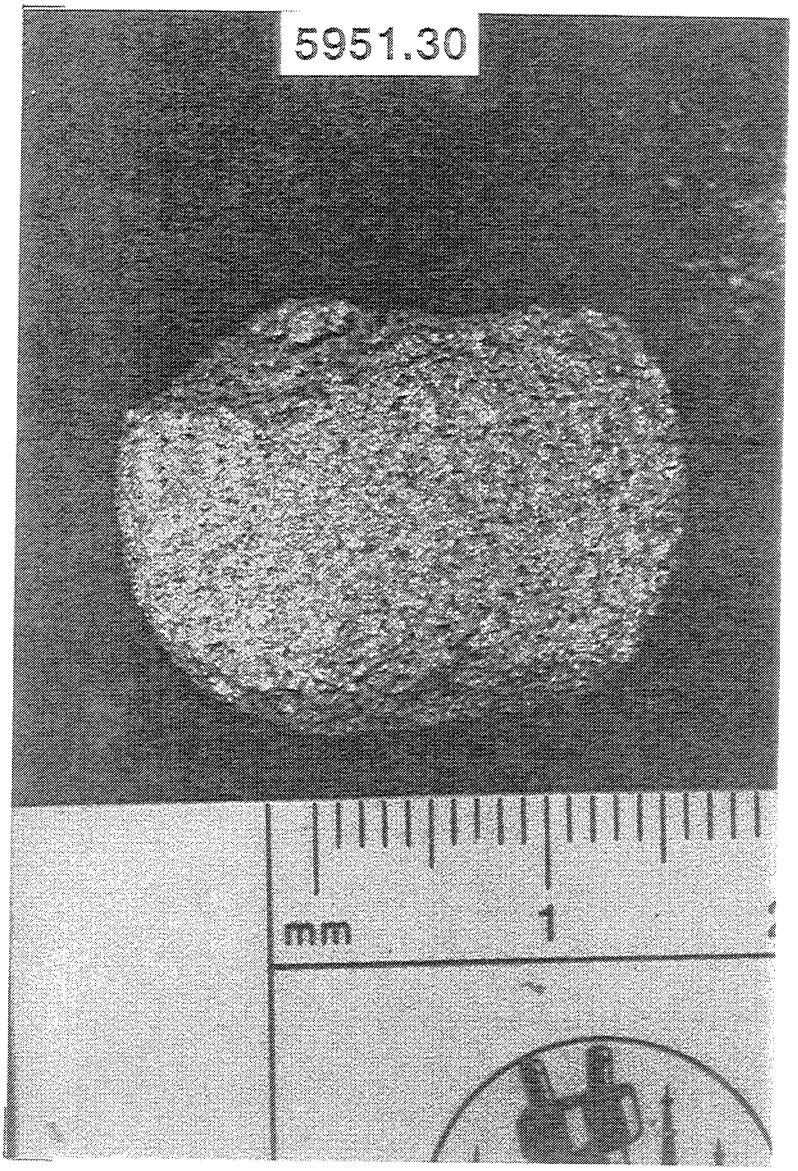
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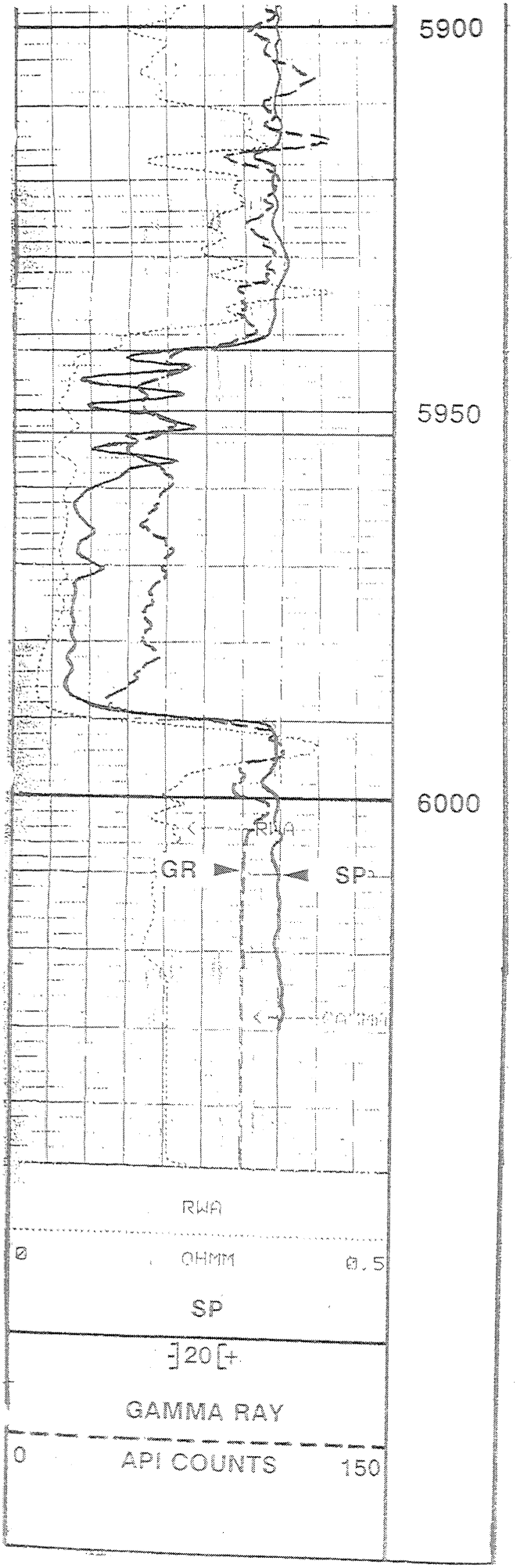
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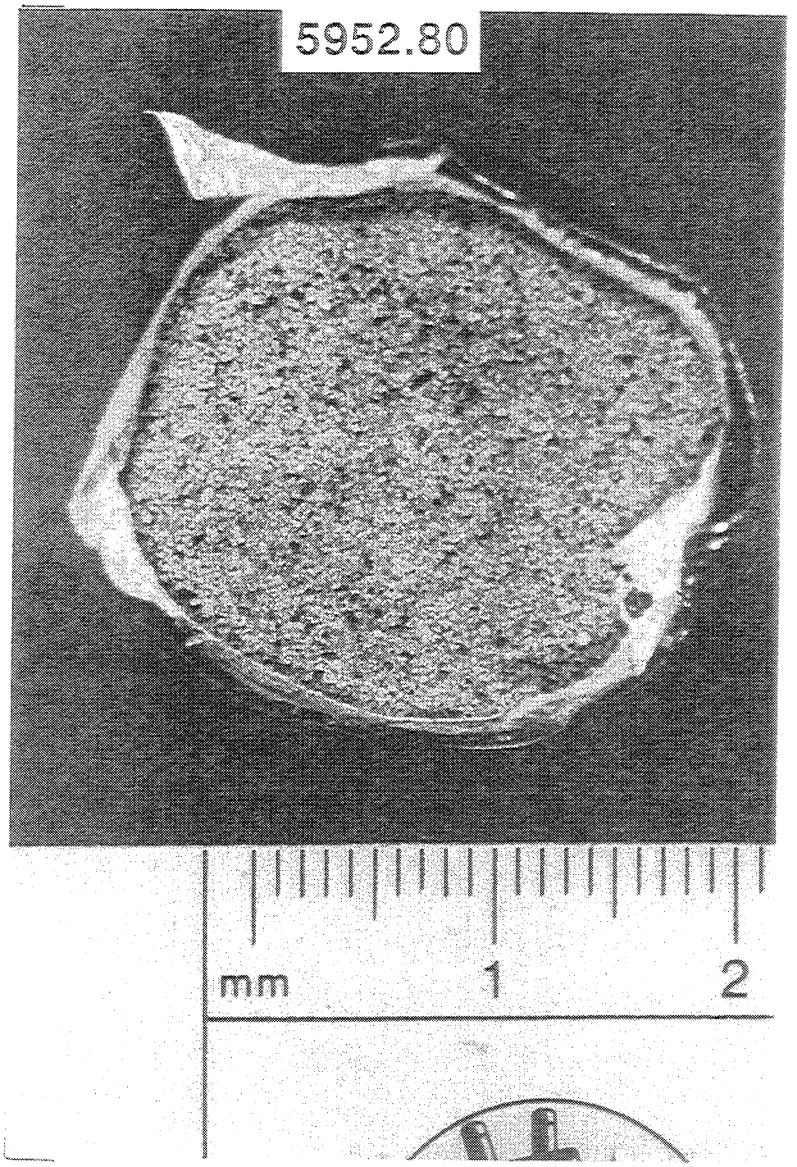
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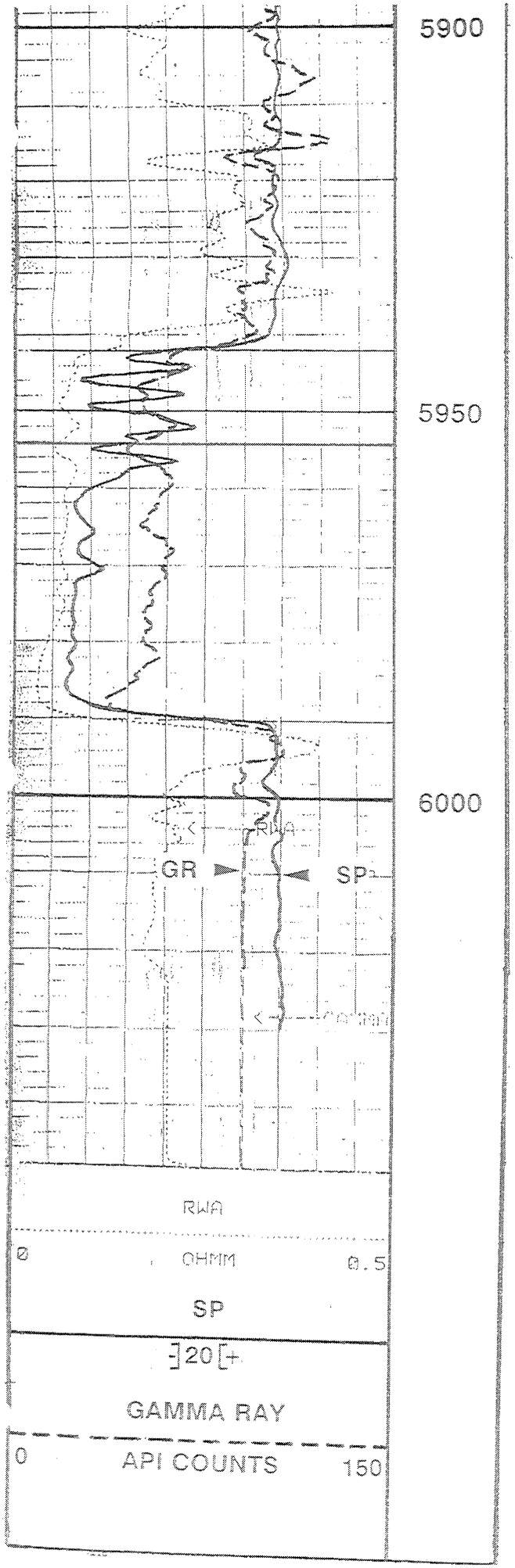
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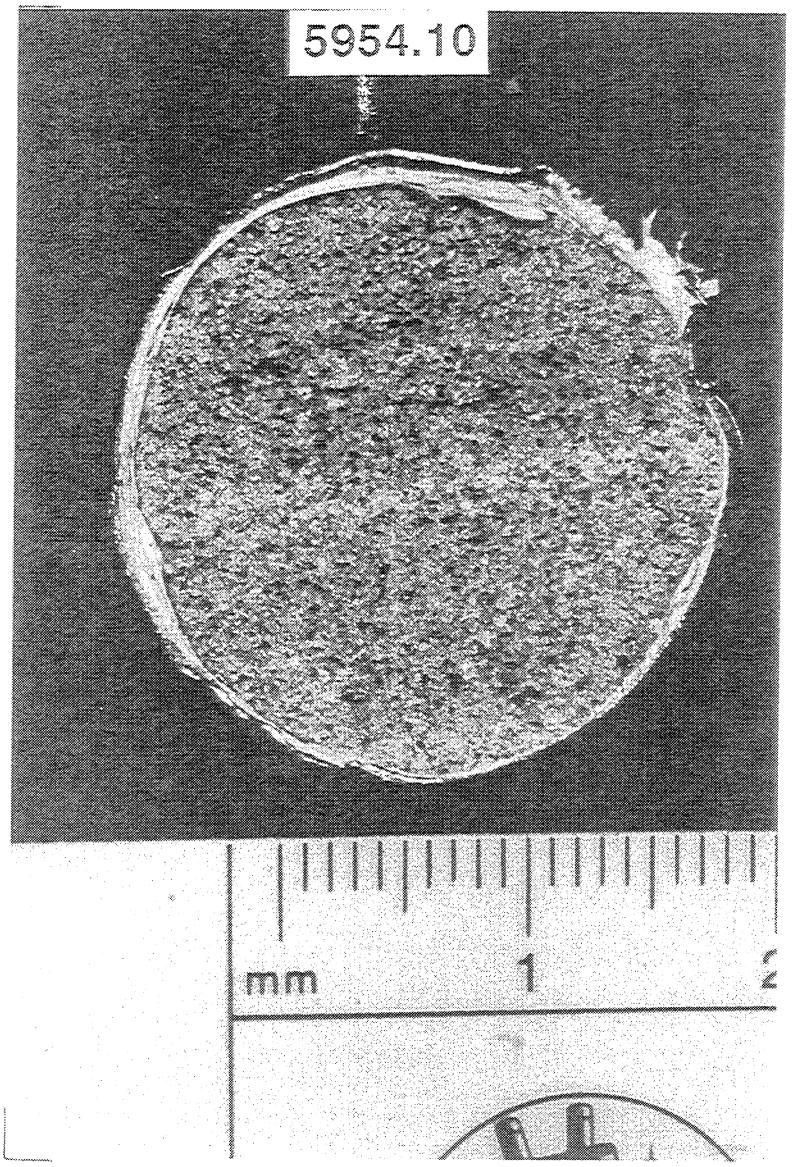
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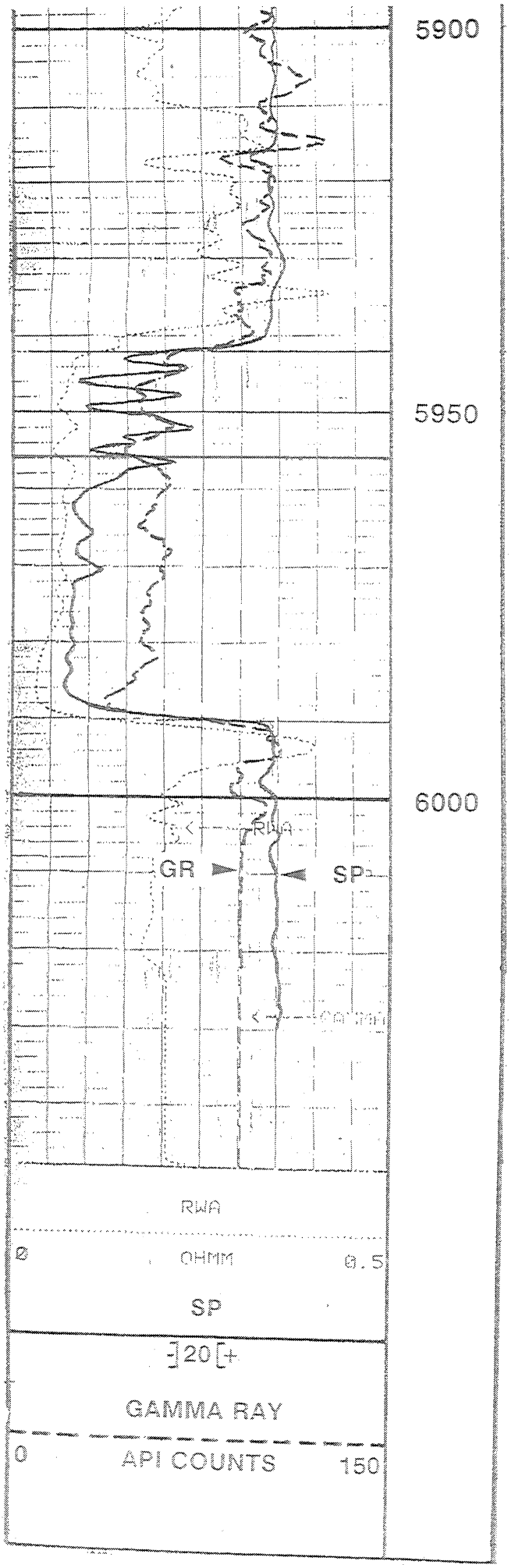
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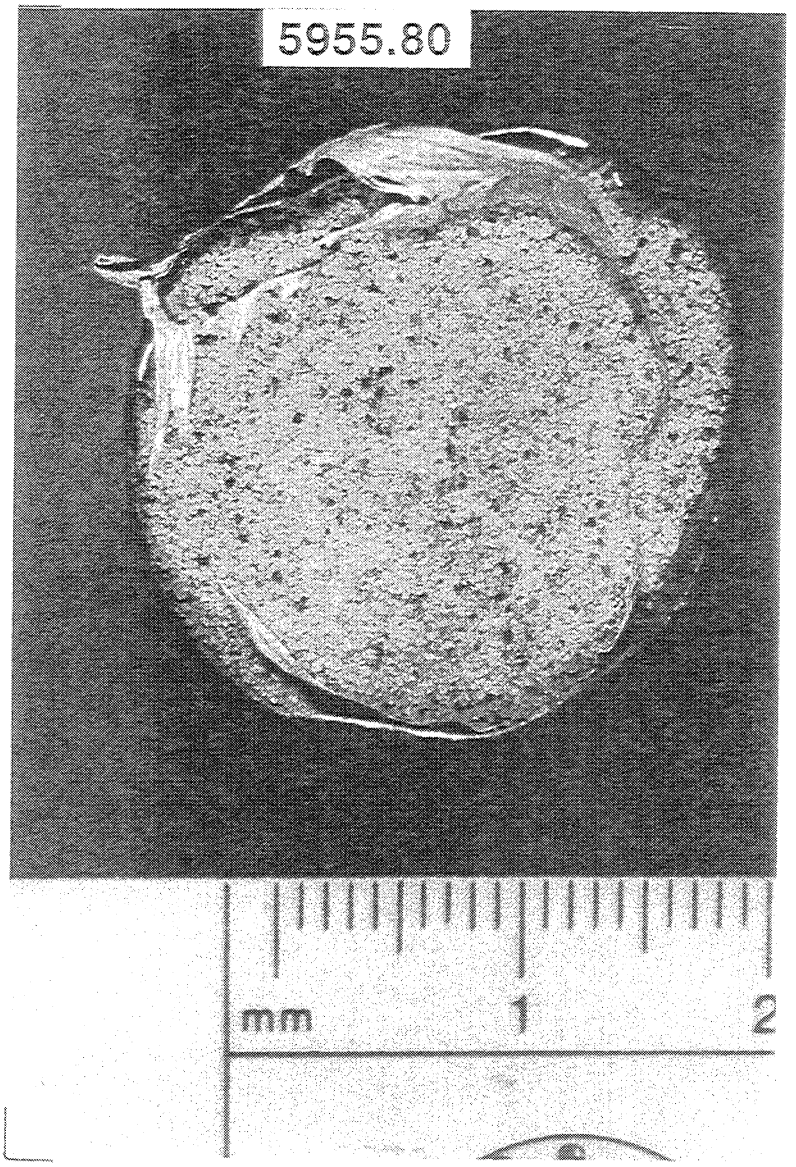
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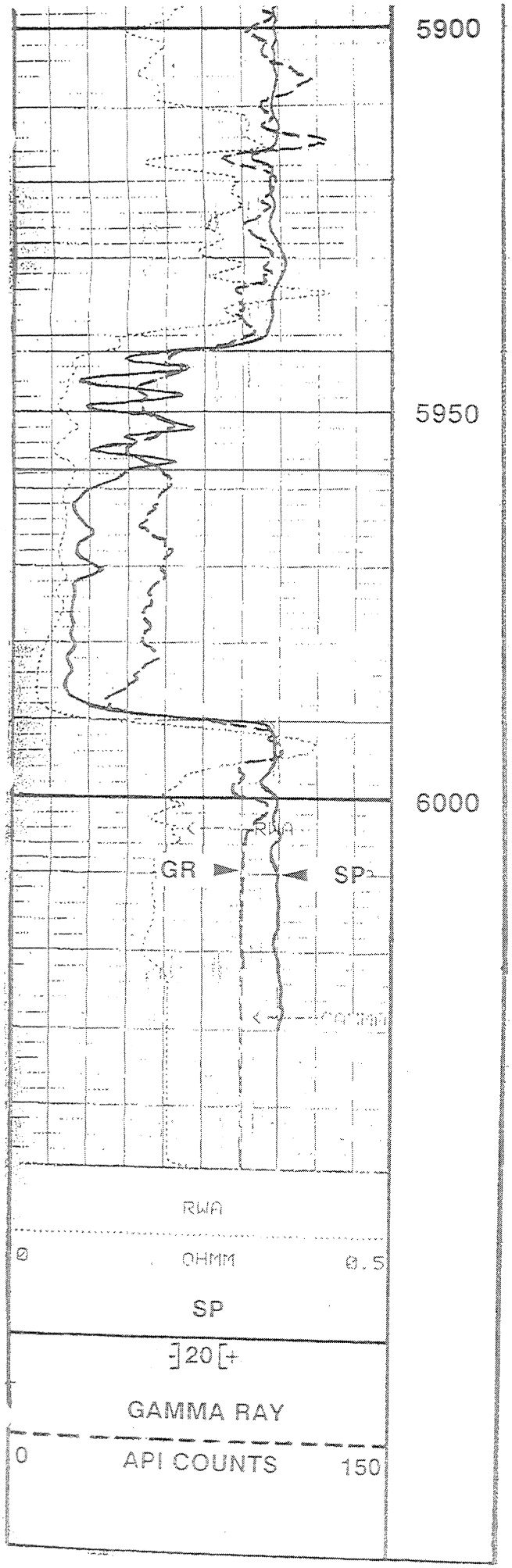
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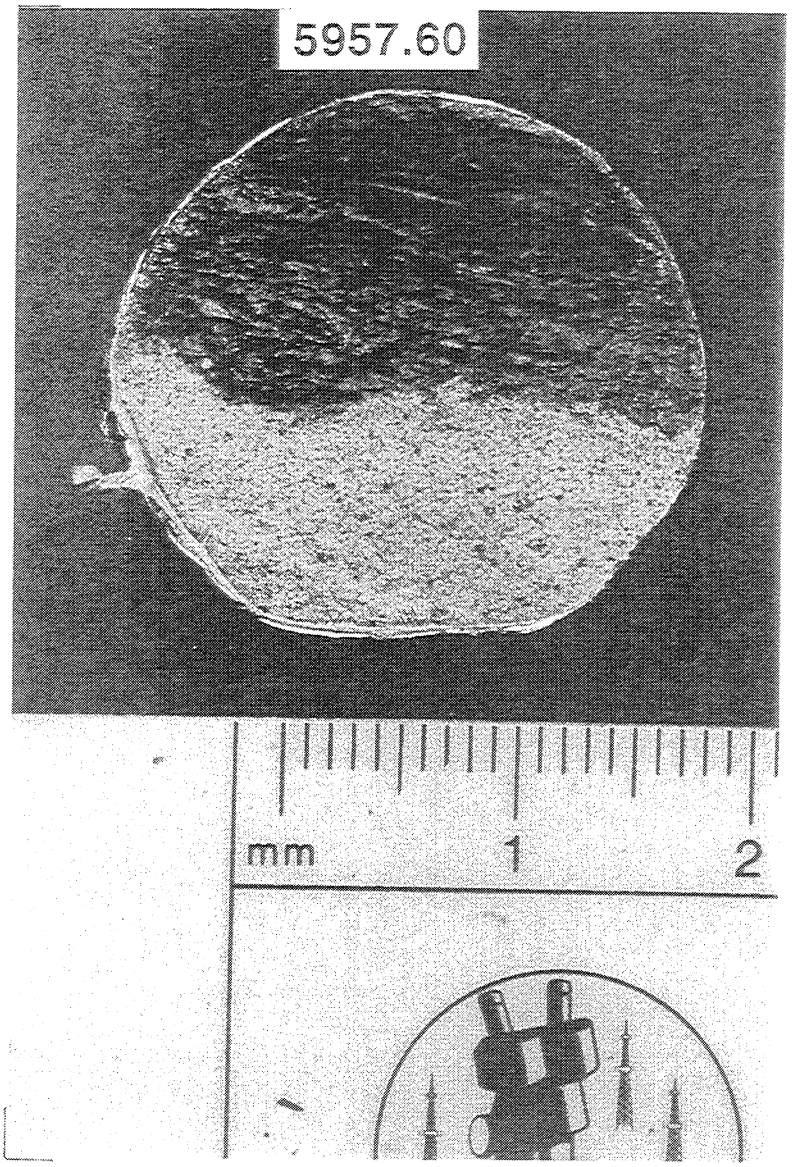
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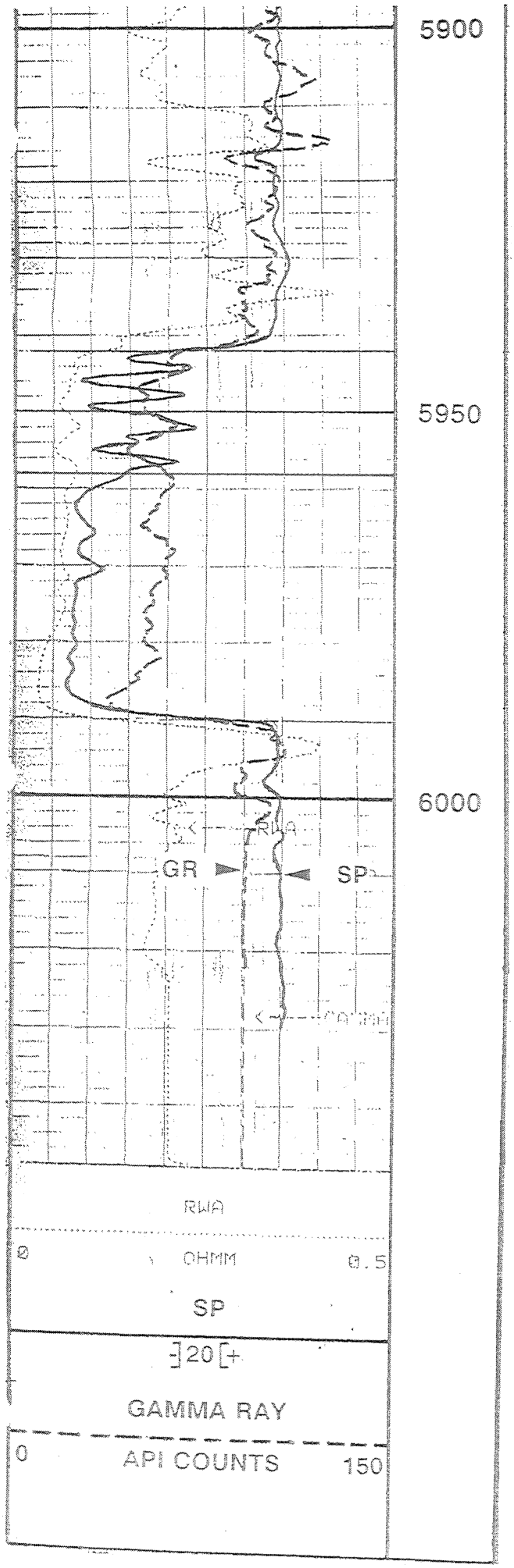
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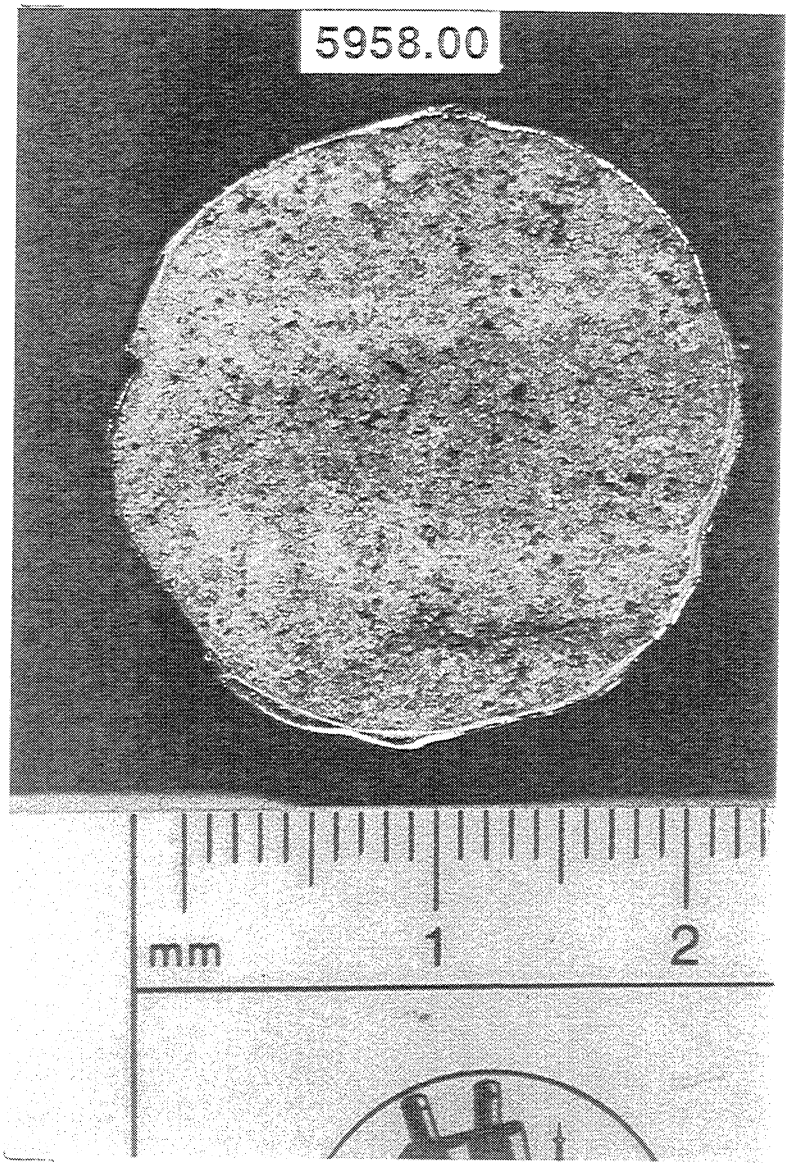
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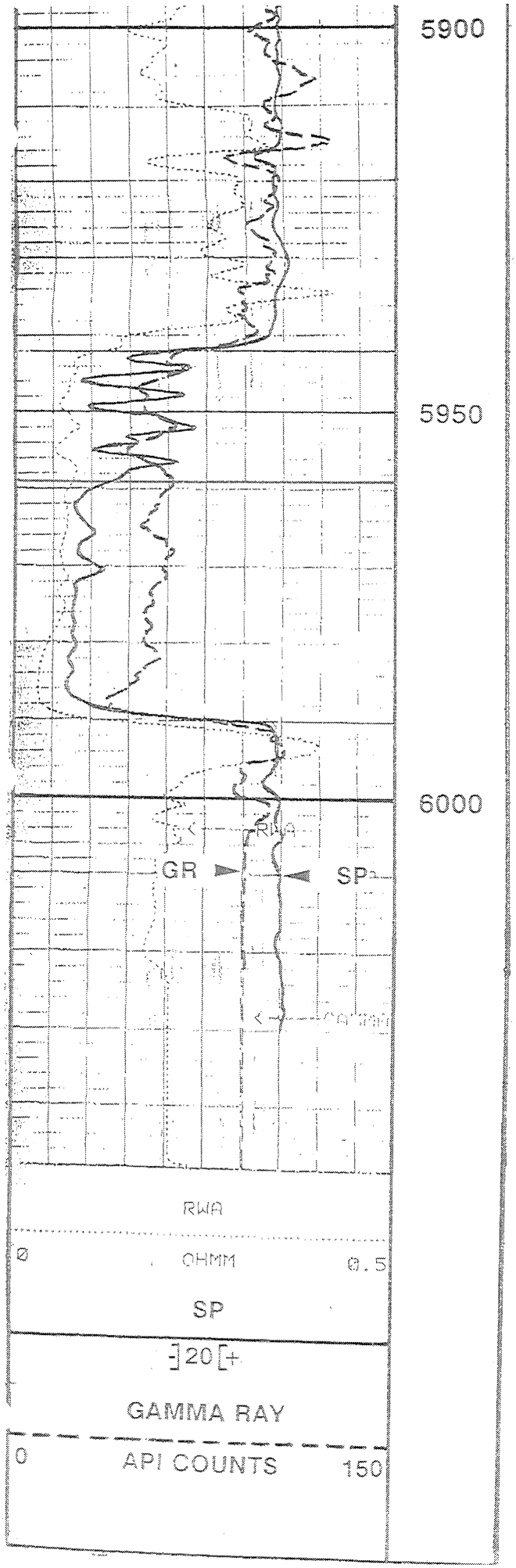
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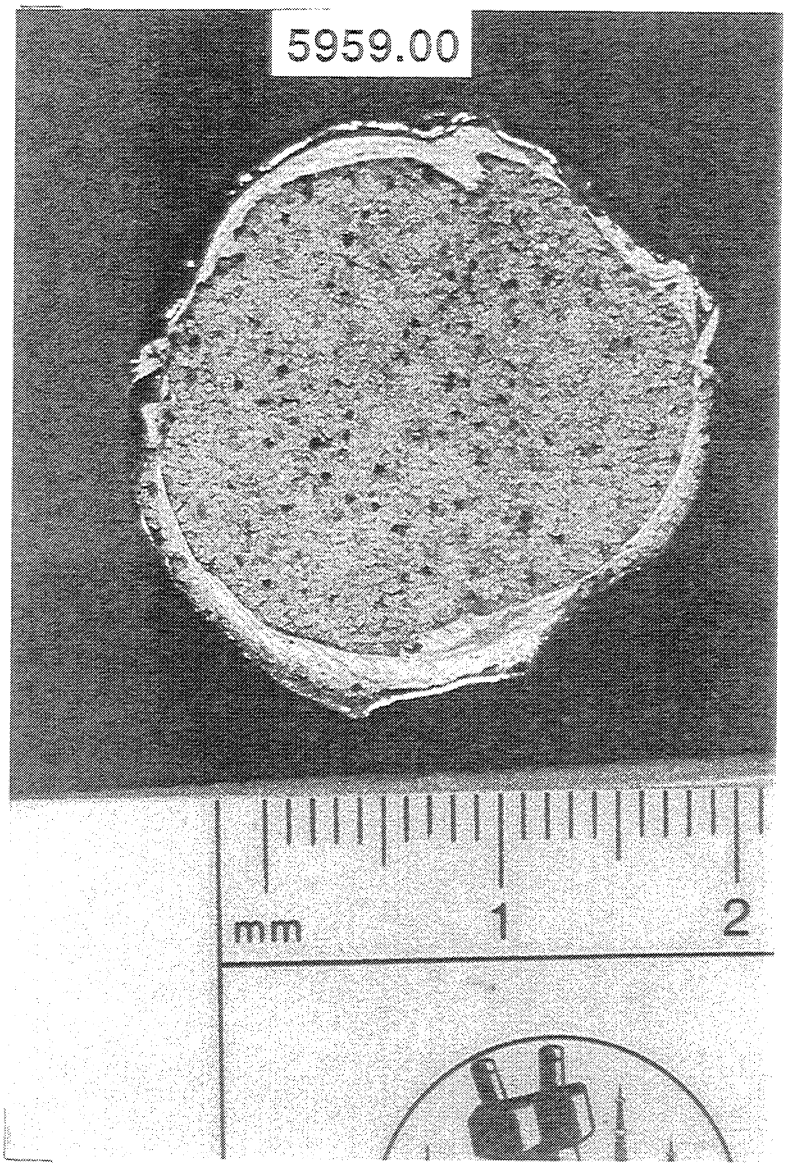
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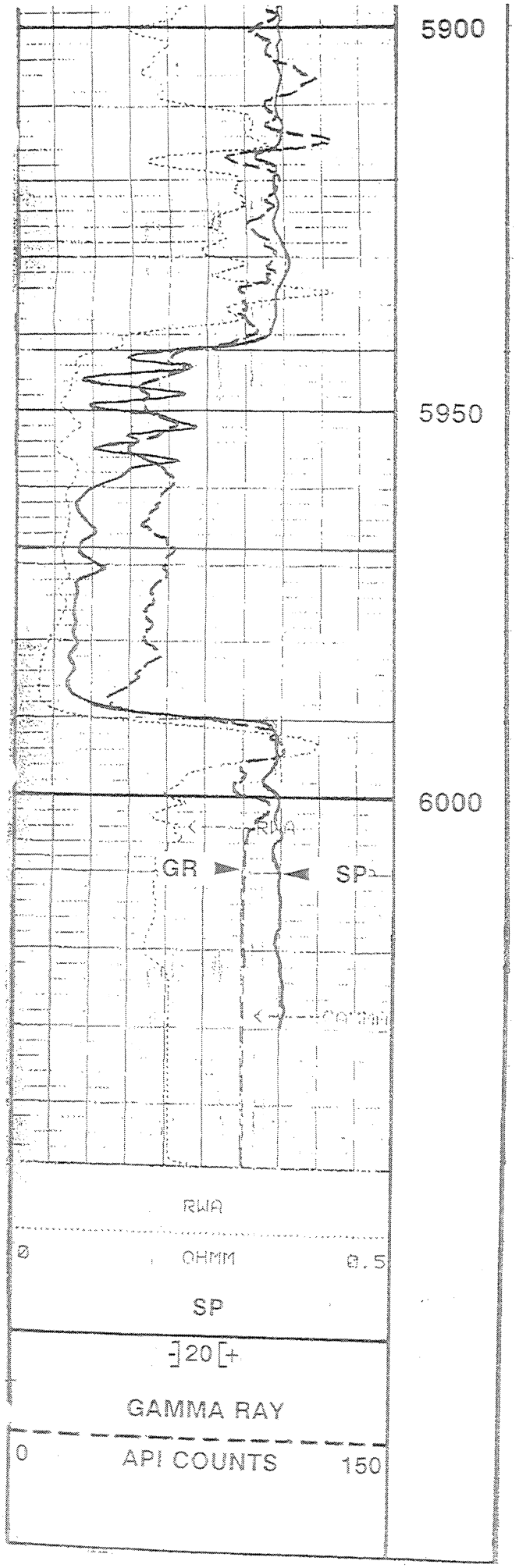
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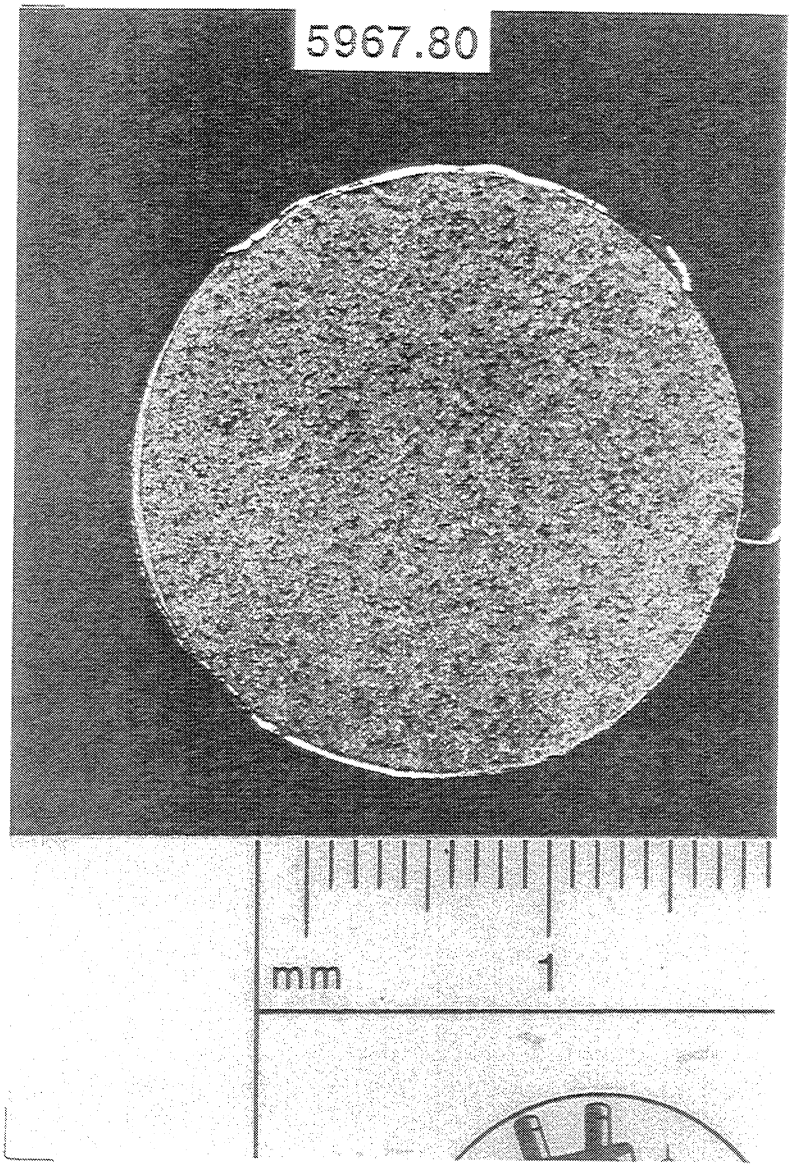
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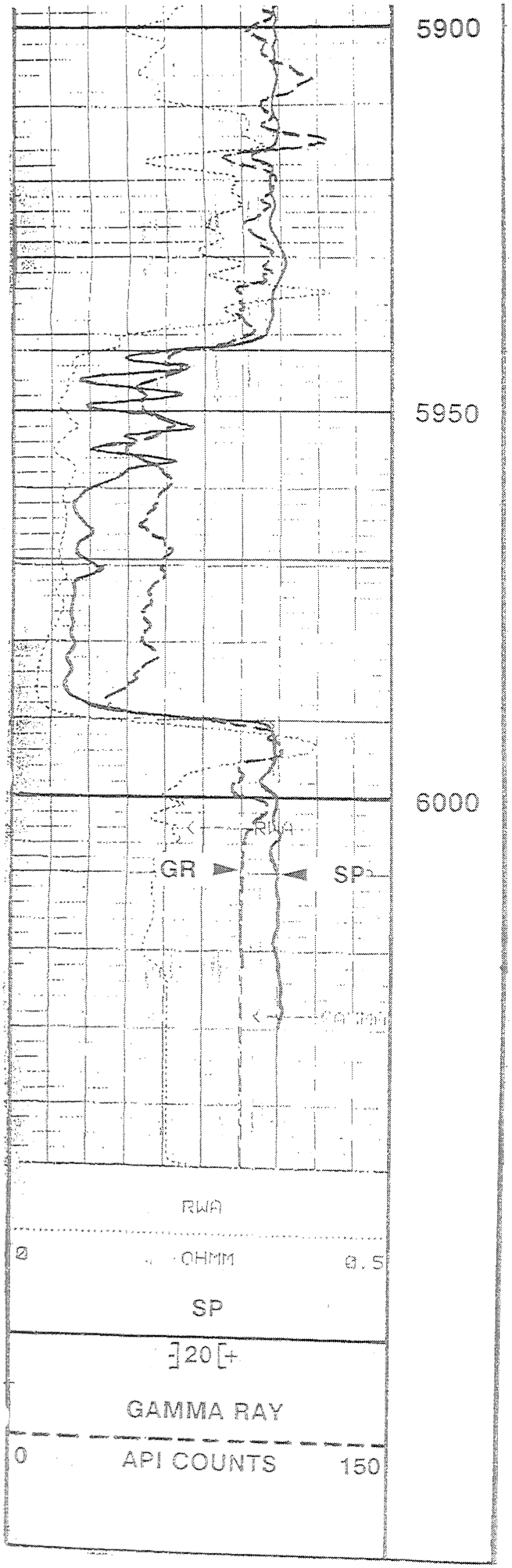
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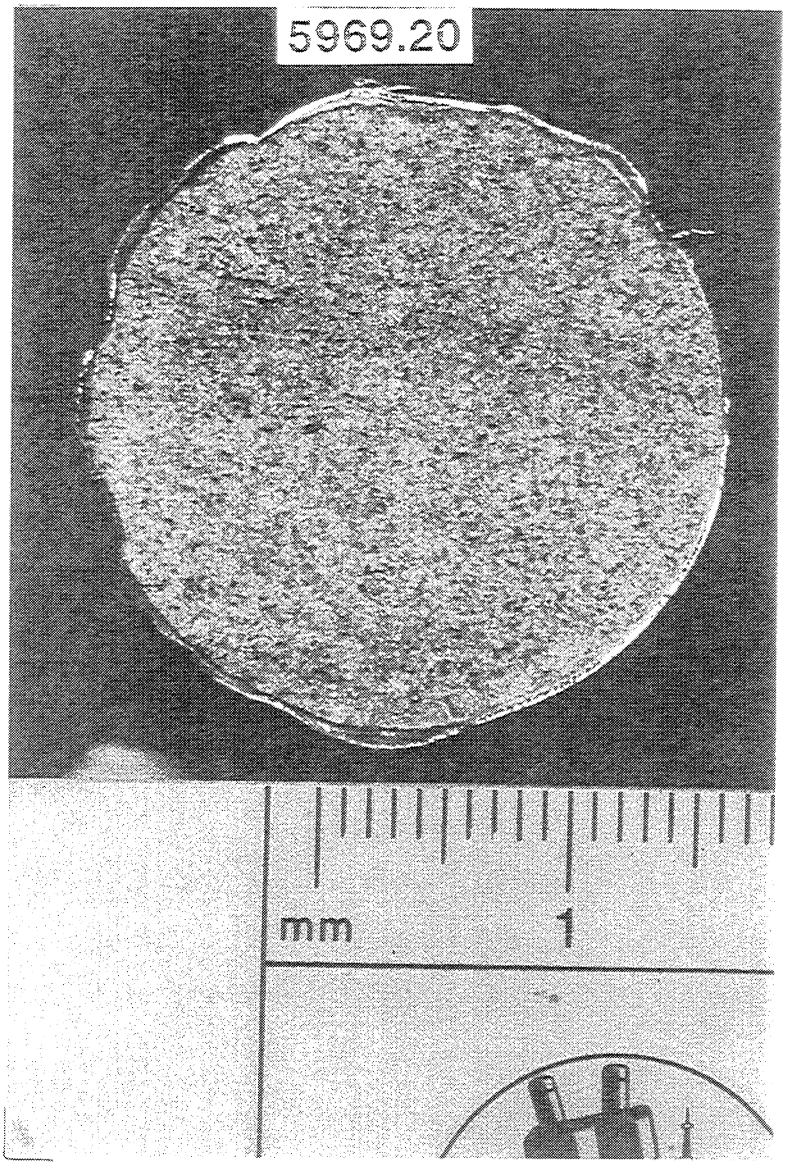
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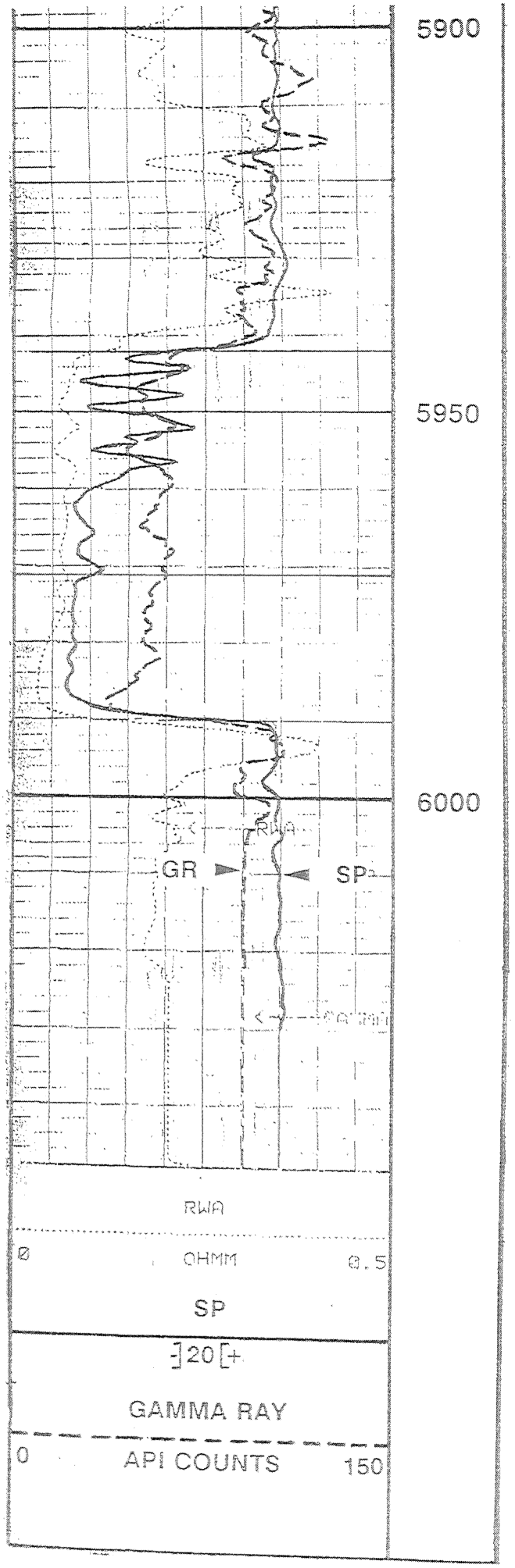
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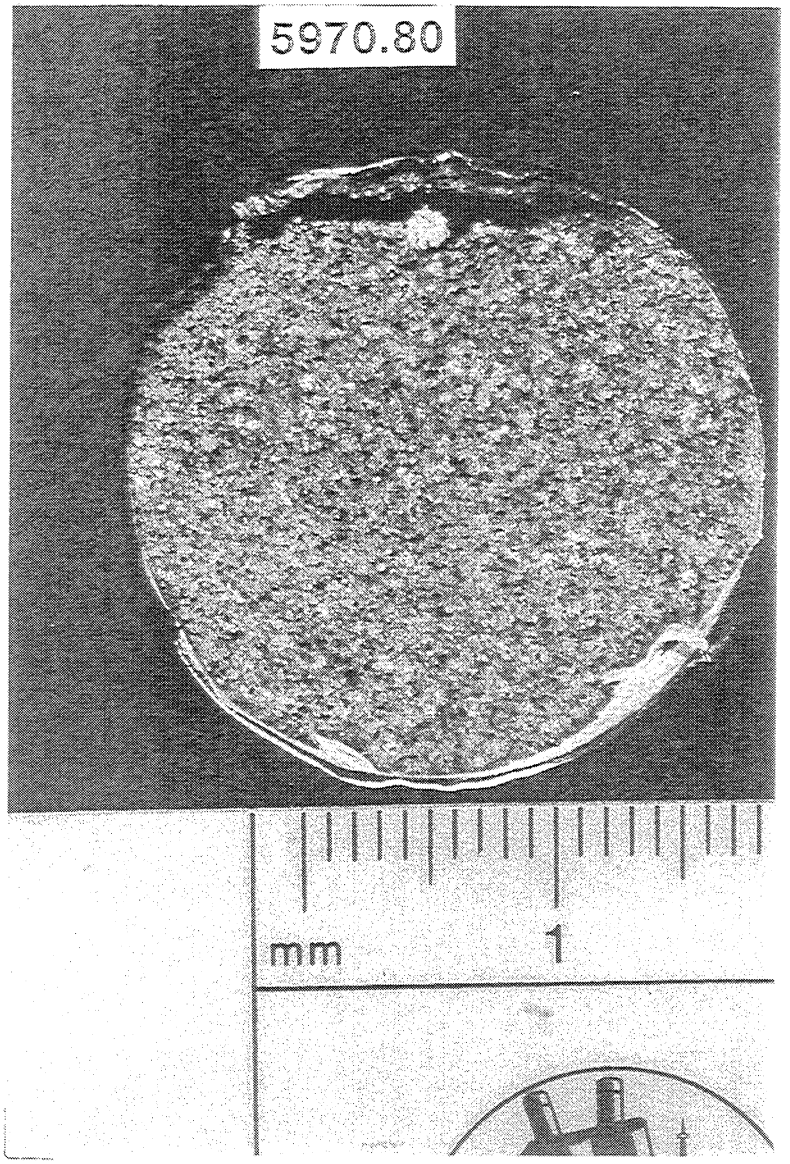
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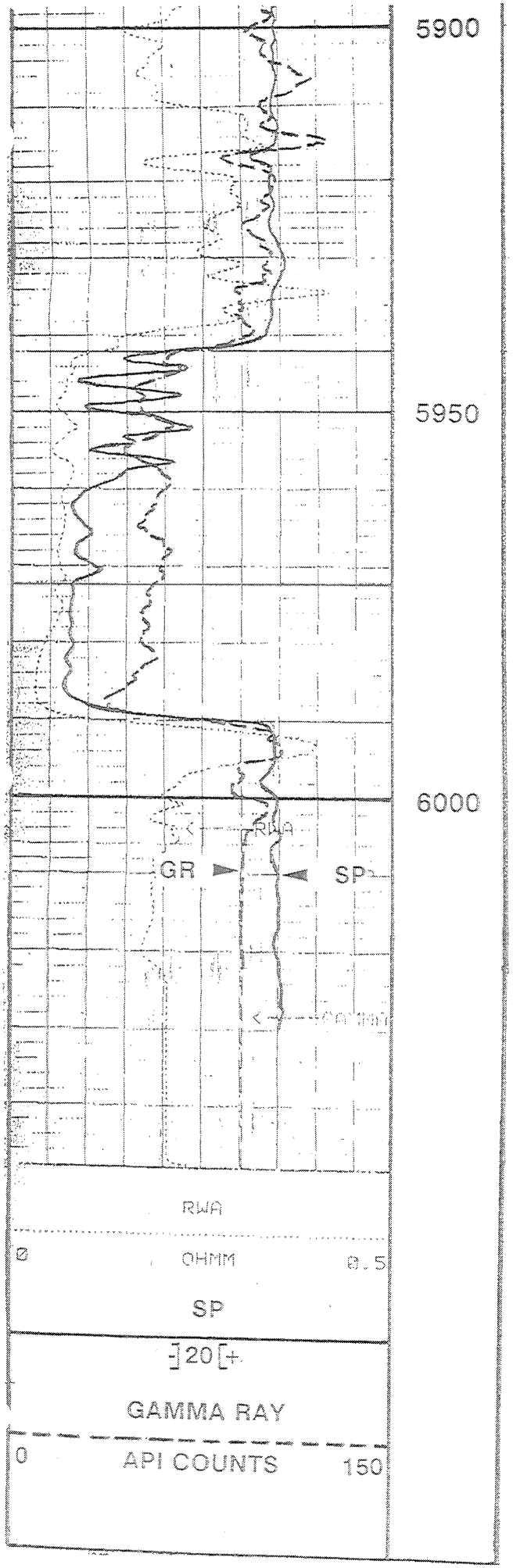
