DOE/BC/14960-8
Distribution Category UC-122

Post Waterflood CO_2 Miscible Flood in Light Oil, Fluvial-Dominated Deltaic Reservoir

Annual Report for the Period
October 1, 1993 to September 30, 1994

By
S. Bou-Mikael

July 1995

Work Performed Under Contract No. DE-FC22-93BC14960

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

Chandra Nautiyal, Project Manager
Bartlesville Project Office
P.O. Box 1398
Bartlesville, OK 74005

Prepared by
Texaco Exploration and Production Inc.
P.O. Box 60252
New Orleans, LA 70160

DISCLAIMER

DISCLAIMER

TABLE OF CONTENTS

"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 data base 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 an 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 Wterflooded 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. A list of the names of all attendees is shown in Appendix "c".

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 94		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. This is supported by reservoir behavior and performance under CO_2 injection.

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 a 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,	1337 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 has 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.

<u>Reservoir Characterization</u>,

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 eventhough 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.

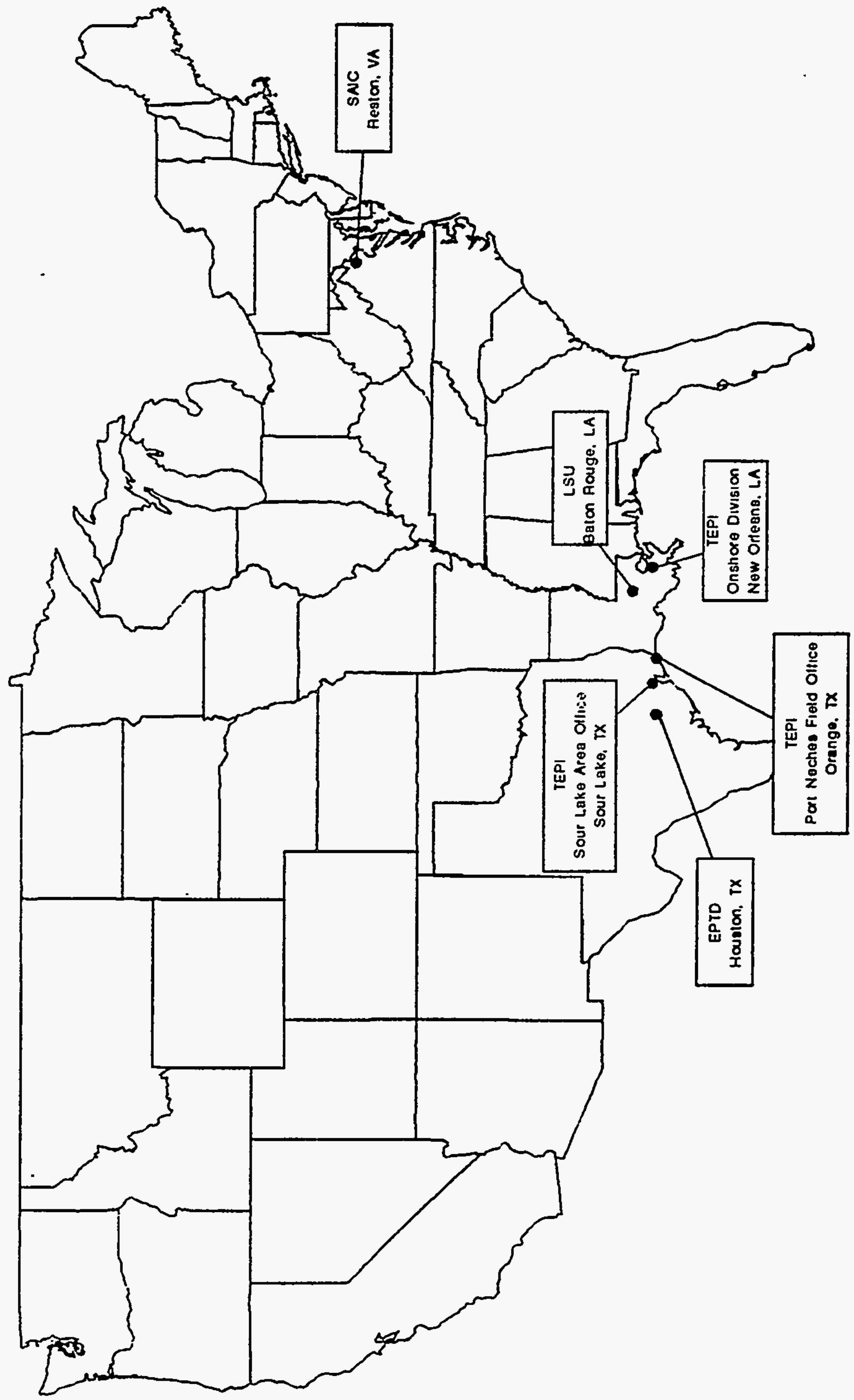
The majority of the produced salt water from this project will be reinjected in the ground for pressure maintenance, while the remaining portion will be decontaminated and discharged in a tidal disposal facility permitted by the state of Texas. The CO_2 pipeline is operating under DOT regulation. The 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.

Geographic Location of Participants



PORT NECHES CO2 PROJECT
LOCATION OF PARTICIPANT OFFICES

Figure 1

CO_2 Project Area

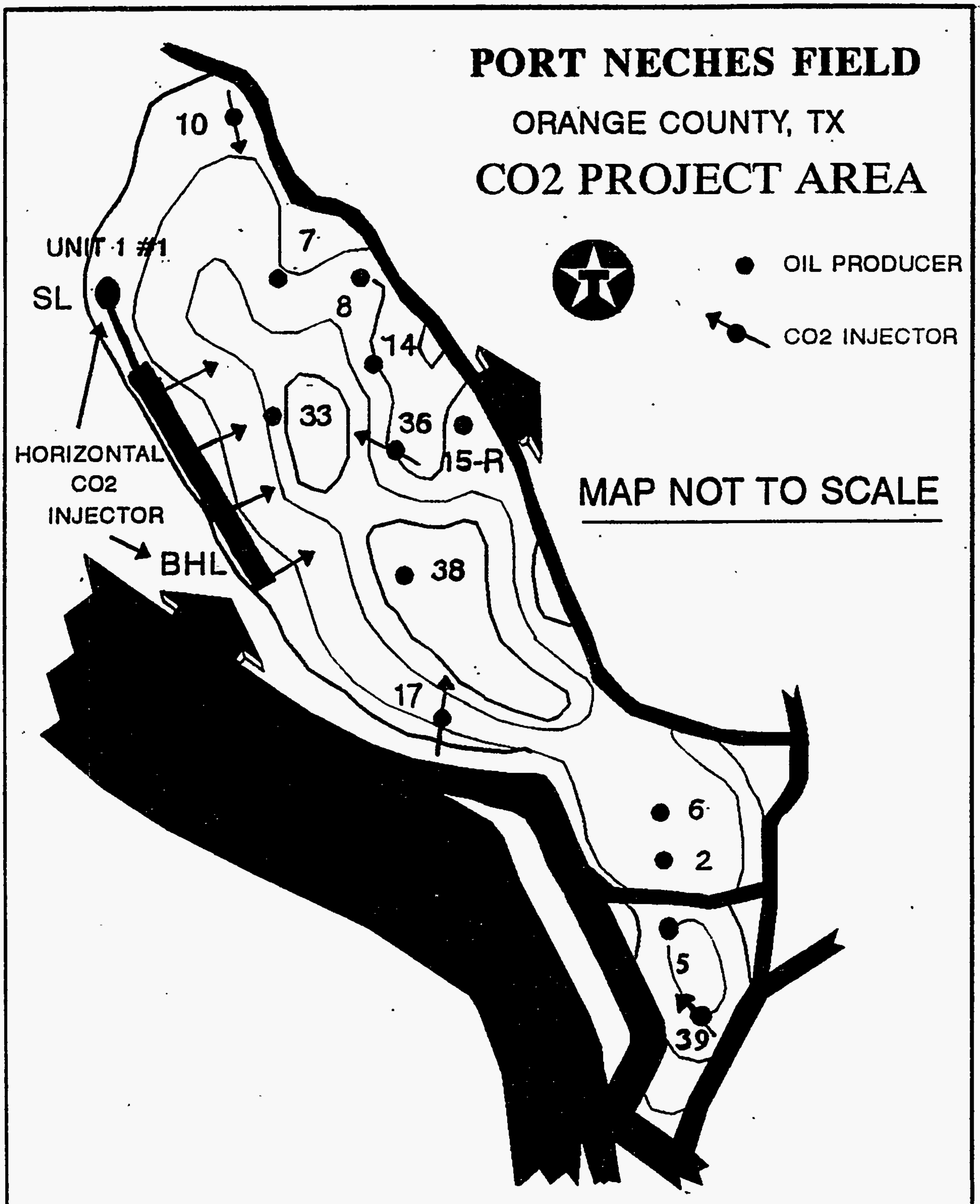


Figure 2

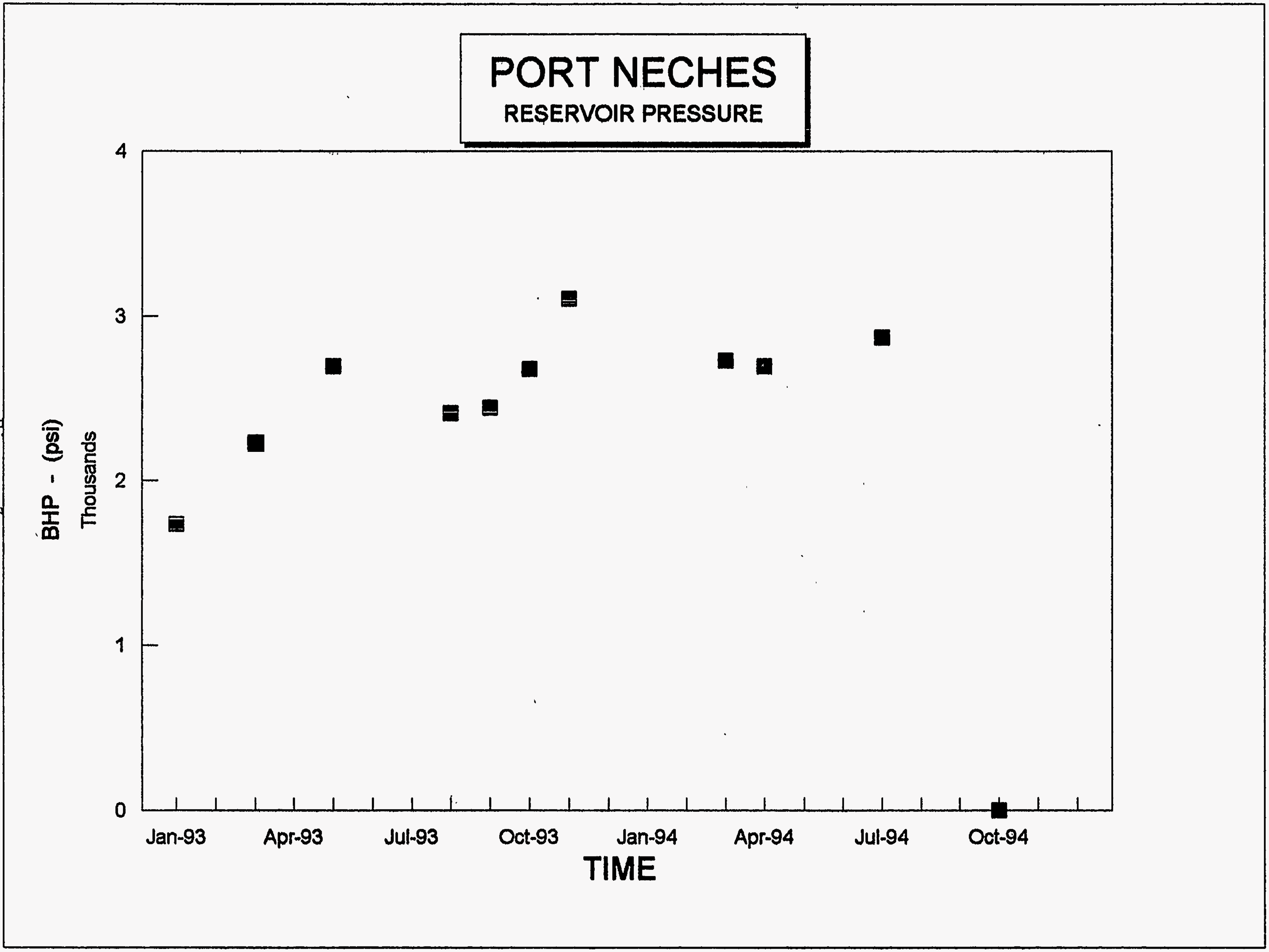

PORT NECHES
RESERVOIR PRESSURE
BHP - (psi)
Thousands
0
1
2
3
4
Jan-93
Apr-93
Jul-93
Oct-93
Jan-94
Apr-94
Jul-94
Oct-94
TIME

Figure 3

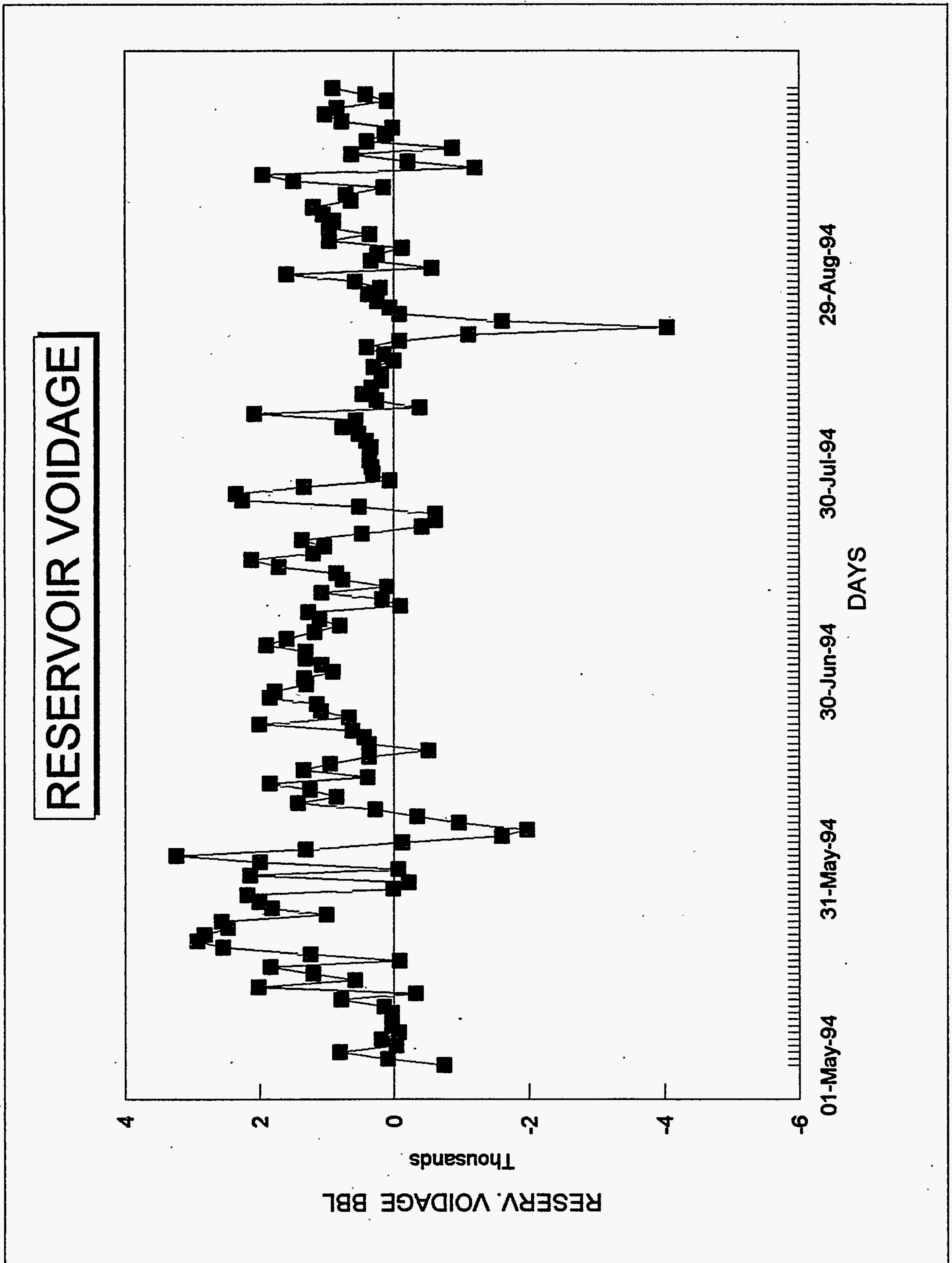

RESERVOIR VOIDAGE
RESERV. VOIDAGE BBL
Thousands
4
2
0
-2
-4
-6
01-May-94
31-May-94
30-Jun-94
30-Jul-94
29-Aug-94
DAYS