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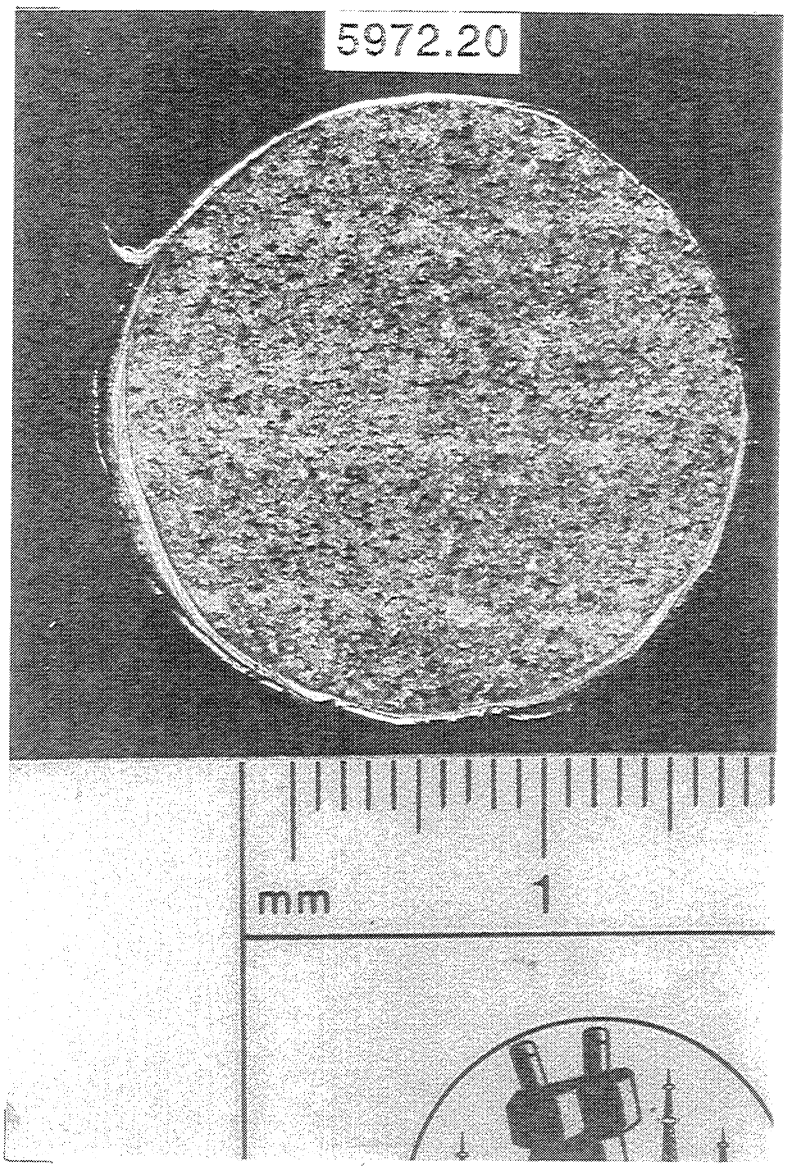
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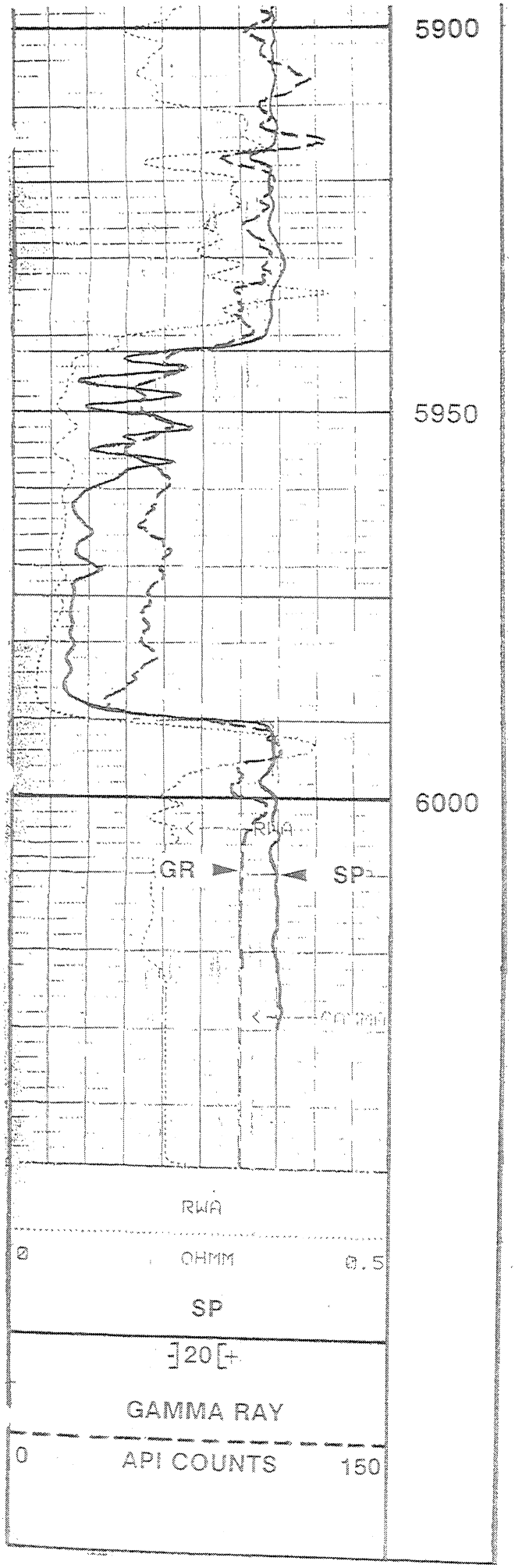
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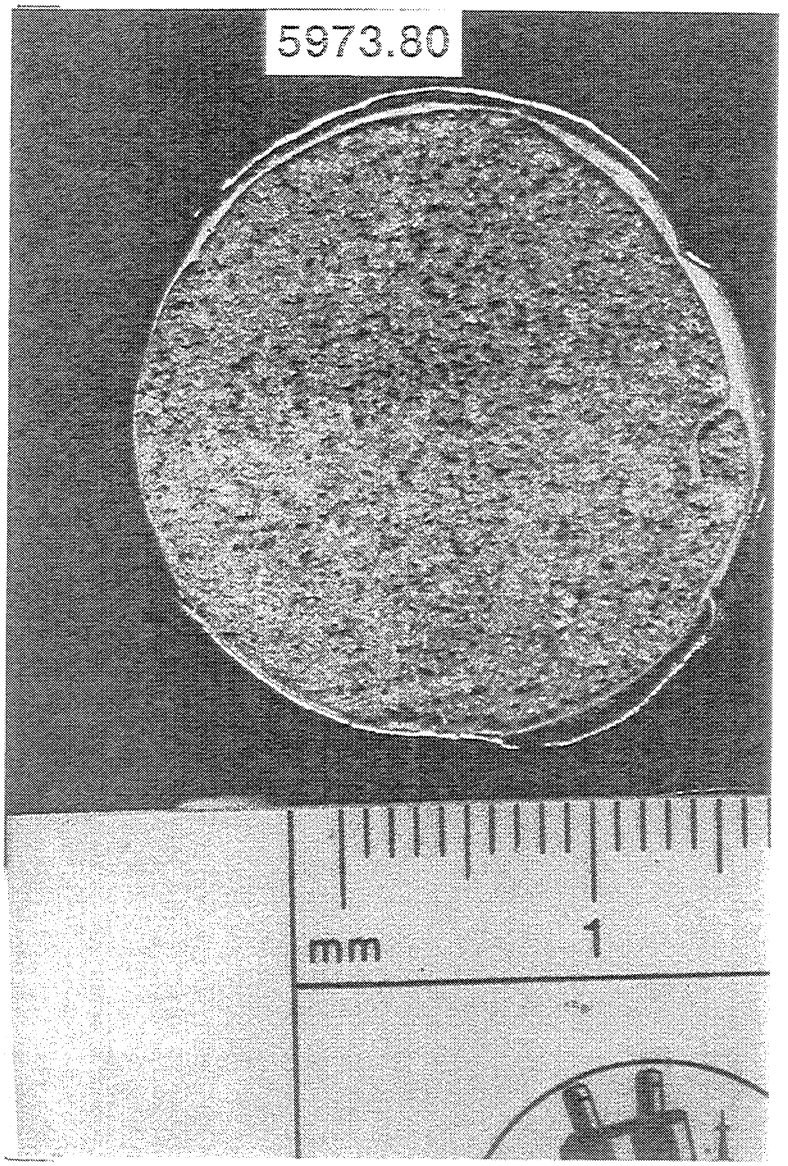
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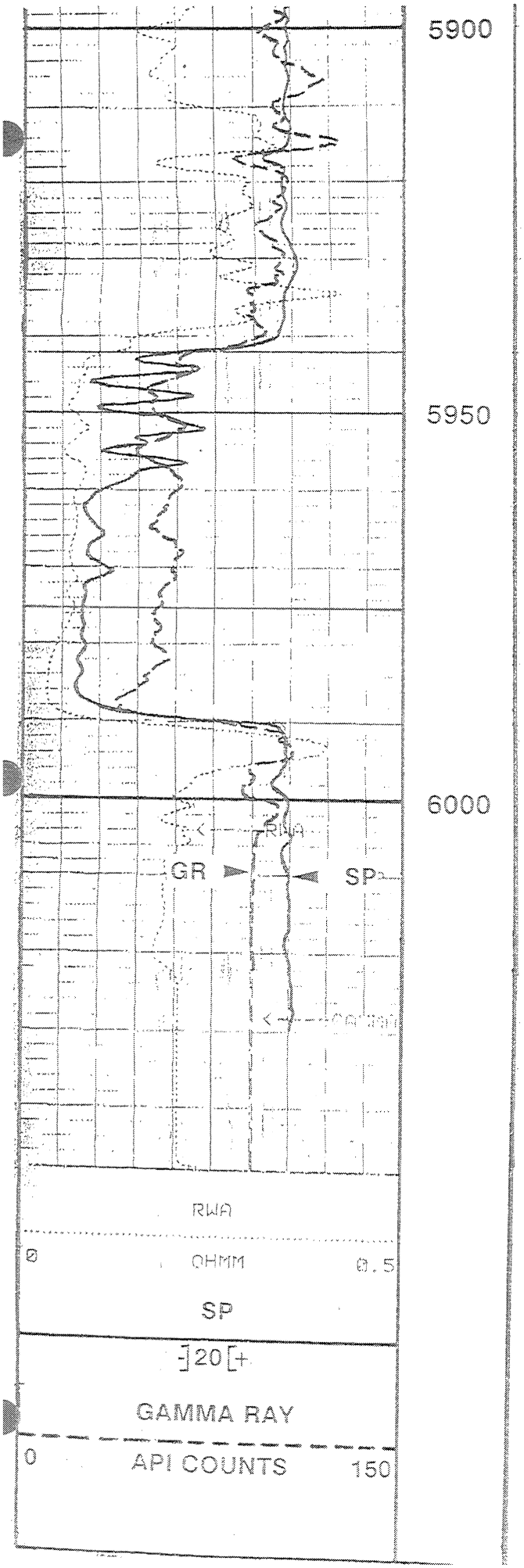
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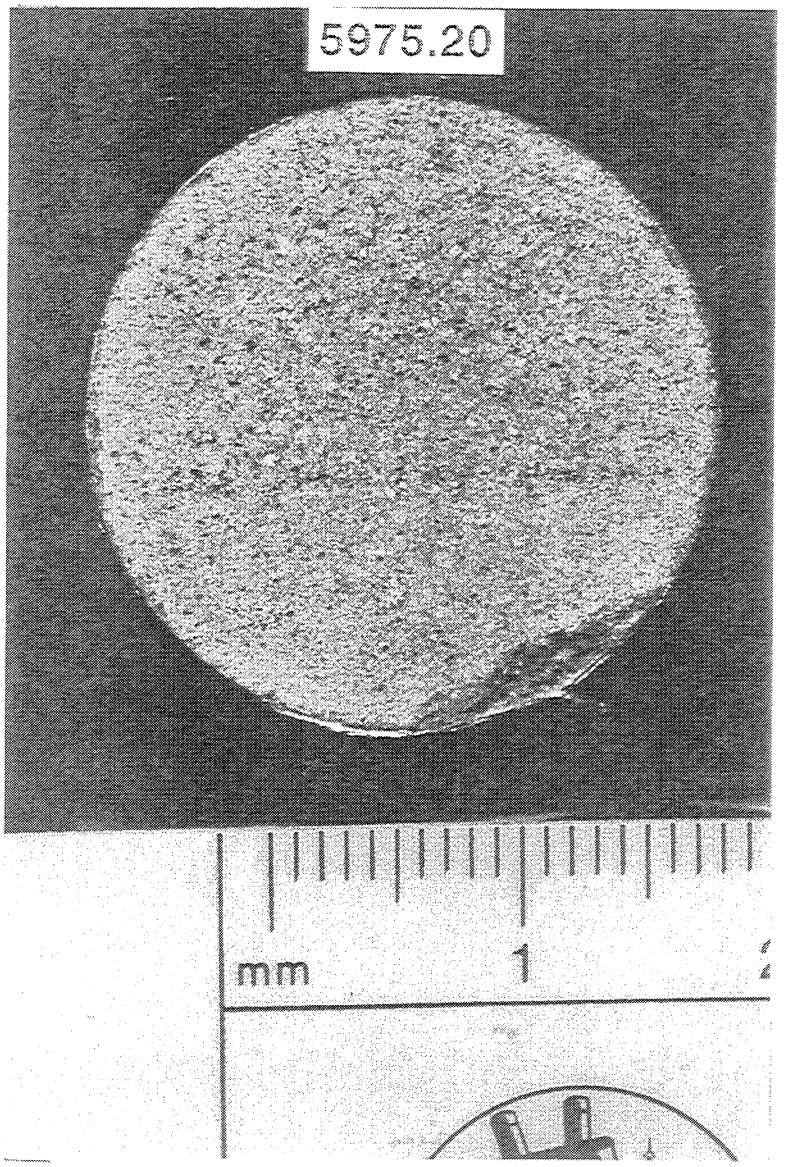
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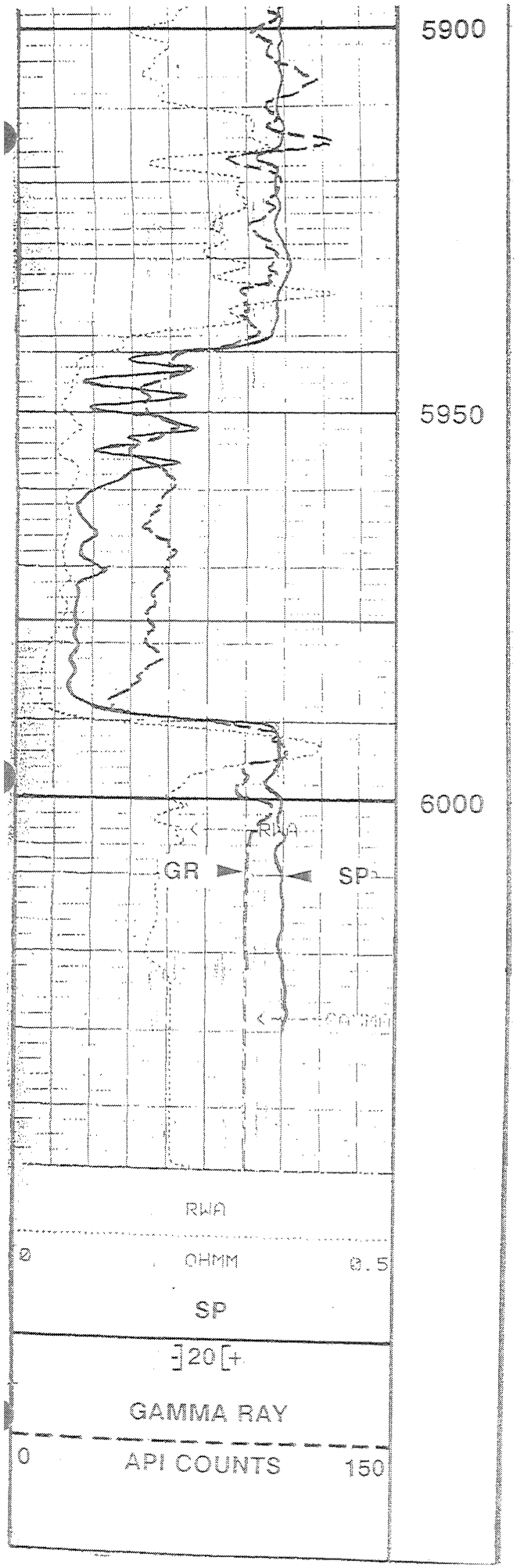
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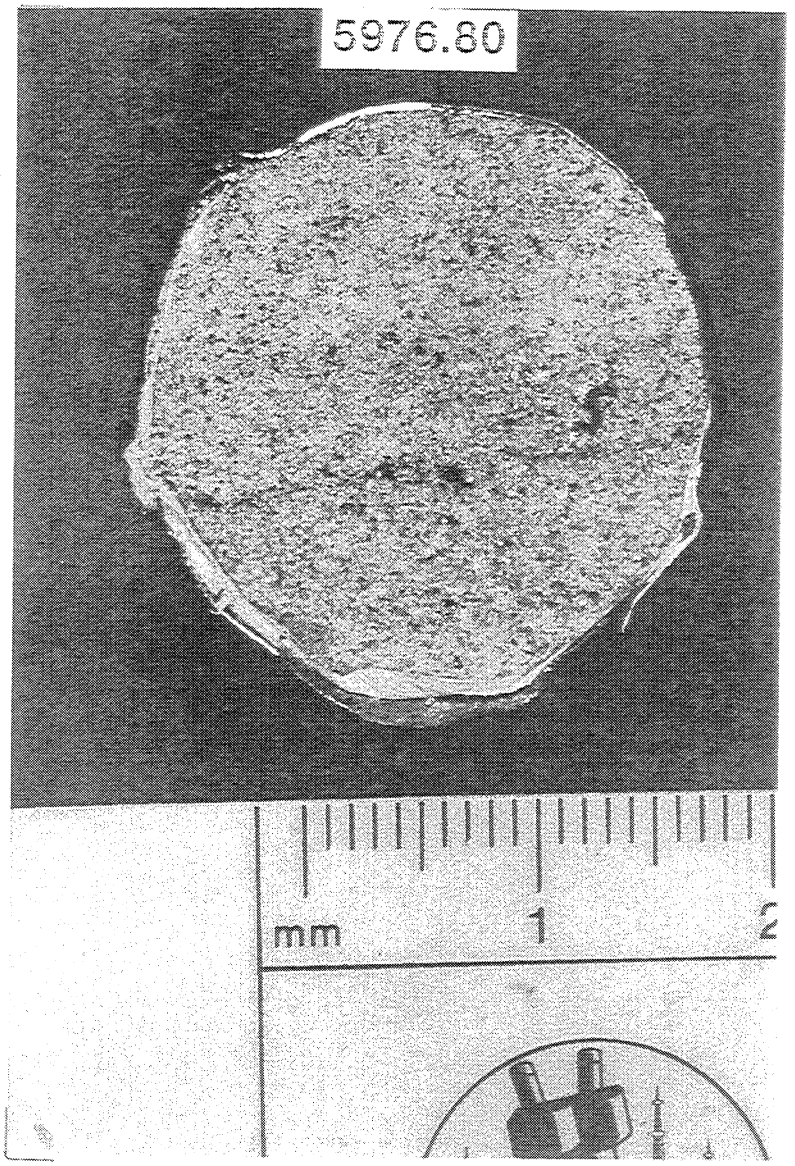
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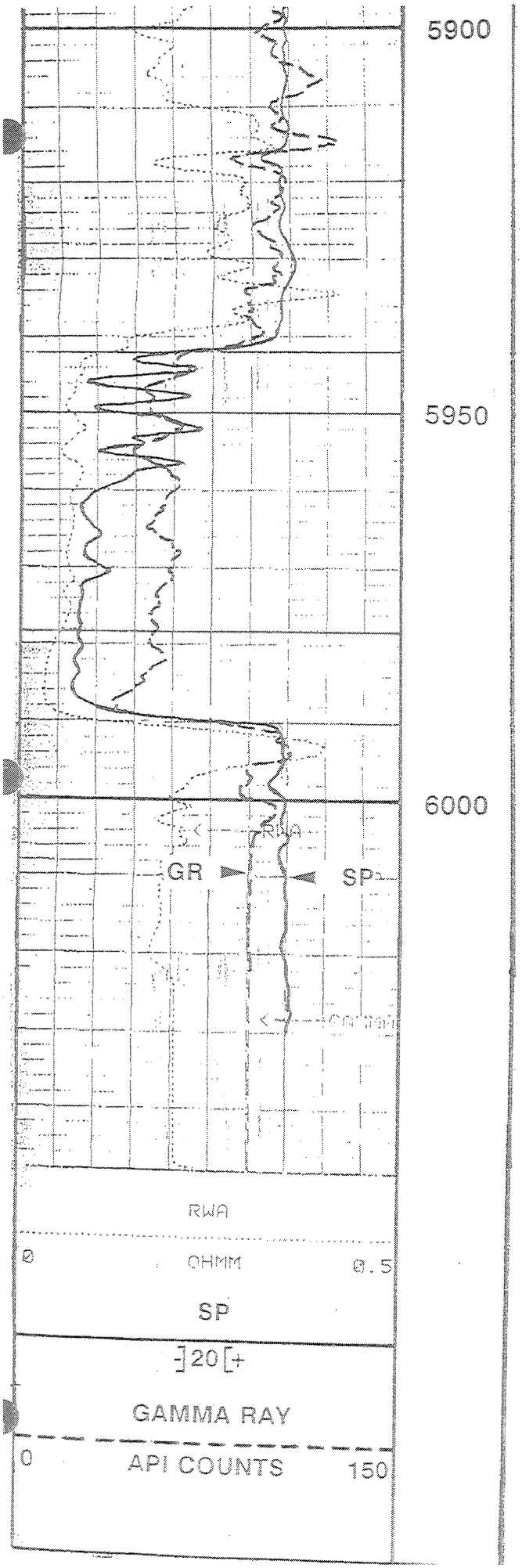
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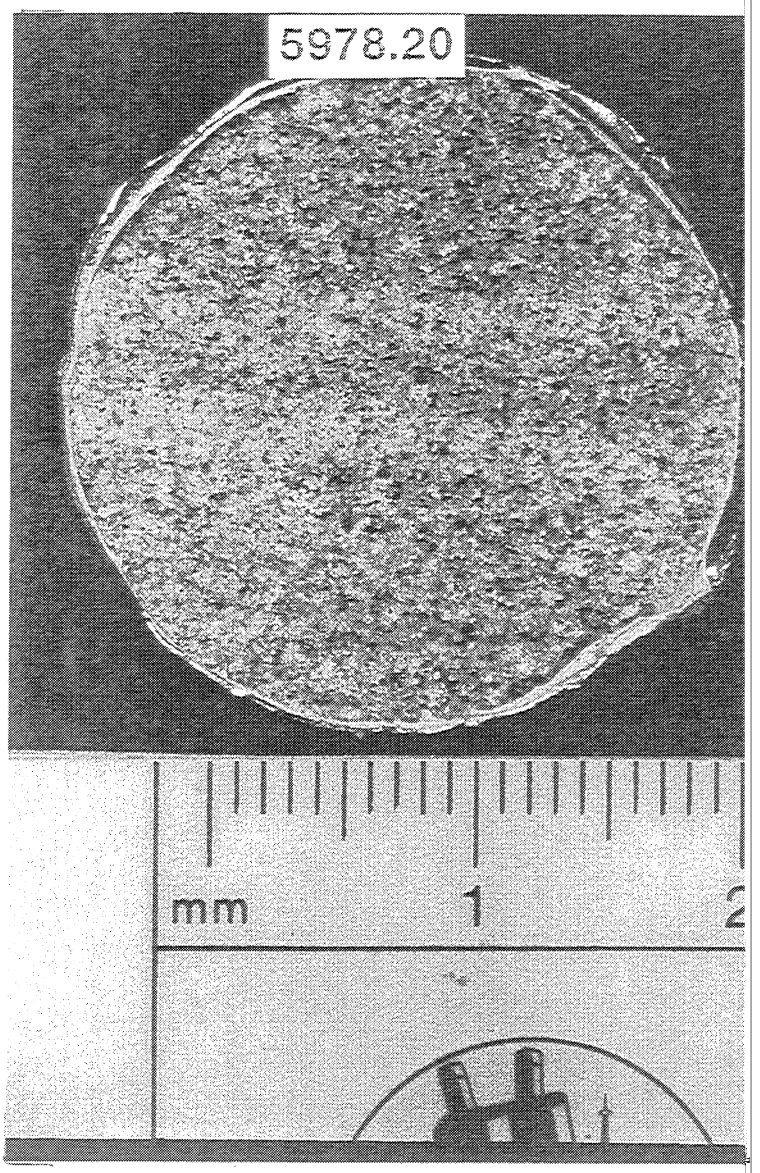
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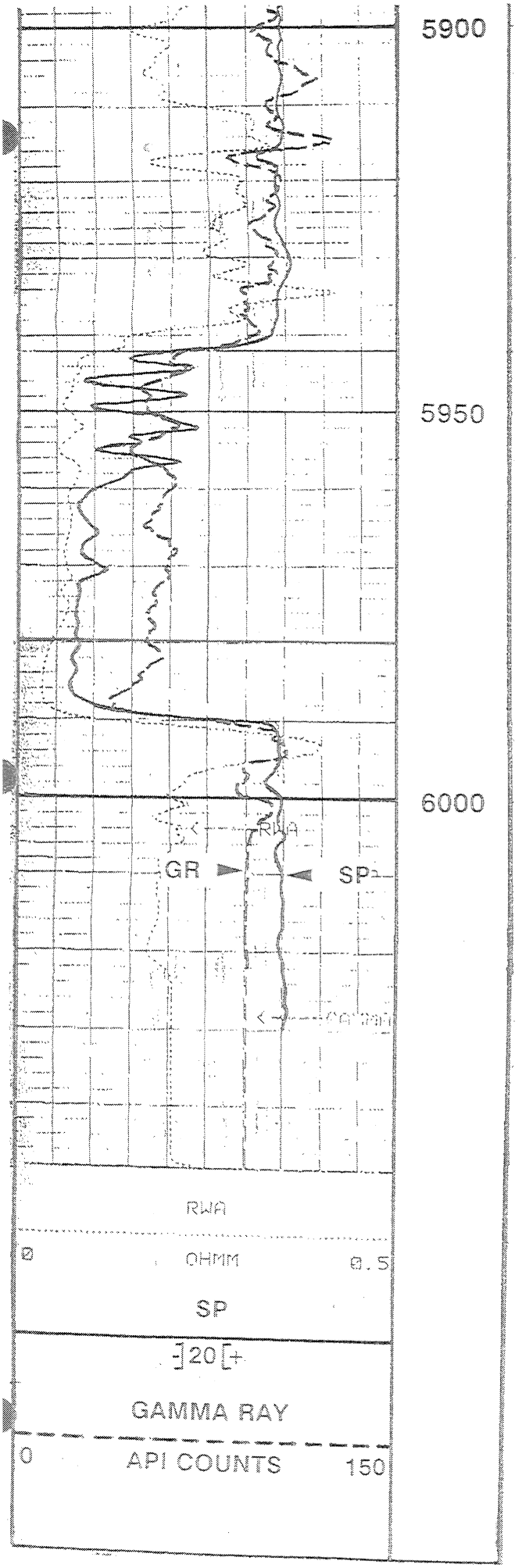
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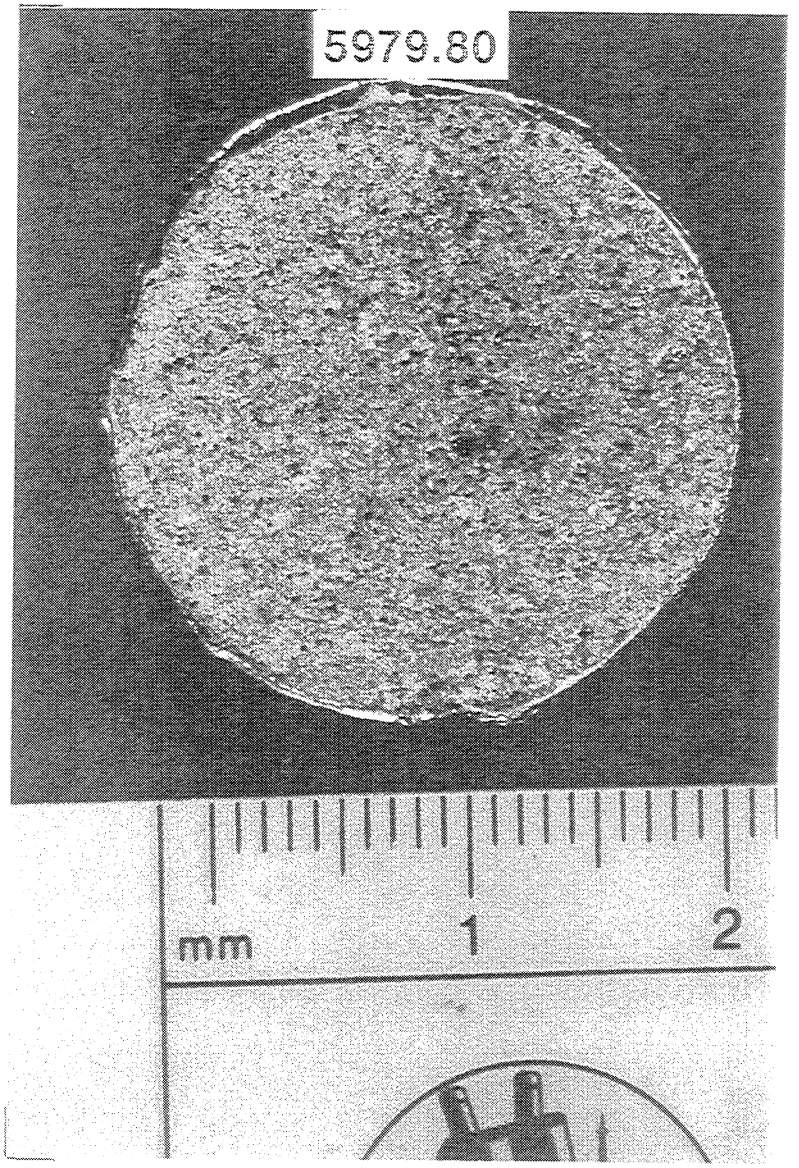
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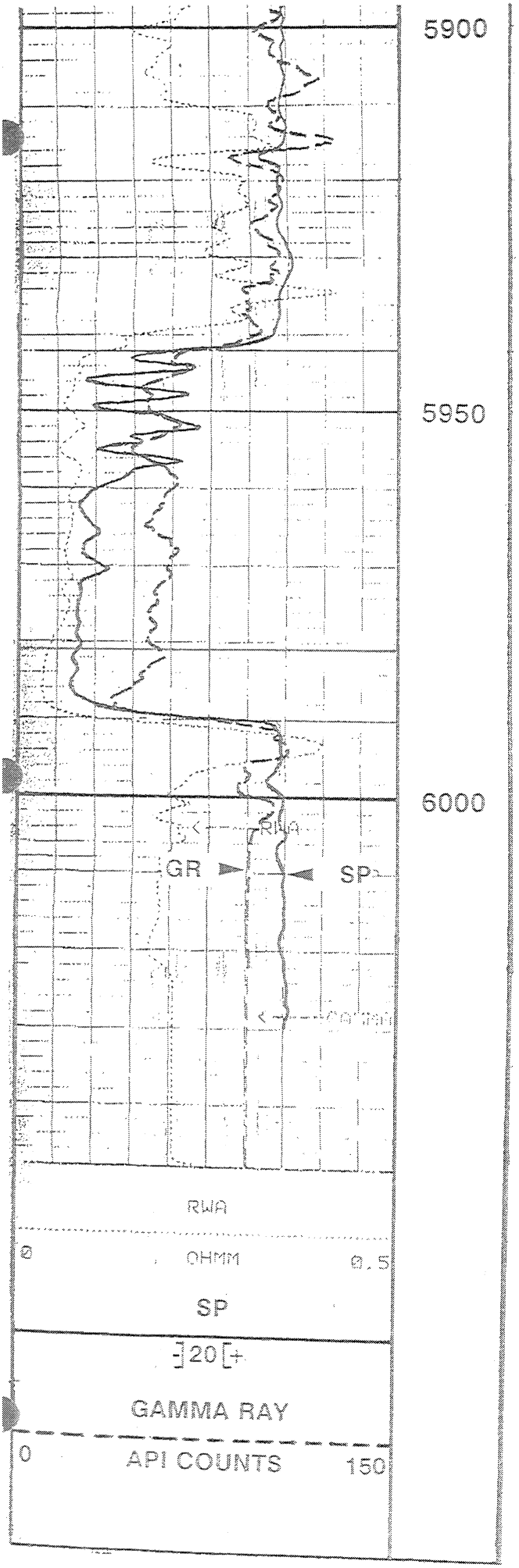
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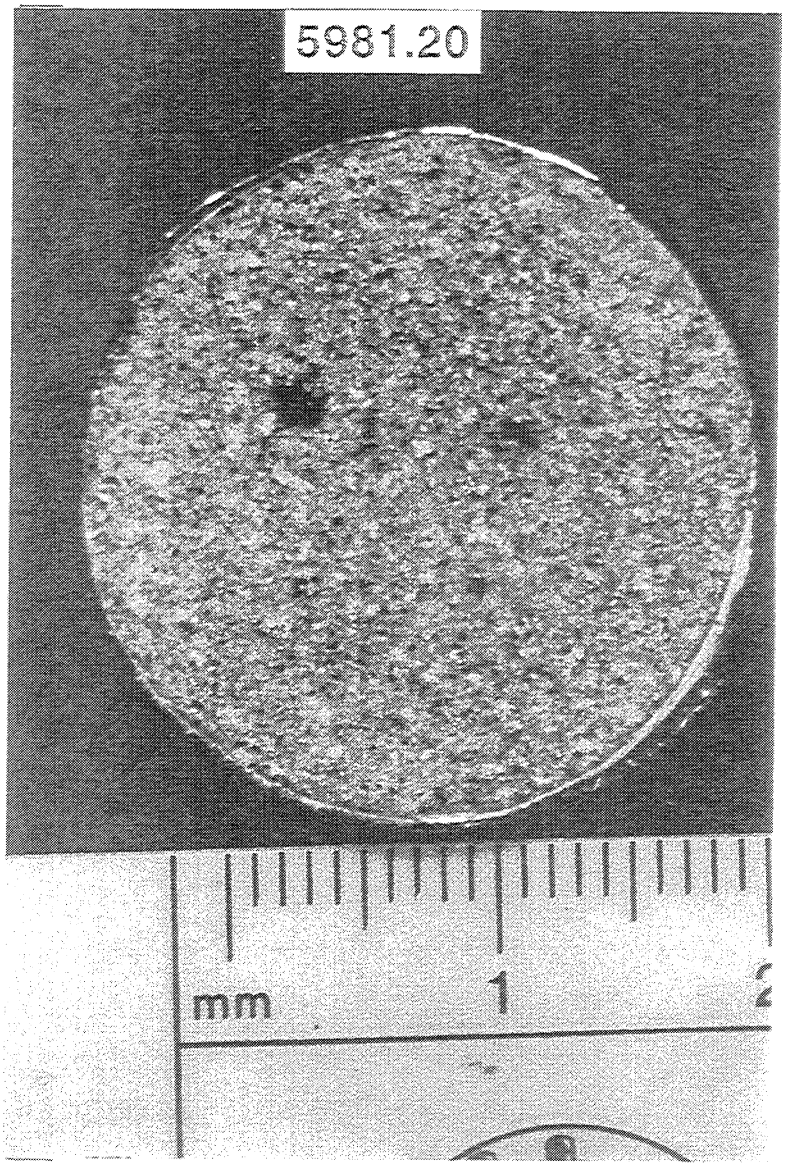
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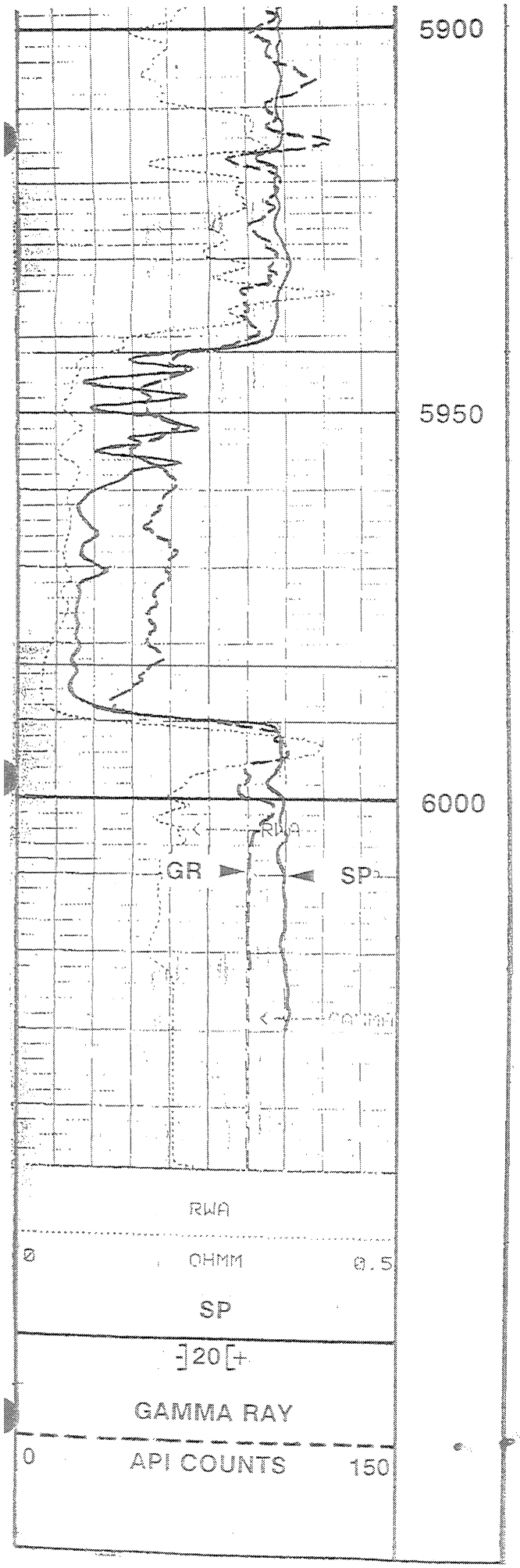
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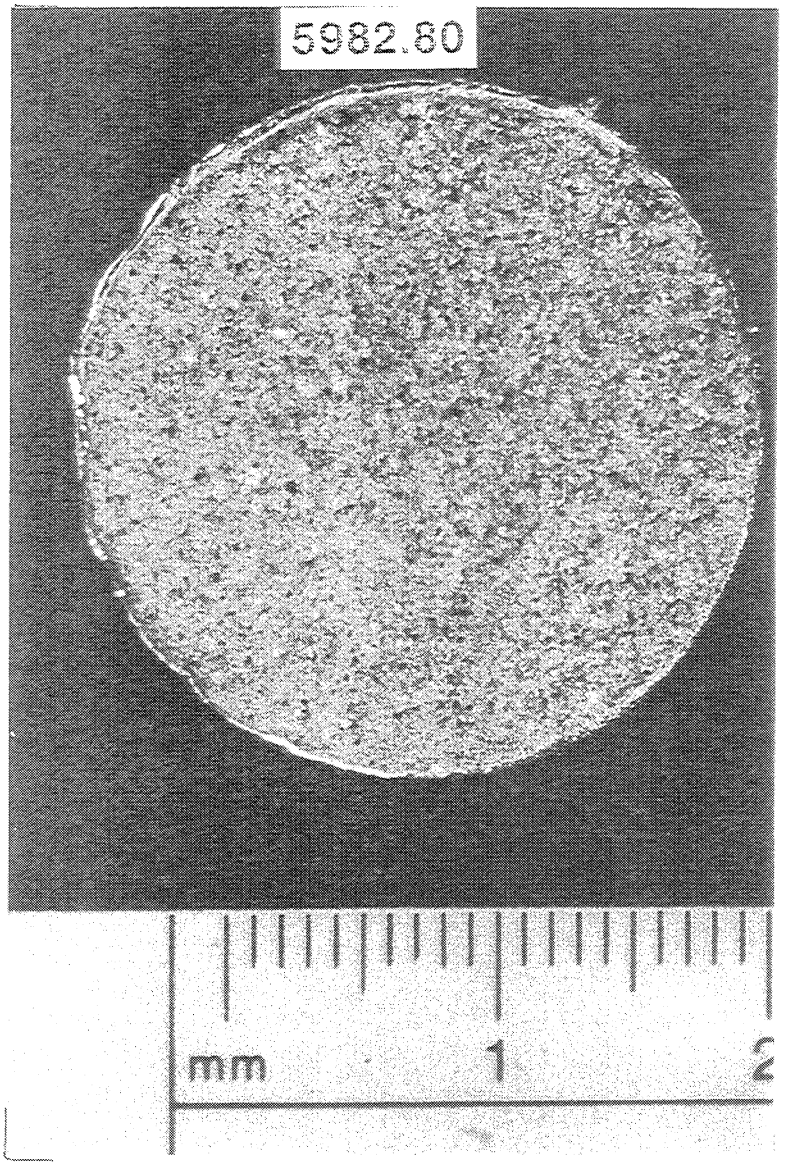
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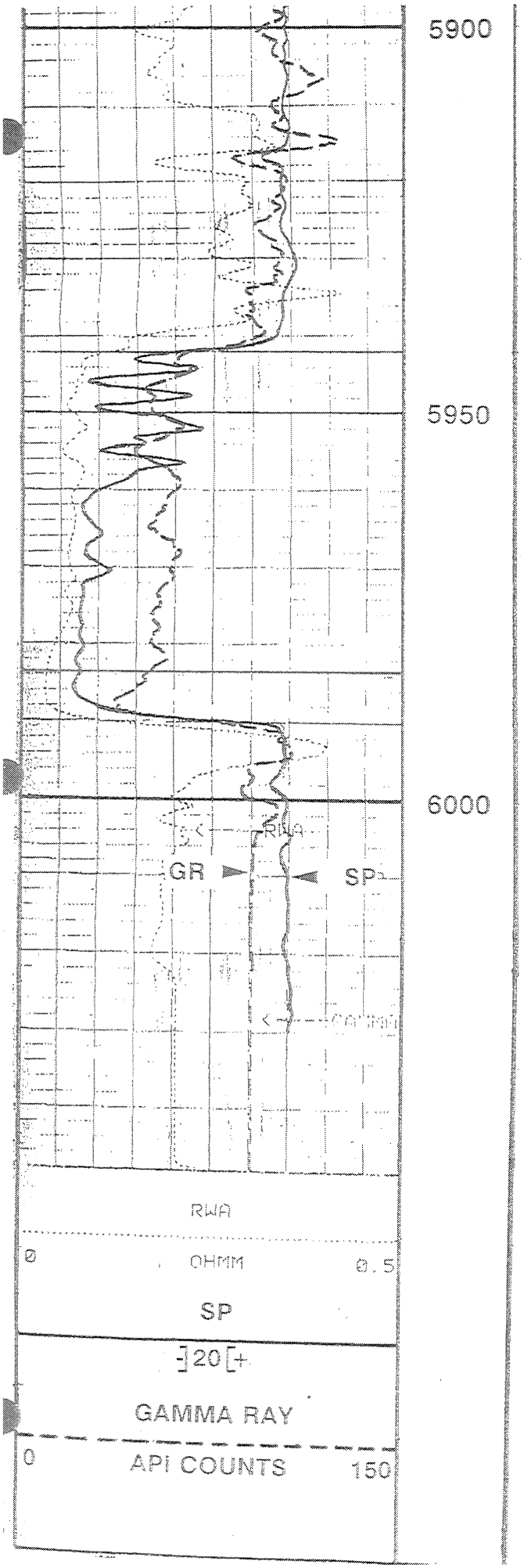
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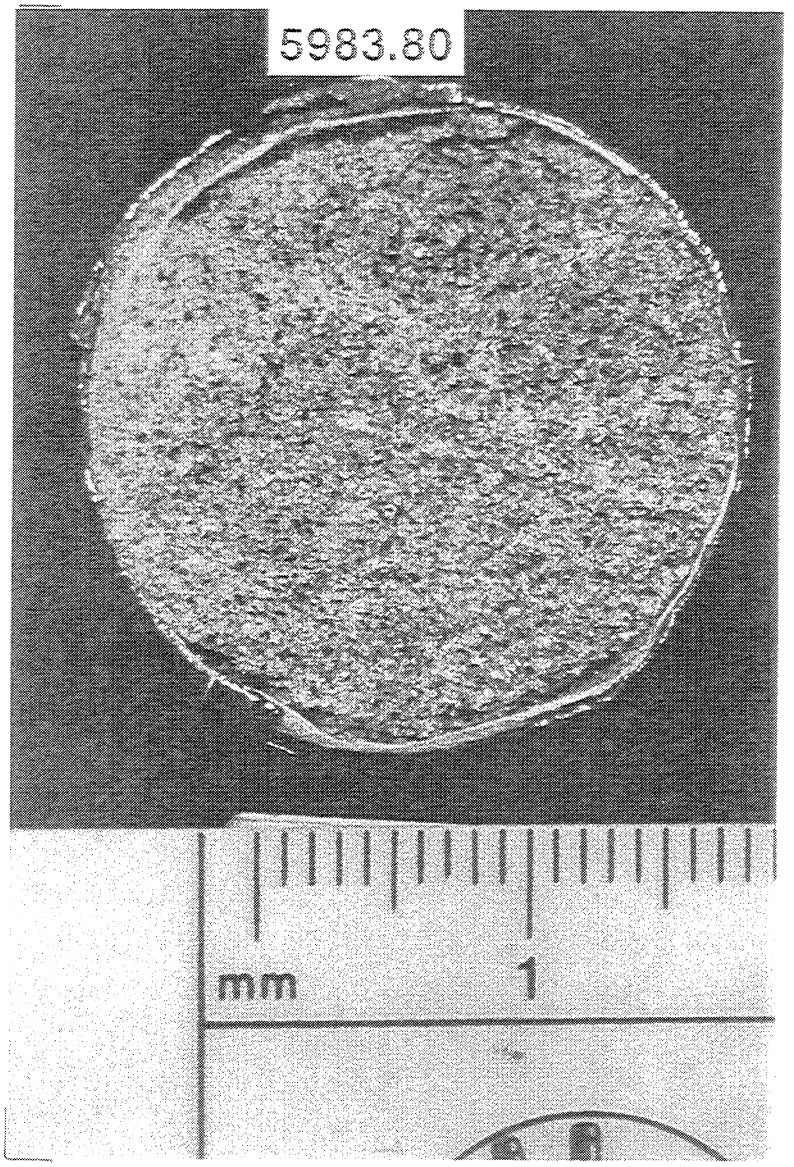
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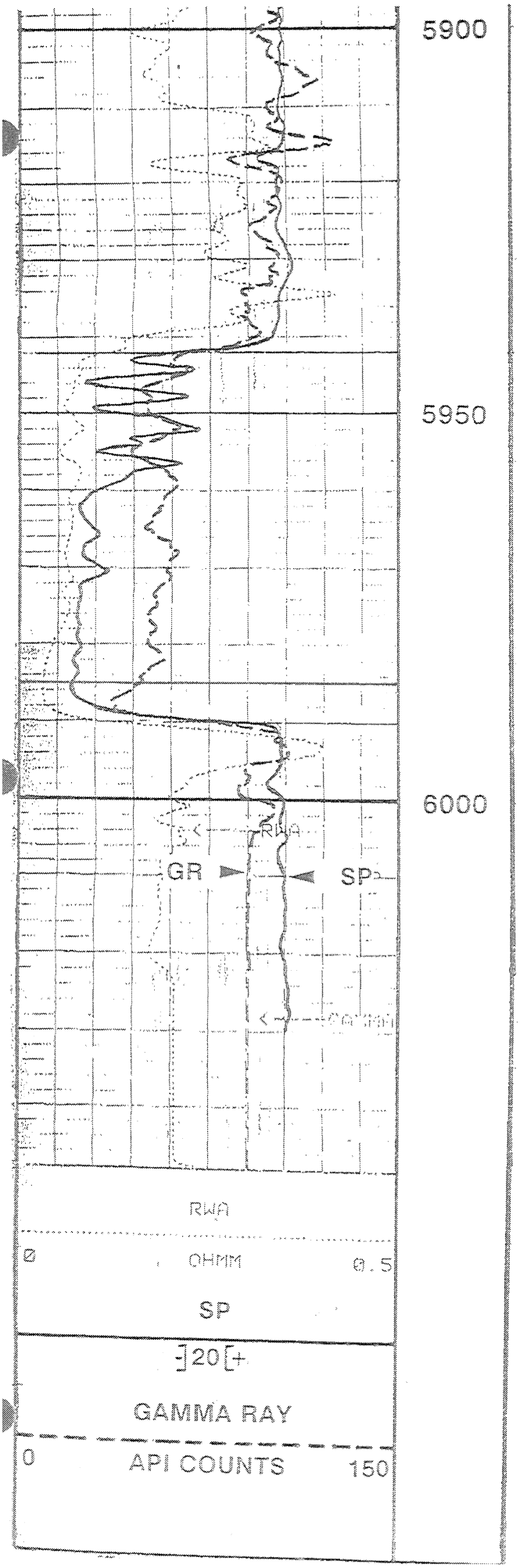
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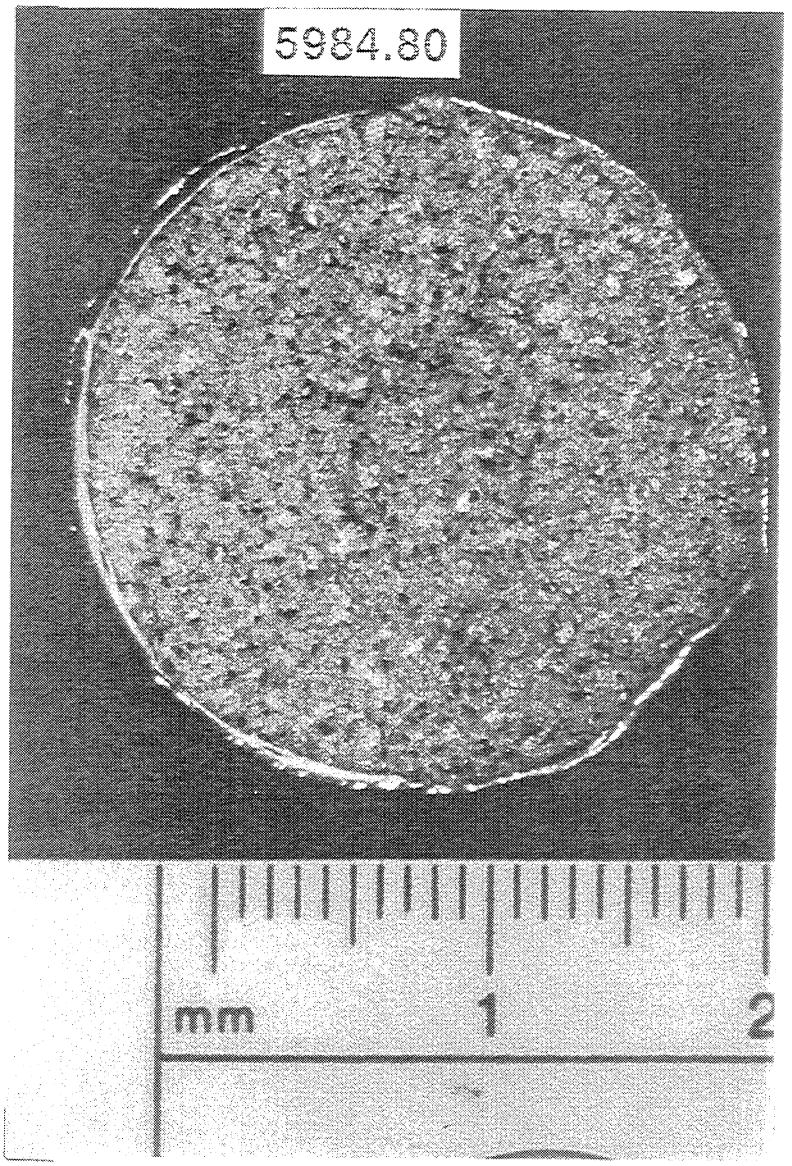
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FIELD IMPLEMENTATION

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.

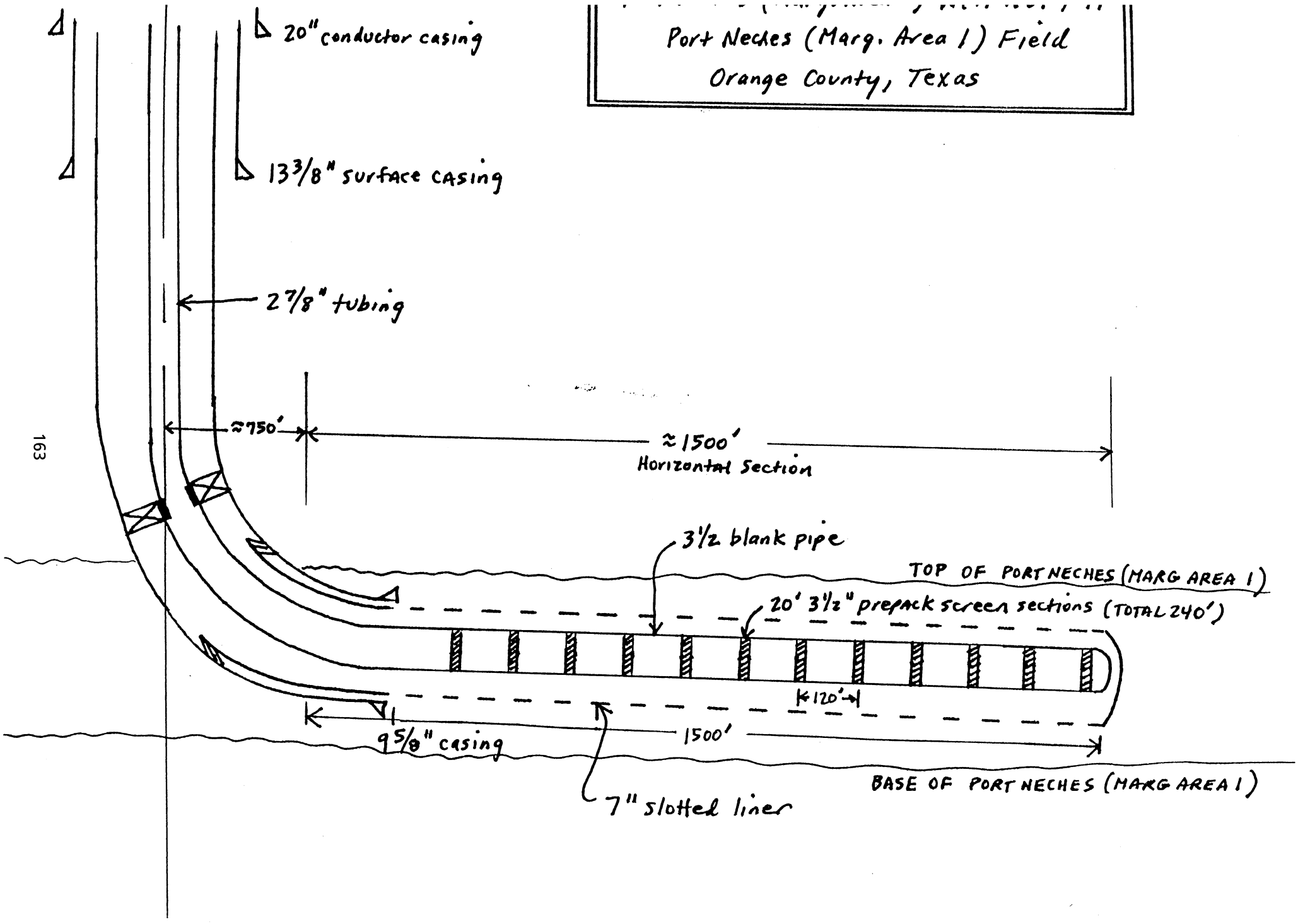
3-K A total of three compressors were overhauled and equipped with corrosion resistant parts.