Figure 4

Port Neches CO2 Project
Allocated Production

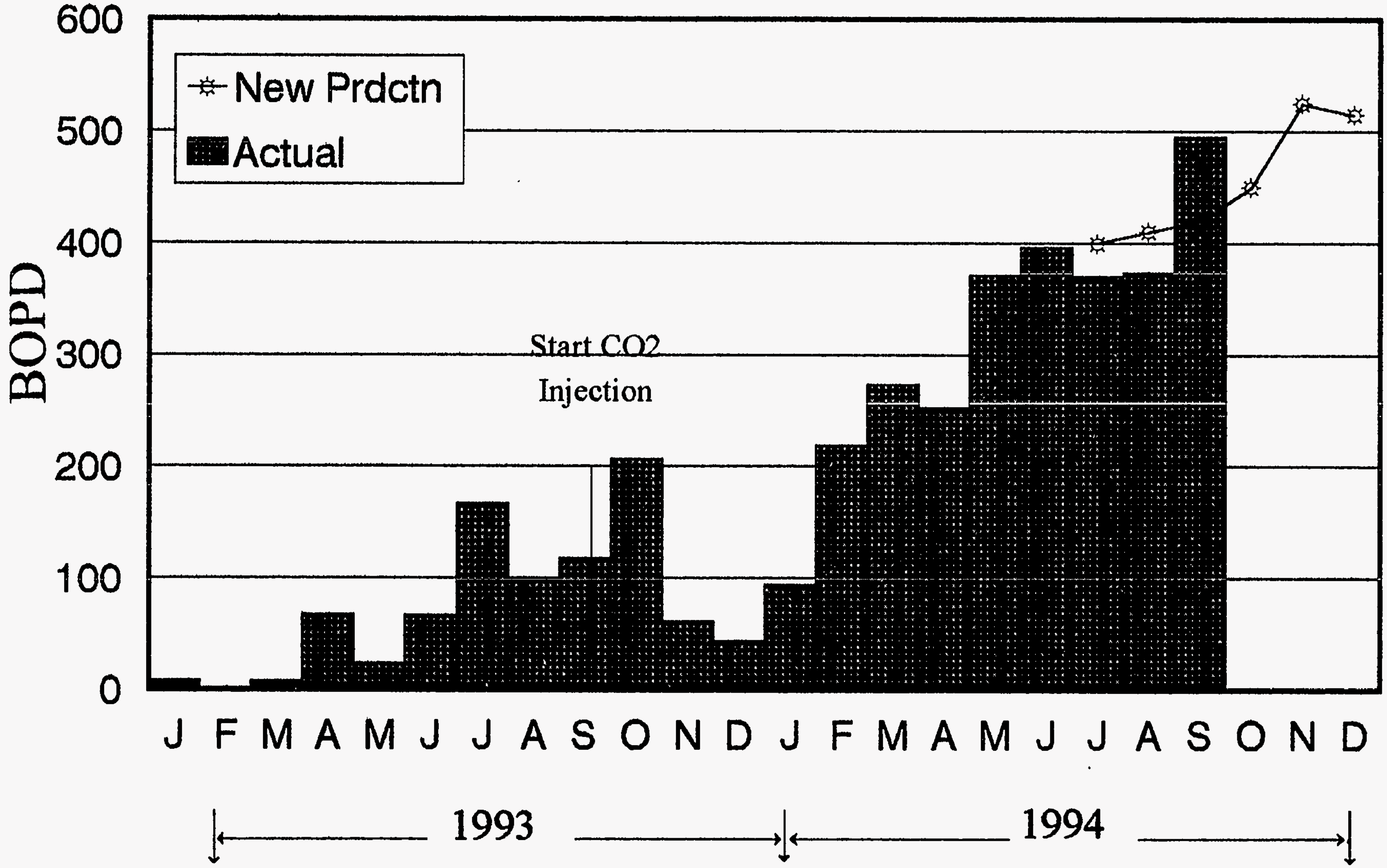


Figure 5

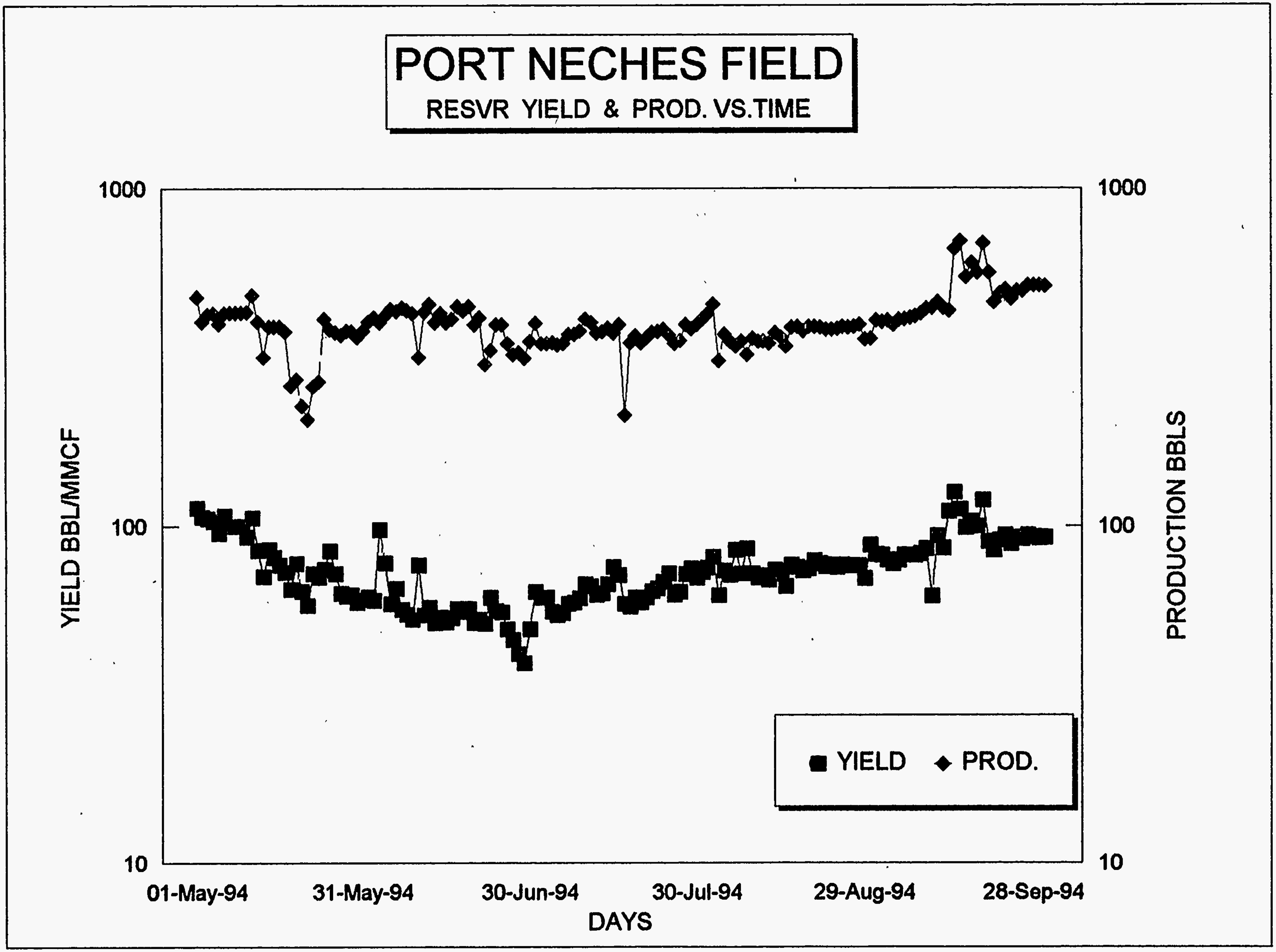
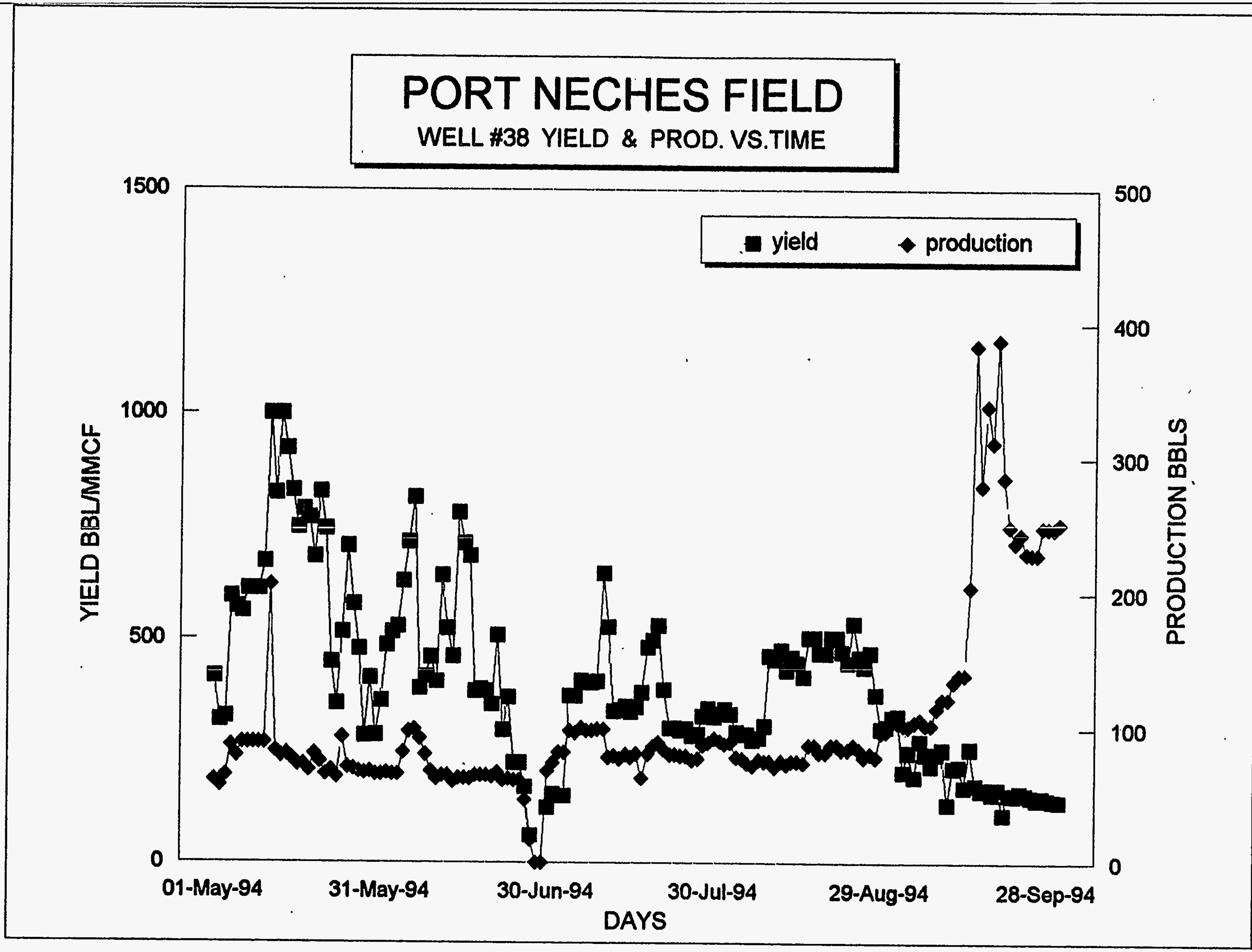

PORT NECHES FIELD
RESVR YIELD & PROD. VS.TIME
1000
100
10
YIELD BBL/MMCF
1000
100
10
PRODUCTION BBLS
YIELD
PROD.
01-May-94
31-May-94
30-Jun-94
30-Jul-94
29-Aug-94
28-Sep-94
DAYS

Figure 6
13



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

Figure 7
14

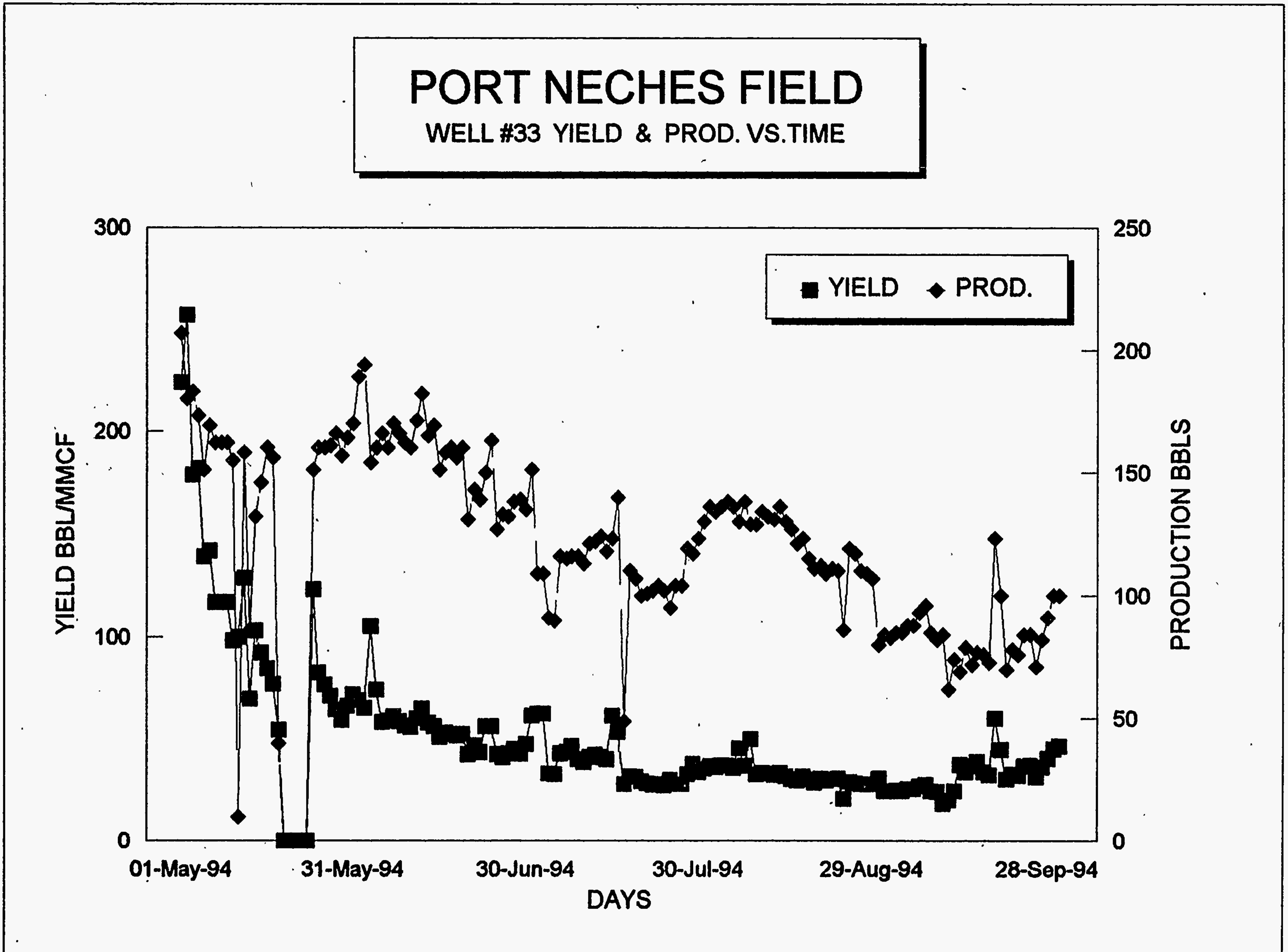

PORT NECHES FIELD
WELL #33 YIELD & PROD. VS.TIME
YIELD
PROD.
YIELD BBL/MMCF
300
200
100
0
PRODUCTION BBLS
250
200
150
100
50
0
01-May-94
31-May-94
30-Jun-94
30-Jul-94
29-Aug-94
28-Sep-94
DAYS

Figure 8

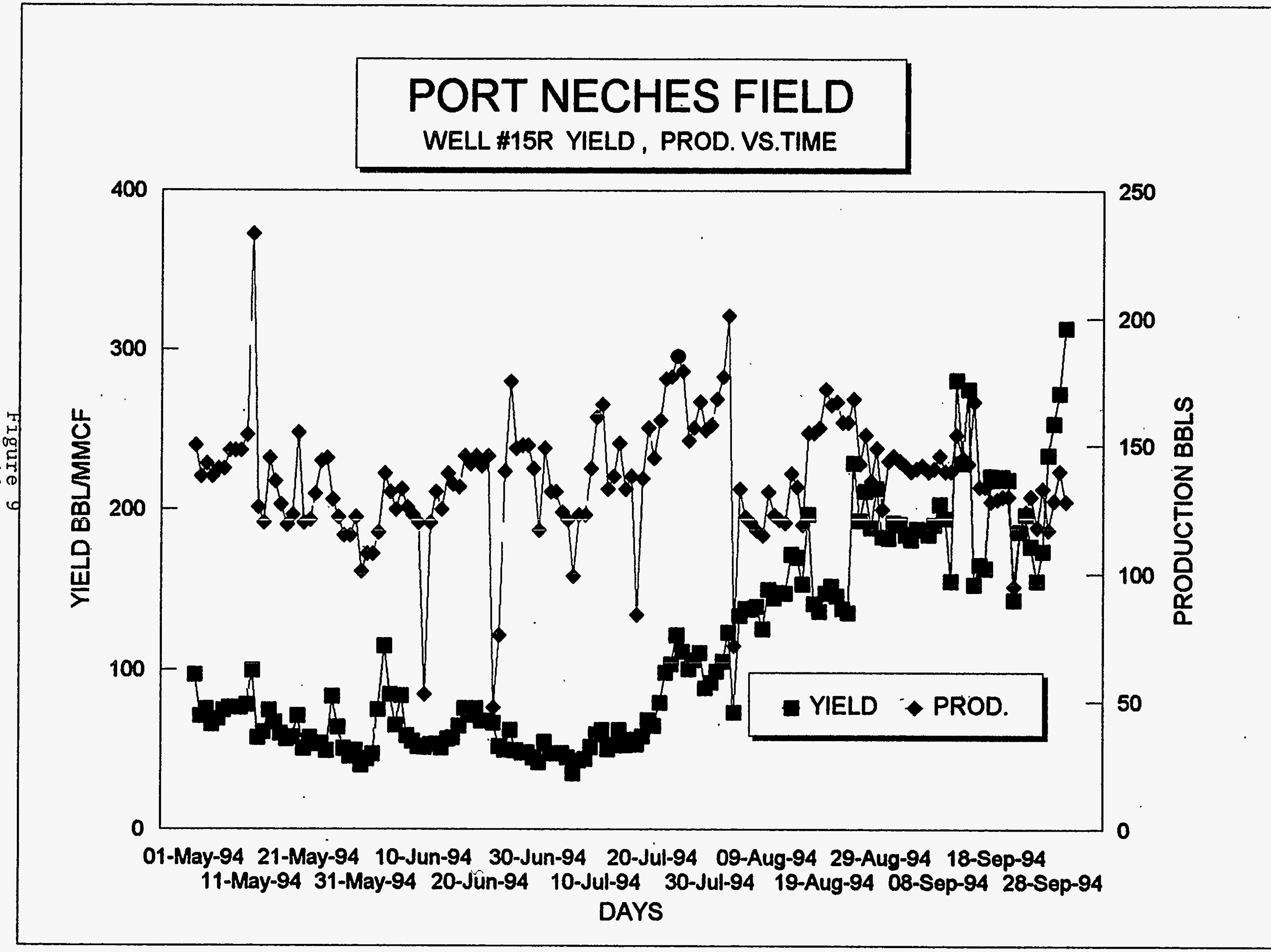

PORT NECHES FIELD
WELL #15R YIELD , PROD. VS.TIME
YIELD BBL/MMCF
PRODUCTION BBLS
400
300
200
100
0
250
200
150
100
50
0
■ YIELD
◆ PROD.
01-May-94
11-May-94
21-May-94
31-May-94
10-Jun-94
20-Jun-94
30-Jun-94
10-Jul-94
20-Jul-94
30-Jul-94
09-Aug-94
19-Aug-94
29-Aug-94
08-Sep-94
18-Sep-94
28-Sep-94
DAYS

Figure 16

PORT NECHES FIELD

WELL #14 YIELD & PROD. VS.TIME

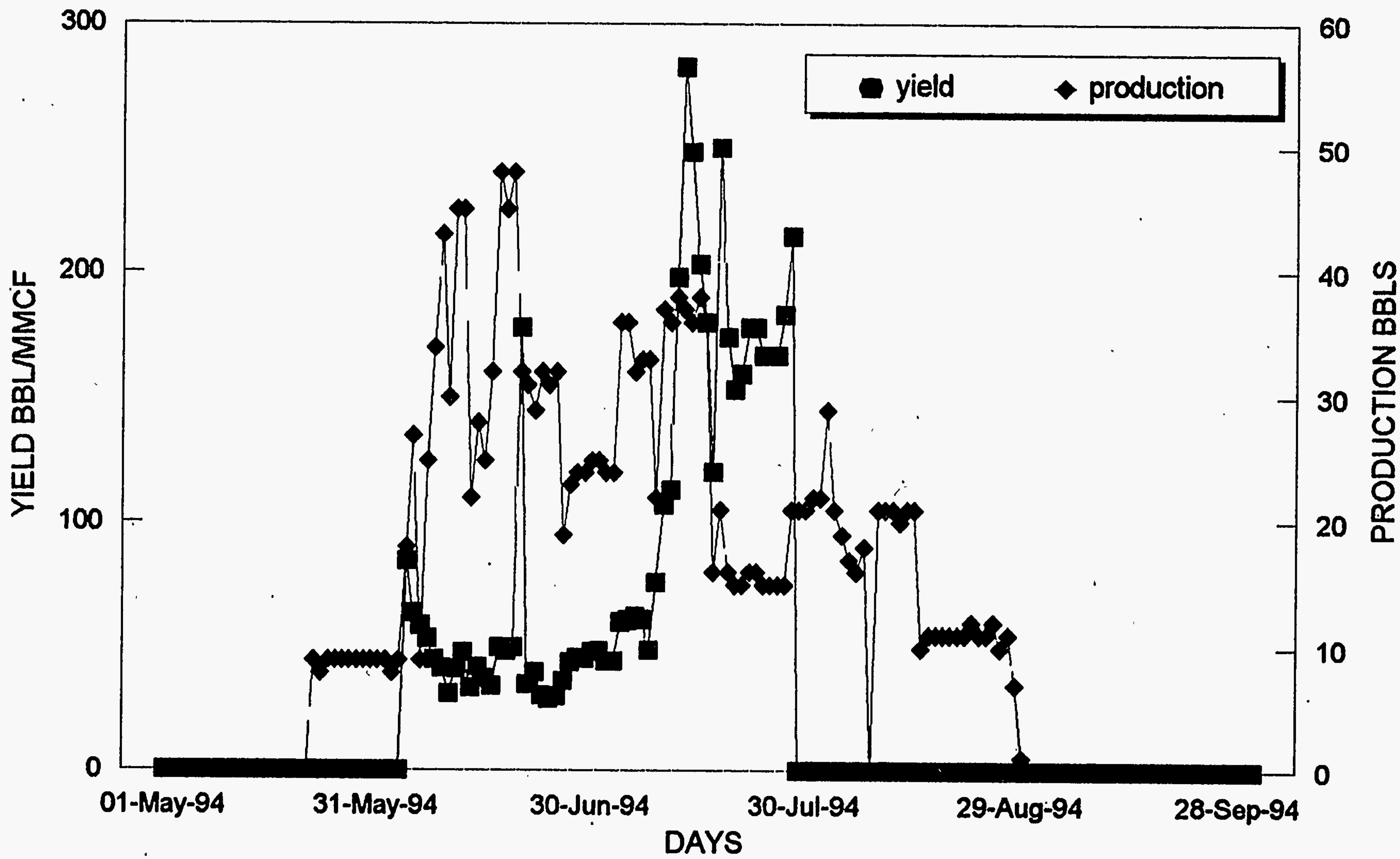


Figure 10
17

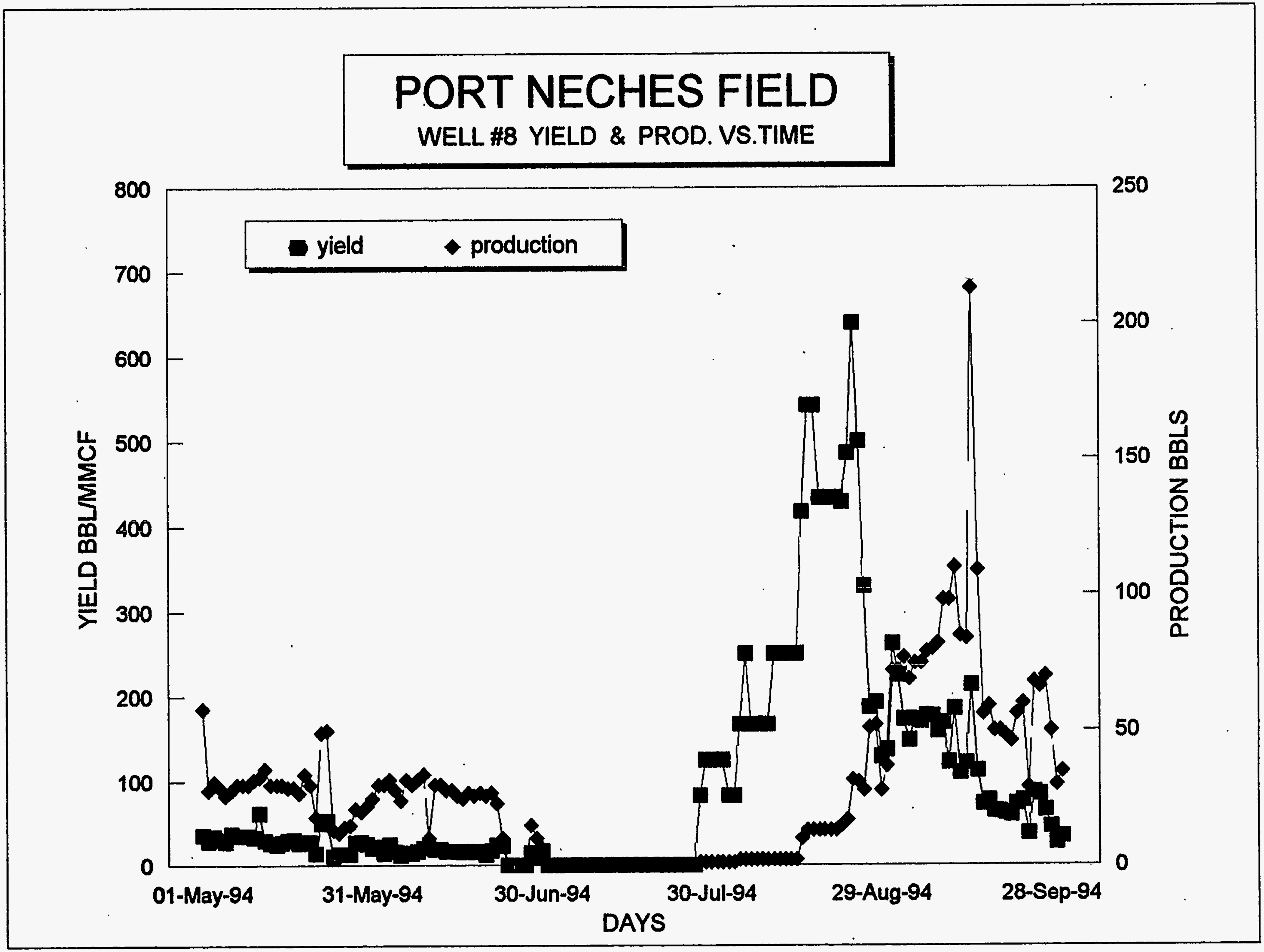
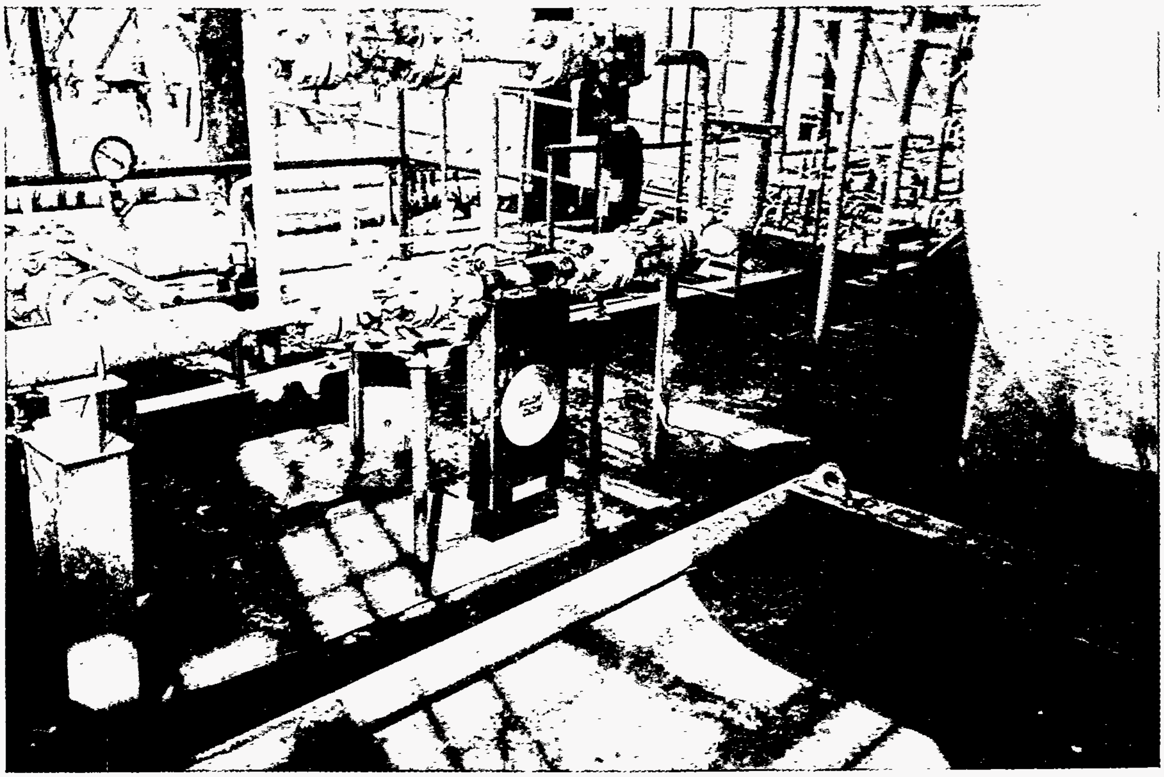
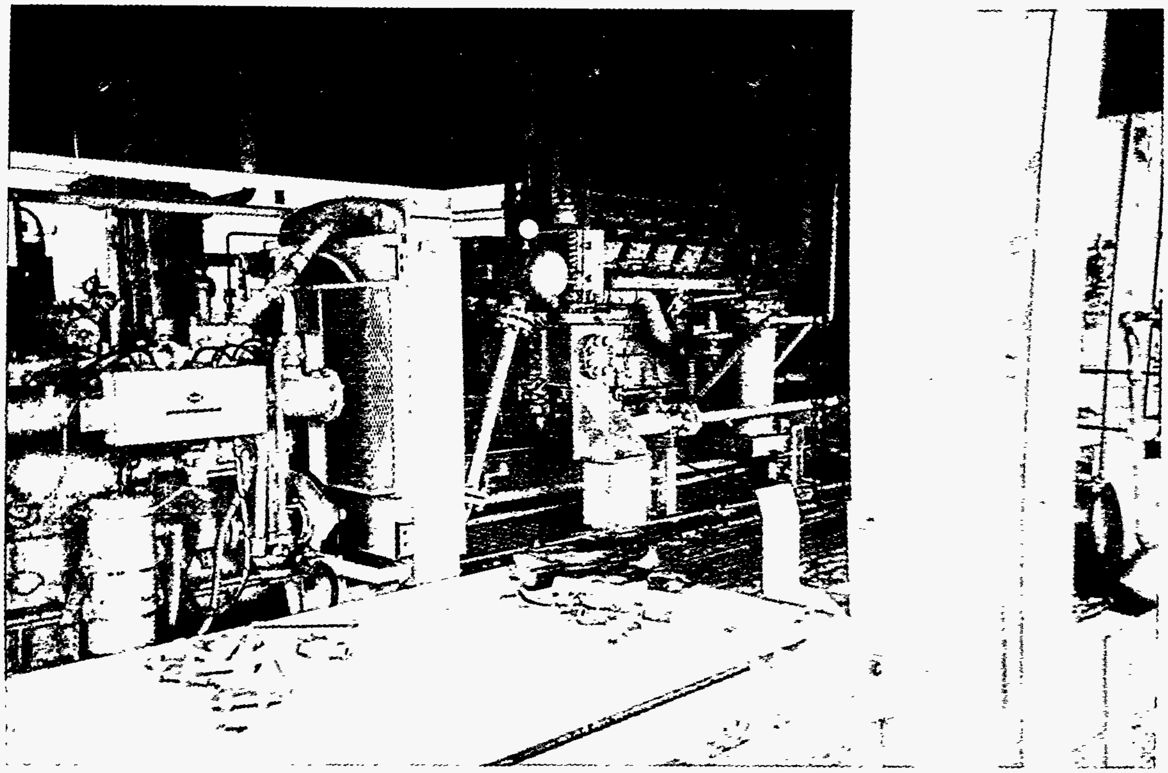

PORT NECHES FIELD
WELL #8 YIELD & PROD. VS.TIME
yield
production
YIELD BBL/MMCF
PRODUCTION BBLS
DAYS
800
700
600
500
400
300
200
100
0
250
200
150
100
50
0
01-May-94
31-May-94
30-Jun-94
30-Jul-94
29-Aug-94
28-Sep-94