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

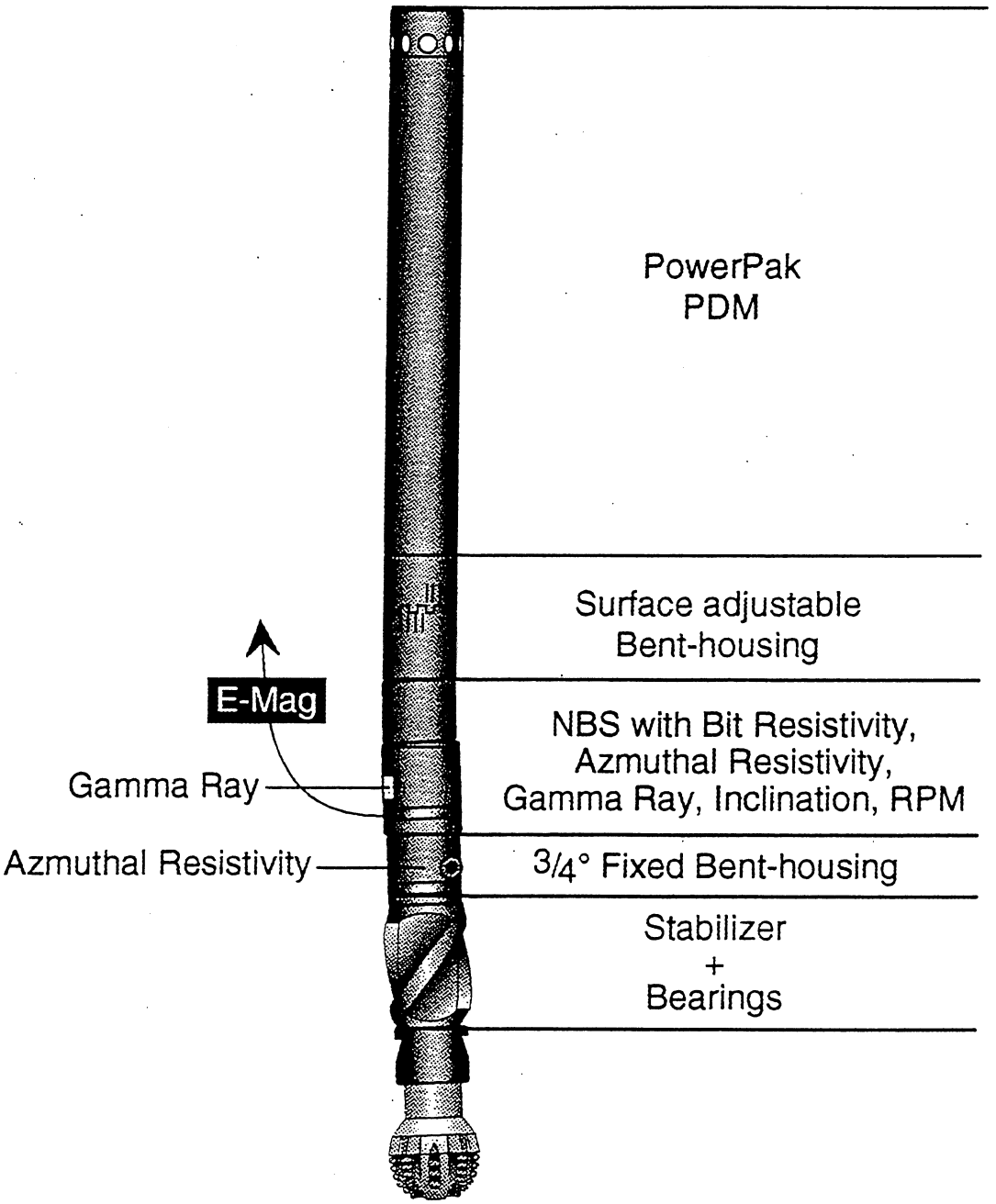
3-M A CO_2 injection pump capable of handling 250 tons per day (4.3 MMCFPD) of CO_2 purchased from Cardox was installed on the upper deck of the compressor barge.

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.

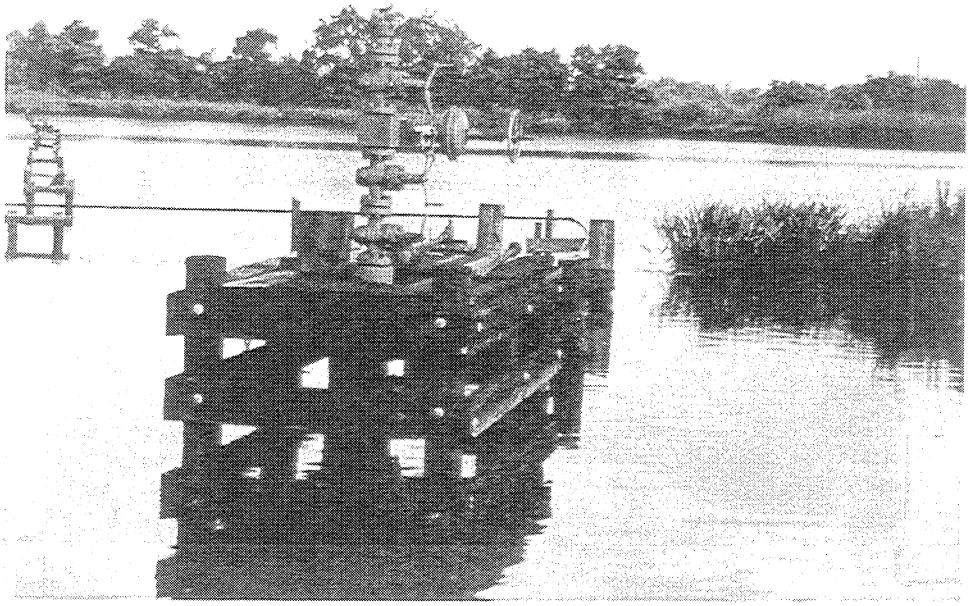
3-O Oil and water production gathered on the compressor barge is piped to the gunbarrel, oil, and water tanks.


Port Neches (Marg. Area 1) Field
Orange County, Texas
20" conductor casing
13 3/8" surface casing
2 7/8" tubing
≈750'
≈1500'
Horizontal Section
3 1/2 blank pipe
TOP OF PORT NECHES (MARG AREA 1)
20' 3 1/2" prepack screen sections (TOTAL 240')
120'
9 5/8" casing
1500'
BASE OF PORT NECHES (MARG AREA 1)
7" slotted liner

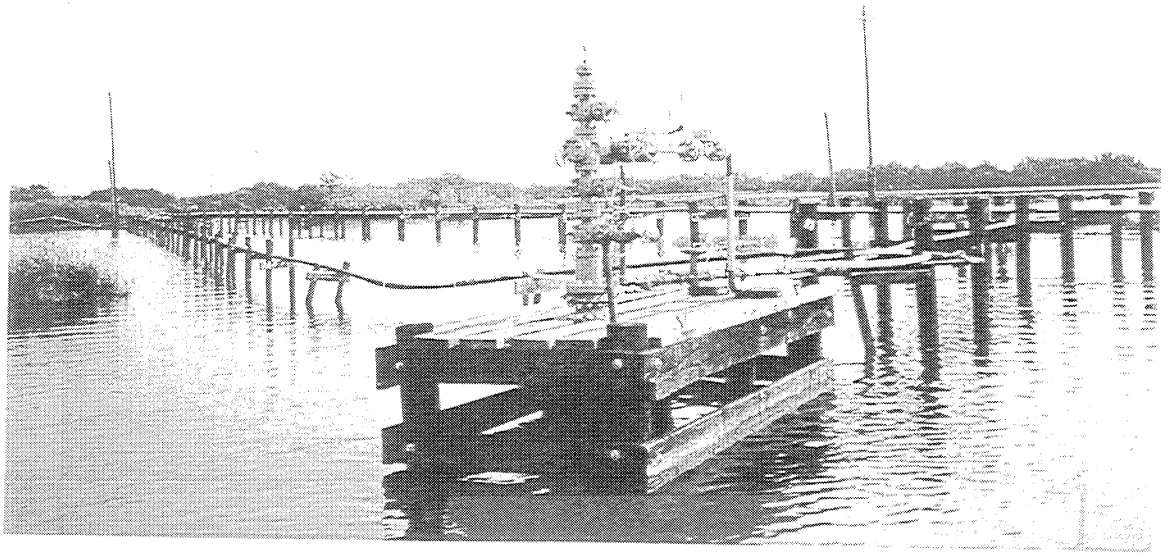
GeoSteering Tool



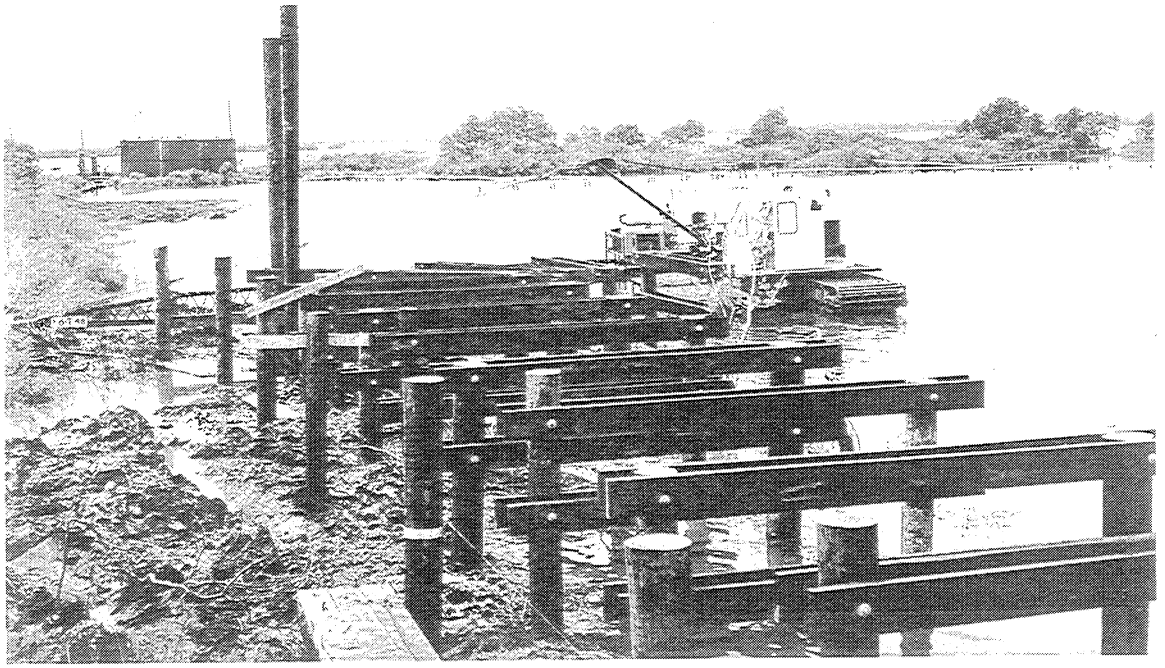
Photograph 3-A



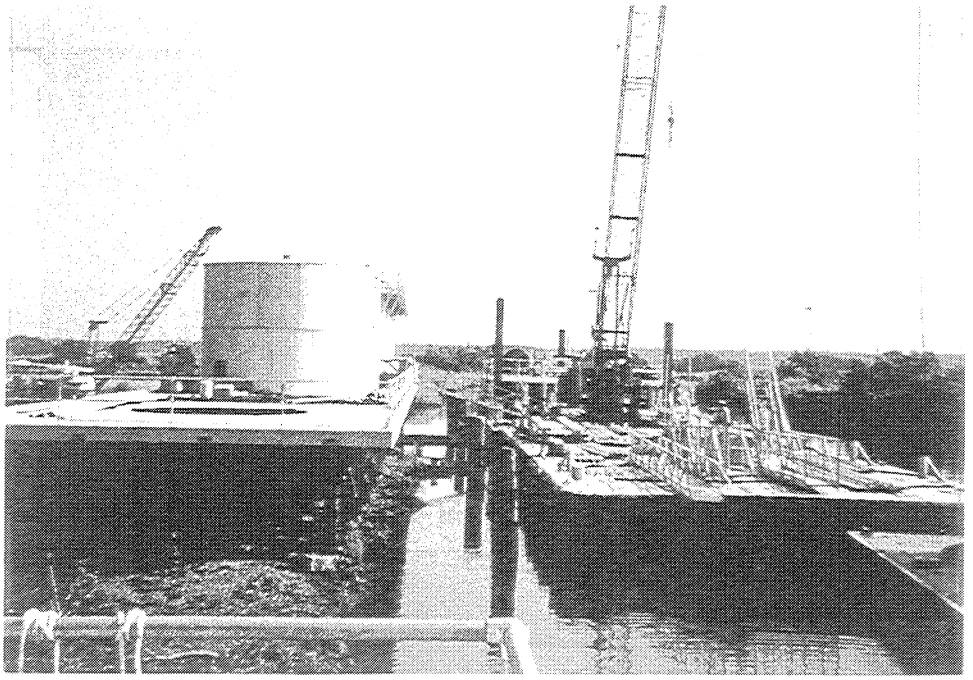
Photograph 3-B



Photograph 3-C



Photograph 3-D



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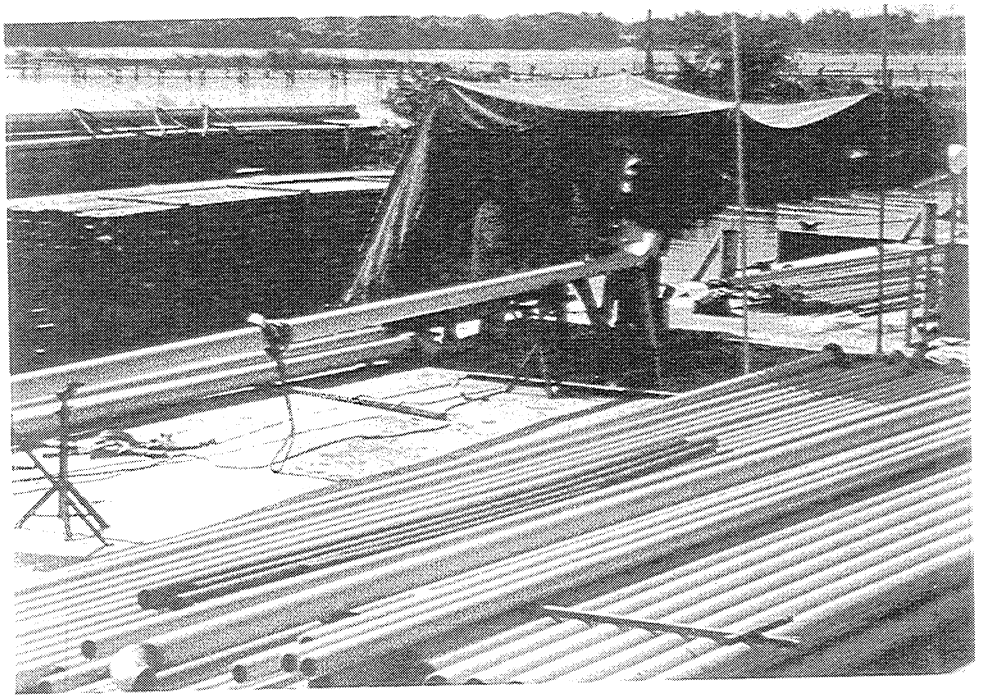

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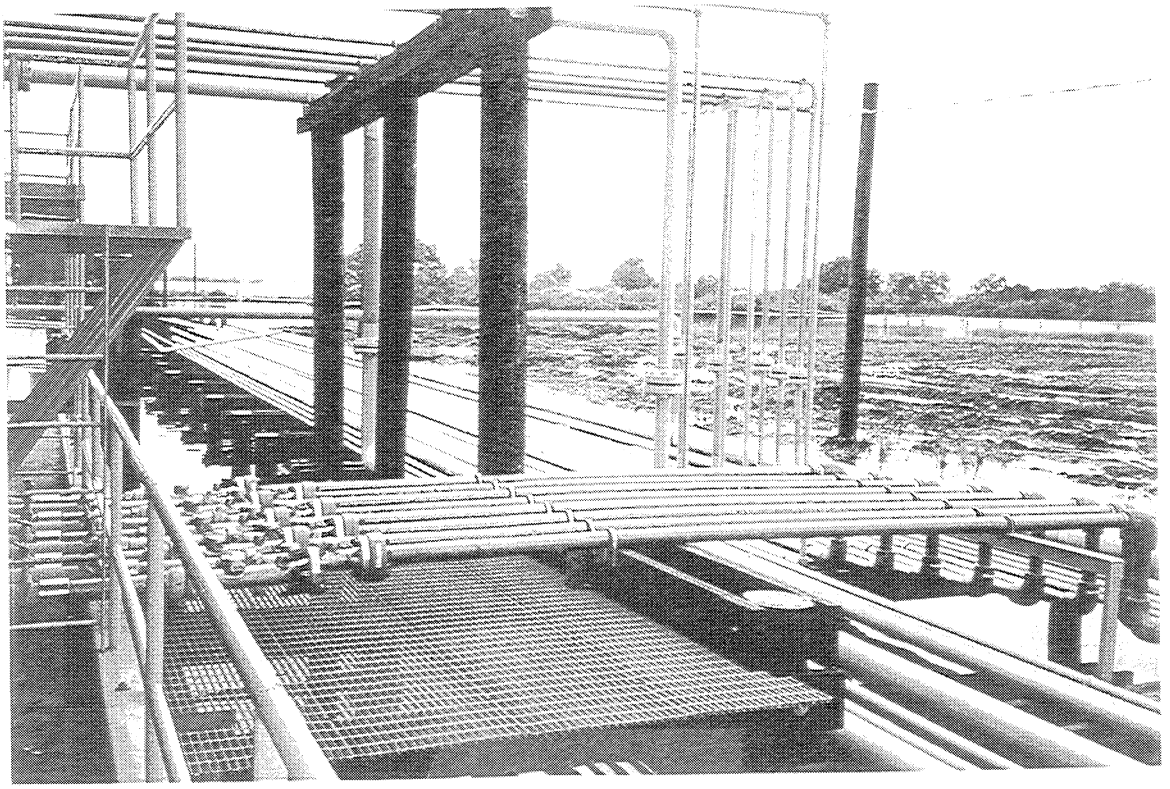