Figure 11
18

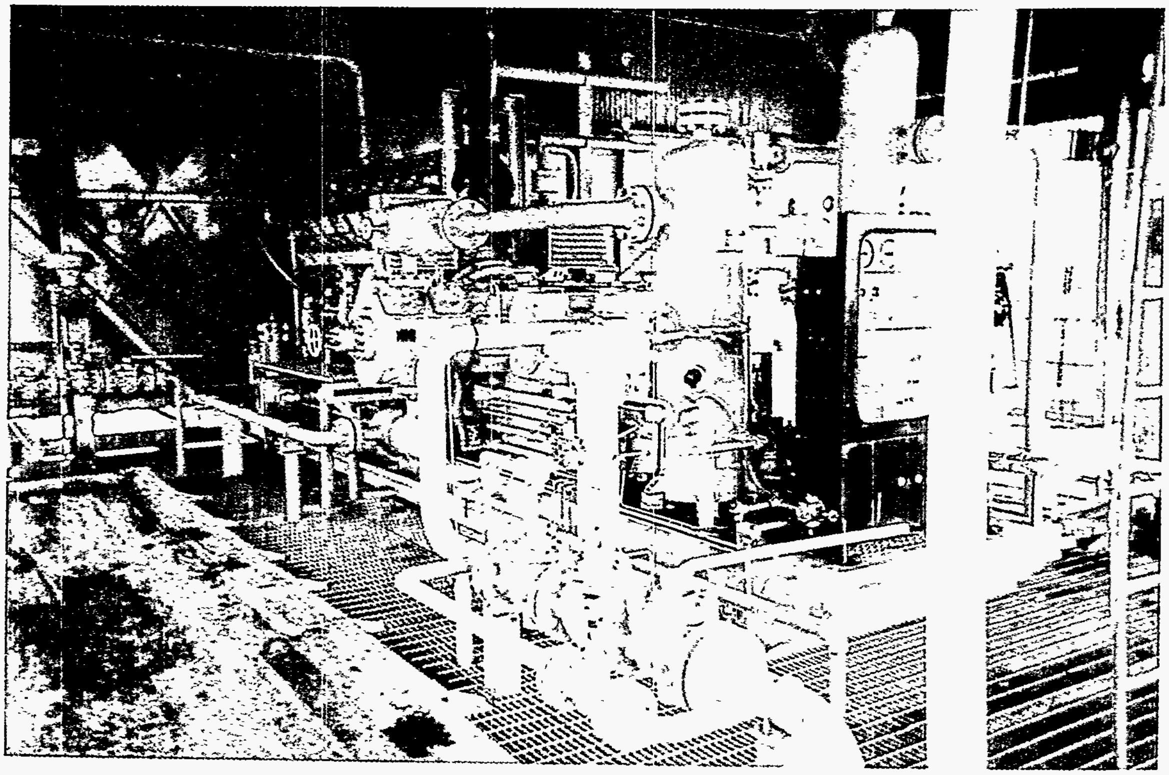


CO_2 Mass Meter

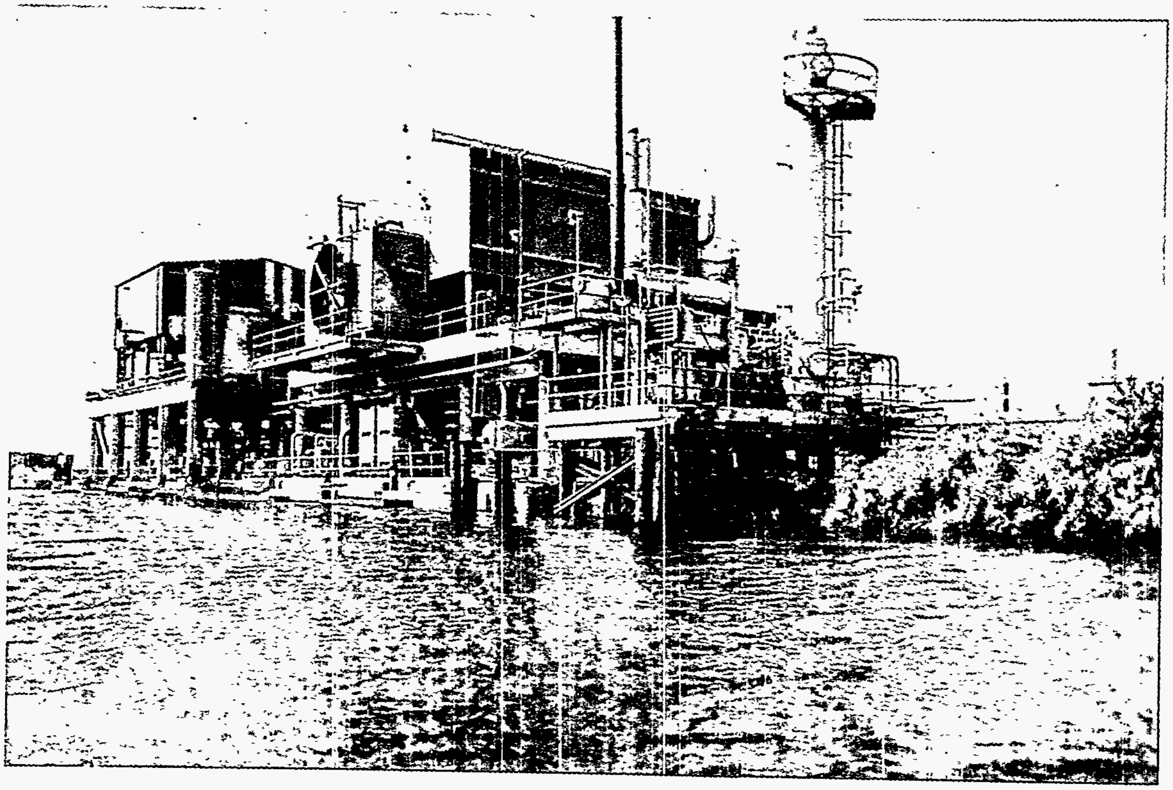


Injection Compressor

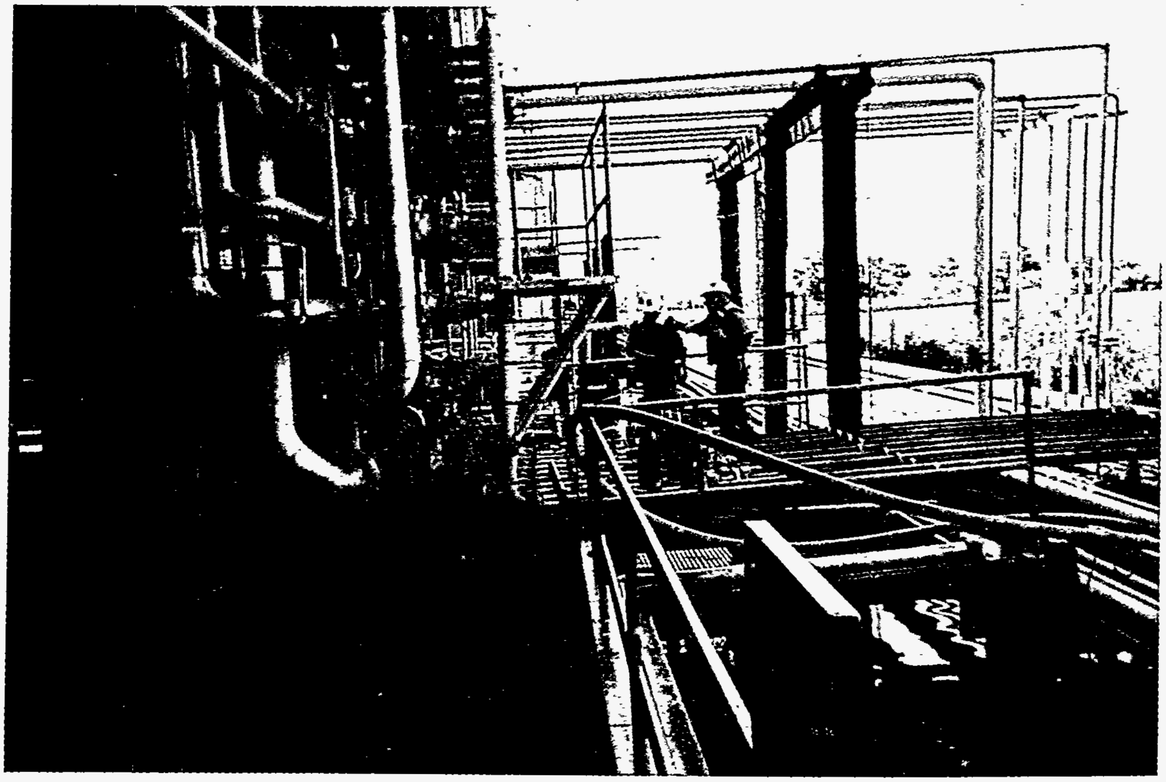
Project Development Photographs



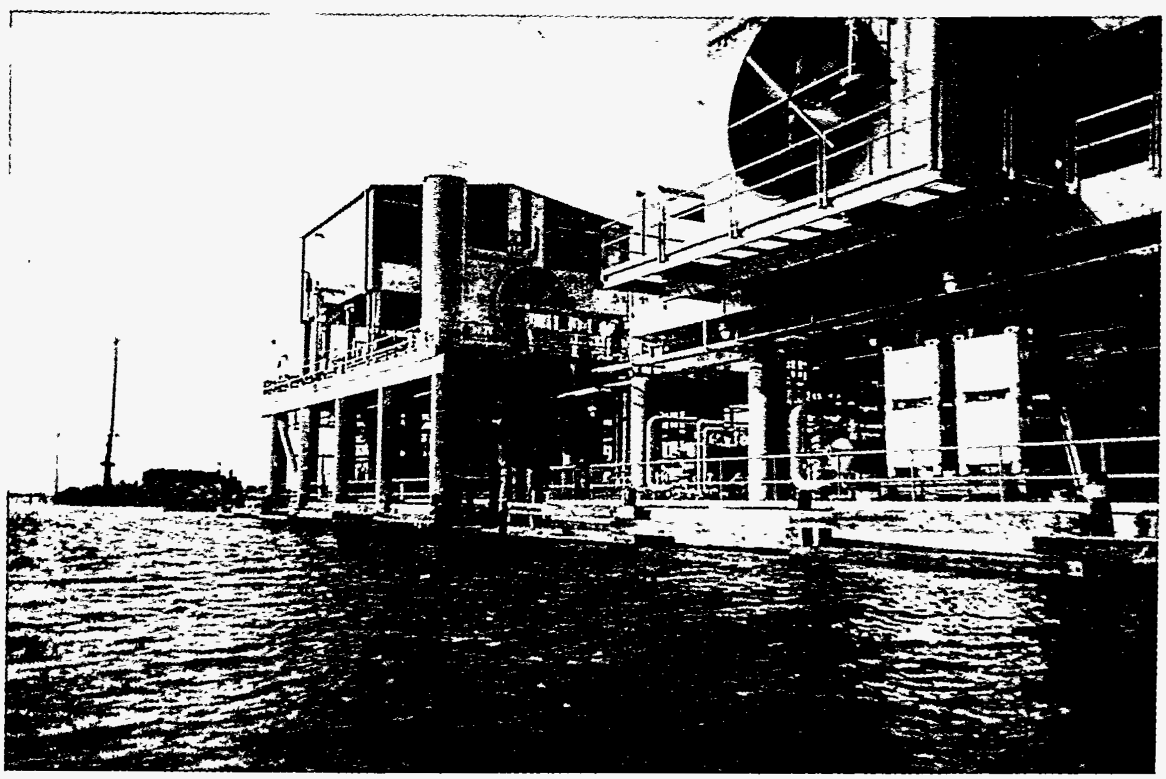
Low Pressure Compressor



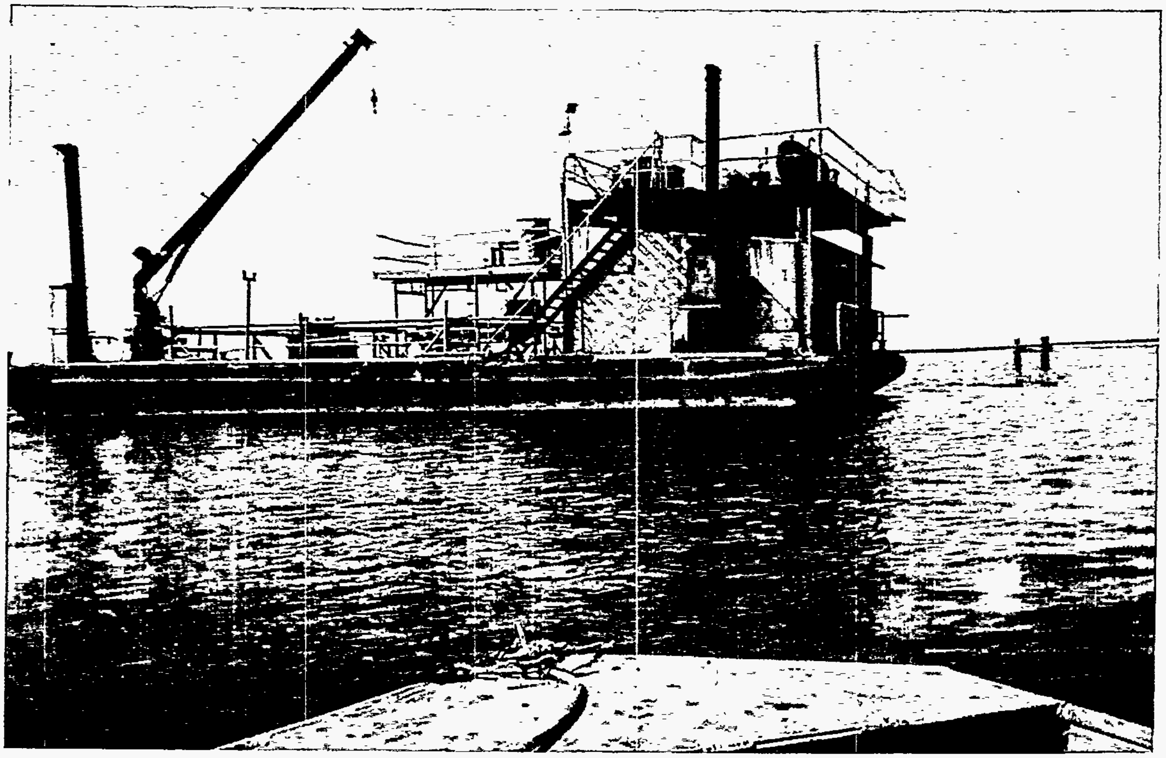
Compressor Station



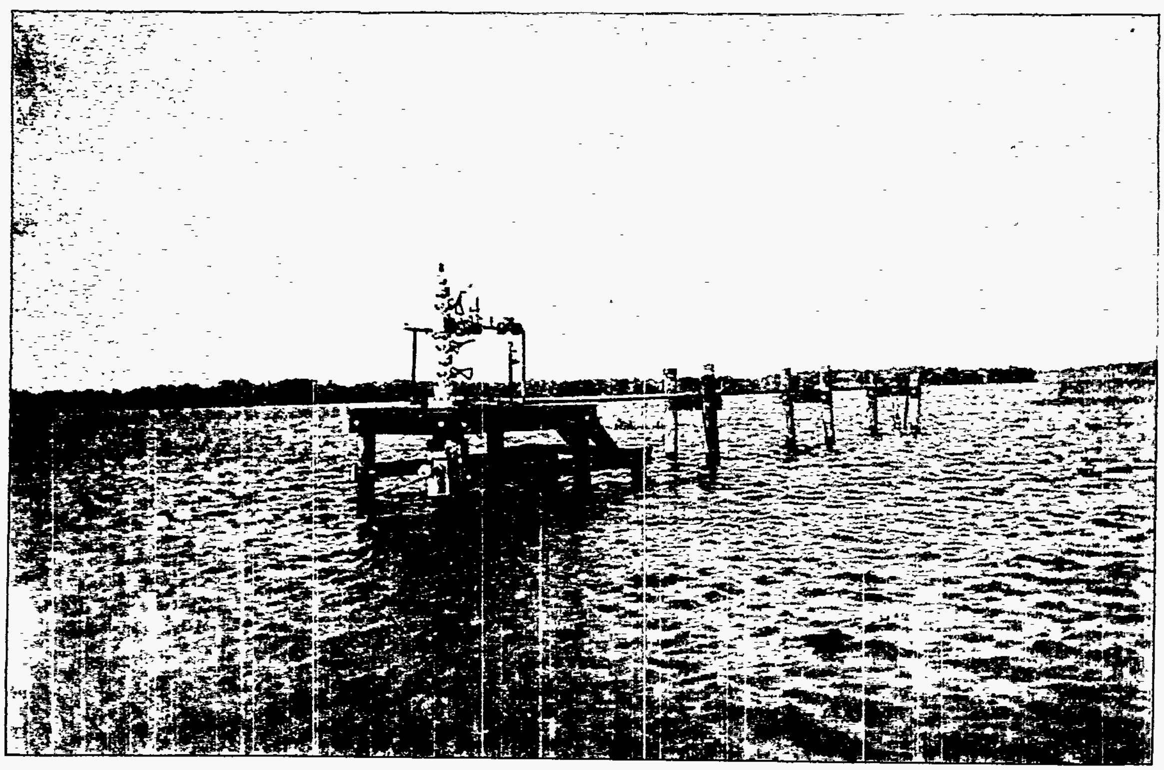
Header Bar



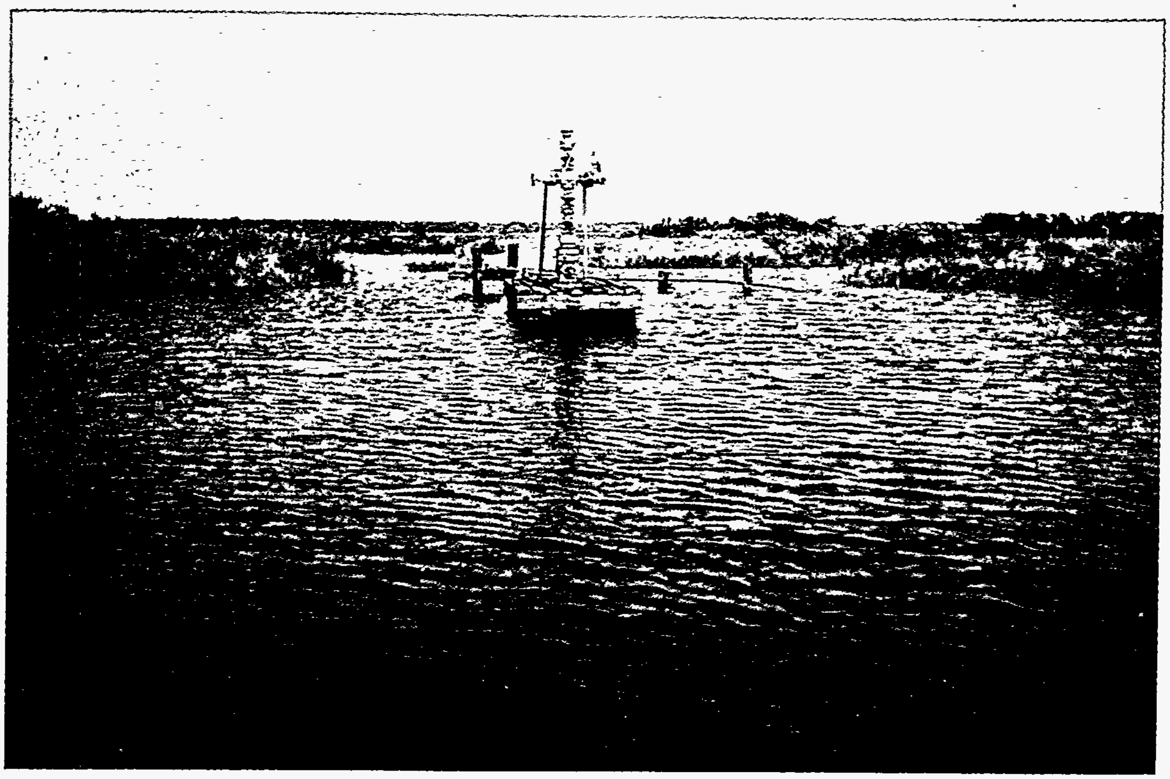
Compressor Station



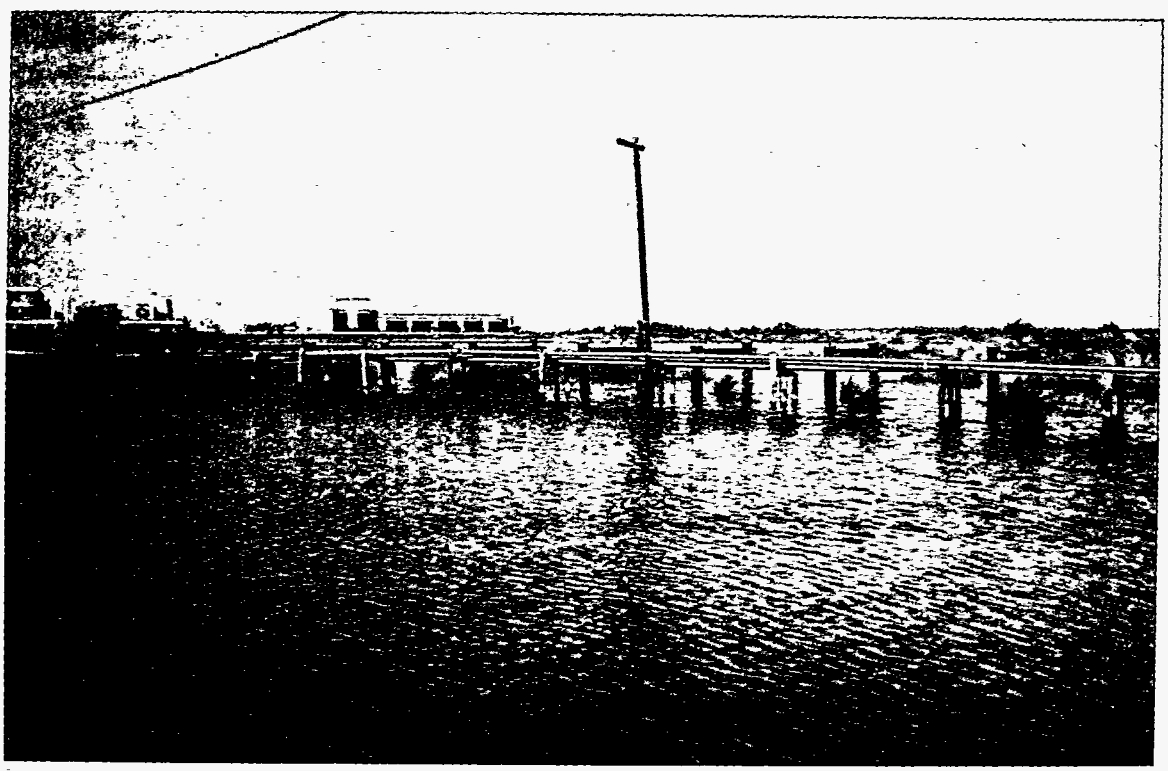
Barge Laying a CO_2 Injection Link



Horizontal CO_2 Injection Well



Producing Well

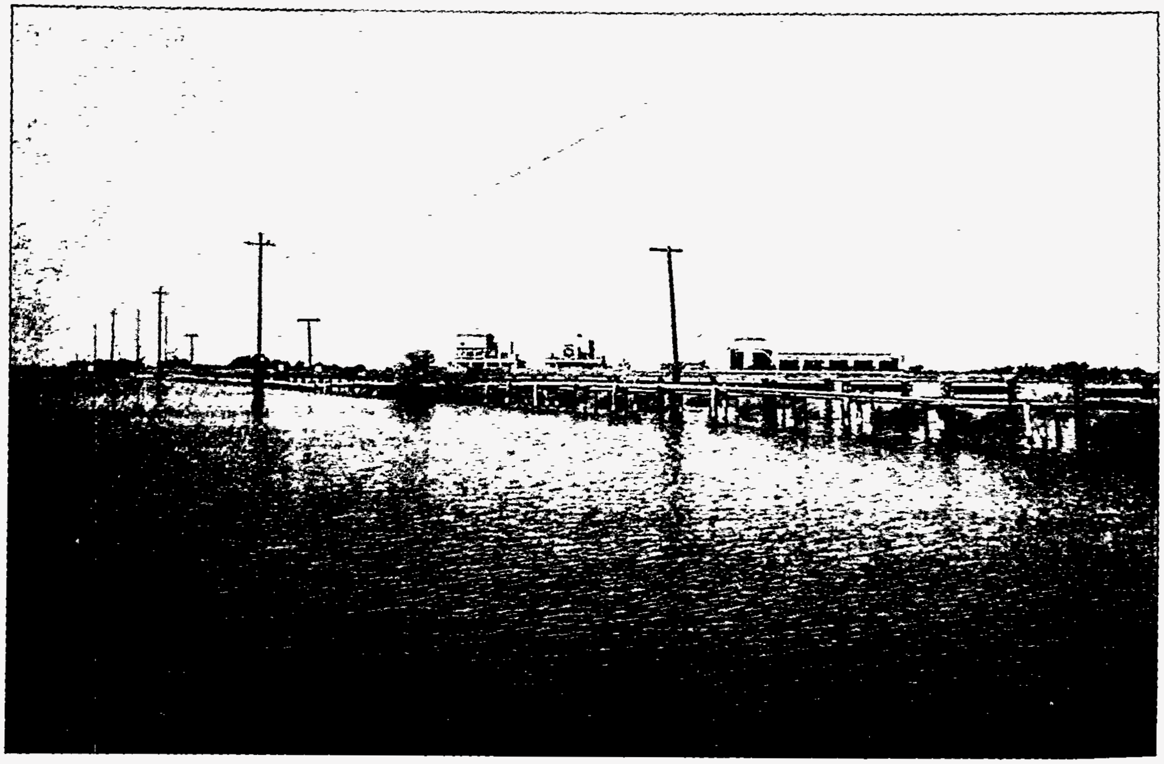


Pipe Rack

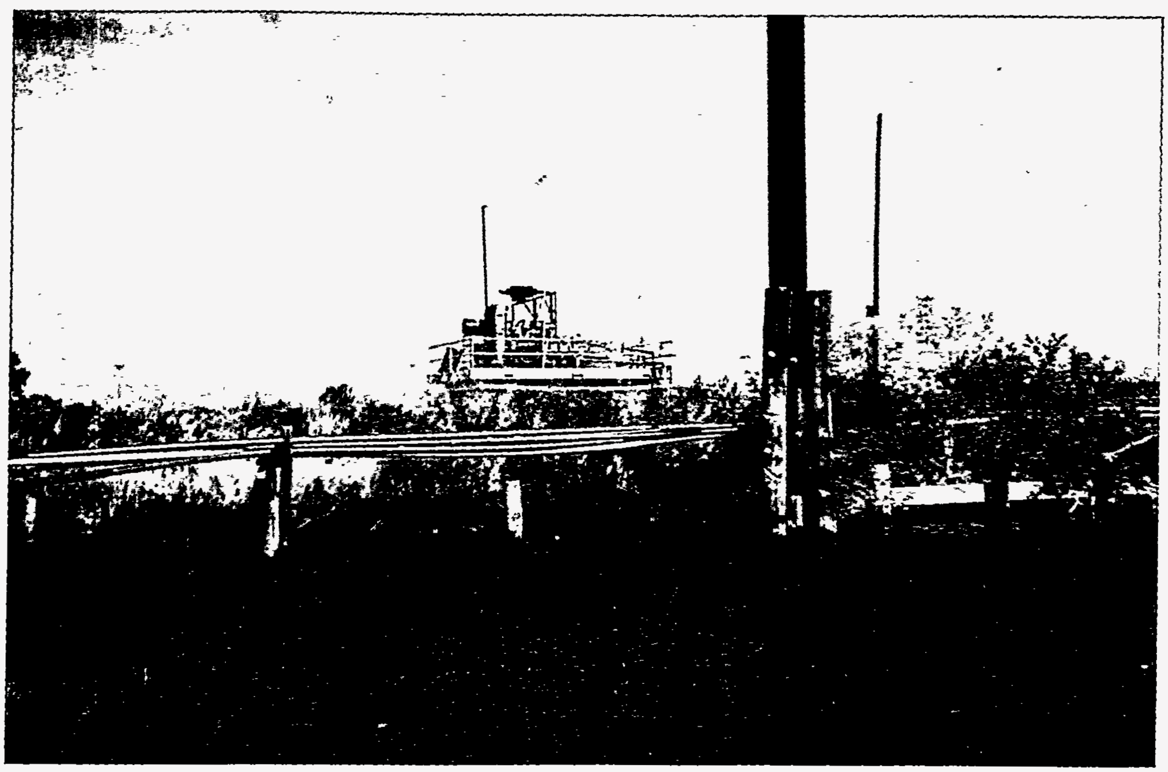
Project Development Photographs

Pipe Rack at Production Facility

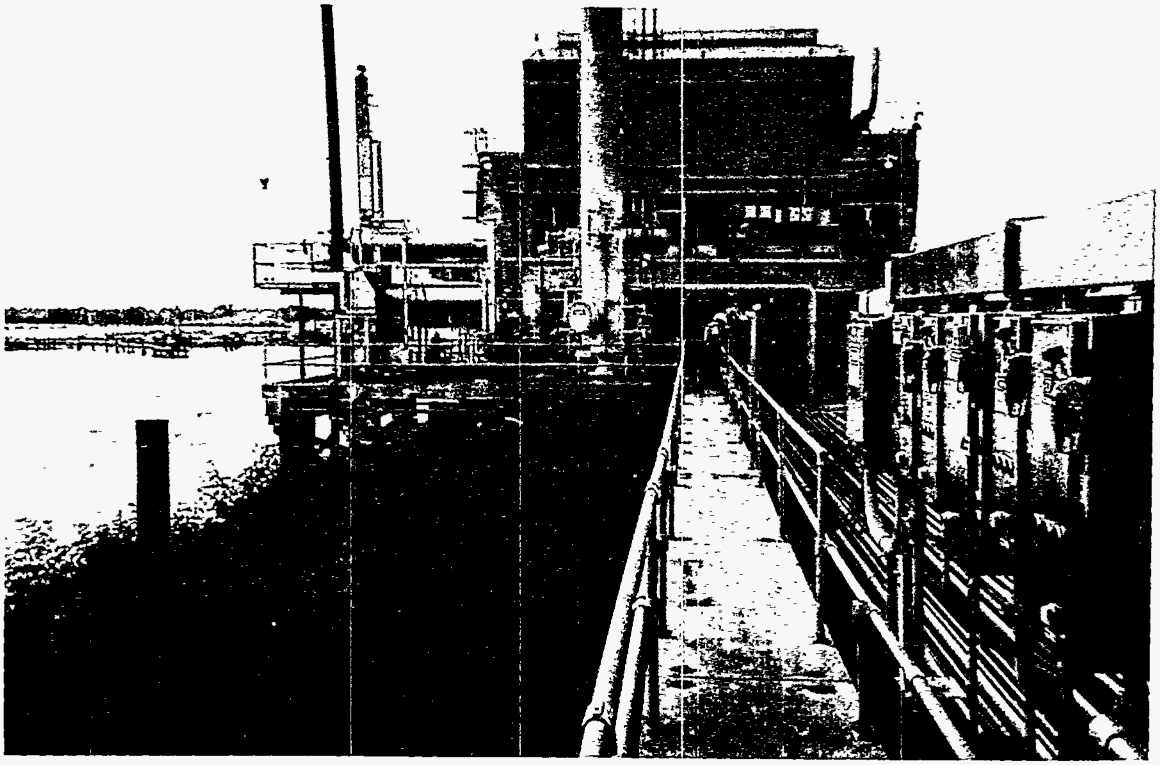
Storage Tanks



Distant View of Tank Battery and Compressor Station



Water Injection Pumps



Dehydration Tower

SPE/DOE 27758

Project Design of a CO_2 Miscible Flood in a Waterflooded Sandstone Reservoir

D.W. Davis, Texaco E&P Inc.

SPE Member

This paper was prepared for presentation at the SPE/DOE Ninth Symposium on Improved Oil Recovery held in Tulsa, Oklahoma, U.S.A., 17–20 April 1994.

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

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[6] 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.

REFERENCES

1. DOE/BC/10327-20, Scientific Software-Intercomp: *Development and Verification of Simplified Prediction Models for Enhanced Oil Recovery Application*. CO_2 (Miscible Flood) Predictive Model - Final Report, (Oct. 1984). Modified by Alston, R. B. et al (Texaco EPTD).

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_{om}	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