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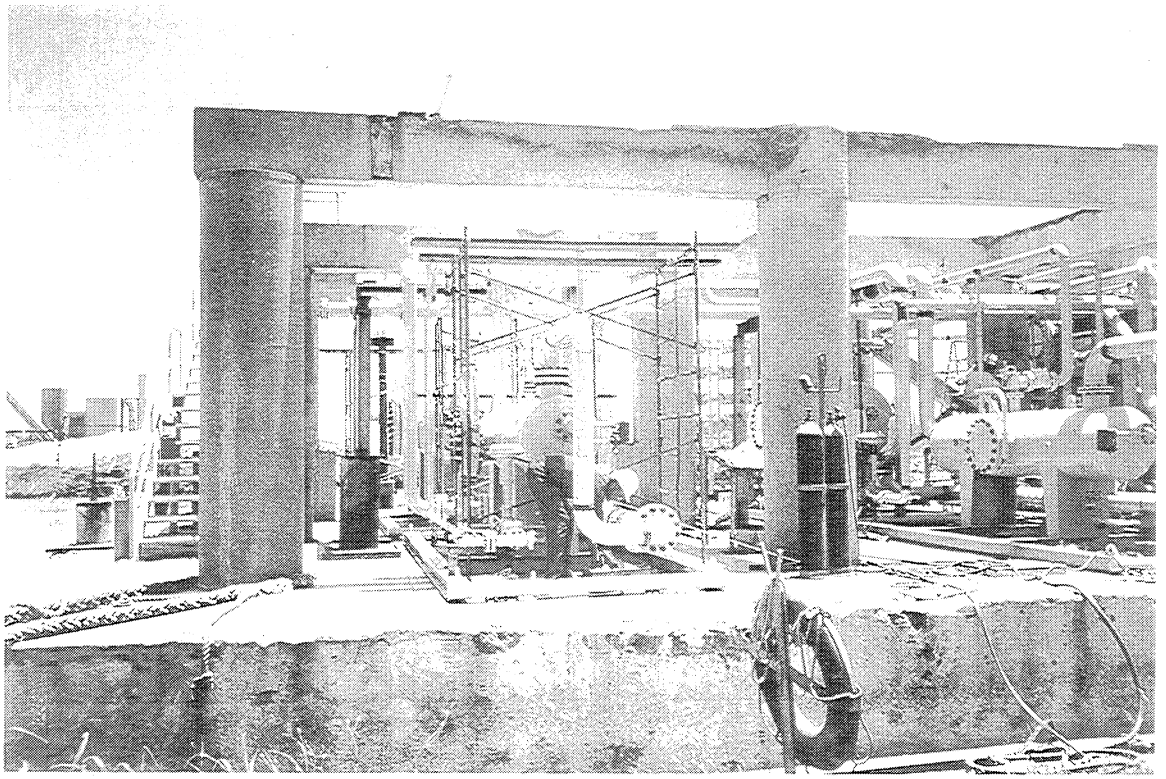
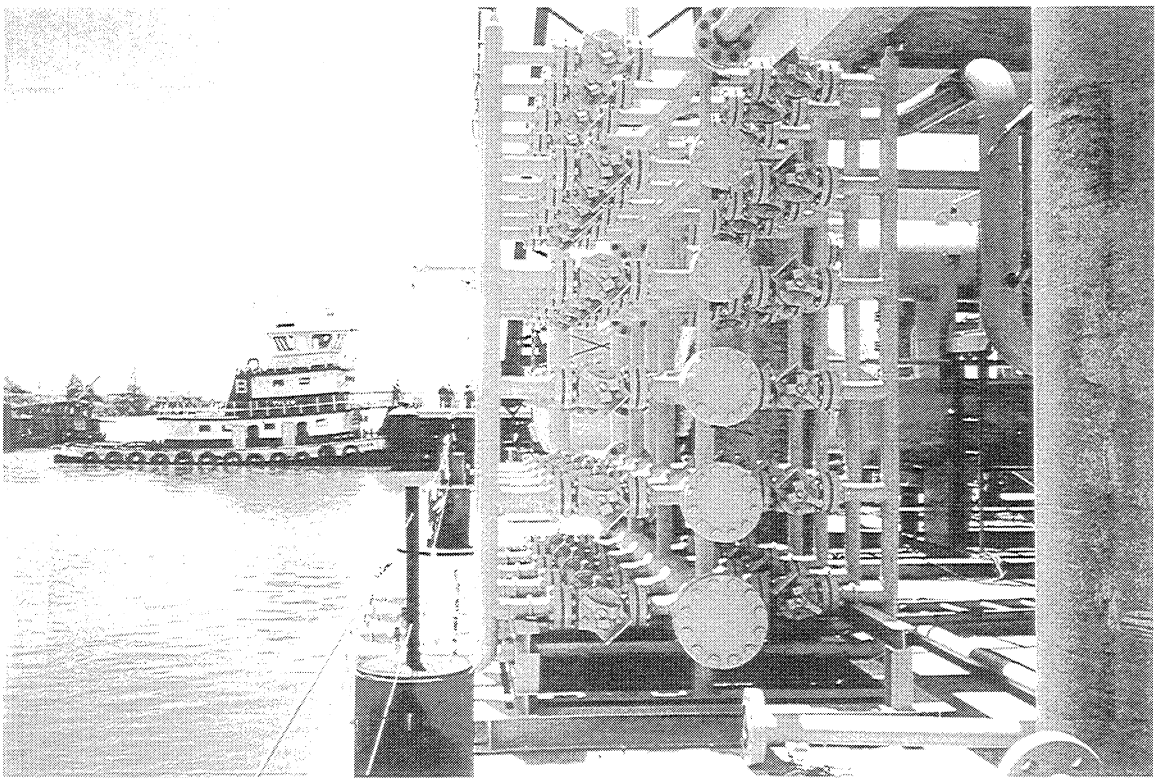
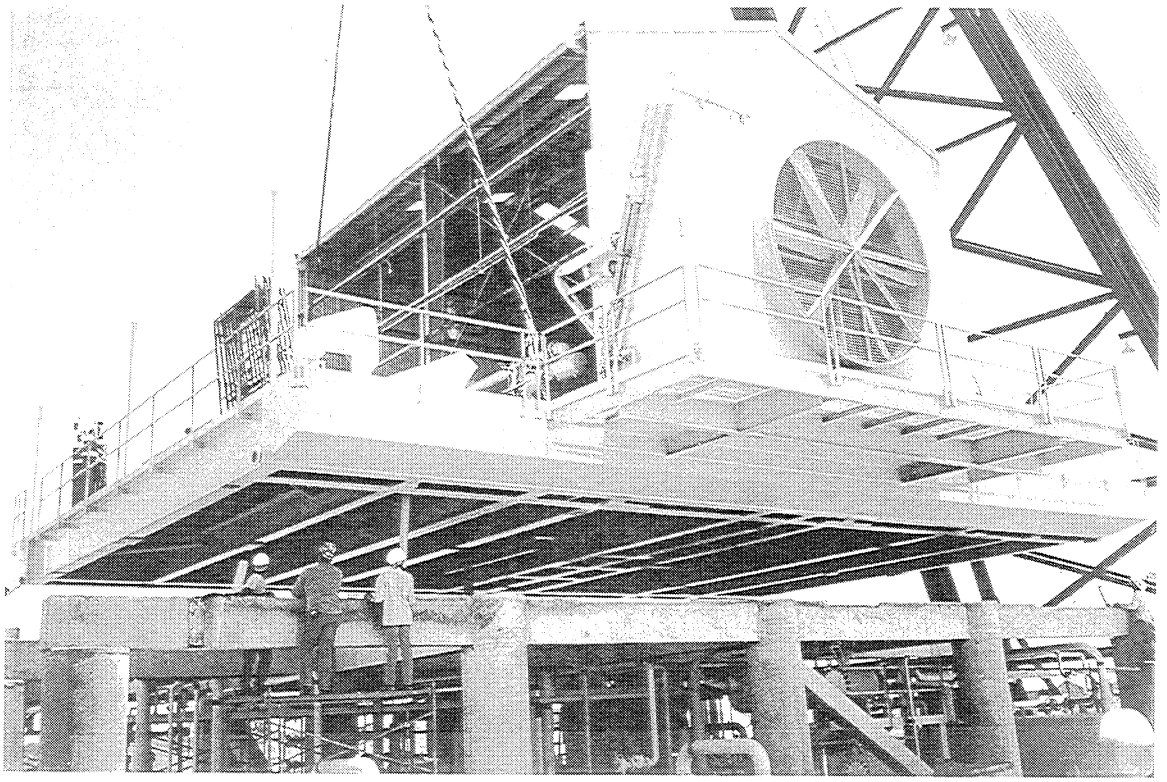


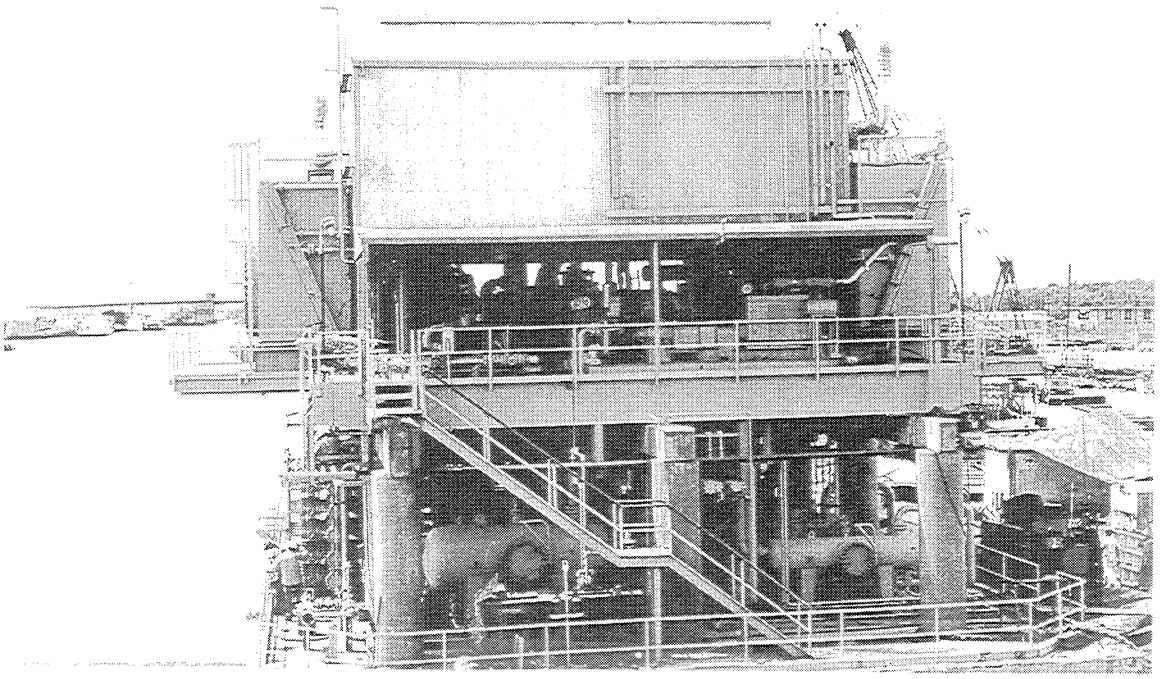
Photograph 3-H



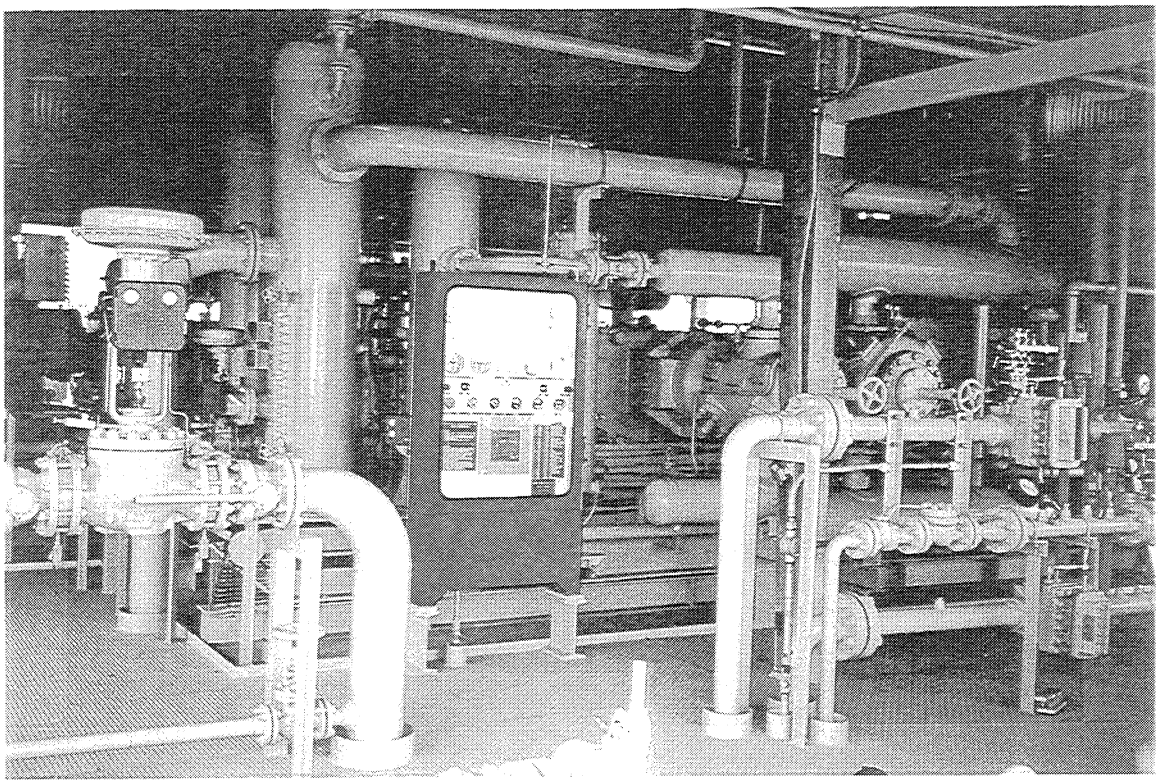
Photograph 3-I



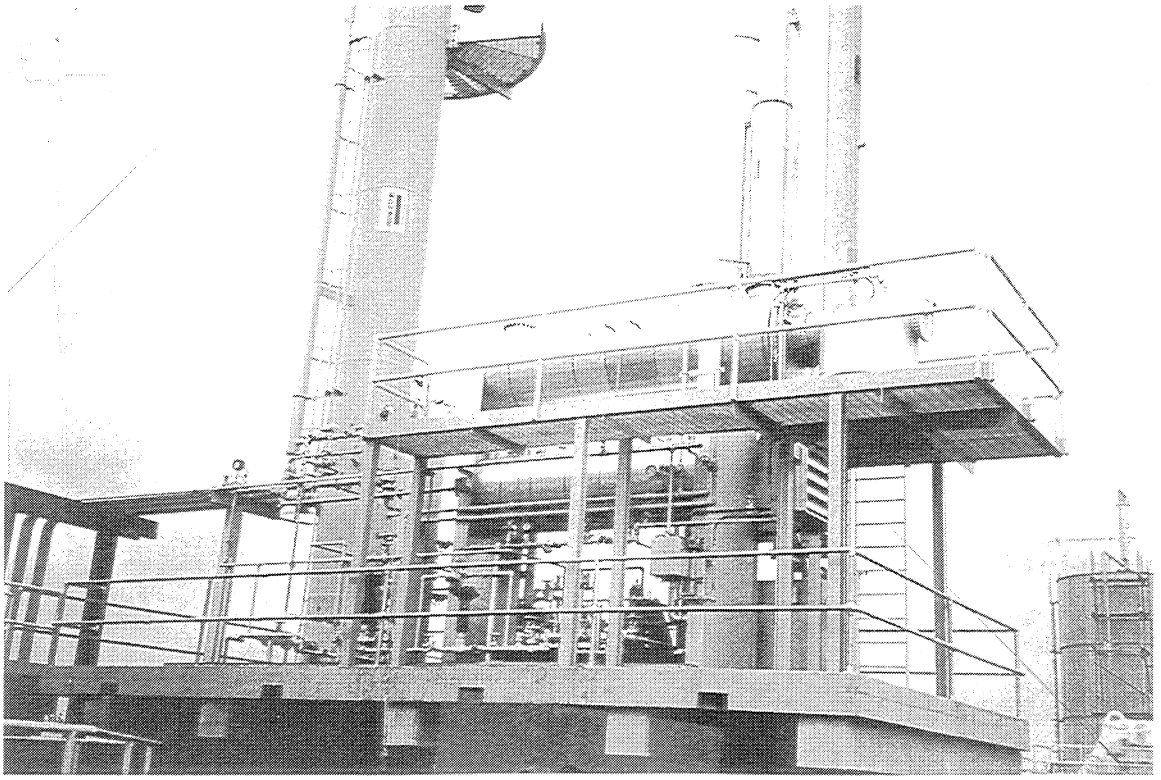
Photograph 3-J



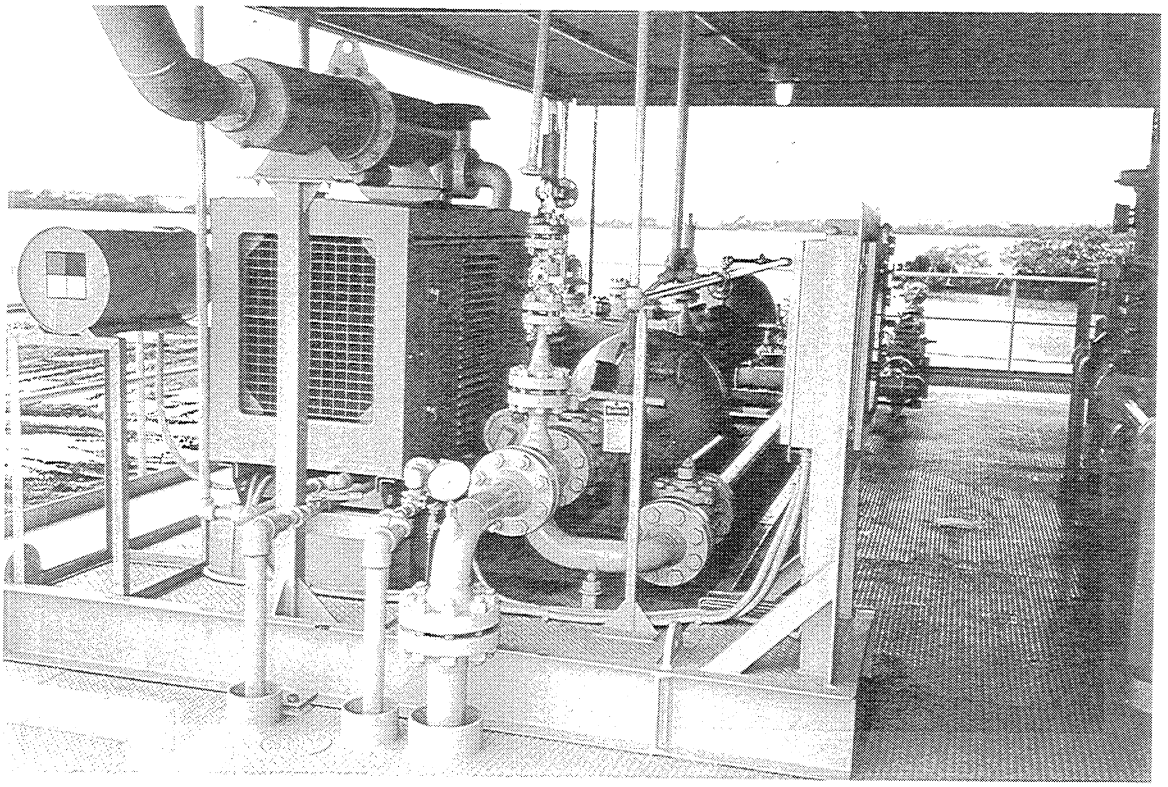
Photograph 3-K



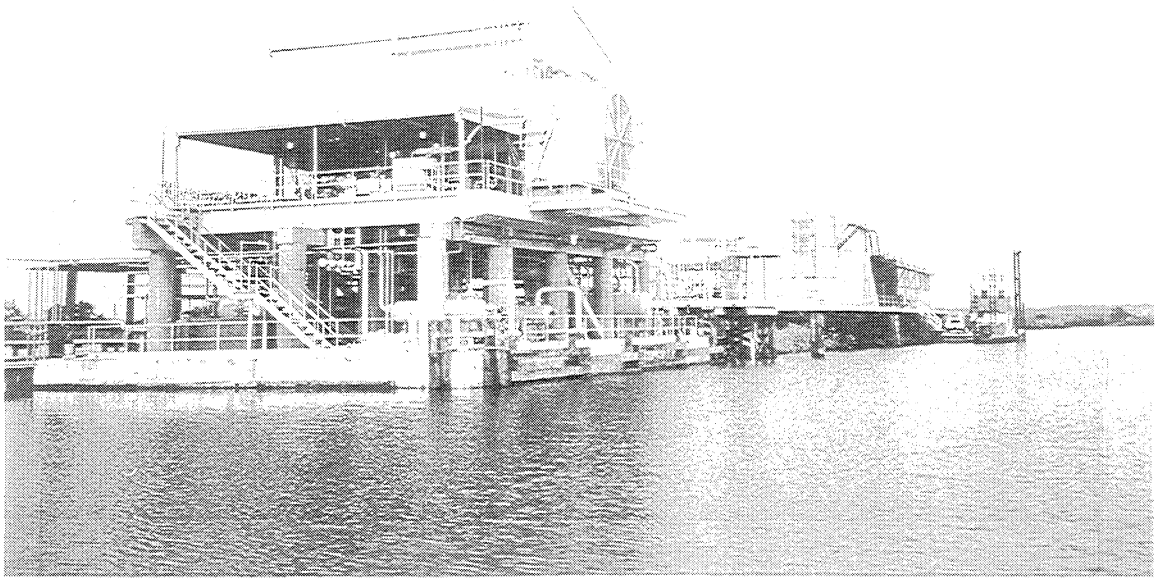
Photograph 3-L



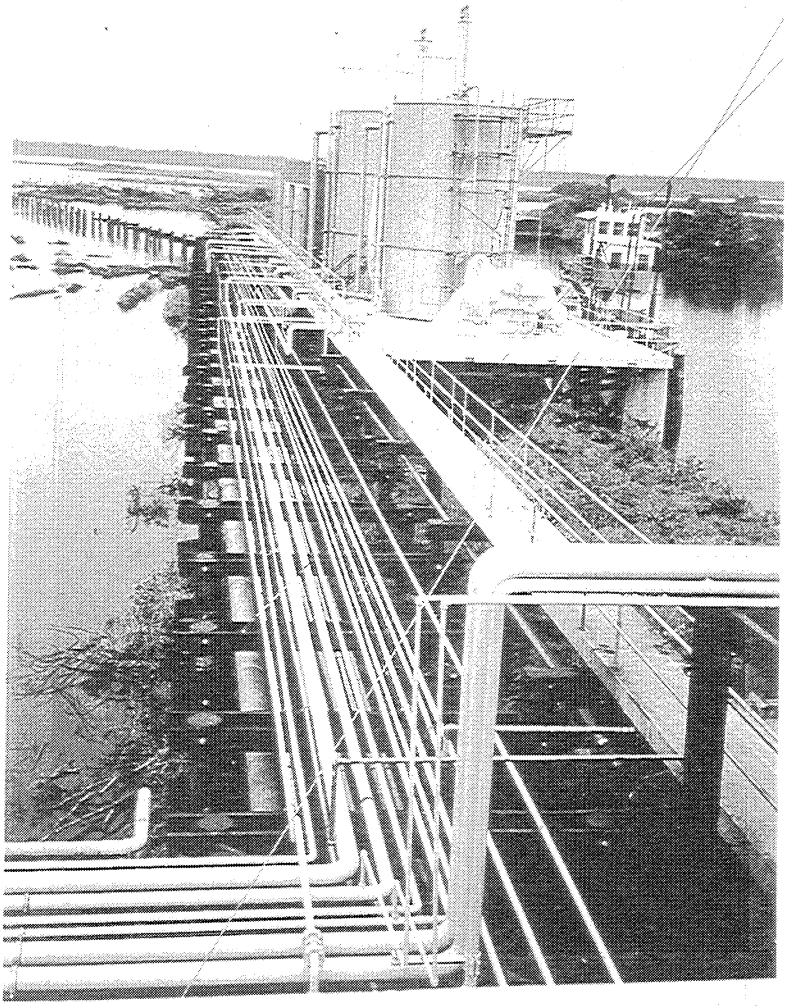
Photograph 3–M



Photograph 3–N



Photograph 3-0



CO2 / CO2 PIPELINE

CO_2/CO_2 Pipeline

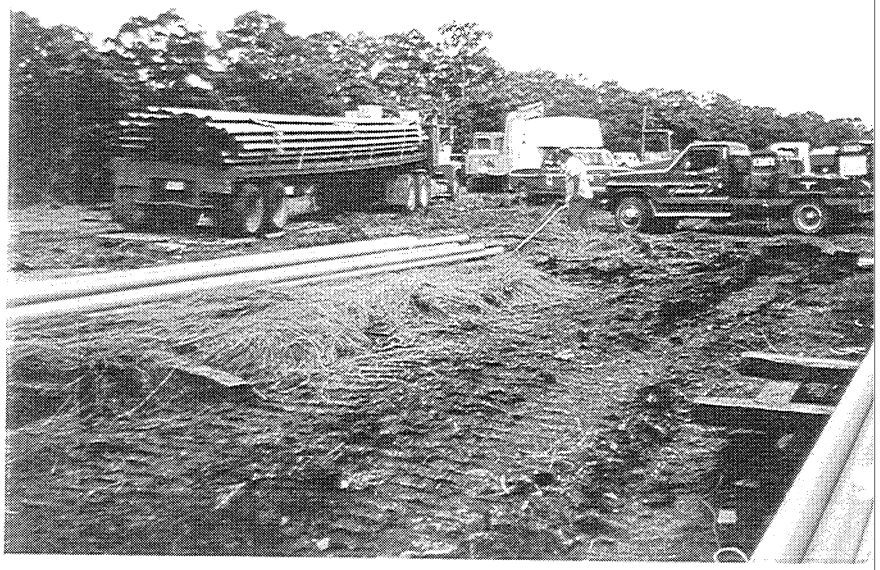
A 4-1/2 mile 4" (I.D.) pipeline was installed from a Cardox CO_2 pipeline tie-in point to the Port Neches Field. Purchases began on September 22, 1993 at a rate of approximately 4 MMCFPD.

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.

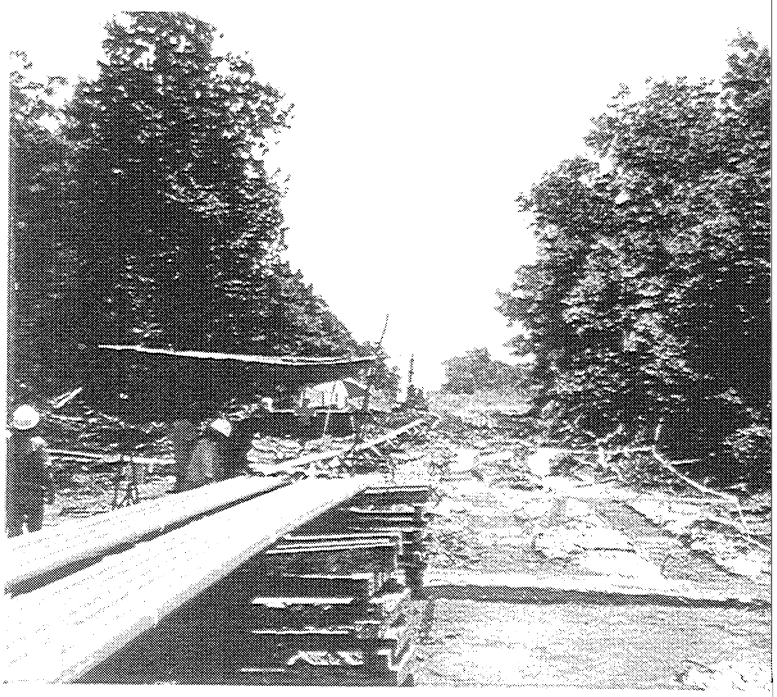
Photographs included are:

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

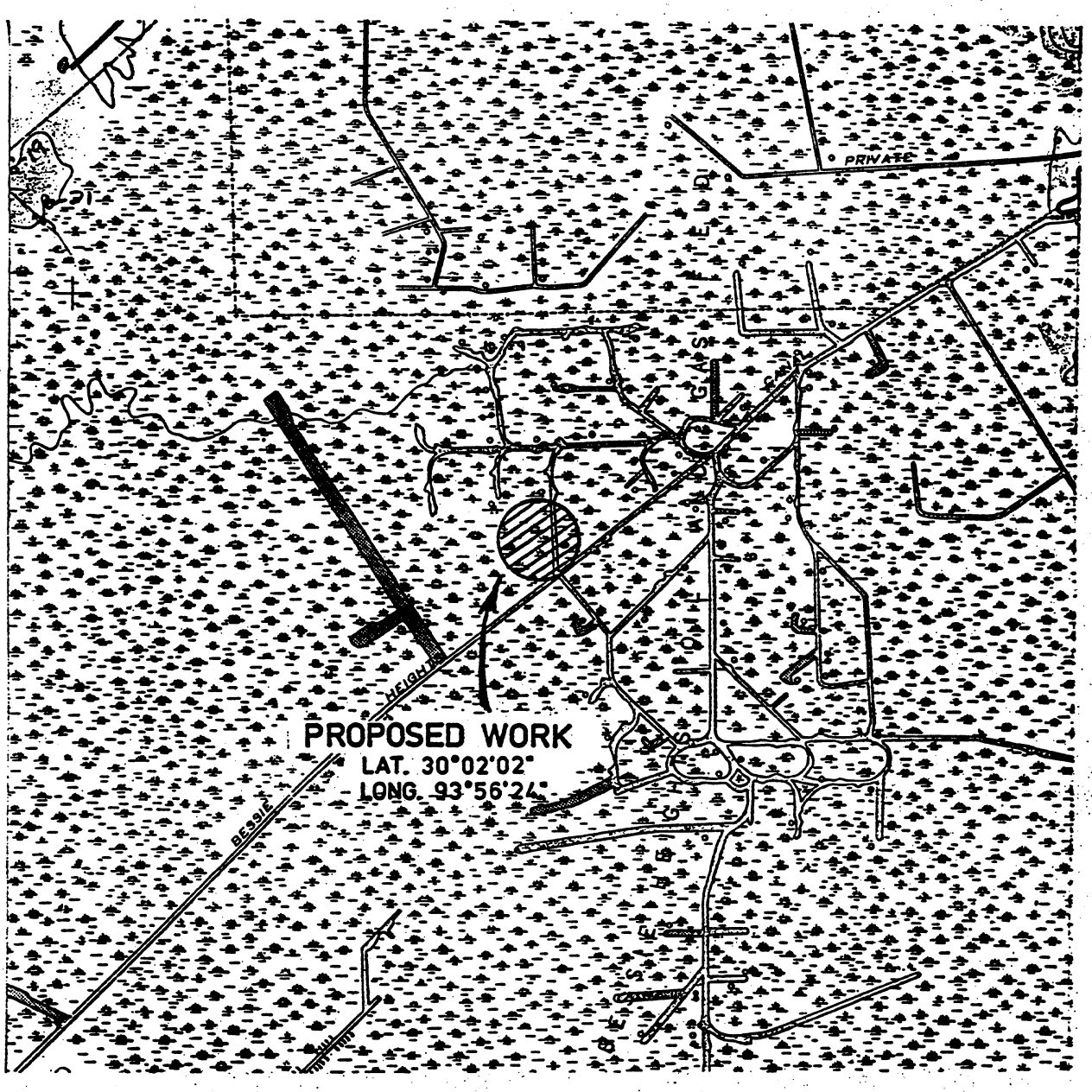
Photograph 4-E

Photograph 4-F

ENVIRONMENTAL

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'

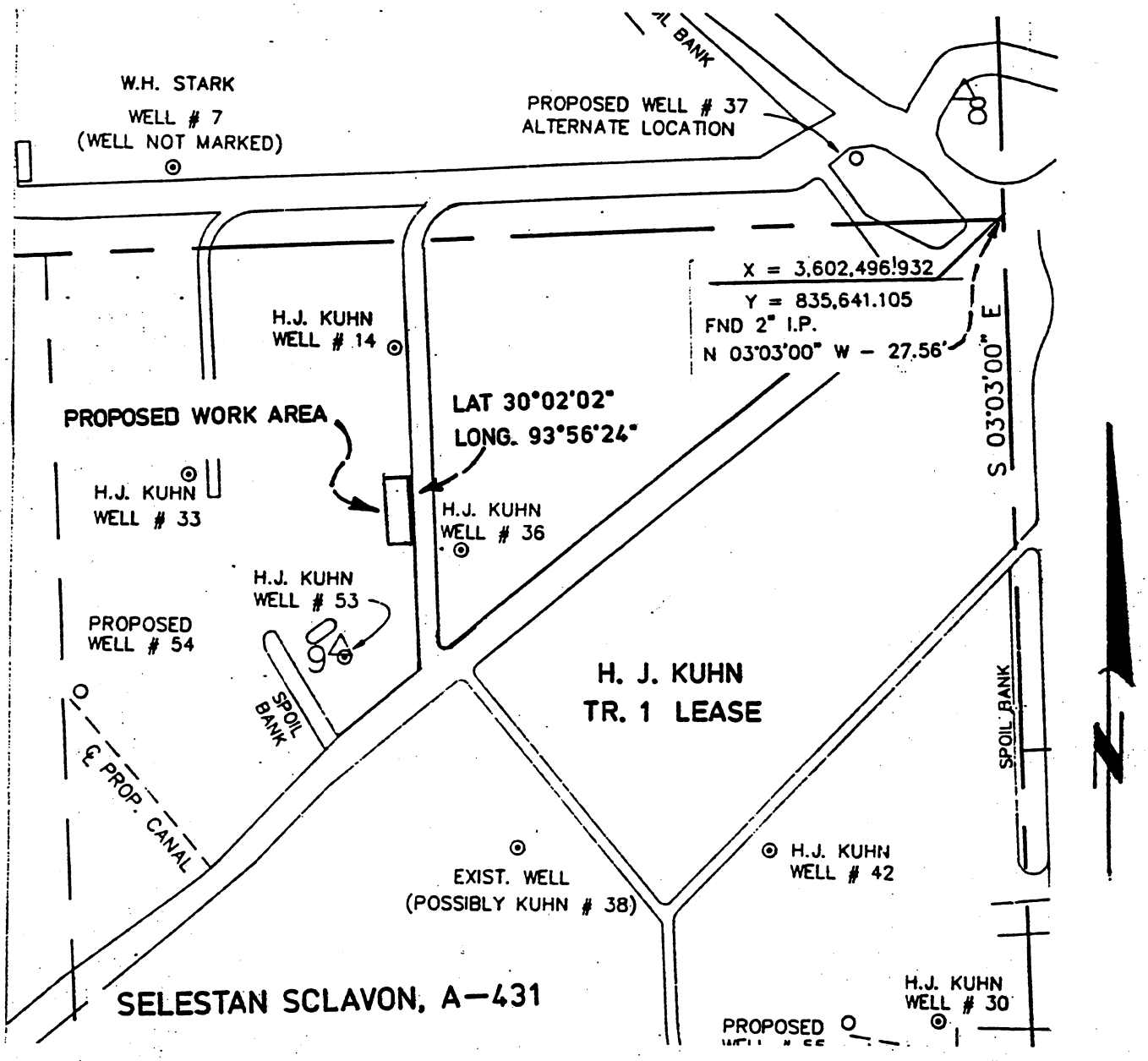
SCALE: 1" = 2000'

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

PORT NECHES FIELD
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	1	4



PLAN

250' 0 500'

SCALE: 1" = 500'

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

PORT NECHES FIELD
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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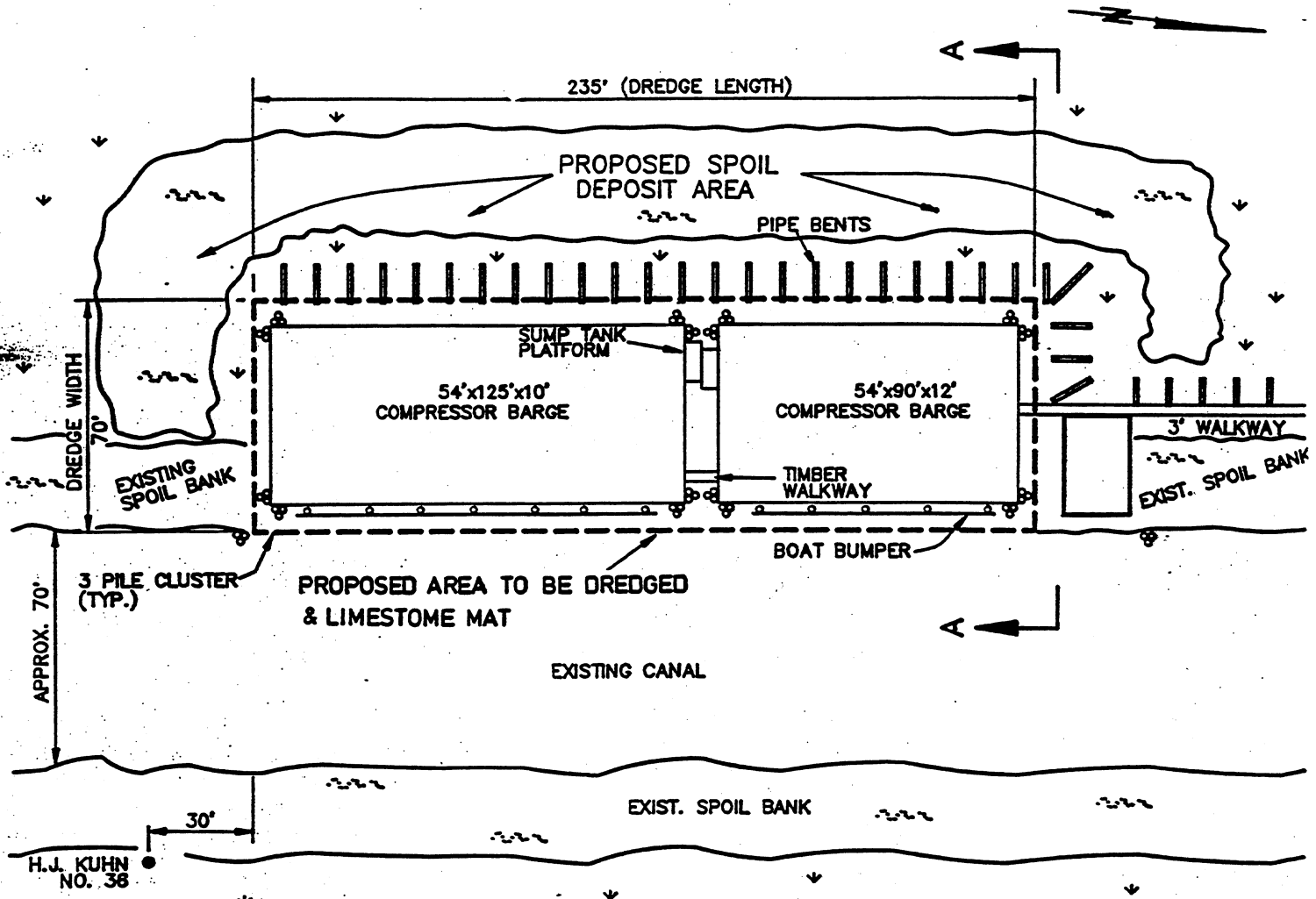

NOTE:
APPROX. 9000 CU. YDS. OF SPOIL WILL BE DREDGED AND PLACED IN AREAS AS SHOWN.

PLAN DETAIL

25' 0 50'

SCALE: 1"= 50'

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

PORT NECHES FIELD
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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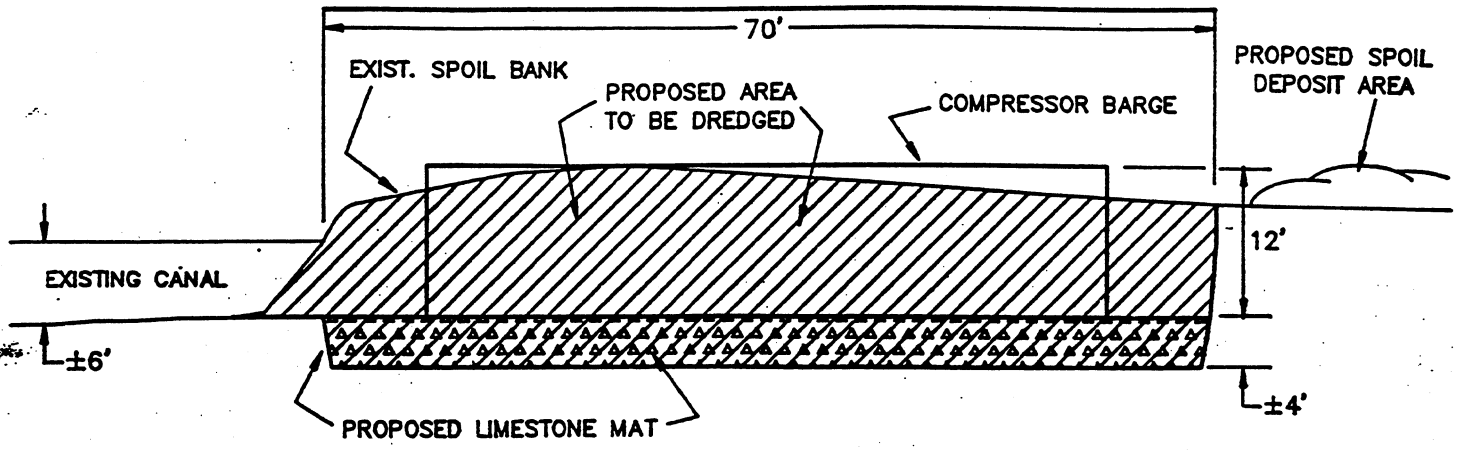


CROSS SECTION A–A

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

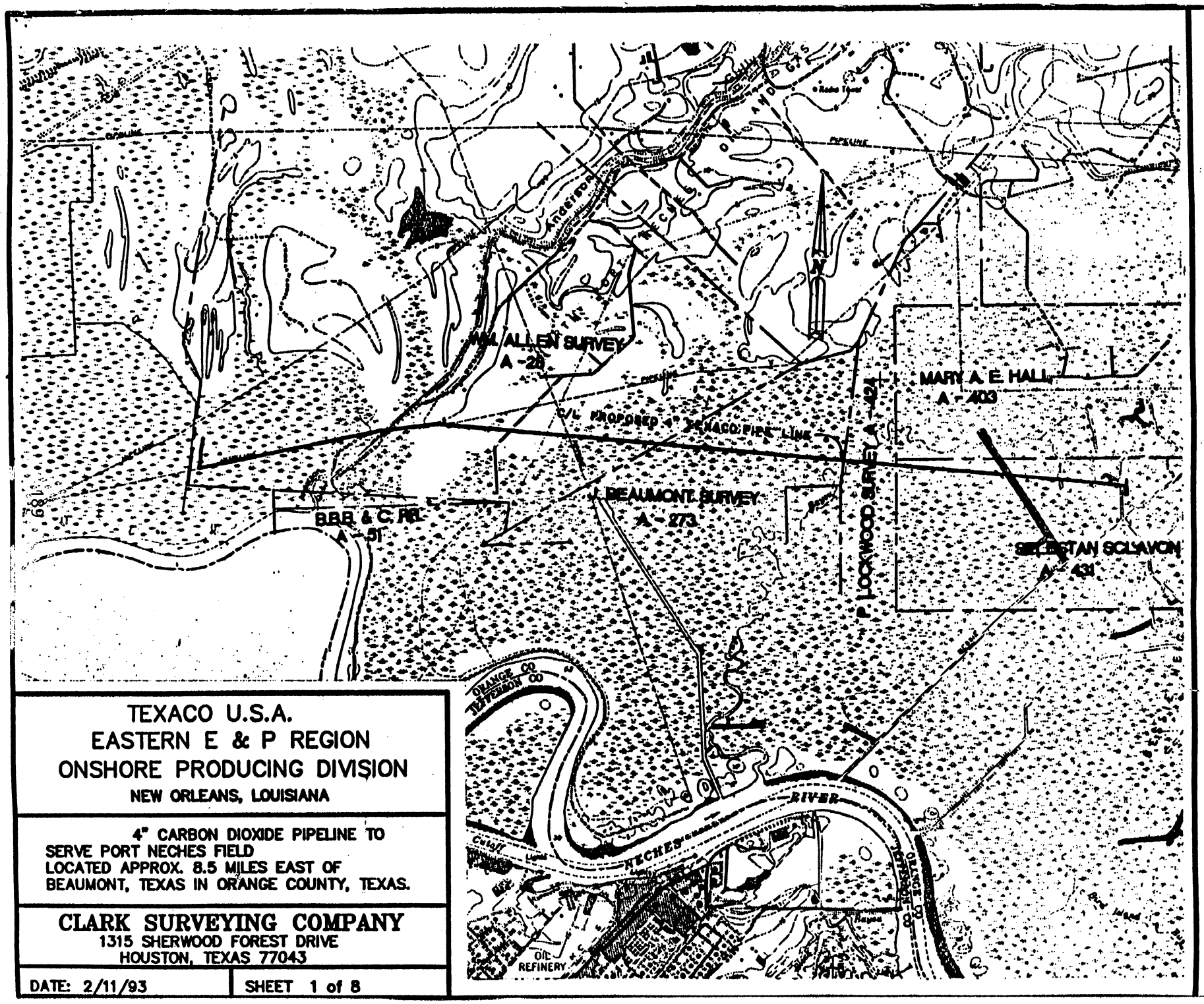
EASTERN E & P REGION

ONSHORE PRODUCING DIVISION OPERATIONS EAST

PORT NECHES FIELD
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

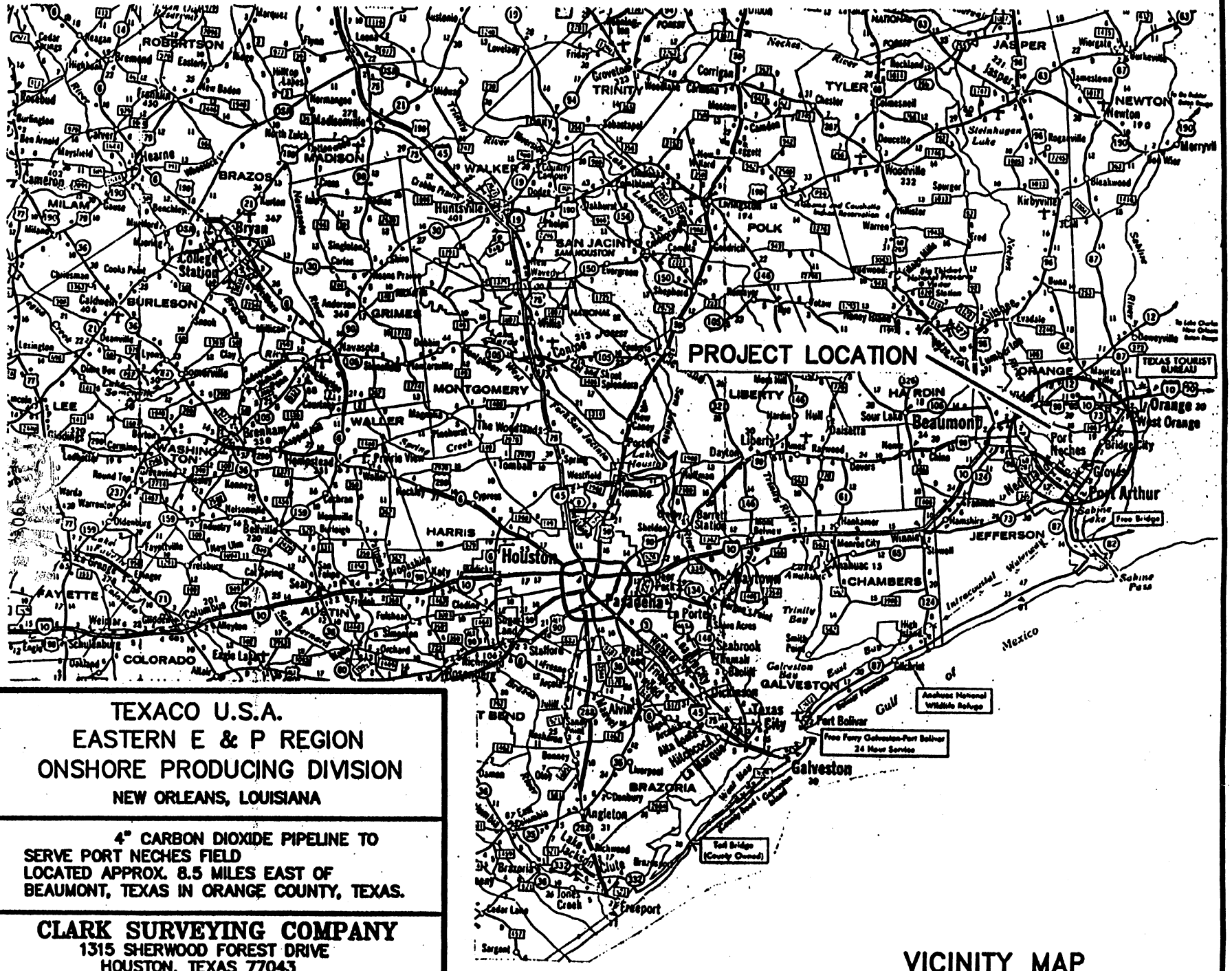


TEXACO U.S.A.
EASTERN E & P REGION
ONSHORE PRODUCING DIVISION
NEW ORLEANS, LOUISIANA

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



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

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

VICINITY MAP

SCALE: 1" = APPROX. 23 MILES

MARY A. E. HALL
A - 403

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

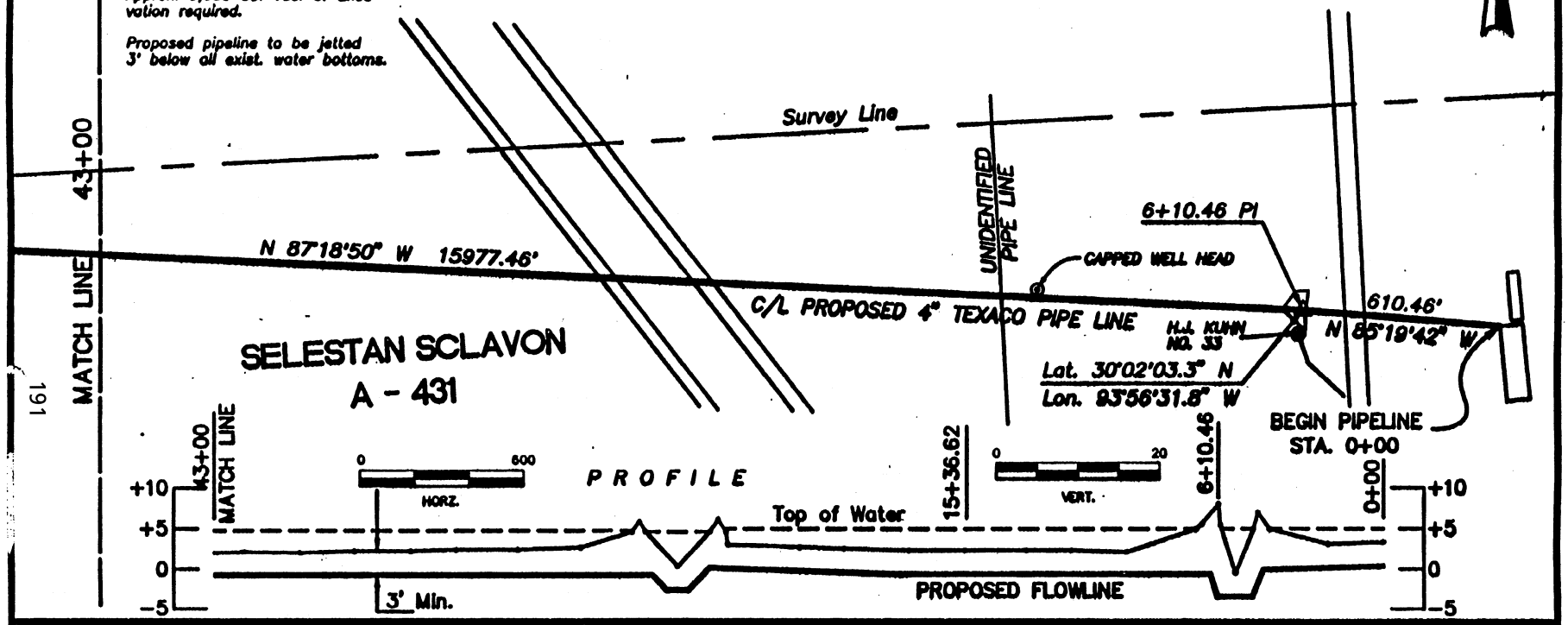
SCALE: 1" = 500'

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.



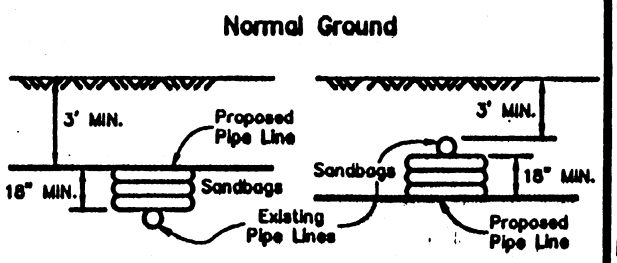
191

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

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

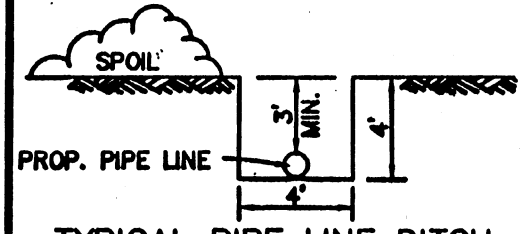
CLARK SURVEYING COMPANY
1315 SHERWOOD FOREST DRIVE
HOUSTON, TEXAS 77043

DATE: 2/11/93 | SHEET 3 of 8



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.



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'

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

83+00

43+00

MATCH LINE

N 87°18'50" W 15977.46'

C/L PROPOSED 4" TEXACO PIPE LINE

PROFILE

0 600
HORZ.

0 20
VERT.

Top of Water

3' Min.

PROPOSED FLOWLINE

+10
+5
0
-5

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

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.
Proposed Pipe Line
18" MIN.
Sandbags
Existing Pipe Lines
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
PROP. PIPE LINE
3' MIN.
4'
4'

TYPICAL PIPE LINE DITCH
NTS

PIPE DATA:

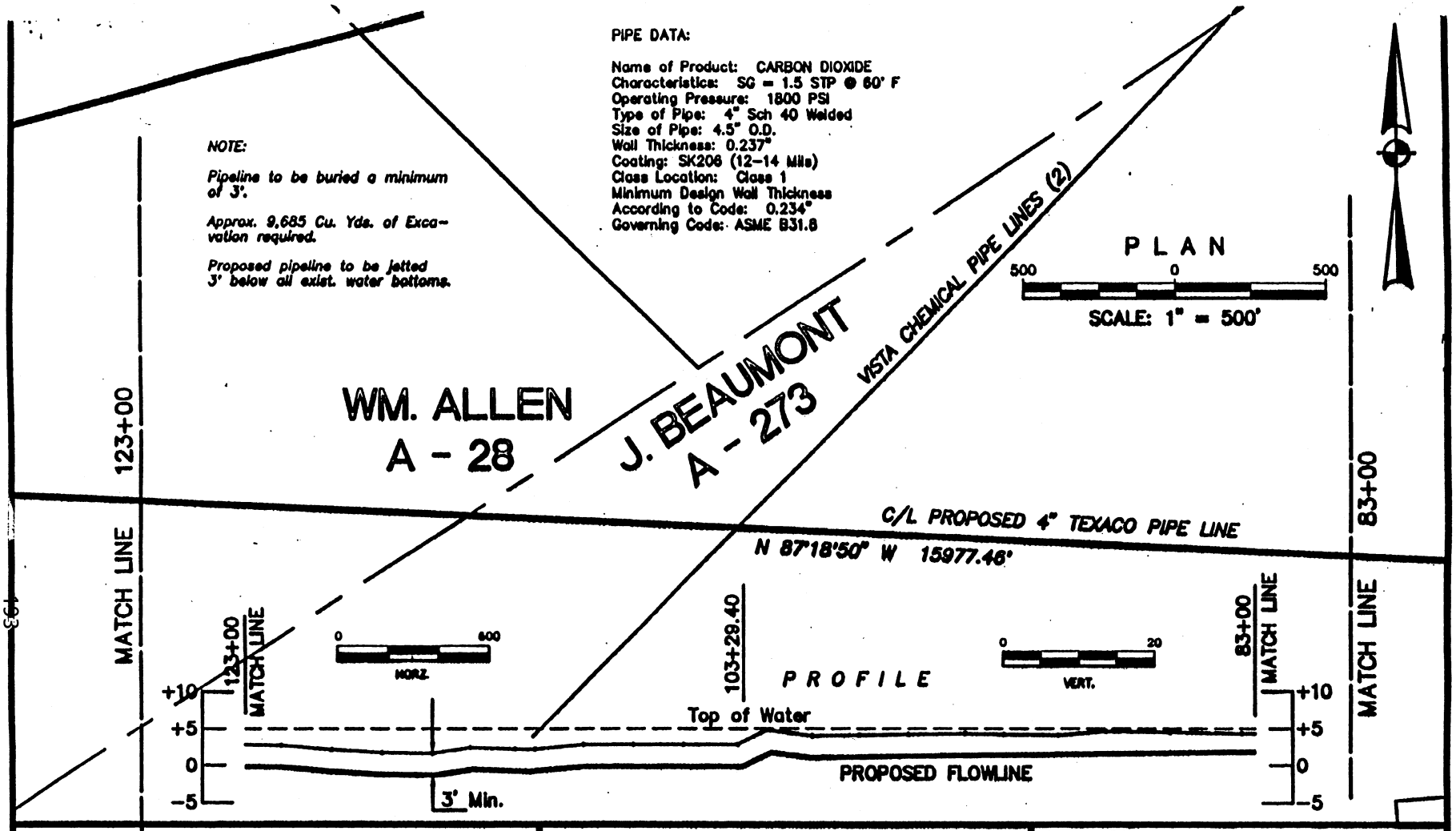
Name of Product: CARBON DIOXIDE
Characteristics: SG = 1.5 STP @ 60° F
Operating Pressure: 1800 PSI
Type of Pipe: 4" Sch 40 Welded
Size of Pipe: 4.5" O.D.
Wall Thickness: 0.237"
Coating: SK206 (12–14 Mils)
Class Location: Class 1
Minimum Design Wall Thickness
According to Code: 0.234"
Governing Code: 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.

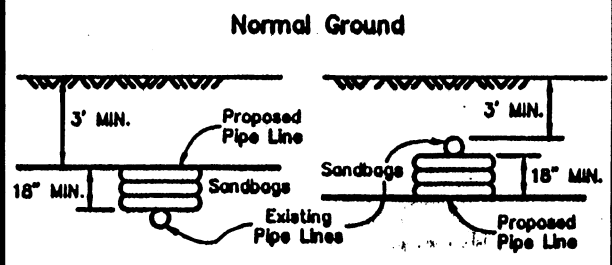


TEXACO U.S.A.
EASTERN E & P REGION
ONSHORE PRODUCING DIVISION
NEW ORLEANS, LOUISIANA

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

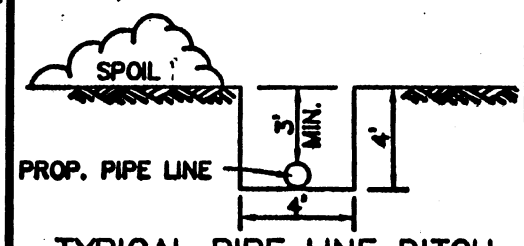
CLARK SURVEYING COMPANY
1315 SHERWOOD FOREST DRIVE
HOUSTON, TEXAS 77043

DATE: 2/11/93 | SHEET 5 of 8



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.



TYPICAL PIPE LINE DITCH
NTS

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'

170+00

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

MATCH LINE

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

S 25°04'11" W 978.49'

LION OIL CO. PIPE LINE

HOUSTON PIPE LINE CO. PIPE LINE

N 87°18'50" W 12565.43'

151+75.89 PI

Lat. 30°02'14.4" N

Lon. 93°58'54.2" W

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.

PROFILE

0 600 HORZ.

0 20 VERT.

170+00 MATCH LINE

+10 +5 0 -5

Top of Water

3' Min.

PROPOSED FLOWLINE

123+00 MATCH LINE

+10 +5 0 -5

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

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

3' MIN. Sandbags 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

PROP. PIPE LINE

3' MIN.

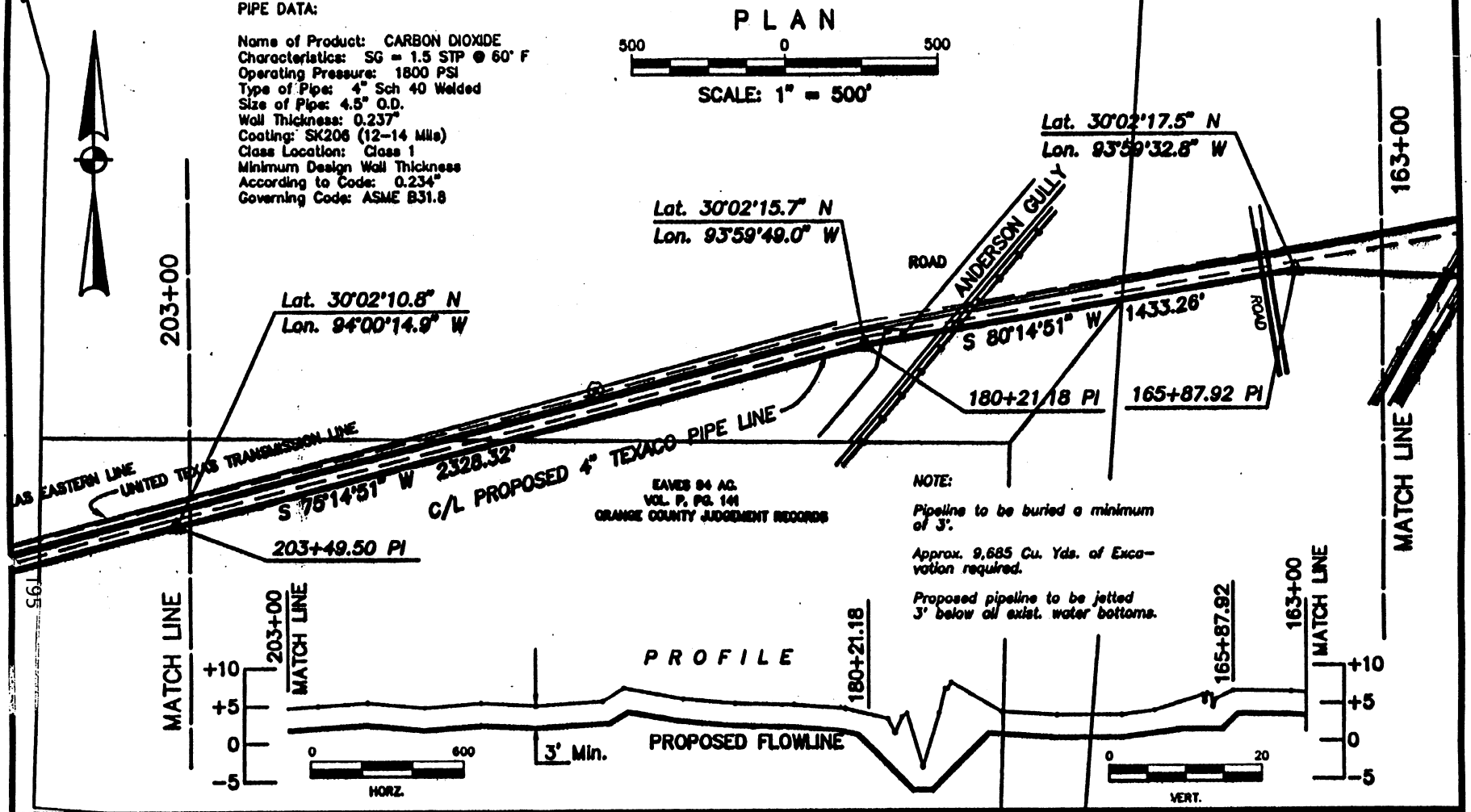
4'

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

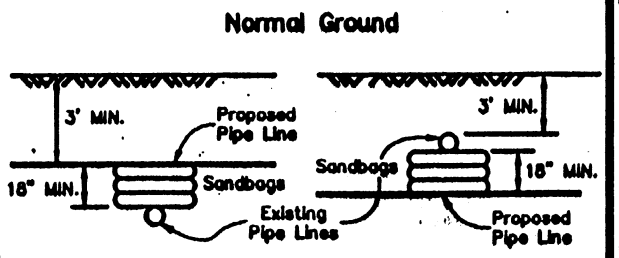


TEXACO U.S.A.
EASTERN E & P REGION
ONSHORE PRODUCING DIVISION
NEW ORLEANS, LOUISIANA

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

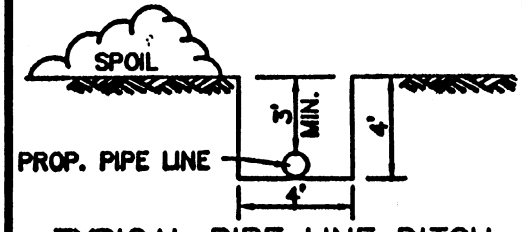
CLARK SURVEYING COMPANY
1315 SHERWOOD FOREST DRIVE
HOUSTON, TEXAS 77043

DATE: 2/11/93 | SHEET 7 of 8



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.



TYPICAL PIPE LINE DITCH
NTS

PIPE DATA:

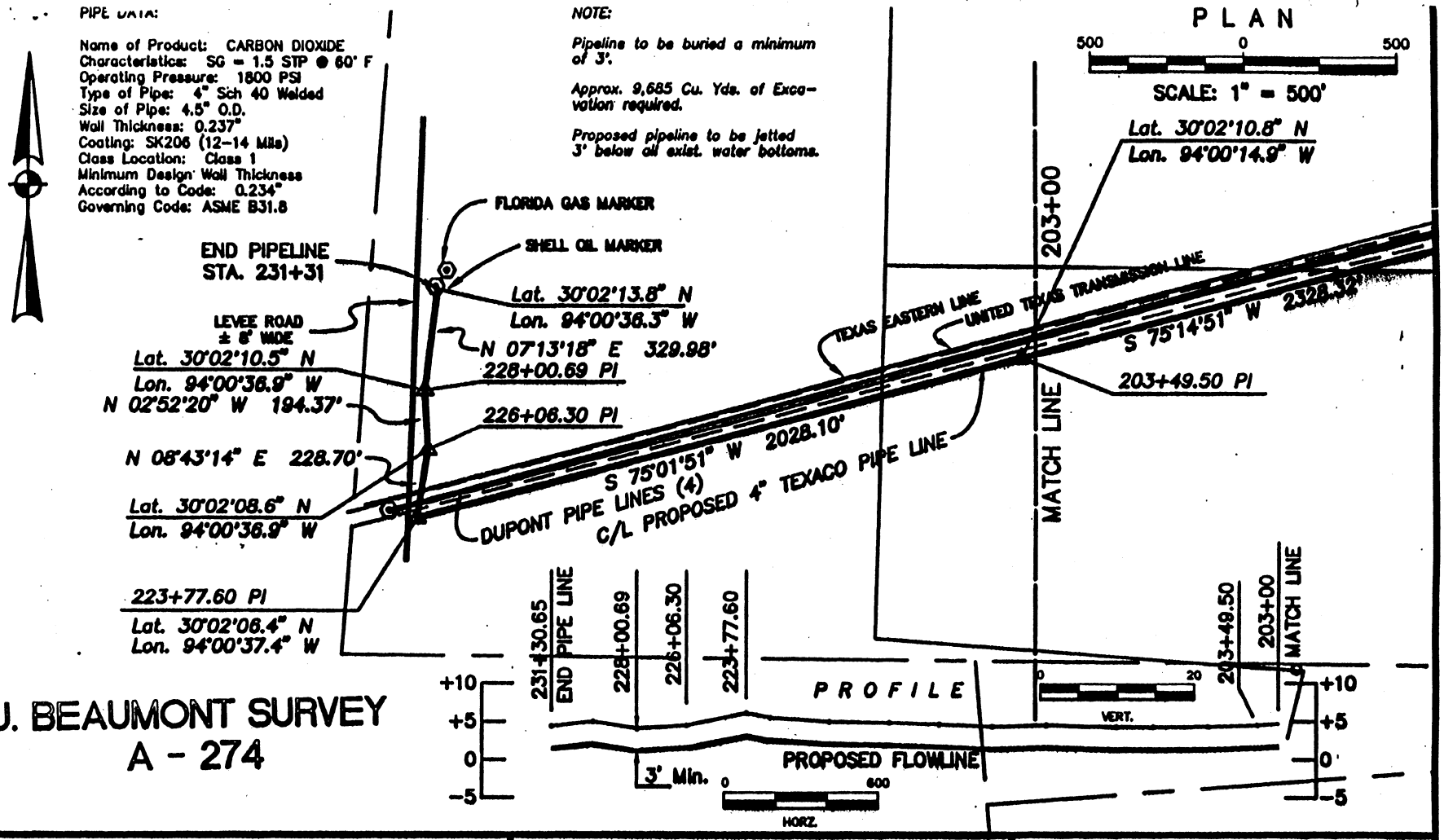
Name of Product: CARBON DIOXIDE
Characteristics: SG = 1.5 STP @ 60° F
Operating Pressure: 1800 PSI
Type of Pipe: 4" Sch 40 Welded
Size of Pipe: 4.5" O.D.
Wall Thickness: 0.237"
Coating: SK206 (12–14 Mils)
Class Location: Class 1
Minimum Design Wall Thickness According to Code: 0.234"
Governing Code: 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.