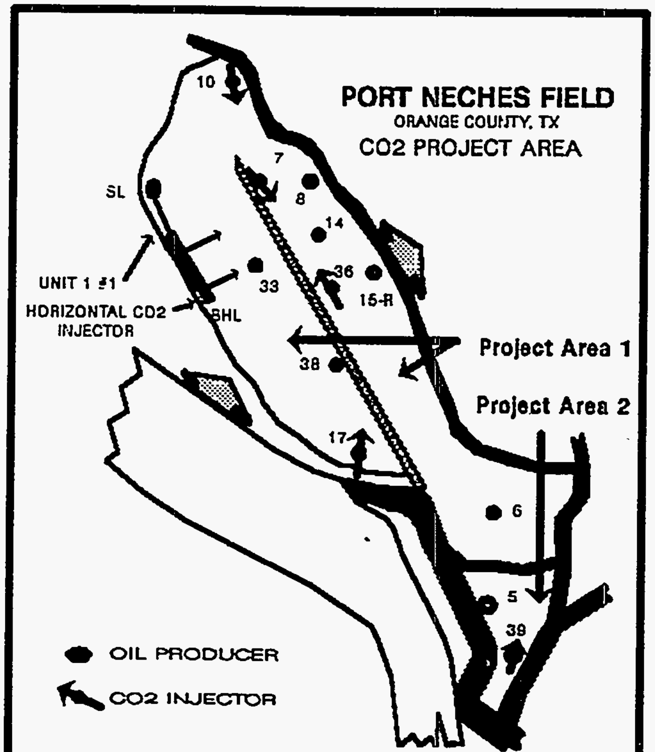


Figure 1 - Field Injection Pattern

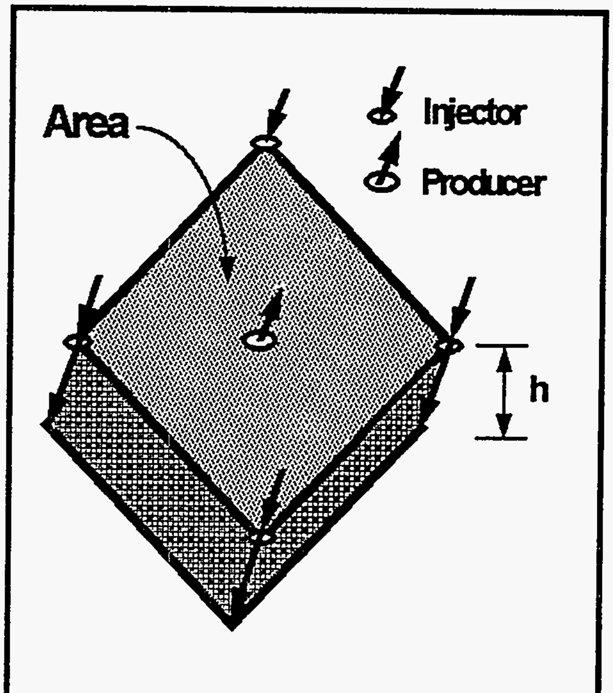


Figure 2 - Five Spot Injection Pattern

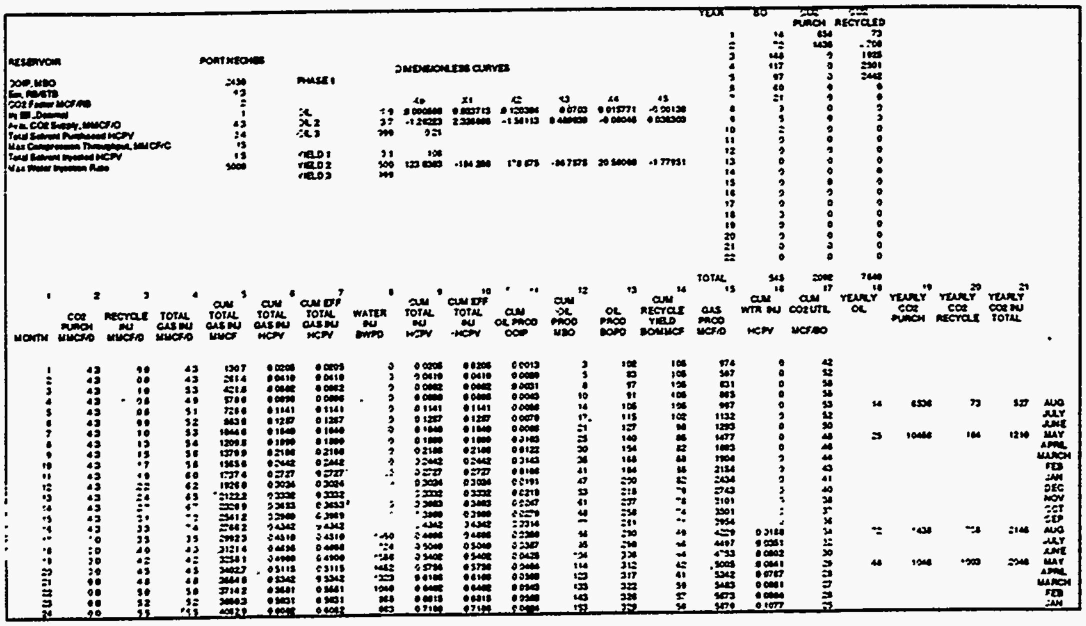


Figure 3 - CO_2 Recycle Volume Determination Spreadsheet

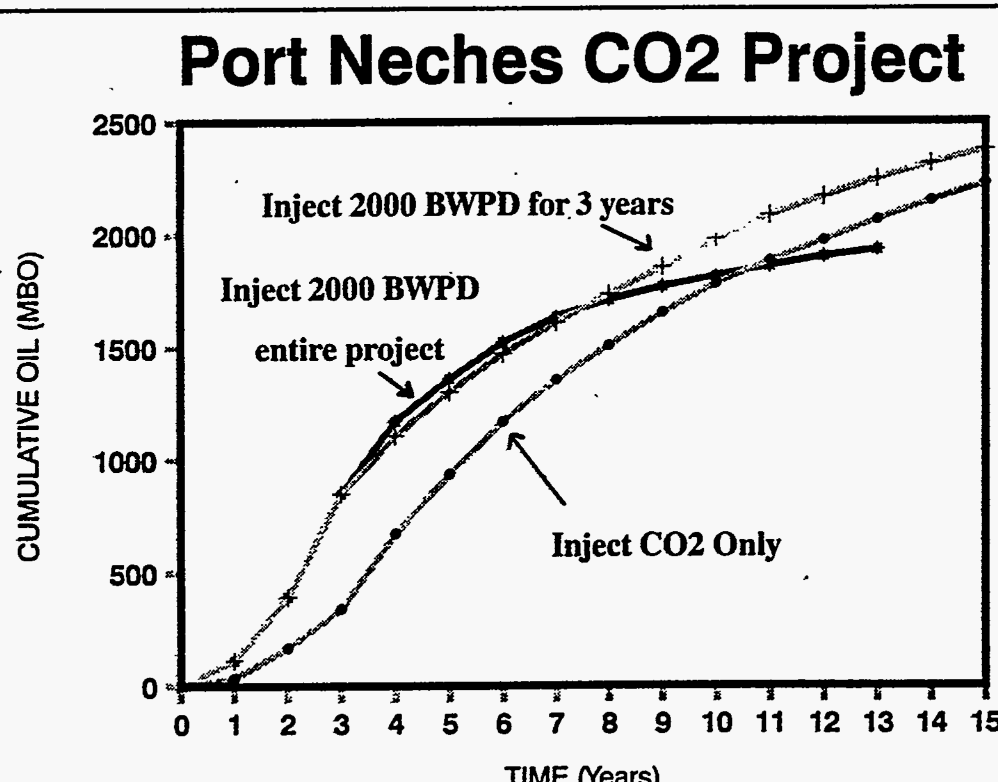


Figure 4 -Advantages of Water Injection

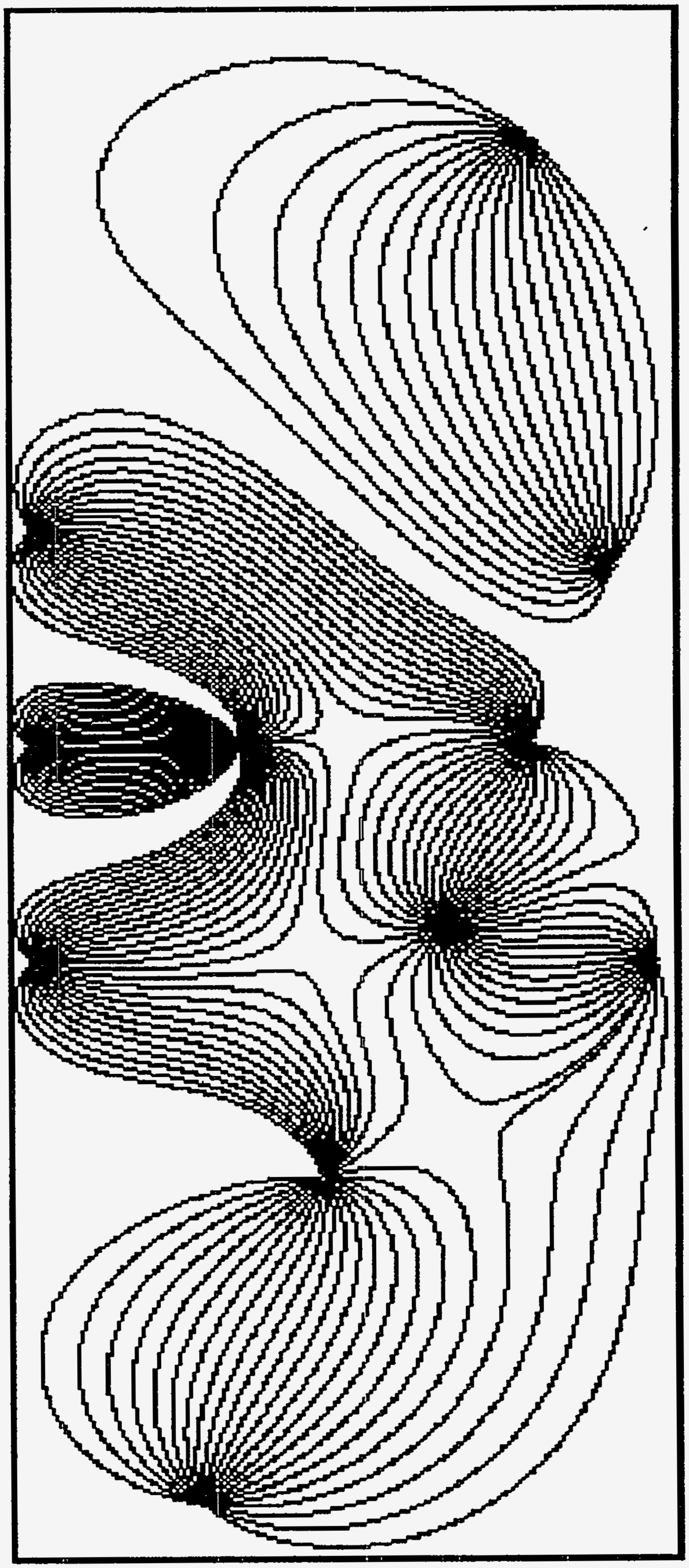


FIGURE 5

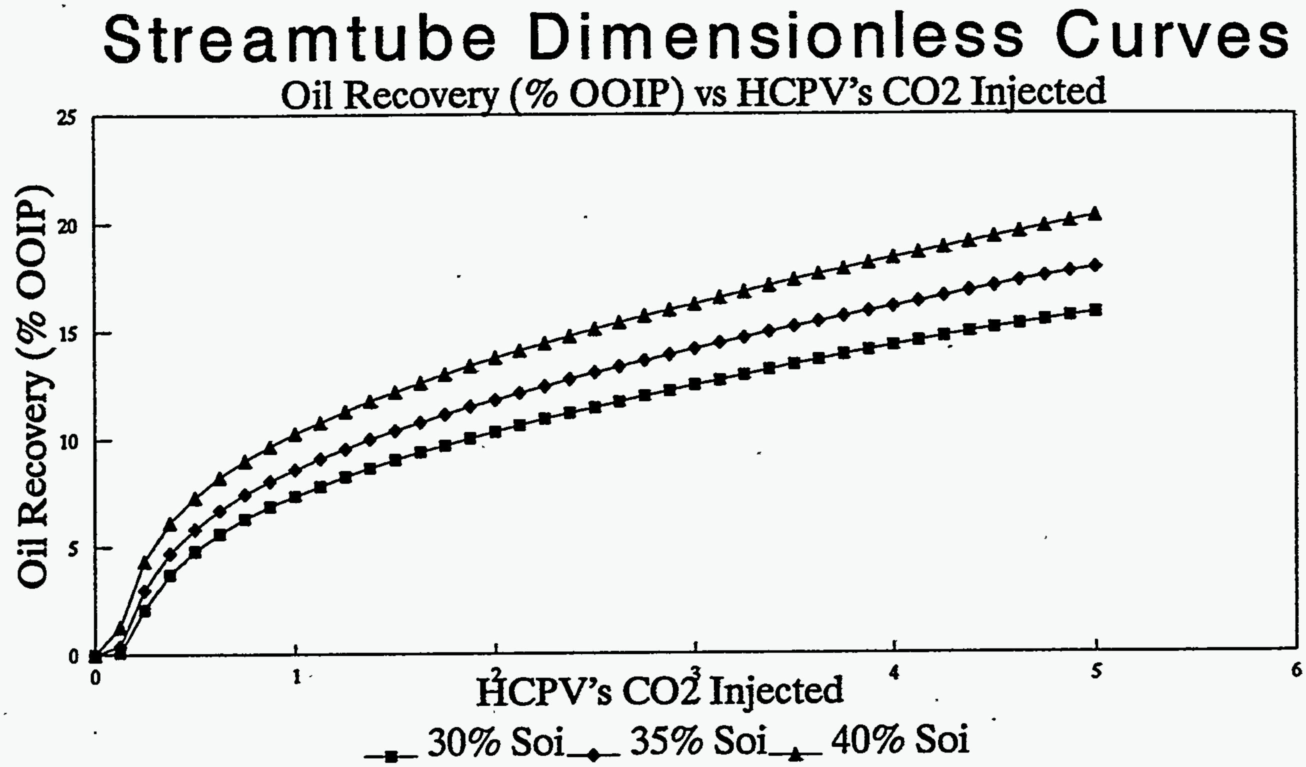


Figure 6. Streamtube Dimensionless Oil Recovery Curve versus HCPV's CO2 injected at varying initial oil saturation.

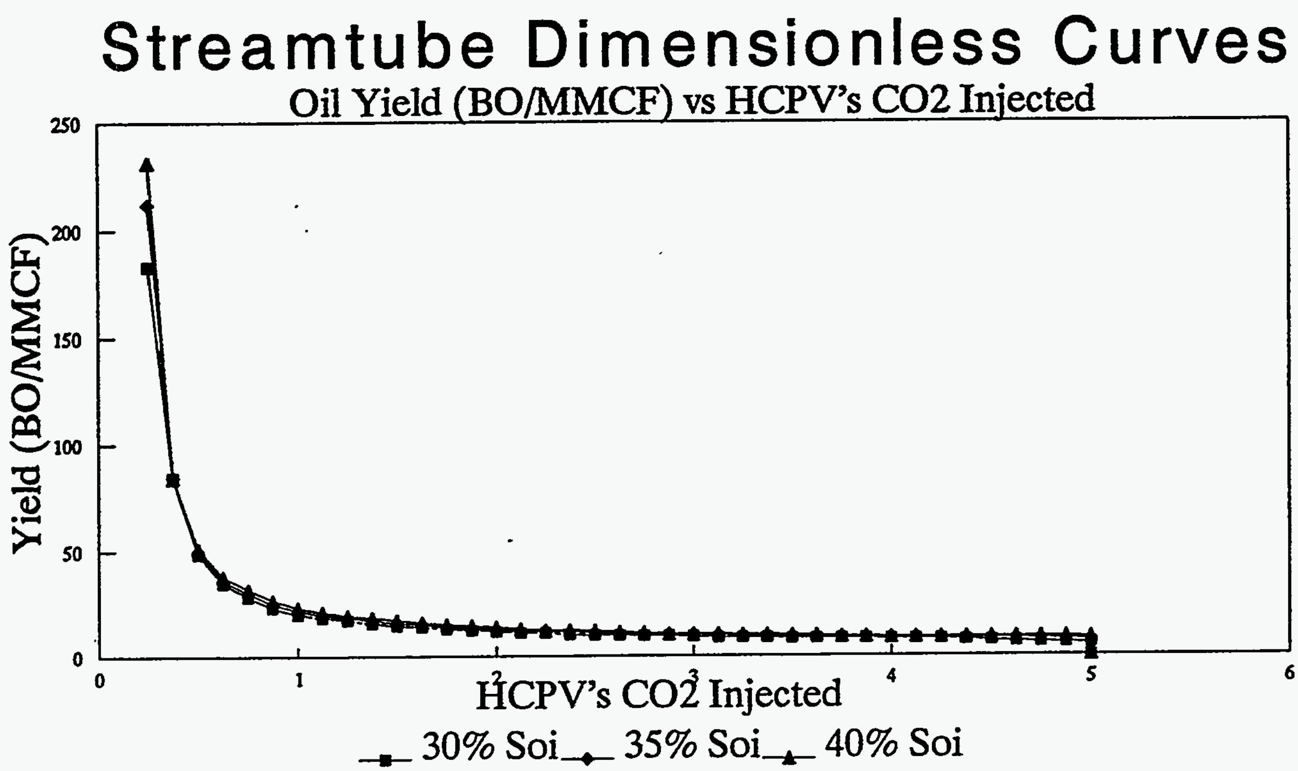


Figure 7. Streamtube Oil Yield Curve versus HCPV's CO2 injected at varying initial oil saturation.

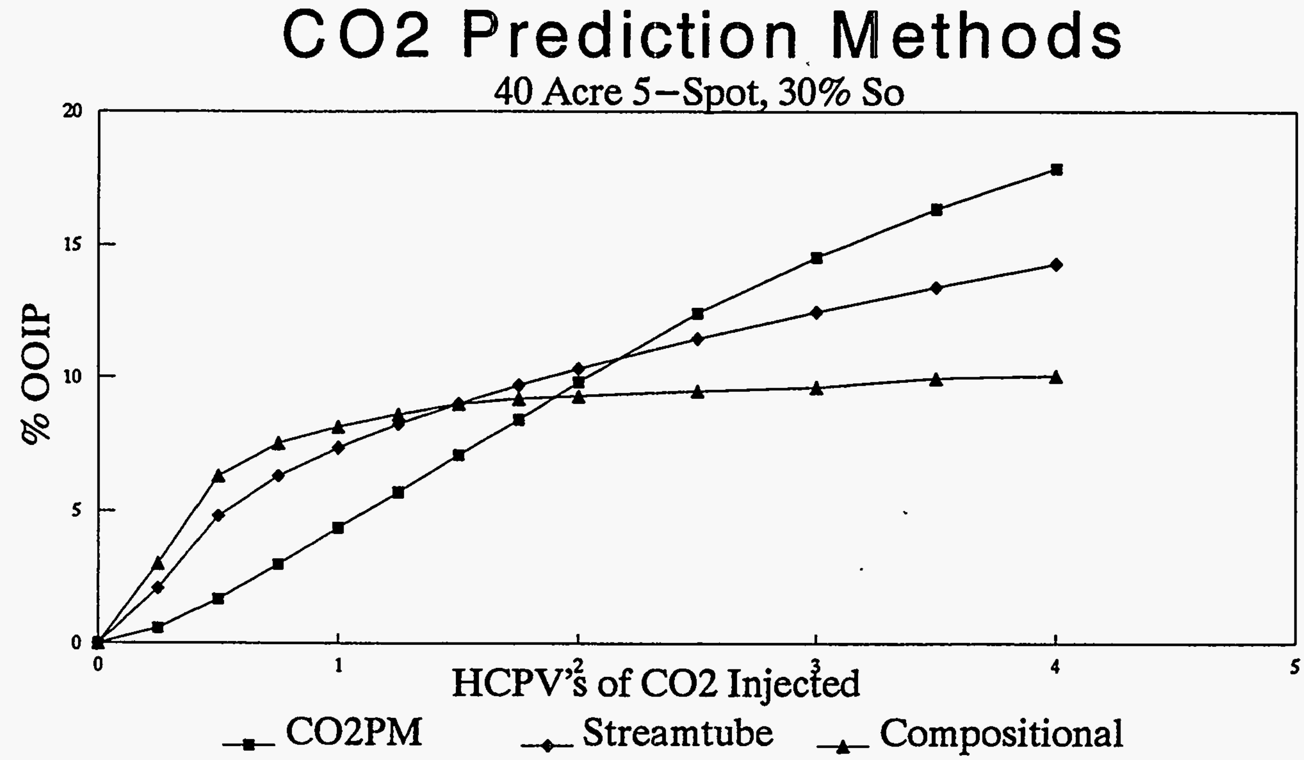


Figure 8. Comparison of Dimensionless Oil Recovery Curves versus HCPV's CO2 injected for three different models.

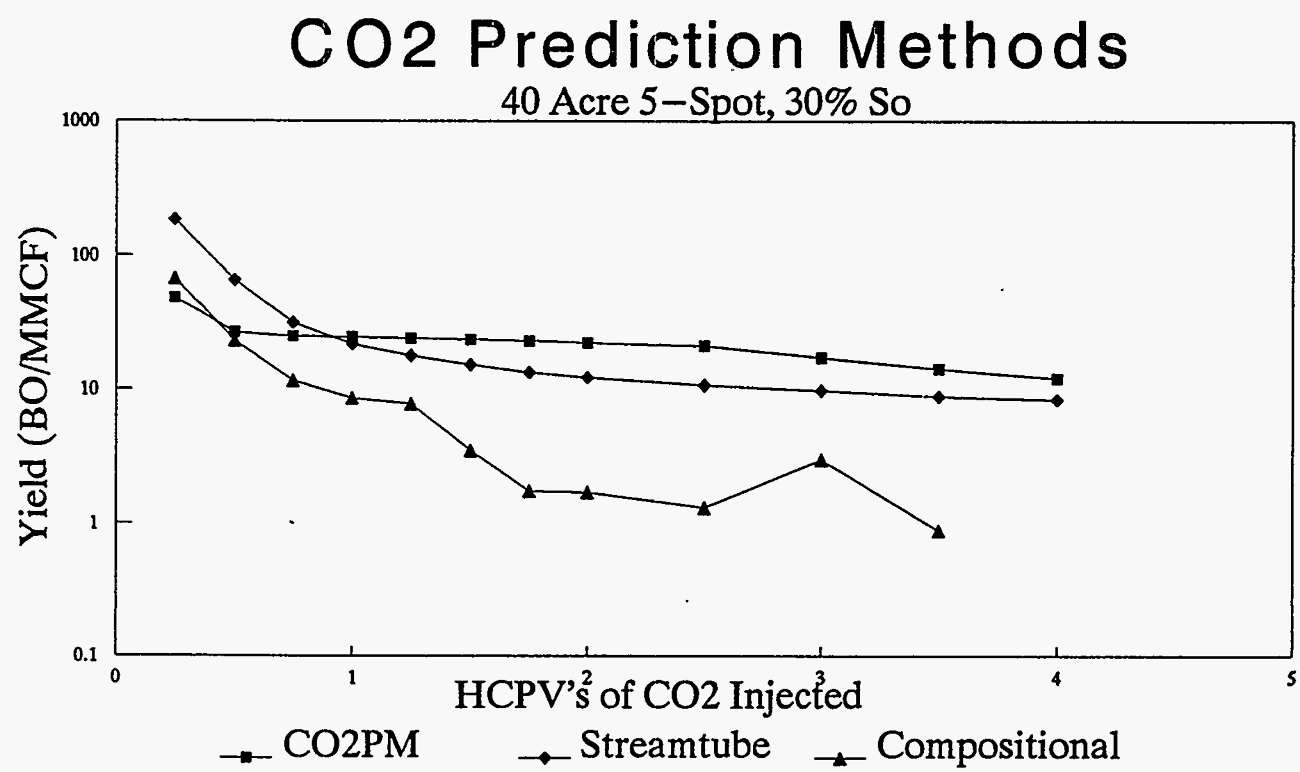


Figure 9. Comparison of Oil Yield Curves versus HCPV's CO2 injected for three different models.

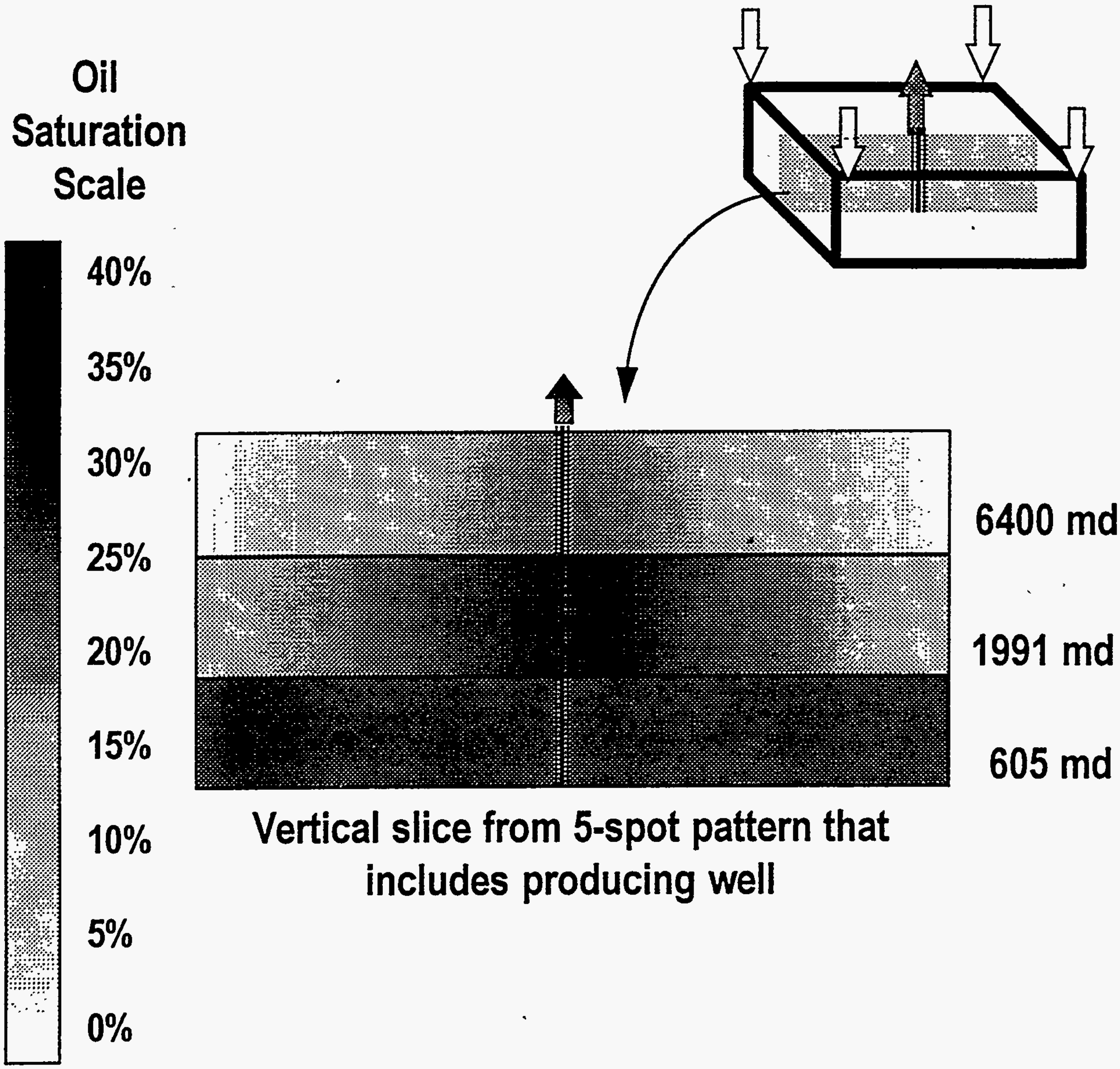


Figure 10 - Remaining Oil Saturation After CO_2 Injection

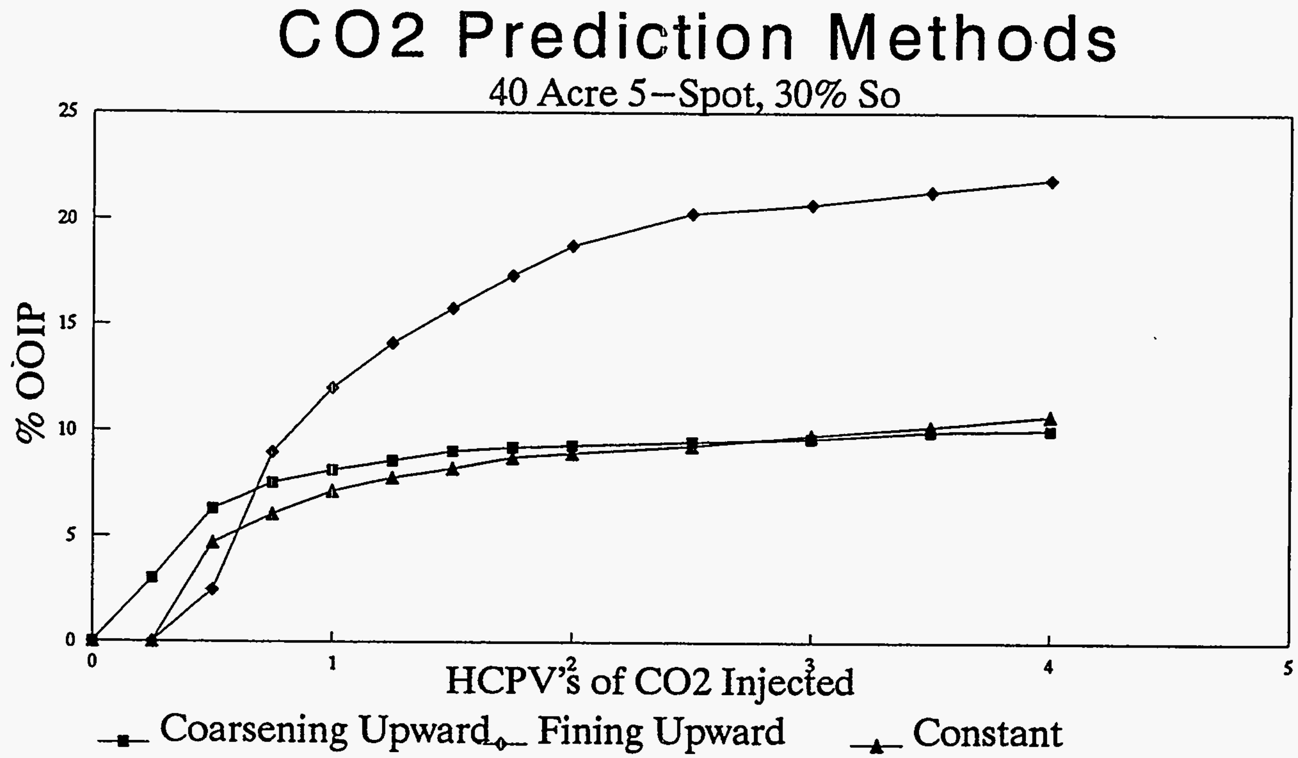


Figure 11. Oil Recovery versus HCPV's CO2 Injection for Five–spot Compositional model with permeability of layers varied.

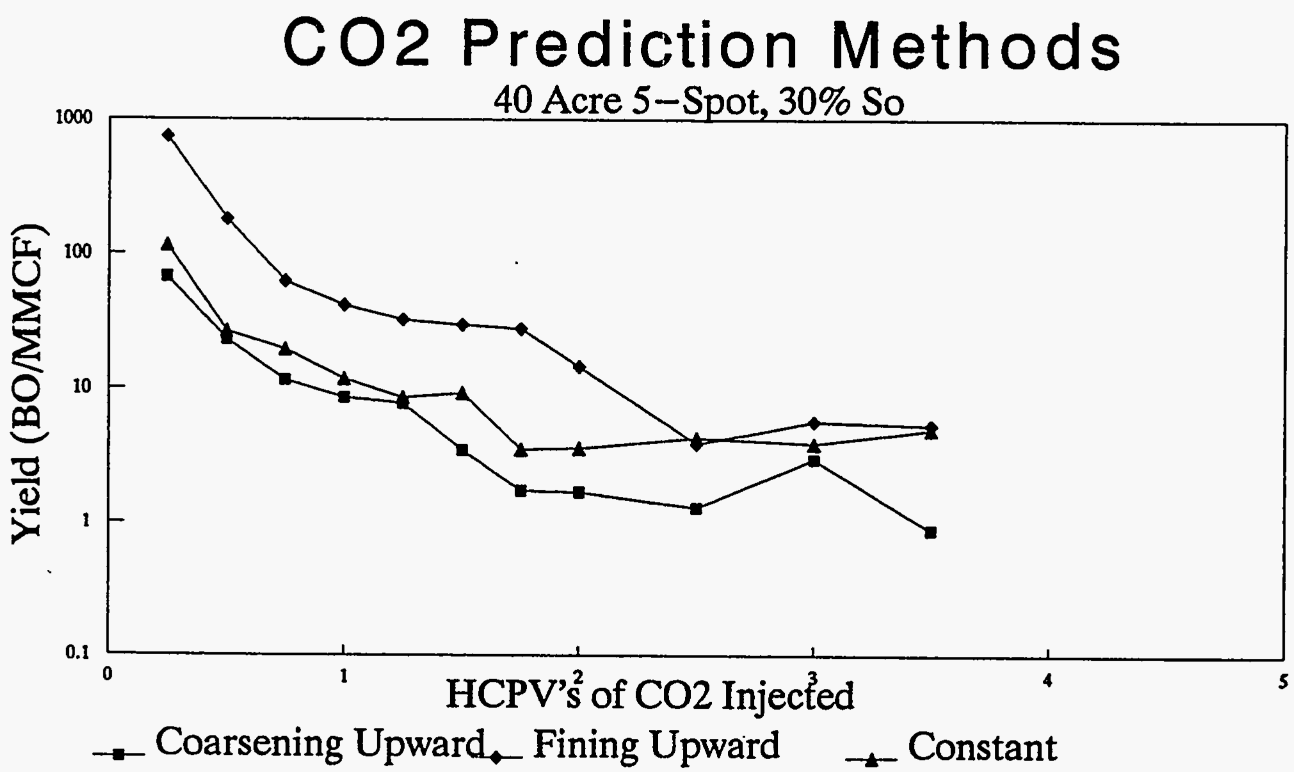


Figure 12. Oil Yield versus HCPV's CO2 Injection for Five–spot Compositional model with permeability of layers varied.

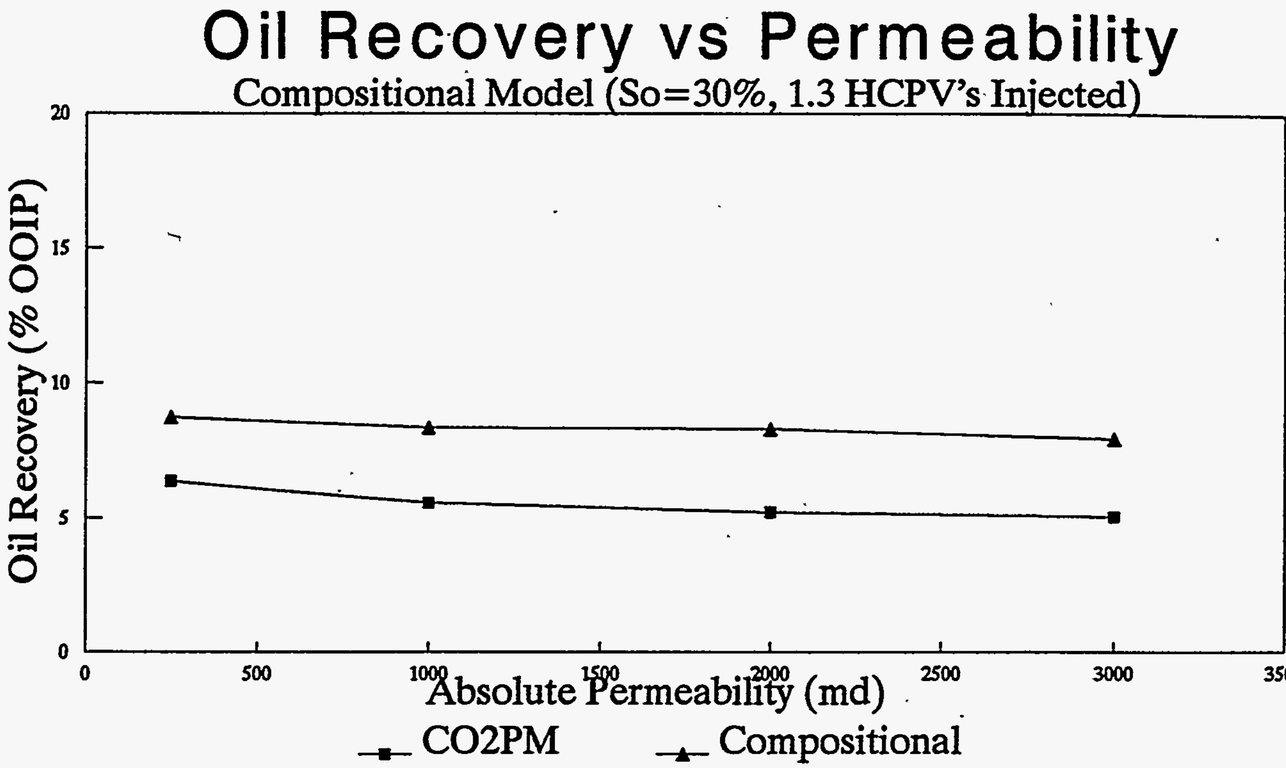


Figure 13. Oil Recovery after 1.3 HCPV's CO2 Injection versus Absolute permeability, as determined by Compositional Five-spot and CO2PM models.

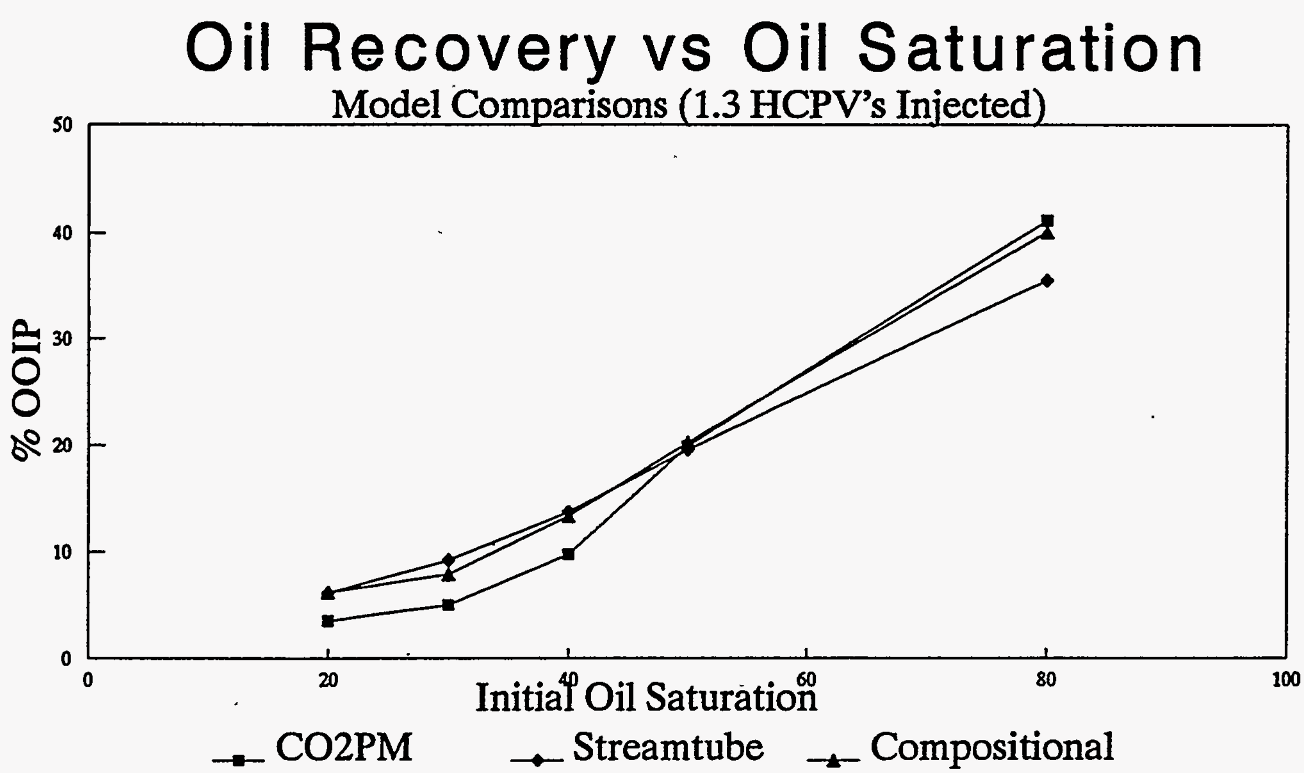


Figure 14. Oil Recovery after 1.3 HCPV's CO2 Injection versus Initial Oil Saturation, as determined by three models.