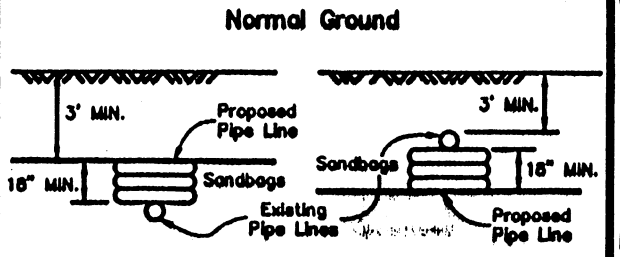
J. BEAUMONT SURVEY
A - 274

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

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

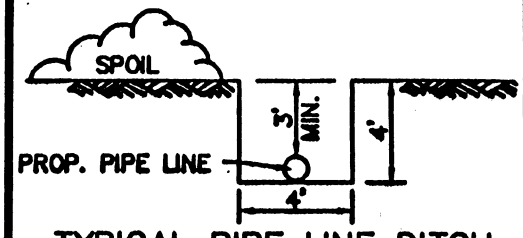
CLARK SURVEYING COMPANY
1315 SHERWOOD FOREST DRIVE
HOUSTON, TEXAS 77043

DATE: 2/11/93 | SHEET 8 of 8



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.



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.

Gas Relative Permeability Higher than that for Oil. 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.

Gas Relative Permeability Smaller than that for Oil. 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.

Secondary Recovery

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.

Figures 12, 13, and 14 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.

Gas Relative Permeability Higher than that for 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 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.