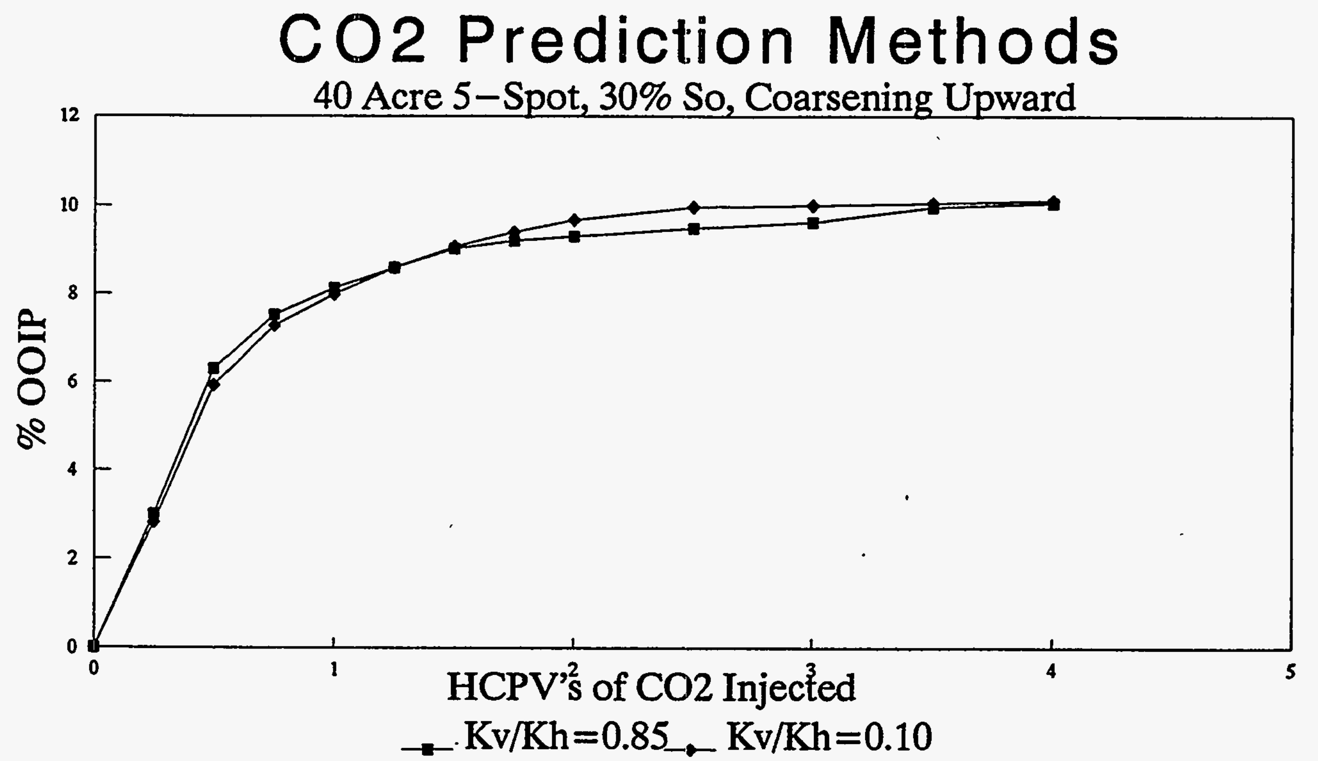


Figure 15. Oil Recovery versus HCPV's CO2 Injection for Five-spot Compositional model with vertical to horizontal permeability varied.

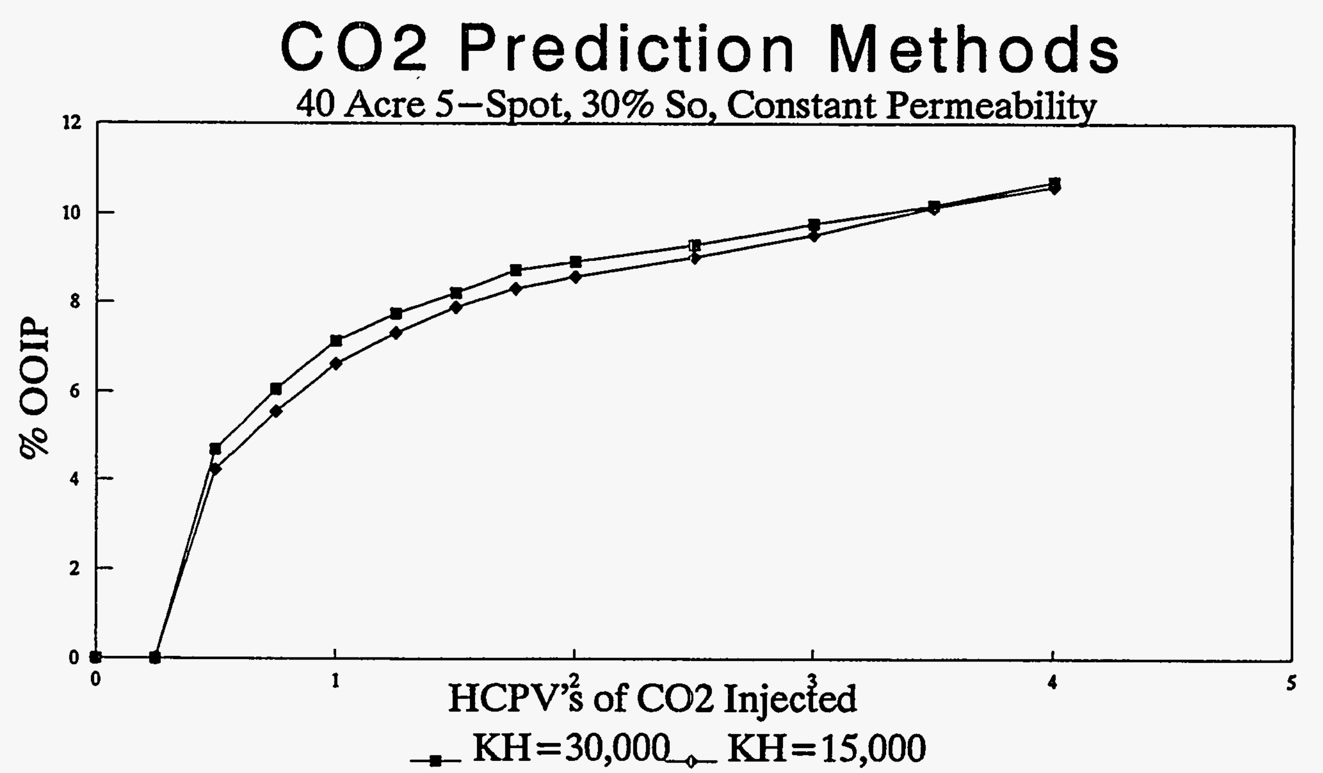


Figure 16. Oil Recovery versus HCPV's CO2 Injection for Five-spot Compositional model with varying KH values.

SPE/DOE 27750

A Stream Tube Model for the PC

J.K. Dobitz and John Prieditis, Texaco Inc.

SPE Members

This paper was prepared for presentation at the SPE/DOE Ninth Symposium on Improved Oil Recovery held in Tulsa, Oklahoma, U.S.A., 17-20 April 1994.

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

The authors thank Texaco Inc. and the Department of Energy for permission to present this paper (DOE Contract No. DE-FC22-93BC14960). The authors also wish to thank J. F. Stevens, J. W. Mueller, and, posthumously, R. B. Alston, who were instrumental in development of CO2-Prophet and R. J. Brugman for performing the compositional simulations.

REFERENCES

1. Todd, M. R. and Longstaff, W. J.: "The Development, Testing, and Application of a Numerical Simulator for Predicting Miscible Flood Performance," J. Pet. Tech. (July 1972) 874-82; Trans., AIME, 253.

2. Dykstra, H. and Parsons, R. L.: "The Prediction of Oil Recovery by Waterflooding," Secondary Recovery of Oil in the United States, 2nd ed., API, New York City, (1950), 160-174.

3. Chopra, A. K., Stein, M. H., and Dismuke, C. T.: "Predictions of Performance of Miscible Gas Pilots," paper SPE 18078 presented at the 63rd Annual Technical Conference and Exhibition, Houston, 1988.

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.

5. Willhite, G. P.: *Waterflooding,* SPE Textbook Series, Richardson, TX (1986) 3, p. 129.

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

7. Prieditis, J. and Brugman, R. J.: "Effects of Recent Relative Permeability Data on CO2 Flood Modeling," paper SPE 26650 presented at the 68th Annual Technical Conference and Exhibition, Houston, 1993.

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

	Gas to oil endpoint relative permeability ratio.			
Model	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

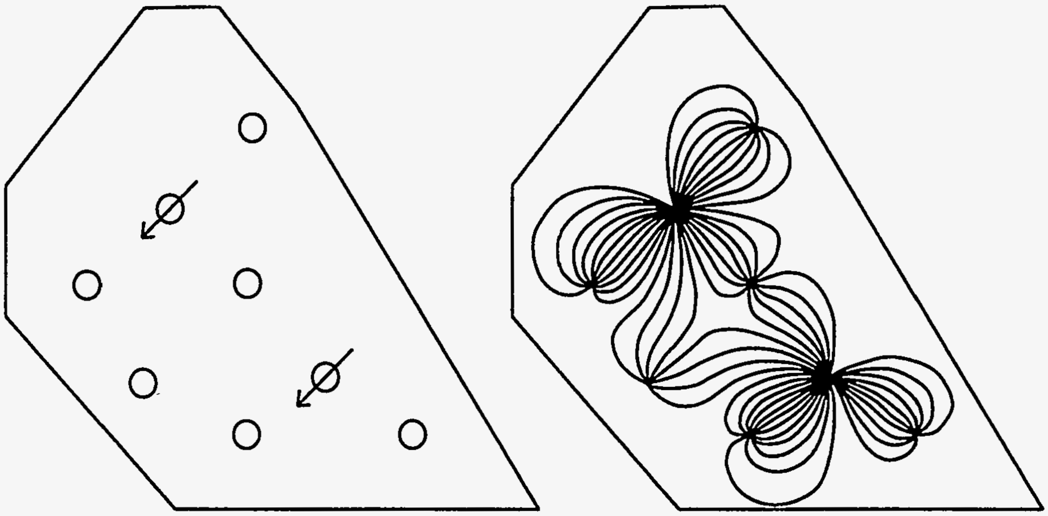


Figure 1. Example pattern and streamlines generated by CO2-Prophet.

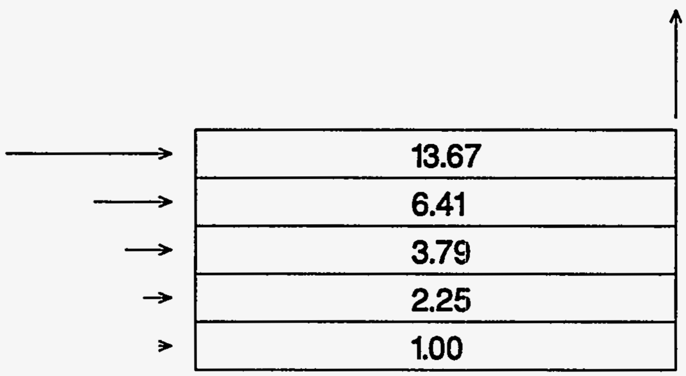


Figure 2. CO2-Prophet initial relative injectivity resulting from a Dykstra-Parsons coefficient of 0.7.

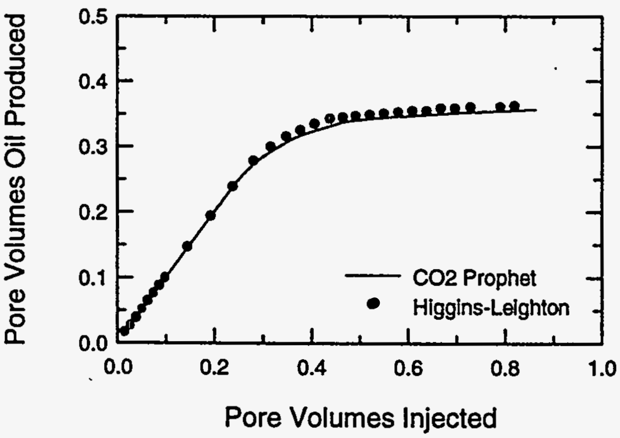


Figure 3. Comparison of CO2-Prophet with Higgins-Leighton model.

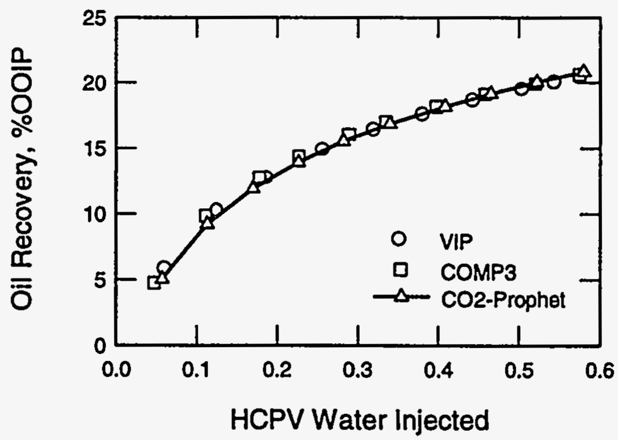


Figure 4. Waterflood comparison between VIP, COMP3, and CO2-Prophet.

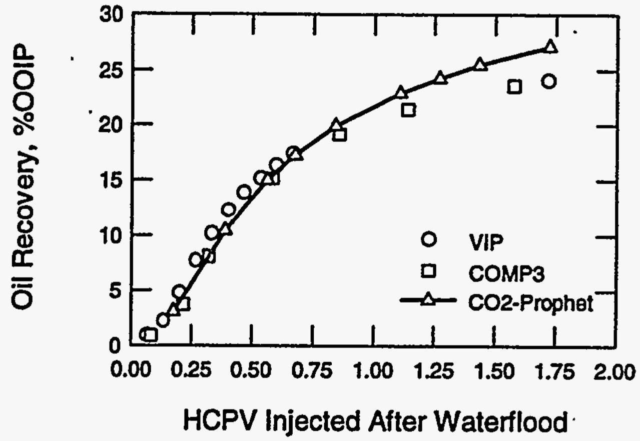


Figure 5. Comparison of CO2-Prophet with VIP and COMP3, 1:1 WAG, cummulative oil production.

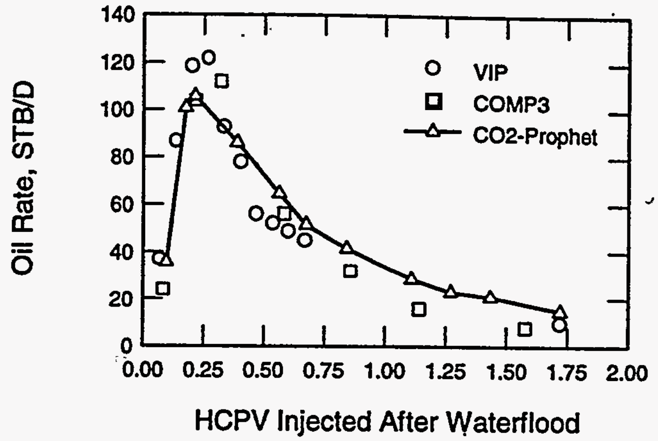


Figure 6. Comparison of CO2-Prophet with VIP and COMP3, 1:1 WAG, oil rate.

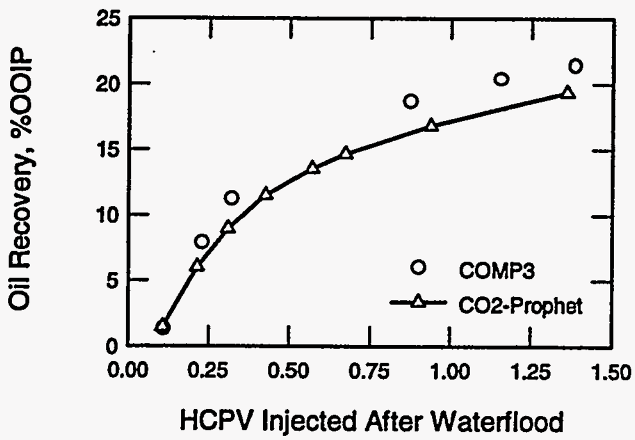


Figure 7. Comparison of CO2-Prophet with COMP3, continuous tertiary CO2 flood.

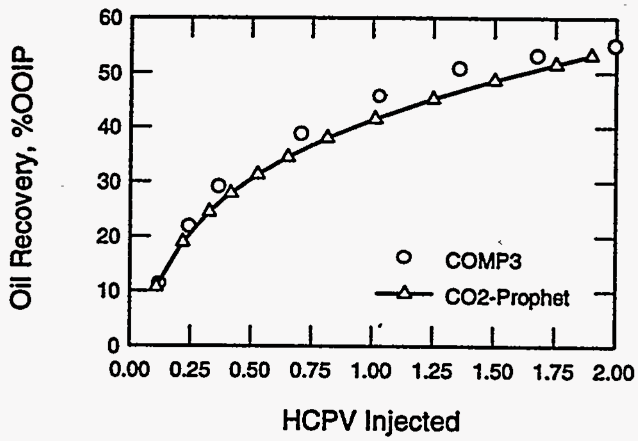


Figure 8. Comparison of CO2-Prophet with COMP3, continuous secondary CO2 flood.

☆U.S. GOVERNMENT PRINTING OFFICE: 1995 - 660-029/20048