Gas Relative Permeability Smaller than that for Oil. 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

```
'ROBERTS UNIT - COMP III COMPARISON'
'********** WELL AND PATTERN DATA ********'
'PATTERN'
'5S'
'NWELLS     NOINJ'
2,     1
'WELLS     WELLY     WELLQ'
0,     0,     1
1,     1,    -1
'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
'*************** FLUID DATA ************'
'VISO     VISW'
1.23,     0.7
'BO     RS     API     SALN     CSG'
1.22,     600,     32,     50000,     0.8
'************** RESERVOIR DATA ***********'
'TRES     P     MMP'
114,     2000,     1500
'DPCOEF   PERMAV   THICK   POROS   NLAYERS'
```

```
0.75,     6,     120.0,     0.1028,     4
'SOINIT     SGINIT     SWINIT'
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	K_{rgcw}/K_{rocw}		
Process Oil Recovery, % OOIP	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

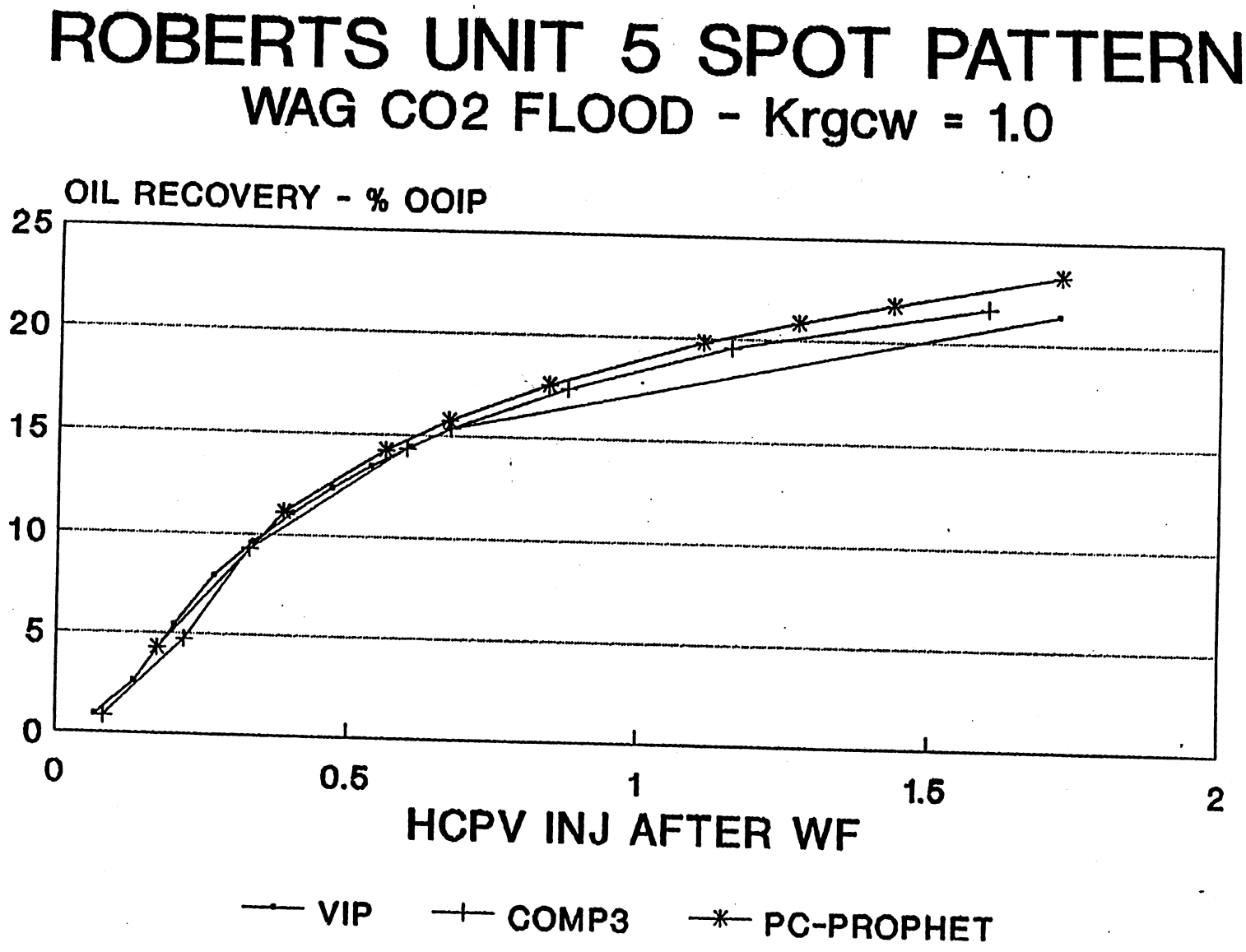

ROBERTS UNIT 5 SPOT PATTERN
WAG CO2 FLOOD - Krgcw = 1.0
OIL RECOVERY - % OOIP
25
20
15
10
5
0
0
0.5
1
1.5
2
HCPV INJ AFTER WF
VIP
COMP3
PC-PROPHET

Figure 2

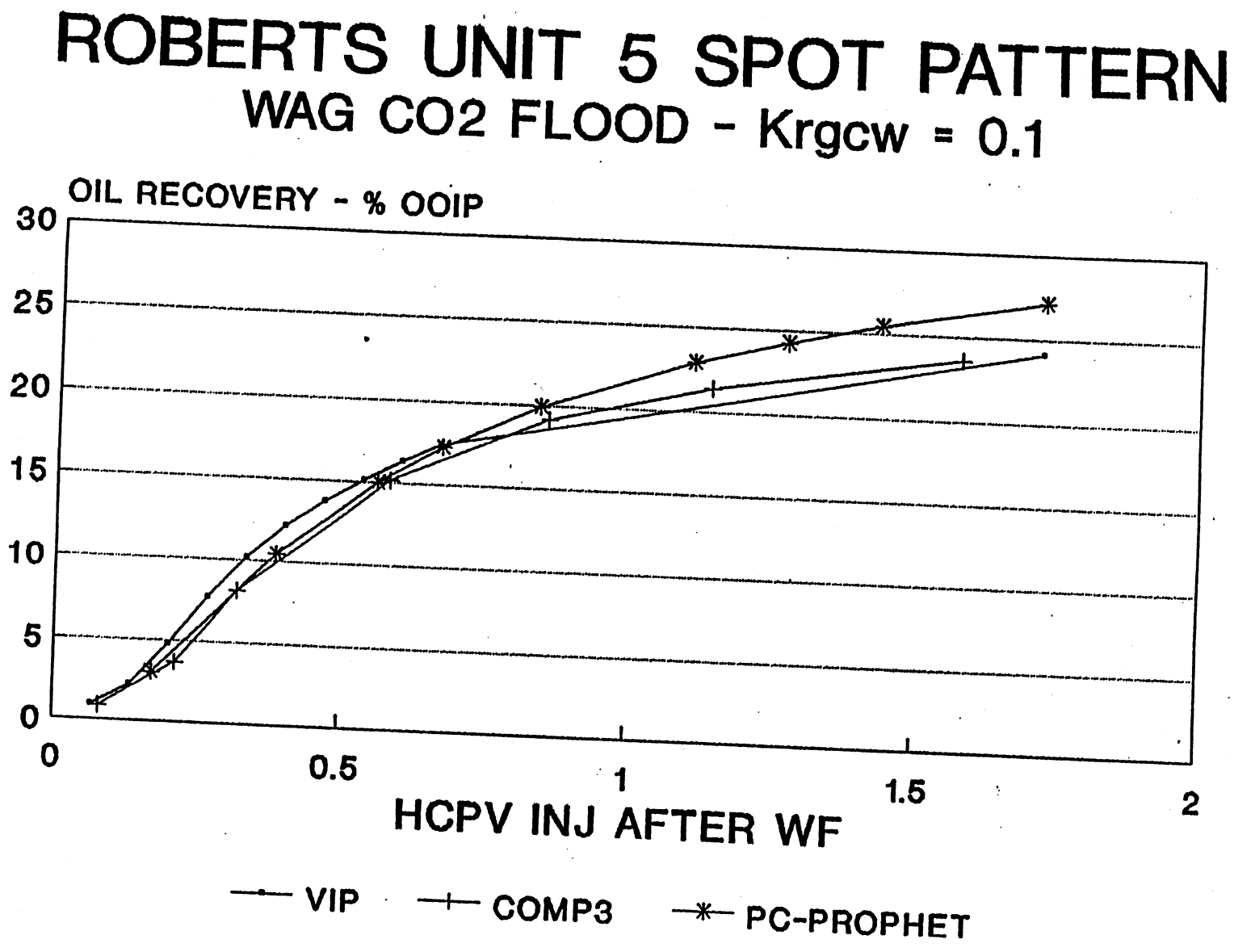

ROBERTS UNIT 5 SPOT PATTERN
WAG CO2 FLOOD - Krgcw = 0.1
OIL RECOVERY - % OOIP
30
25
20
15
10
5
0
0
0.5
1
1.5
2
HCPV INJ AFTER WF
VIP
COMP3
PC-PROPHET

Figure 3

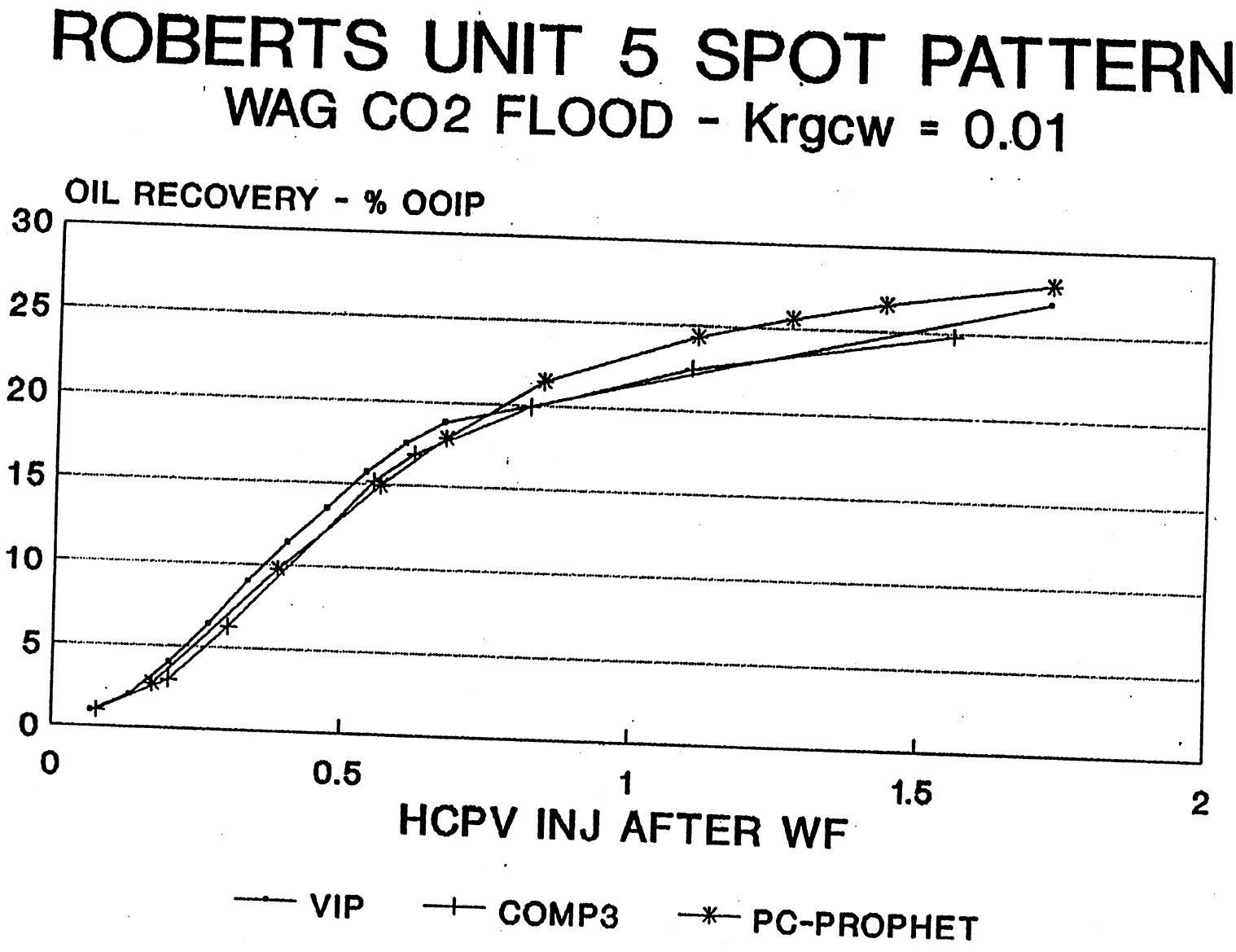

ROBERTS UNIT 5 SPOT PATTERN
WAG CO2 FLOOD - Krgcw = 0.01
OIL RECOVERY - % OOIP
30
25
20
15
10
5
0
0
0.5
1
1.5
2
HCPV INJ AFTER WF
VIP
COMP3
PC-PROPHET

Figure 4

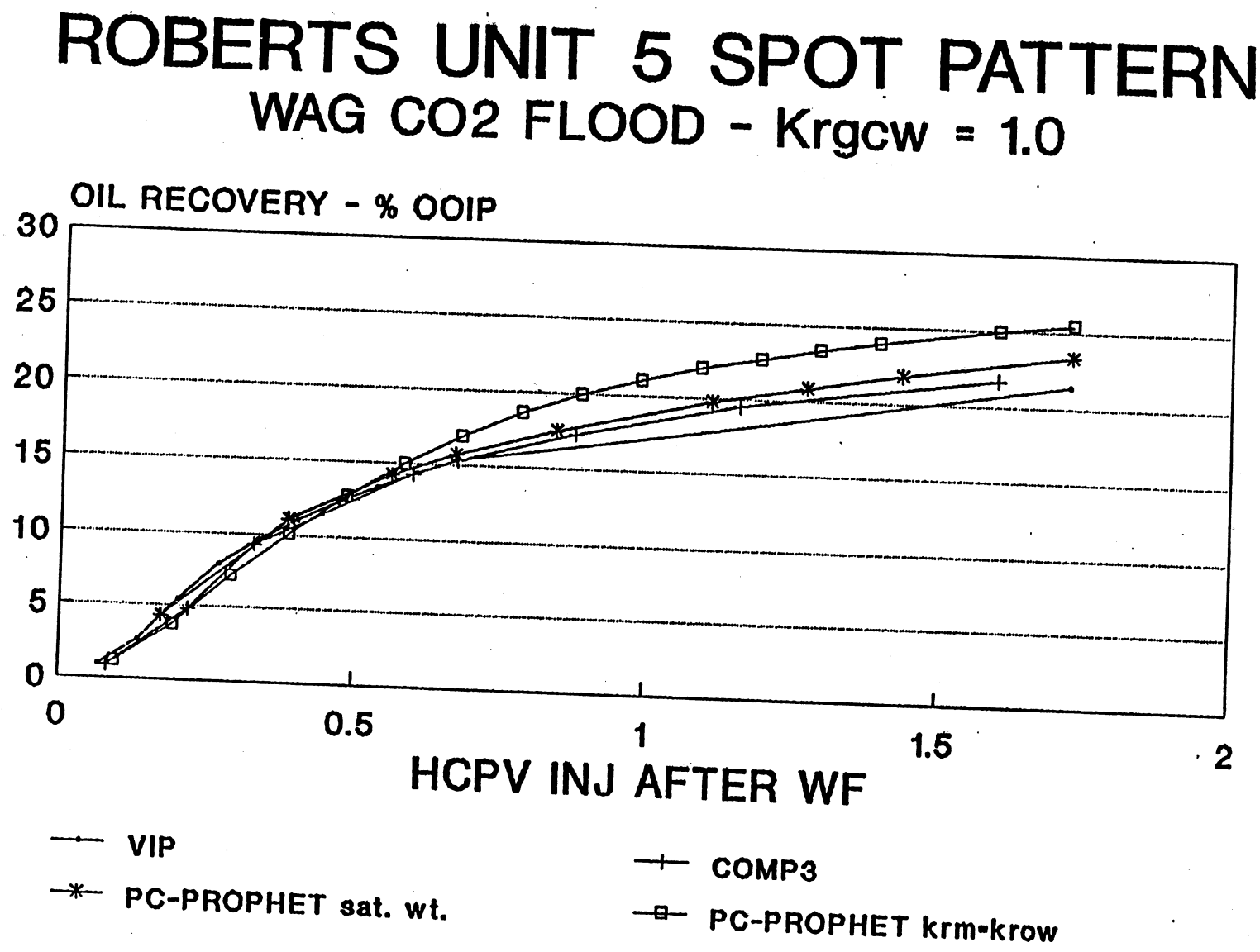

ROBERTS UNIT 5 SPOT PATTERN
WAG CO2 FLOOD - Krgcw = 1.0
OIL RECOVERY - % OOIP
30
25
20
15
10
5
0
0
0.5
1
1.5
2
HCPV INJ AFTER WF
VIP
PC-PROPHET sat. wt.
COMP3
PC-PROPHET krm=krow

Figure 5

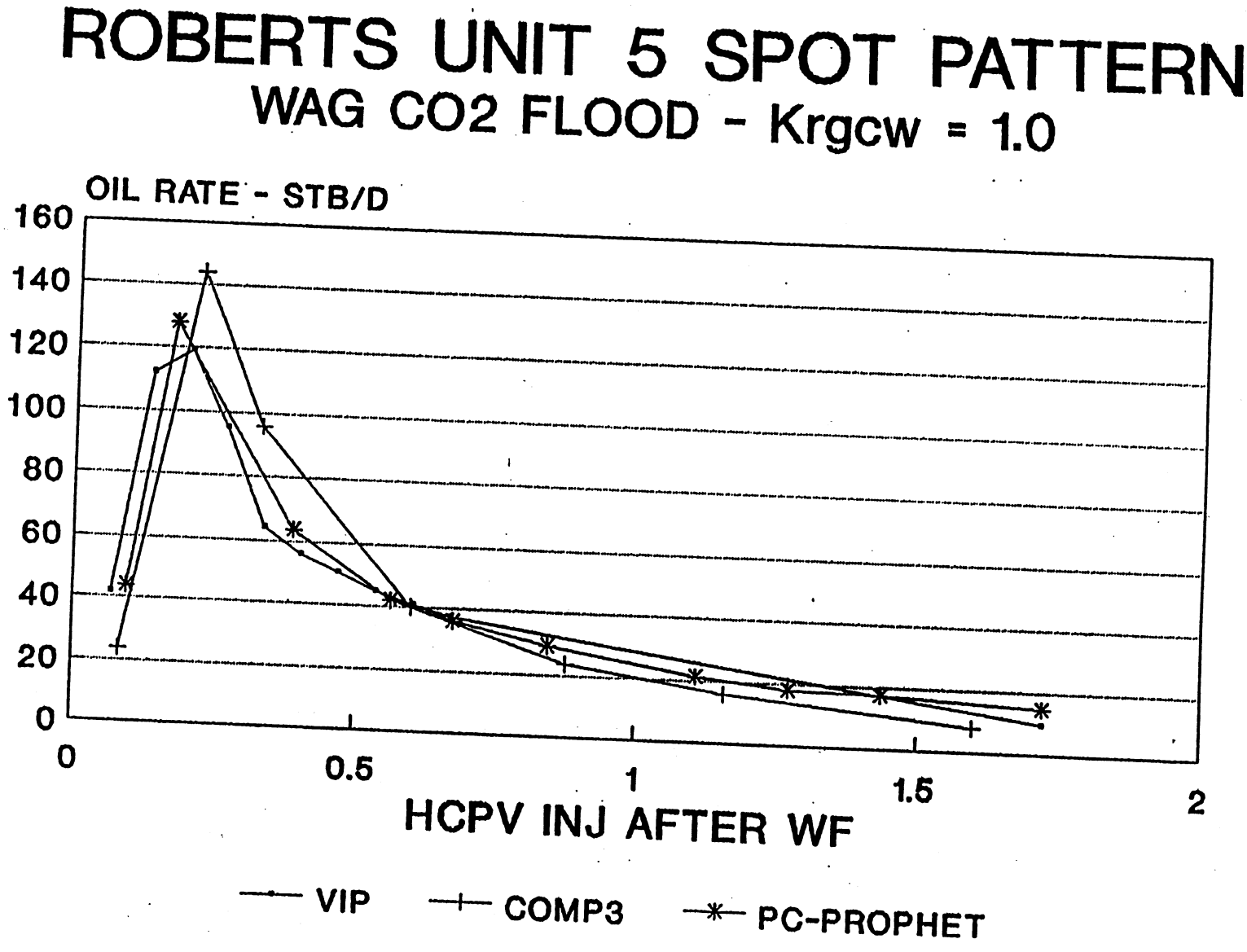

ROBERTS UNIT 5 SPOT PATTERN
WAG CO2 FLOOD - Krgcw = 1.0
OIL RATE - STB/D
160
140
120
100
80
60
40
20
0
0
0.5
1
1.5
2
HCPV INJ AFTER WF
VIP
COMP3
PC-PROPHET

Figure 6

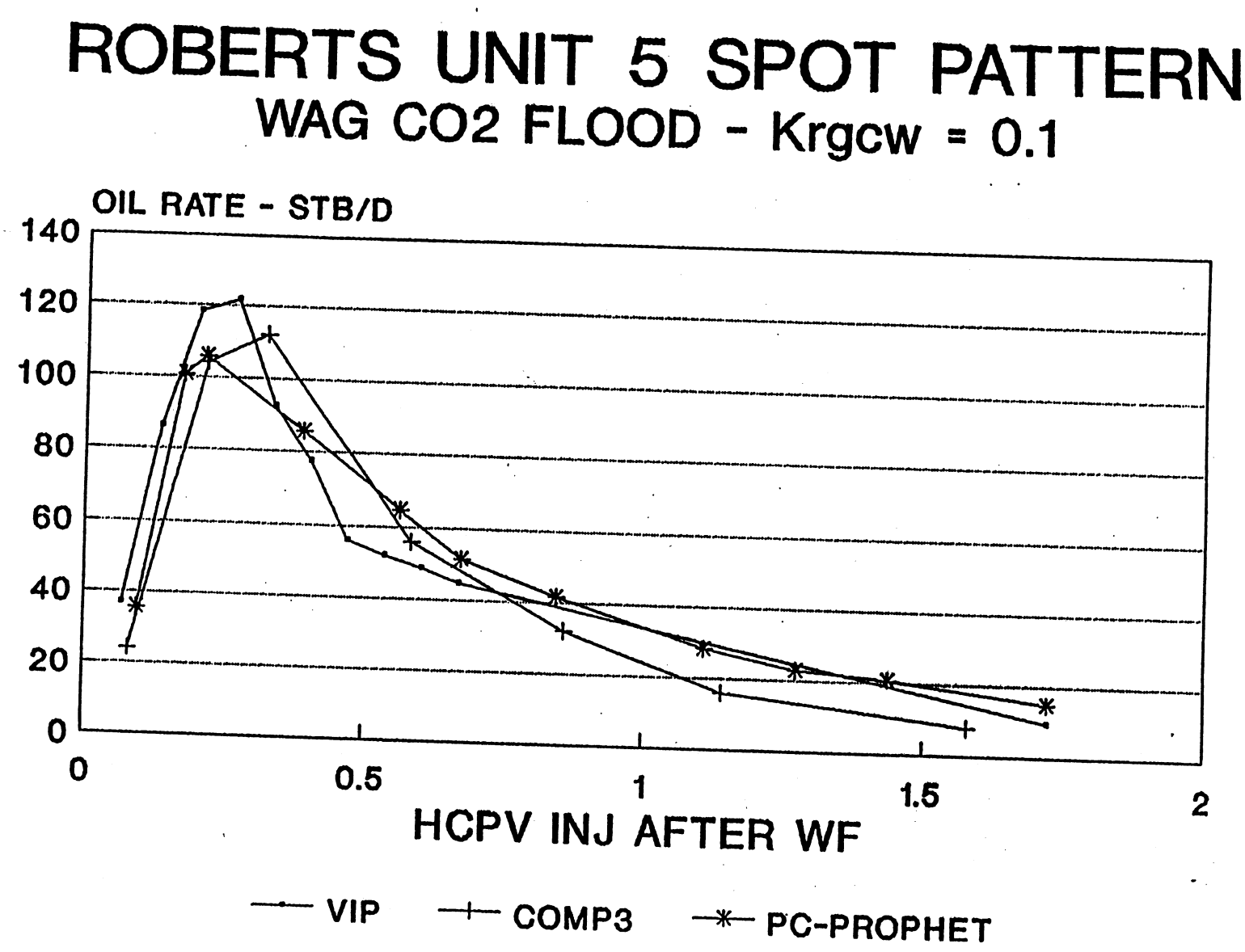

ROBERTS UNIT 5 SPOT PATTERN
WAG CO2 FLOOD - Krgcw = 0.1
OIL RATE - STB/D
140
120
100
80
60
40
20
0
0
0.5
1
1.5
2
HCPV INJ AFTER WF
VIP
COMP3
PC-PROPHET

Figure 7

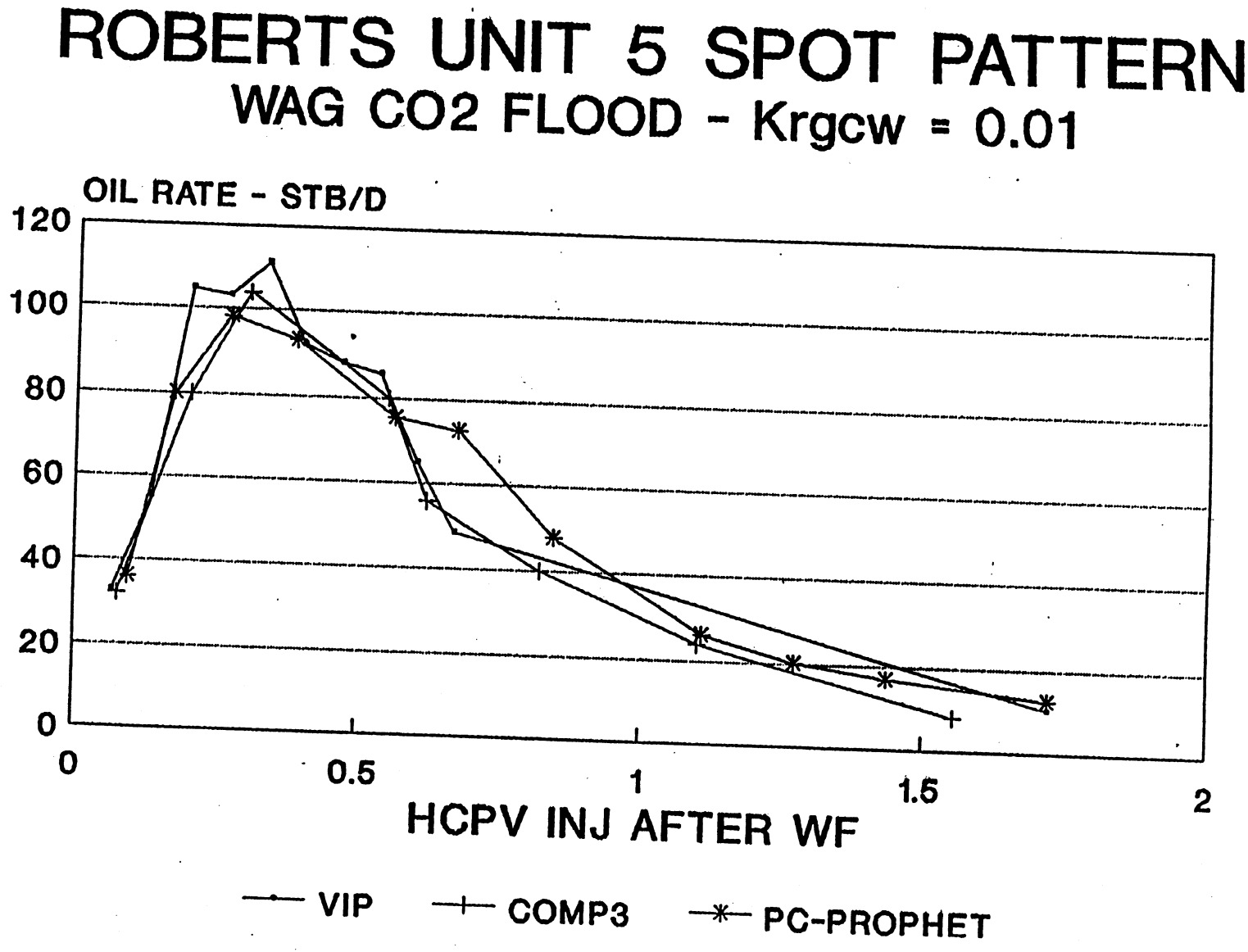

ROBERTS UNIT 5 SPOT PATTERN
WAG CO2 FLOOD - Krgcw = 0.01
OIL RATE - STB/D
120
100
80
60
40
20
0
0
0.5
1
1.5
2
HCPV INJ AFTER WF
VIP
COMP3
PC-PROPHET

Figure 8

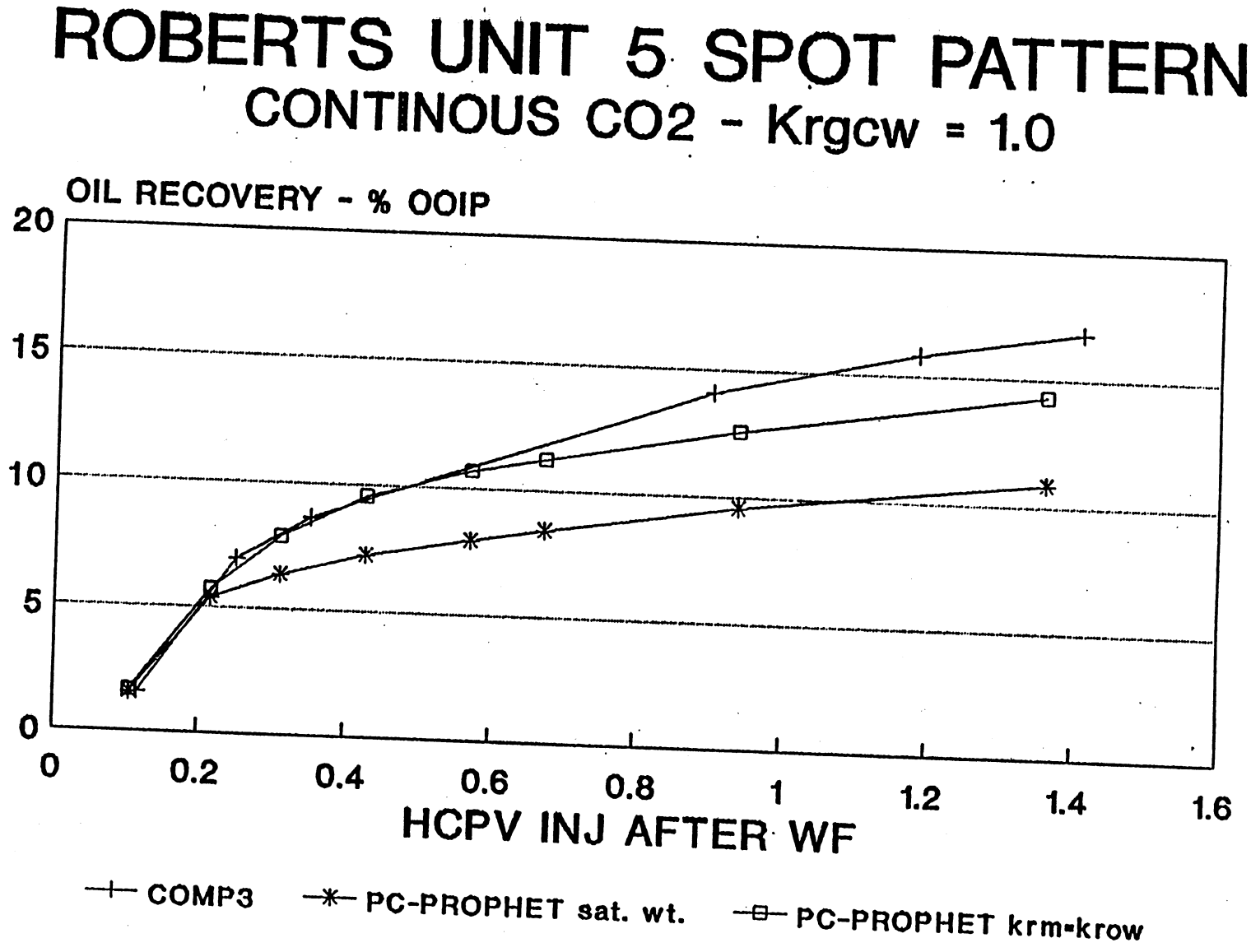

ROBERTS UNIT 5 SPOT PATTERN
CONTINOUS CO2 - Krgcw = 1.0
OIL RECOVERY - % OOIP
20
15
10
5
0
0
0.2
0.4
0.6
0.8
1
1.2
1.4
1.6
HCPV INJ AFTER WF
COMP3
PC-PROPHET sat. wt.
PC-PROPHET krm=krow

Figure 9

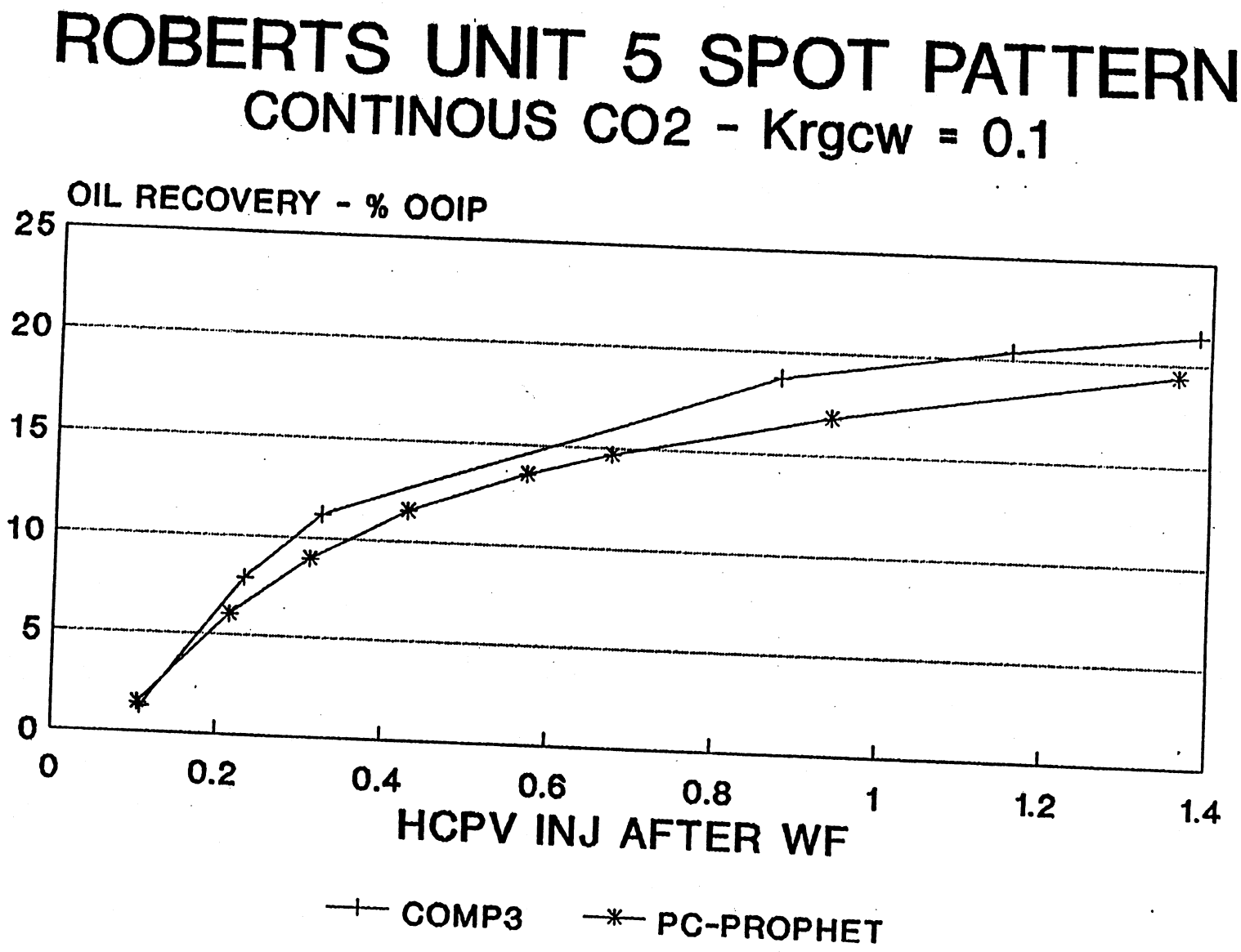

ROBERTS UNIT 5 SPOT PATTERN
CONTINOUS CO2 - Krgcw = 0.1
OIL RECOVERY - % OOIP
25
20
15
10
5
0
0
0.2
0.4
0.6
0.8
1
1.2
1.4
HCPV INJ AFTER WF
COMP3
PC-PROPHET

Figure 10

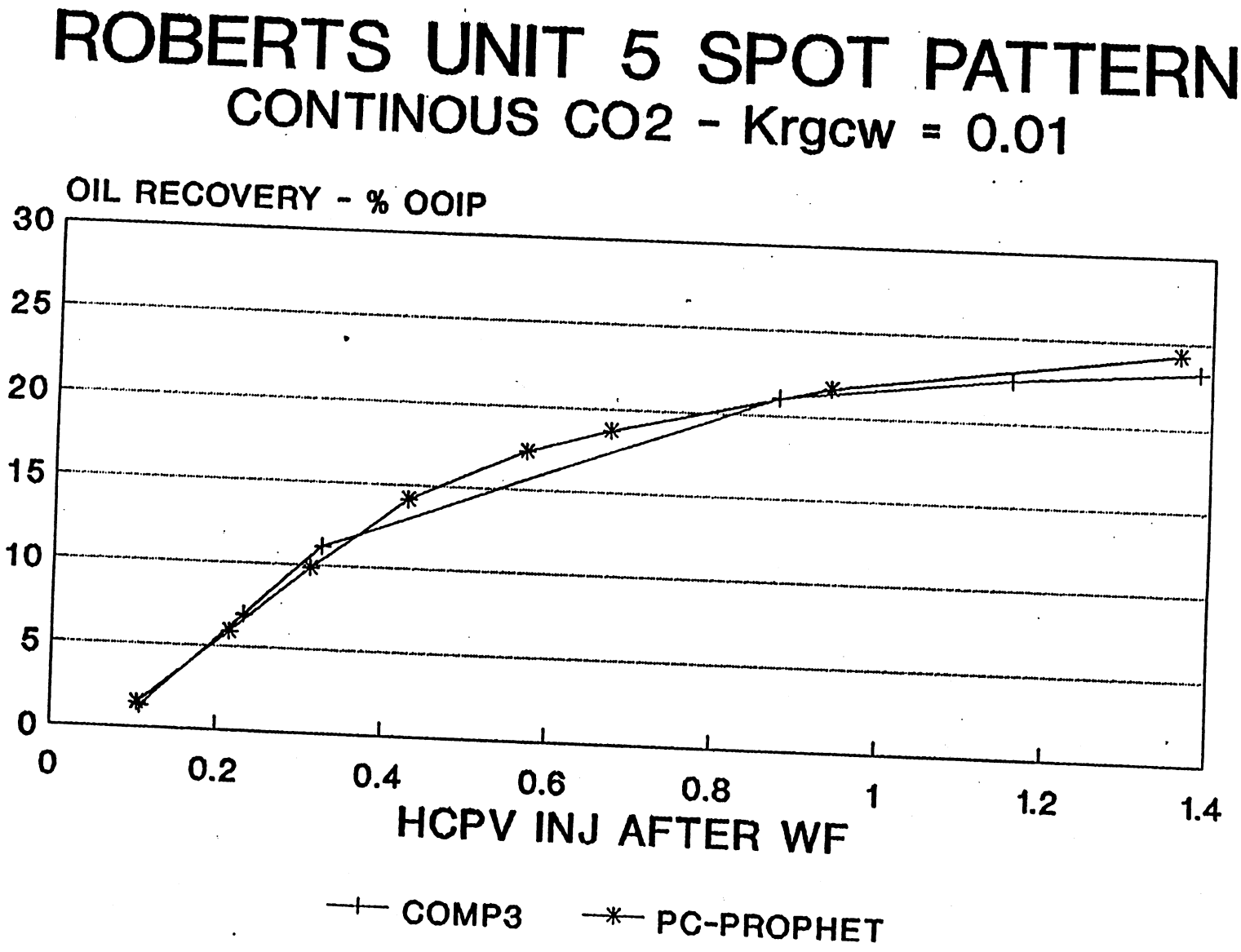

ROBERTS UNIT 5 SPOT PATTERN
CONTINOUS CO2 - Krgcw = 0.01
OIL RECOVERY - % OOIP
30
25
20
15
10
5
0
0
0.2
0.4
0.6
0.8
1
1.2
1.4
HCPV INJ AFTER WF
COMP3
PC-PROPHET

Figure 11

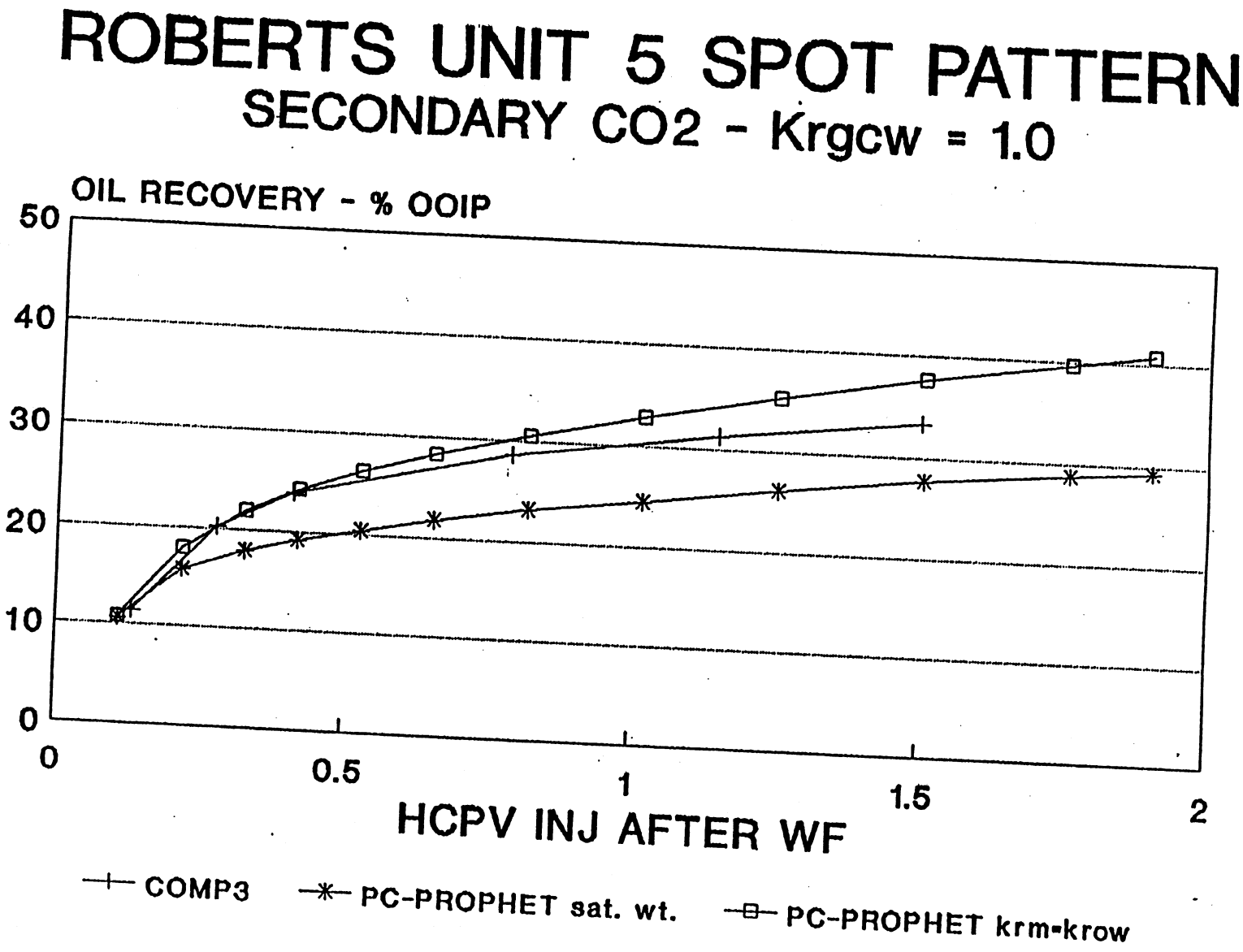

ROBERTS UNIT 5 SPOT PATTERN
SECONDARY CO2 - Krgcw = 1.0
OIL RECOVERY - % OOIP
50
40
30
20
10
0
0
0.5
1
1.5
2
HCPV INJ AFTER WF
COMP3
PC-PROPHET sat. wt.
PC-PROPHET krm=krow

Figure 12

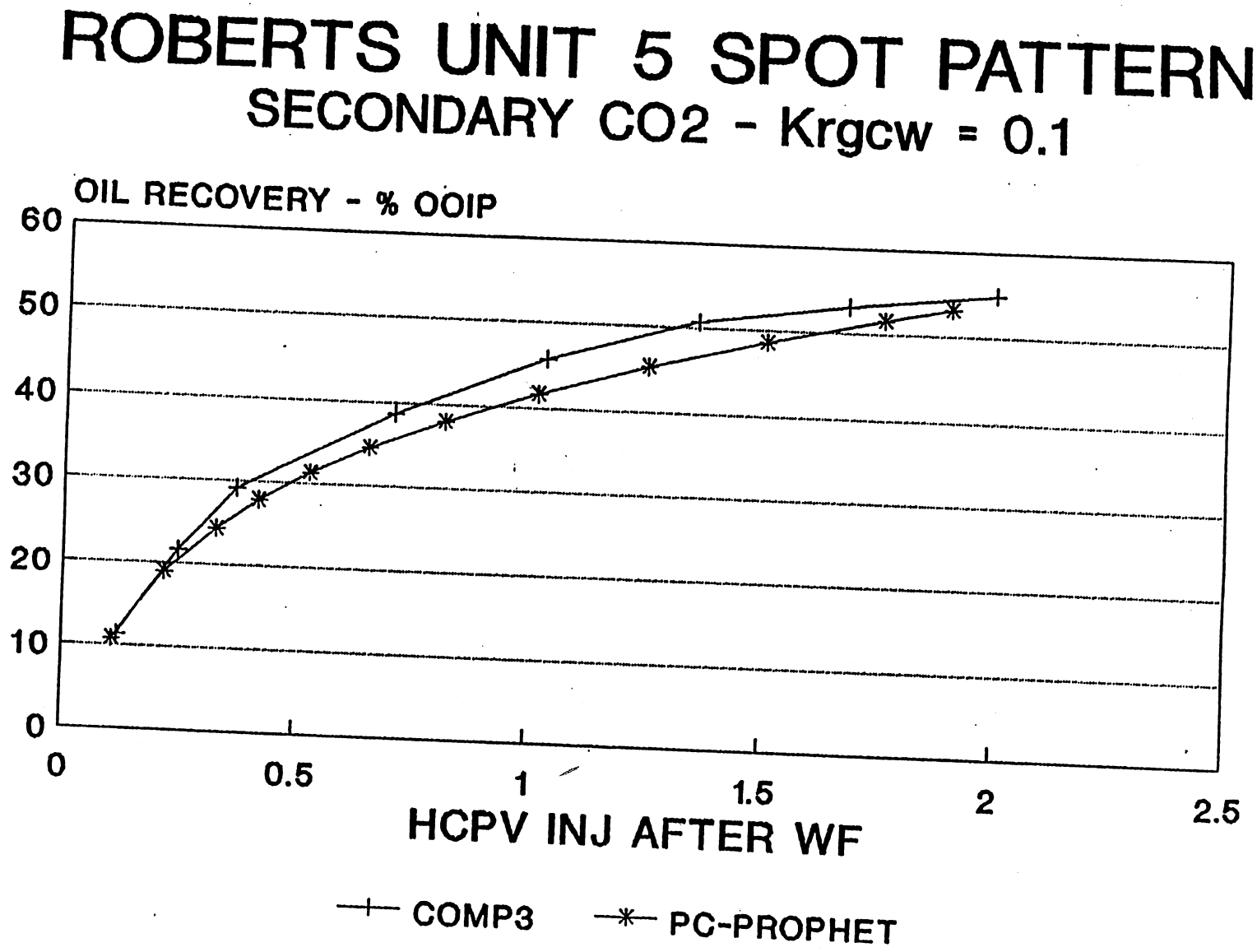

ROBERTS UNIT 5 SPOT PATTERN
SECONDARY CO2 - Krgcw = 0.1
OIL RECOVERY - % OOIP
60
50
40
30
20
10
0
0
0.5
1
1.5
2
2.5
HCPV INJ AFTER WF
COMP3
PC-PROPHET

Figure 13

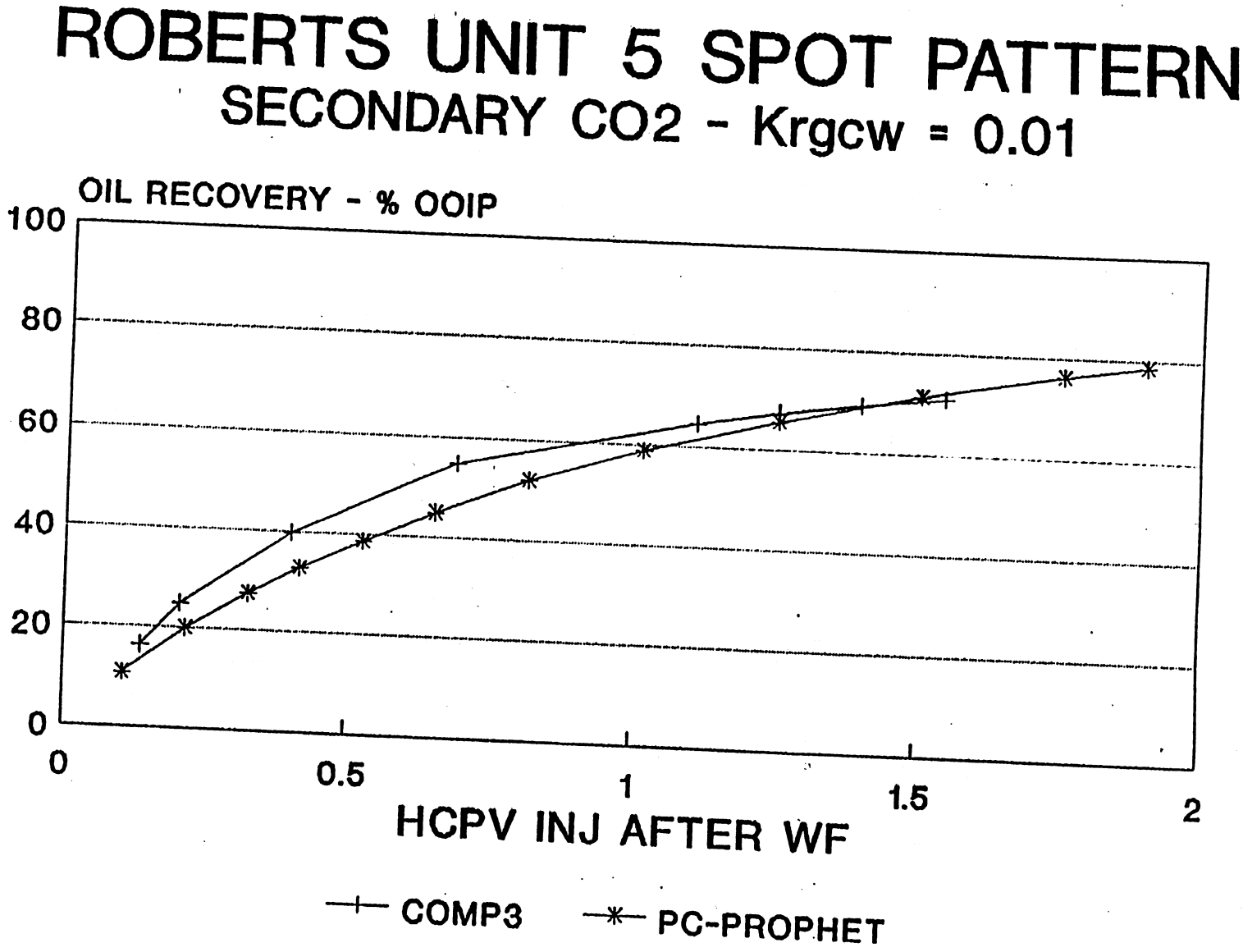

ROBERTS UNIT 5 SPOT PATTERN
SECONDARY CO2 - Krgcw = 0.01
OIL RECOVERY - % OOIP
100
80
60
40
20
0
0
0.5
1
1.5
2
HCPV INJ AFTER WF
COMP3
PC-PROPHET

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

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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, Fluvial 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[8] 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}

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

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

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

equal to k_{row}

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

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

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

and the oil relative permeability is

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

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[1,6,8,9,10]. 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.

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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

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

The effective oil viscosity μ_{oe} is given by

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

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

$$\mu_{sm} = \mu_s^{1-\omega}\mu_m^{\omega} \qquad \text{(C-3)}$$

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

$$\mu_{om} = \mu_o^{1-\omega}\mu_m^{\omega} \qquad \text{(C-4)}$$

The mixed viscosity μ_m is defined by

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

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, base	0.35
S_{wc} (connate water saturation)	0.2	
S_{wir} (residual water saturation)	varied, base	0.2
k_{rocw} (endpoint oil rel perm)	0.5	
k_{wro} (endpoint water rel perm)	0.3	
k_{rso} (endpoint solvent rel perm)	varied, base	0.05
k_{rgcw} (endpoint gas rel perm)	varied, base	0.4
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.

Fluid Pair	Endpoint Mobility Ratio
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_{rw}	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_{rw}	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_{rw}	S_{wr}	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	0.2896
Sat. Weight	0.2	0.0187	0.2065	0.3059	---	---	---
	0.25	0.0201	0.2146	0.3115	0.0170	0.2089	0.3037
	0.3	0.0230	0.2205	0.3143	0.0224	0.2192	0.3133
	0.35	0.0266	0.2206	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 ($k_{rw} = k_{row}$)

		Tertiary Oil Recovery (HCPV)									
						Hybrid - WAG					
		Continuous CO_2				1:1 WAG			1:2 WAG		
k_{rw}	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_{rw}	R_k	S_{wr}	CO_2 Slug	WAG	Water Chase
Equal to k_{row}	---	---	0.0	0.0231	0.1928	0.2904
Average	0.8	0.8	0.0	0.0223	0.1916	0.2891
Average	0.1	0.1	0.0	0.0181	0.1878	0.2828
Sat. Weight	0.1	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	0.1	0.10	0.0167	0.1876	0.2767
Sat. Weight (oil hysteresis and water hysteresis with S_{wr} = 0.30)	0.1	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_{rm}	CO_2 Slug	WAG	Water Chase
Equal to k_{rm}	—	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_{rm}	—	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_{wr} = 0.30)	0.1	0.10	0.0102	0.2856	0.3504

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

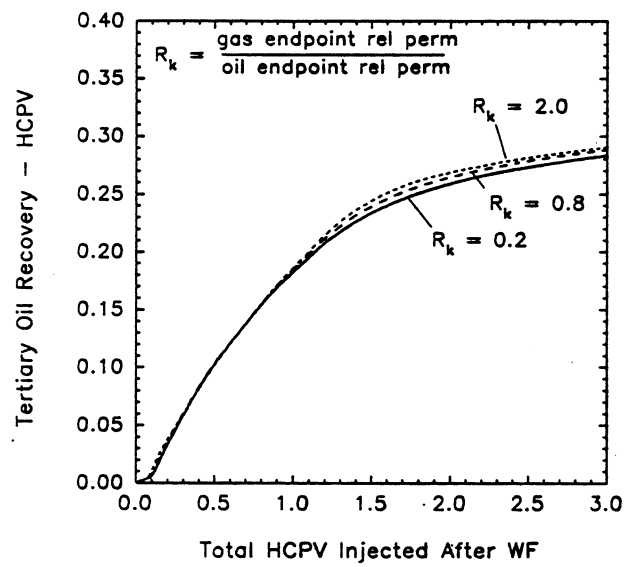


Figure 1. Impact of Endpoint Gas Relative Permeability on Oil Recovery for the Simple Average Method

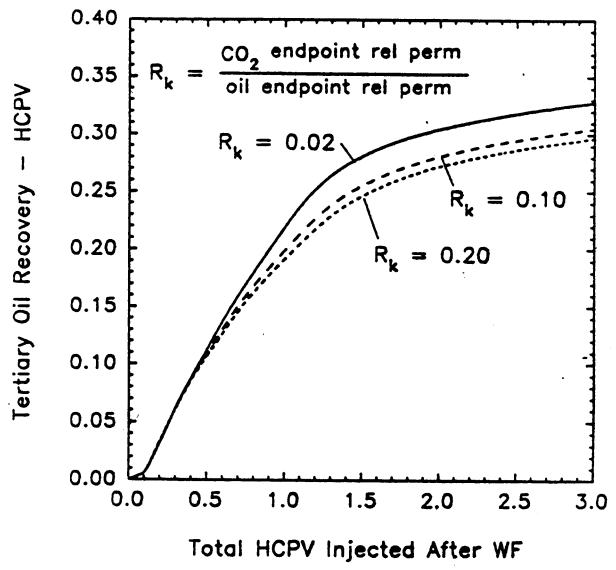


Figure 3. Impact of Endpoint CO_2 Relative Permeability on Oil Recovery for the Saturation Weighted Method

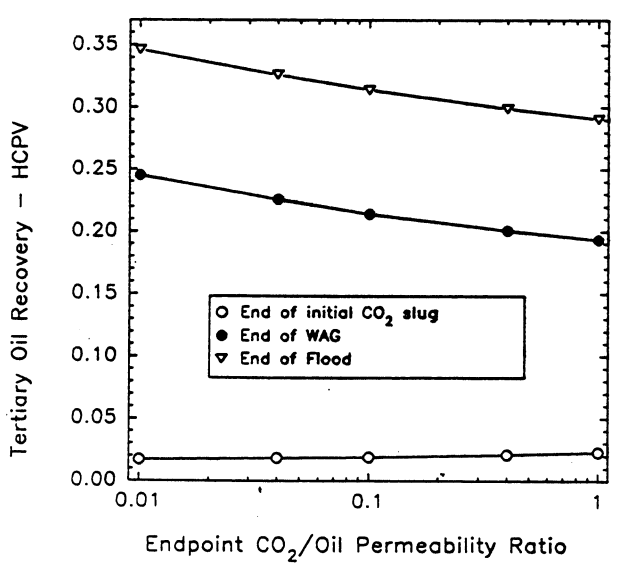


Figure 2. Effect of Endpoint CO_2/Oil Relative Permeability Ratio on Tertiary Oil Recovery for the Hybrid WAG Process

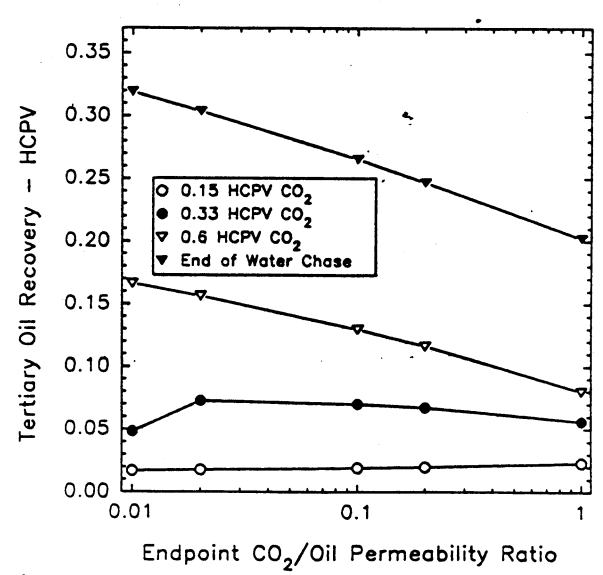


Figure 4. Effect of Endpoint CO_2/Oil Relative Permeability Ratio on Tertiary Oil Recovery for the Continuous CO_2 Process

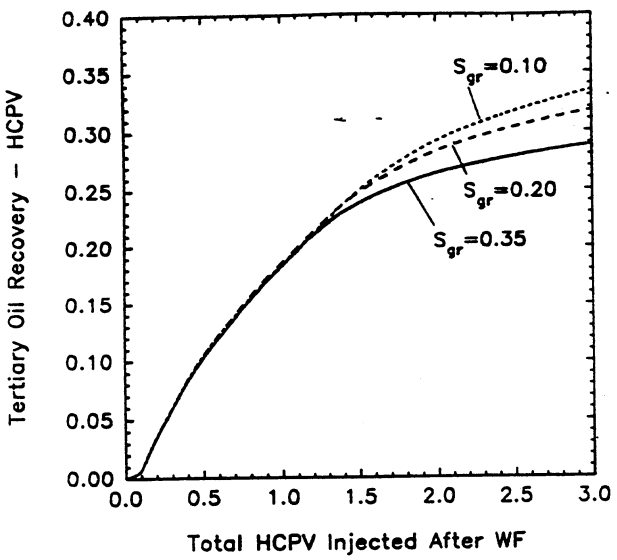


Figure 9. Effect of Residual Gas Saturation on CO_2 Flood Performance

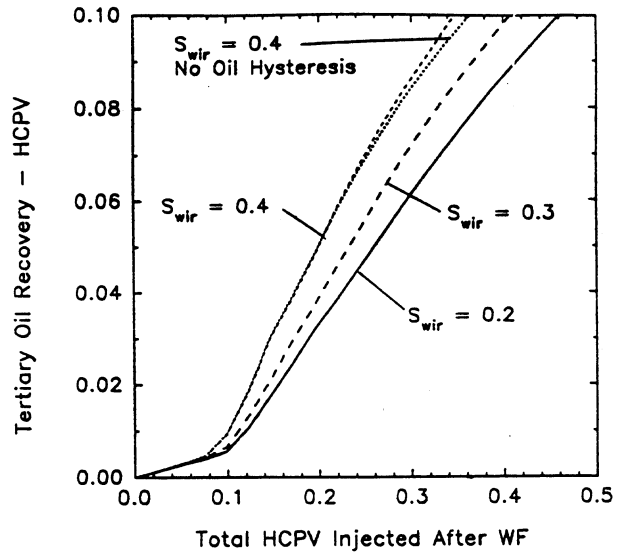


Figure 11. Hysteresis Effects in Early Stages of CO_2 Flood

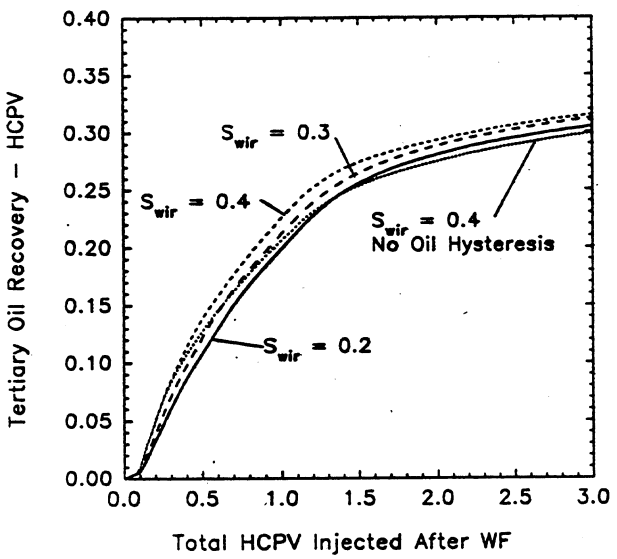


Figure 10. Effects of Water and Oil Relative Permeability Hysteresis on CO_2 Flood Performance

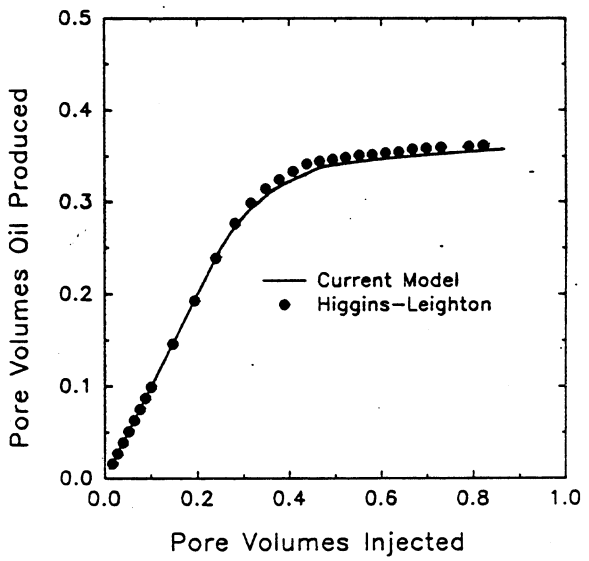
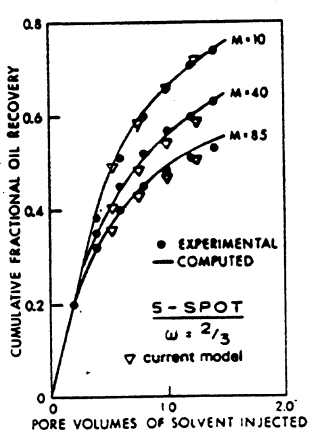


Figure A-1. Comparison of Current Model and Higgins-Leighton Method (Ref. 11) for Predicted Waterflood Performance in a Five-Spot



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)